BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-61:
2023 ERP Phase II Modeling Assumptions

Colorado PUC E-Filings System

Modeling Assumptions

The following table and discussion identify the modeling assumptions to be used in Phase I of Tri-State's 2023 ERP.

Table 1: Modeling Assumptions

Category	Assumption	Description of Modeling Input
Financial	Electric and Gas Forward Curves, and Transport Cost	• Horizon[1] 2023 Spring Forecasts for electric and gas forward curves • Transport adders based on interstate gas provider rates
	Coal Forward Curve	March 2023 forecast in real and nominal dollars
	Capital Expenditures and Fixed O&M	Tri-State 2023 O&M Budget and 10-Year Capital Plan
	Variable O&M	2023 O&M Budget of thermal resource VOMs
	Annual Inflation Forecast	Annual inflation projections as of February 2023
	Depreciation Costs and Schedules	2023 Depreciation Study will inform the rate that existing assets are depreciated in the financial modeling
	Renewable and Storage Generic Resource Prices – PPAs and Build Transfers	Updated based on 2020 ERP Phase II bid responses, IRA impacts, latest PTC/ITC, and $1/MWh Wyoming Wind Tax
	Gas Generic Resource Build Prices	B&V reviewed and refreshed generic gas pricing
	Innovative Technology Pricing	Newly added resource types and modeling assumptions (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.)
	Resource Integration Adder (Ancillary Service Costs)	Generic resources (as applicable) as follows: WCO, WY-WNE, and ECO updated with WACM; and NM updated with PNM
	Discount Rate / Weighted Average Cost of Capital (WACC)	Updated to 4.12%
	LRS 2 & 3 Retirement Cost Profile	Reflects continuation of fixed and capex costs through useful life
	Springerville Unit 3 (SPV 3) Retirement Cost Profile	Financing and equity partner penalties applicable if unit retired early
	Craig Station Decommissioning Cost	Reflects third-party cost estimate, and Tri-State's share of the cost
	Book Life for Generic Li-Ion Batteries, Renewables, and Gas	Use of book life assumptions for each generic resource and useful life for each existing resource
	Third Party Transmission	• Reflects network and firm point to point transmission available between planning regions

[1] Horizons Energy is a data and analytics consulting company providing market price forecasts for the energy industry. See: https://www.horizons-energy.com/market-price-forecasting/.

		• Added ability to procure additional transmission between planning regions as available at a cost.
Operational	CRSP Hydro Forecast	Forecasted capacity from CRSP hydro contract reflects continued reduction through the planning period due to drought.
	Load Forecast	Forecast as of Summer 2022 with United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025
		Partial Requirements Contracts for May 2021 and May 2022 Open Seasons (excluding Mountain Parks) included as applicable load reductions beginning January 2026
	Beneficial Electrification	Achievable-Moderate level from 2023 BE Potential Study[2]
	Distributed Generation Forecast	Forecast of Member DG as of March 2023 with appropriate Member exits (United Power and Mountain Parks)
	Constraints	Updated constraints on new resource builds and transmission interconnection
	Level I & II Reliability Metrics	Scenarios were modeled to meet minimum Level I and II reliability requirements
	Thermal Build Constraint	No thermal builds allowed before 2028
	Gas Retirement Constraint	No gas resources allowed to retire
	Coal Unit Uptime	Uptime minimum 12 hours
	Coal Unit Downtime	Downtime minimum 8 hours
	Craig 3 Modeling	Craig 3 is modeled in ECON mode
	Craig Unit Retirements	• Craig Units 1 and 2 retirements are modeled to occur on the announced dates. • Craig Unit 3 is modeled to retire between 2028-2029.[3]
	Tri-State Exit MBPP[4]	Allowed in modeling beginning January 1, 2027
	SPV 3 Retirement	Allowed in modeling beginning January 1, 2037
	SPV 3 Max Capacity	SPV 3 rerated to 419 MW per 2022 testing
	Effective Load Carrying Capability (ELCC)	Based on third-party study
	Scheduled Outages	Planned outage schedules updated for all thermal units
	Forced Outage Factors	Applied unit-specific rates based on 5 years of historical data from GADs. Updated forced outage method in dispatch runs to have random outage days instead of a derate.
	Modeling of Market Sales and Purchases Depths	• Market sales and purchases hourly depth updated. • Values are reflective of:

[2] Attachment G-3 of the ERP Report (LKT-1)
[3] Also see Attachment B-3 of the ERP Report (LKT-1) for unique scenario assumptions.
[4] Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP") – see written information regarding this modeling assumption below.

		○ Member exits ○ Moving WACM load (WY/WNE, WCO and a portion of ECO) to SPP RTO in April 2026 ○ Remainder of ECO load and all NM load to RTO by 2030.
	Modeling of Term Sales	Known and anticipated term sales opportunities are reflected in modeling
	Modeling of Proxy Sales	Anticipated capacity and energy sales opportunities are reflected in modeling
	Generic Resource Availability	The model will be able to select generic resources starting in as soon as 2026, depending on lead time of each technology
	PPA and Contract Information	Updated latest known COD and reflect any updated terms
	SRP Contract	Model based on market optimization
	System Loss Factor	NM region losses are financial; updated ECO, WCO and WY/NE to 3.5%
Demand-Side Management	Demand Response	DR Target (4% of load) modeled for ECO and WCO; Tri-State DR Program Levels selectable for NM and WY
	Energy Efficiency (EE)	EE Targets modeled for ECO and WCO; Achievable-Low NM and Low WY allowed for model to select and updated per Mesa Point 2023 DSM Potential Study[5]
Environmental	Emissions and Water Use Rates	Updated generator emission and water use rates per TS Environmental and eGrid 2021 rates, as applicable. Thermal resource rates were provided by B&V, while rates for innovative technologies were sourced from public resources.
	Emissions Reduction Targets	26% in 2025 36% in 2026 46% in 2027 80% in 2030
	APCD Workbook Inputs and Resource, Market & Contract Emissions Rates	*2005 Emissions Baseline:* Updated to reflect Partial Requirements Contracts and Member Exits
		Market & Contract Emissions Rates:[6] Generator Resource emission rates updated per TS Environmental. Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates; Basin Western Interconnection contract proxy emission rate is updated to LRS rate for 2025 and 2021 eGRID rate for 2026 to 2029. Market purchase and

[5] May 2023 "Addendum to 2020 Demand-Side Management and Energy Efficiency Potential Study."
[6] Settlement Agreement section 3.11.3. "…Tri-State will use published system, region or market rates as applicable and consistent with APCD regulations and guidance for unspecified source market and contract purchases…" and section 3.11.4. "…Tri-State will convene a meeting before the next ERP to discuss the emissions rate for unspecified energy purchases…" That meeting was held on August 16, 2022.

		sales updated to 2021 eGRID RMPA and AZNM rates as applicable.
	Social Cost of Carbon	As of February 2021 IWG[7] @ 2.5% discount rate
	Social Cost of Methane	As of February 2021 IWG @ 2.5% discount rate

Financial

Electric and Gas Forward Curves, and Transport Costs

Tri-State has updated the electric and gas forward curves using Horizons Energy's Spring 2023 Advisory Reference Case results. The Advisory Service provides fundamental analysis of electricity markets. Horizons Energy produces the EnCompass National Database for developing fundamental prices of the electricity markets including fuel and energy throughout North America related to integrated resource planning. Horizons Energy used Henry Hub gas forward prices from Natural Gas Intelligence through December 2023 and then trended forward through 2050. Cheyenne Hub forecasted basis is used for CIG and Waha forecasted basis is used for Waha fuel curves. Horizons Energy electric forward curves are provided for the four WECC areas of Eastern and Western Colorado, New Mexico, and Wyoming. Tri-State forward price curve blends all four areas equally for an average hourly market price through 2050. Monthly forward price curves are modeled in real 2023 dollars.

Figure 1 represents the electric forward curve data in real (2023) dollars for the resource planning period (RPP):

Figure 2 represents the gas forward curve in real (2023) dollars.

[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[redacted]

Table 1 summarizes the additional transport costs and forward curves associated with each gas generating unit:

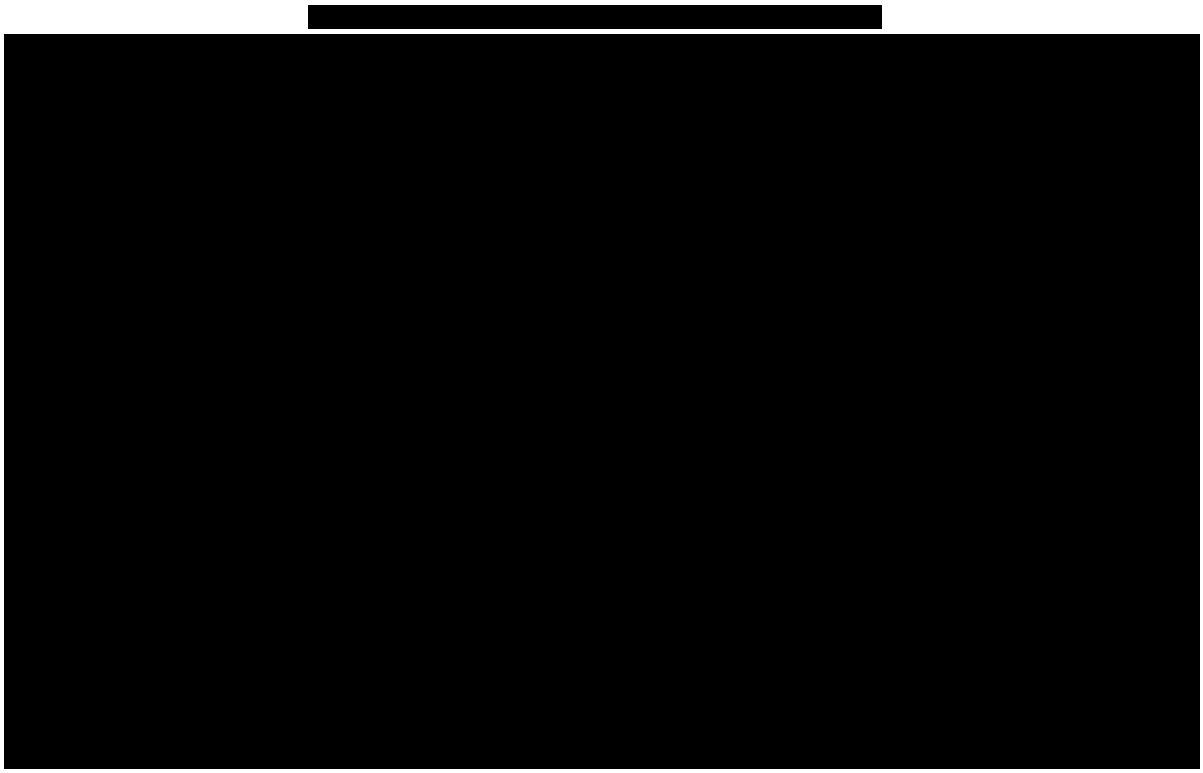
Table 1: Transportation Costs & Fuel Forward Curve for Gas Resources

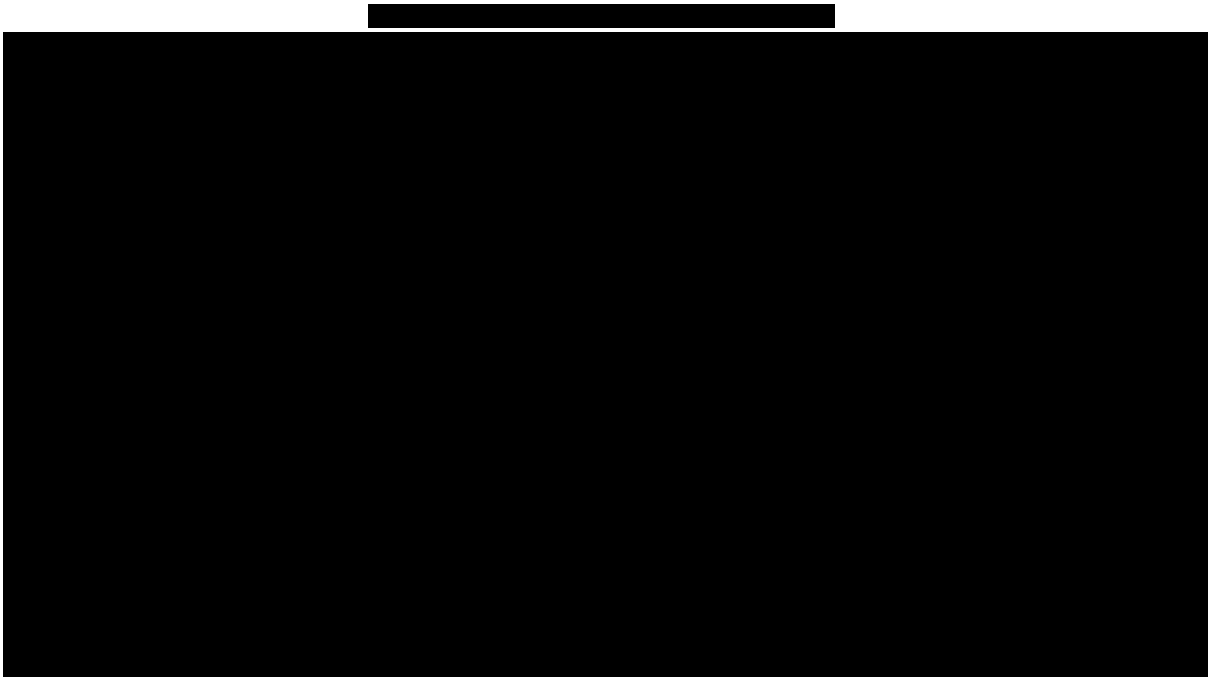
Existing Gas Plant	[redacted]	Forward Curve
Limon	[redacted]	CIG
Knutson	[redacted]	CIG
Pyramid	[redacted]	Waha
JM Shafer	[redacted]	CIG
Generic Gas Resources – CO & WY	[redacted]	CIG
Generic Gas Resources – NM	[redacted]	Waha

Coal Forward Curve

Tri-State's forward coal prices change at least annually. The coal price forecast, including rail delivery fees (or "freight"), are used in EnCompass and in the final PVRR analysis in UIPlanner. Tri-State updated the Craig coal forward curve in March 2023. [redacted]

[redacted]





Capital Expenditures and Fixed O&M

Tri-State forecasts capital expenditures based on actual planned or expected projects. Tri-State updated its capital expenditure forecast for use in the modeling.

[redacted][9]

[redacted]

Tri-State also reviews historical data for O&M costs and incorporates known changes impacting future O&M costs to produce an annual forecast of O&M costs. Tri-State utilized its O&M forecast to derive a new fixed O&M forecast for use in the modeling.

[redacted]

[redacted]

Variable O&M

The variable O&M (VOM) reflects the latest average VOM calculated by Tri-State Generation Engineering for the units. Use of the most recent average VOM results in [redacted]

[9] Axial Basin and Dolores Canyon solar resources are not yet operational; therefore, no capital expenditures have been forecasted. Initial capital construction cost is reflected in the financial analysis.

[redacted] Other units' average VOM costs remained relatively consistent with values used in previous modeling.

[redacted]

Annual Inflation Forecast

Tri-State's financial planning and analysis team applies an assumed rate of inflation to adequately budget fixed costs and modeled capital and O&M expenditures used in ERP modeling throughout the resource planning period. The escalation rate is 2.5% in 2024, 2.2.% in 2025, 2.30% in 2026 and 2027, and 2.15% thereafter.

Depreciation Costs and Schedules

Depreciation costs and schedules for existing resources were modeled based on Tri-State's 2023 Generation Plant Depreciation Study completed in May 2023. Also see Attachment C-3 of the ERP Report (Attachment LKT-1). Generic resource modeling assumptions, including book life and operating life, can be found in Attachment C-2.

Renewable and Storage Generic Resource Prices – PPAs and Build Transfers

Tri-State's consultant, CDG, updated the forward price curves for generic renewable, and hybrid resource Power Purchase Agreements (PPAs) as well as renewable build-transfer and standalone storage build costs reflect updated capital and operating expense forecasts, Inflation Reduction Act (IRA) tax credit additions and extensions (production tax credits (PTC) and investment tax credits (ITC)), 2020 ERP Phase II pricing, and, for generic wind in Wyoming, the Wyoming $1/MWh "Wind Tax" is included.

Gas Generic Resource Build Prices

In 2023, Black & Veatch (B&V) reviewed and refreshed generic gas pricing assumptions for the ERP. The assumptions can be found in Attachment C-2: Generic Resources Summary.

Innovative Technology Pricing

Per the 2020 ERP Phase I Settlement Agreement,[10] Tri-State added new generic resource types (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) with associated pricing and technology assumptions, as identified in Attachment C-2: Generic Resources Summary.

Resource Integration Adder (Ancillary Service Costs)

Integration Adders are modeled to reflect the ancillary service cost for generic resources in the Balancing Authority Area (BAA) operating in each Tri-State planning region. The adders were updated to reflect 2023 pricing and were applied in the modeling are as follows:

PNM (NM):

- No extra intermittent resource specific charges

WACM (WCO, WYO-WNYE, and ECO):

- Wind: Schedule 3 Regulation $0.4293/kW month
- Solar: Schedule 3 Regulation $0.8427/kW month

Discount Rate

Tri-State's weighted average cost of capital (WACC), or discount rate, as of February 2023 was 4.12%. For comparison, Tri-State's WACC was 4.18% in 2020 ERP Phase II and 4.15% in 2020 ERP Phase I.

LRS 2 & 3 Retirement Cost Profile

Tri-State's portion of the fixed O&M and capital expenditures for Laramie River Station (LRS) Units 2 and 3 are reflected in the financial analysis for each scenario as a sunk cost, continuing through each unit's useful life. Given that these costs are a contractual obligation, they are not an avoidable cost in the expansion plan modeling.

Springerville Unit 3 Retirement Cost Profile

Springerville Unit 3 (SPV 3) retirement cost profile reflects the latest estimated calculation of the following [redacted]

- [redacted]
- [redacted]
- [redacted]

The SPV 3 retirement cost profile still does not reflect potential penalties or costs associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which could occur under an early retirement scenario, but continue to be unknown at this time.

[10] Section 3.11.15 of Attachment A of the Unopposed Comprehensive Settlement Agreement, filed January 18, 2022 in Proceeding No. 20A-0528E.

Craig Station Decommissioning Cost

The cost for decommissioning Craig Station was updated in the financial modeling, replacing the previous internal estimate with an estimate that reflects a third-party quote. The decommissioning cost was also updated to reflect Tri-State's share of the cost.

Book Life for Generic Li-Ion Batteries, Renewables and Gas

Generic resources' book life assumptions are identified in Attachment C-2. Useful life of existing resources is identified in Attachment C-3.

Third Party Transmission

All available third-party transmission between planning regions, whether network or purchased long term firm point to point transmission, is included in the model and associated sunk costs are included in the financial model. Also included in the dispatch model is the option to purchase:

- up to 133 MW of hourly transmission at PSCO's Open Access Transmission Tariff (OATT) rate as needed for additional transfers from ECO to NM;
- up to 76 MW of third-party transmission at CRSP's OATT rate from ECO to WCO at an incremental cost; and
- up to 100 MW of third-party transmission at PNM's OATT rate from NM to ECO at an incremental cost.

Operational

CRSP Hydro Forecast

Energy and capacity profiles for Colorado River Storage Project (CRSP) contracts through the RPP are at normal levels, for the following regions: CRSP ECO, CRSP NM, CRSP WCO. This assumption is in light of the U.S. Bureau of Reclamation's May 2023 projection[11] for the Colorado River system of a 0% probability of minimum power pool through 2027 along with recent improvements in near term hydro allotments.

Load Forecast

The load assumptions used in the modeling are based on Tri-State's latest finalized long-term load forecast produced in June 2022. The methodology used for load forecasting is outlined in Attachment F of the ERP Report (LKT-1). Adjustments were made to the forecast to reflect Member exits,[12] Partial Requirements contract load reductions, Colorado energy efficiency, system-wide beneficial electrification for the Tri-State system, and member distributed generation.

Member exits assumed include the following:

- United Power exiting May 1, 2024;
- Northwest Rural Public Power District (NRPPD) exiting May 1, 2024; and

[11] https://www.usbr.gov/lc/region/g4000/riverops/crss-5year-projections.html

[12] Paragraph 63 of Decision No. C23-0437, issued in Proceeding No. 20A-0528E, directed Tri-State to "…submit a load forecast that is indicative of anticipated member departures at the time of filing…"

- Mountain Parks exiting February 1, 2025.

Tri-State is no longer planning its system or acquiring resources to serve the load and reliability needs of these three Members, therefore they are not included in the resource plan.

Separate from the gross load forecast, an offset for 280 MW of Partial Requirements[13] load reduction is included in the model. The quantity of Partial Requirements Member MAX selections known at the time of the start of modeling is 163 MW beginning in 2026 and the quantity for MARS selections is 117 MW beginning in 2026. Based on this, the 163 MW MAX selections reduce the system capacity that Tri-State is responsible for by 163 MW, but the 117 MW MARS selection is a capacity reduction at a prorated amount equivalent to the type of intermittent resource selected (modeled as utility-scale solar). Partial Requirements elections reflect May 2021 and May 2022 Open Seasons, excluding Mountain Parks' election.

System-wide beneficial electrification, discussed below, is added to the load forecast, and Colorado energy efficiency targets—which were modeled as a base assumption in every scenario rather than as a selection by the dispatch model—are subtracted from the gross load forecast in modeling every scenario. Member-owned renewable or distributed generation projects are a deduction to gross load in the modeling process.

Beneficial Electrification

Beneficial Electrification (BE) is included in ERP modeling as additional load in the load forecast. An Achievable-Moderate level BE is modeled for all planning regions in all 2023 ERP Phase I scenarios in alignment with the 2020 ERP Phase I Settlement Agreement.[14] The Achievable-Moderate level of BE load is determined by the BE Potential Study (Attachment G-3 of the ERP Report (LKT-1). "Achievable" potential takes into account barriers that hinder consumer adoption of measures and the capability to ramp up BE program activity over time. The BE Potential Study incorporated the following BE technologies and program opportunities: electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.

The Achievable-Moderate level of potential assumes BE measures are incented at 50% of the incremental cost, resulting in ~668 GWh of cumulative growth on the Tri-State system through 2040 (roughly 4.4% addition to 2040 base gross load). In the ERP financial analysis, the cost of attaining an Achievable-Moderate level of BE is reflective of Tri-State BE staff forecasted expenditures for incentives and program delivery.

Distributed Generation Forecast

Distributed generation (DG) forecast consists of energy and demand forecasts on a project level for Member self-supply options, including Board Policy 115 – renewable distributed generation on Member Systems, Board Policy 119- Community Solar, and Partial Requirements MARS options. Projects are forecasted based on technology type and location with the use of historical load shapes where available.

[13] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.
[14] Section 3.11.11.

Constraints

See Attachments B-1 and B-2 of the ERP Report (LKT-1).

Level I & II Reliability Metrics

All 2023 ERP scenarios were modeled to achieve the minimum Level I and II Reliability Metrics identified in the ERP Report (LKT-1).

Thermal Build Constraint

No new thermal builds allowed until 2028 due to infeasibility of engineering, procurement, construction, and permitting completion prior to 2028.

Gas Retirement Constraint

Gas and oil units, including those with dual-fuel capability available for contingency operations are not allowed to retire in the modeling given that they are necessary for maintaining reliability. These units operate during extreme weather events, support market price arbitrage to reduce costs, support reliability during coal unit outages, and can offer surplus interconnection benefits for co-located renewable resources.

Coal Unit Uptime

Minimum run-time for all coal units was set to 12 hours in the modeling, reflective of a May 2020 report[15] by the Western Electricity Coordinating Council (WECC).

Coal Unit Downtime

Minimum down-time for all coal units was set to 8 hours in the modeling, reflective of a May 2020 report[16] by the WECC.

Craig 3 Modeling

Per the 2020 ERP Phase I Settlement Agreement,[17] Tri-State modeled Craig 3 in the ECON designation, allowing the model to economically commit and dispatch the unit subject to the minimum up and down times.

Craig Unit Retirements

Craig Units 1 and 2 retirements are modeled to occur on the announced dates; and Craig Unit 3 is modeled to allow the unit's retirement between January 1, 2028 and December 31, 2029, except where otherwise modeled per unique scenario assumptions (see Attachment B-3: Unique Scenario Assumptions of the ERP Report (LKT-1)). Craig Unit 3 is not allowed to retire prior to January 1, 2028 in the modeling to ensure sufficient lead-time for the community transition between completion of the 2023 ERP and the earliest potential retirement date and to allow sufficient time for replacement resources to be secured. Craig Unit

[15] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (720 minutes Minimum Up Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[16] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (480 minutes Minimum Down Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[17] Section 3.6.6.

3 is not allowed to retire later than December 31, 2029 given that date is the publicly announced retirement date for the unit as identified in Colorado Regulation No. 23 Regional Haze Limits.

Tri-State Exit MBPP

Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant and receives a portion of Laramie River Station (LRS) generation and transmission through its share of the MBPP contract. Tri-State is only a partial owner of LRS, therefore any "LRS early retirement" modeling simulates Tri-State exit of the MBPP Agreement, not retirement of the unit. This assumption is applied to be informative to the resource plan modeling.

SPV 3 Retirement

SPV 3 is allowed to retire beginning January 1, 2037, upon the conclusion of the 100 MW third-party supply contract (Fall 2036), except where otherwise modeled per unique scenario assumptions (see Attachment B-3 of the ERP Report (LKT-1)).

SPV 3 Max Capacity

In July 2022, a capacity test was conducted affirming the previous maximum capacity rating for SPV 3 of 419 MW.

Effective Load Carrying Capability

ELCCs were updated for wind, solar, storage, coal, and gas resources for the 2023 ERP based on the third-party study completed in August 2023. The ELCC methodology and study results are provided in Attachment G-1 of the ERP Report (LKT-1). For capacity expansion modeling, firm capacity of each unit reflects the Equivalent Forced Outage Rate (eFOR) by unit identified in *Table 18. TSGT UCAP Capacity* of Attachment G-1 of the ERP Report (LKT-1).

Scheduled Outages

The following identifies the scheduled outages modeled for coal units during the RAP.

Table 4: Scheduled Coal Unit Outages During the RAP

Forced Outage Factors

Dispatch plan modeling reflects the average FOFs by unit,[18] as shown in Table 5.

Table 5: Thermal Unit Forced Outage Factors (FOFs)

Unit	5-yr Average FOF (%)
Craig 1	4.00
Craig 2	2.05
Craig 3	13.89
LRS 2	6.49
LRS 3	7.18
SPV3	5.78
Burlington 1	0.99
Burlington 2	0.53
Knutson 1	1.98
Knutson 2	0.72
Limon 1	0.67
Limon 2	0.33
Pyramid 1	0.19
Pyramid 2	1.24
Pyramid 3	0.44
Pyramid 4	0.95
JM Shafer	4.71

These FOF factors were developed using five years of historical FOFs data from 2018-2022, shown in Table 6.

Table 6: Historical Thermal Unit FOFs

Unit	2018	2019	2020	2021	2022
Craig 1	5.53	1.21	3.35	8.18	1.75
Craig 2	0.27	2.18	0.99	2.17	4.65
Craig 3	45.24	3.39	3.67	4.36	12.78
LRS 2	6.33	2.20	7.82	12.71	3.39
LRS 3	0.01	0.51	10.34	23.47	1.56
SPV3	7.77	9.09	1.41	7.8	2.82
Burlington 1	2.46	0.70	0.43	1.34	0
Burlington 2	0.67	0.32	0.35	0.87	0.45
Knutson 1	0.33	0.89	0.22	0.03	8.45
Knutson 2	0.21	0.66	1.55	0.4	0.77
Limon 1	1.71	0.29	0.06	0.01	1.29

[18] The input field in EnCompass is FOR.

Unit	2018	2019	2020	2021	2022
Limon 2	0.45	0.57	0.12	0.45	0.07
Pyramid 1	0.27	0.35	0.02	0.02	0.31
Pyramid 2	2.76	0.07	0.39	0	2.97
Pyramid 3	0.26	0.97	0.91	0.08	0
Pyramid 4	0.26	2.41	0.18	1.88	0
JM Shafer	5.04	13.13	1.46	2.12	1.8

EnCompass randomly selects for each day how many individual units will be forced out due to operational failure. This random selection is based on the FOR and Random Outage Seed inputs. The model uses the FOR to determine the number of full forced outage days per year and will randomly select the dates in each year.

Modeling of Market Sales and Purchase Depths

All market purchases and sales are transacted at a regional level trading hub within the model. Market depths in 2024 are reflective of Member exits, and access to existing Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets. Market depths beginning in 2026 are reflective of the WACM BA moving to SPP RTO. Additional market depth in ECO is added in 2030 reflective of an assumption that PSCo will be in an RTO by 2030. Market depths in New Mexico are reflective of assumptions that PNM joins an RTO by 2030. The tables below show the market depths as modeled.[19]

Table 7: Market Sales Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC(MW)
ECO	200	250	300
WCO	100	200	200
NM	75	75	150
WYO-WNE	100	200	200

Table 8: Market Purchase Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC (MW)
ECO	150	200	200
WCO	100	200	200
NM	100	100	200
WYO-WNE	75	200	200

Tri-State currently meets its contingency reserve requirements through its membership in the Southwest Reserve Sharing and two sub-entity Reserve Sharing Group agreements. Modeling includes contingency

[19] Market sales were reviewed by a third-party consultant in May 2023.

reserve requirements for these existing reserve sharing groups. Potential regulation and contingency reserve sales opportunities within the SPP RTO are not reflected in the Phase I modeling.[20]

Modeling of Short & Long-Term Sales

Modeling reflects existing term sales as follows:

- **City of Farmington Sale** (Modeled as a Term Sale)**:** 25 MW per hour maximum on-peak capacity; 15 MW per hour maximum off-peak capacity ~181 GWh/year in energy sales. Effective date 7/1/23; contract expires 12/31/25.
- **DOE National Nuclear Security Administration Sale** (Modeled as a Term Sale)**:** Up to 40 MW capacity, ~351 GWh/year in energy sales. Contract is effective from 1/1/24-12/31/25.
- **SRP Sale:** SPV 3 located in Arizona, 100 MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036. In some of the modeled scenarios, Springerville 3 is retired before the end of the contract date. Tri-State cannot terminate operations of Springerville 3 and the related third-party contract without reaching agreement with impacted parties.

Modeling of Proxy Sales

Tri-State modeled proxy sales for near-term years in anticipation of the ability to sell excess power upon Member exits. Proxy sales include:

- [redacted]
- [redacted]

In September 2023, Tri-State issued a reverse RFP and resulting potential sales are still under evaluation with some negotiations in progress.

Generic Resource Availability

The model is able to select generic resources to be added in the expansion plan starting as soon as 2026, depending on lead time of each technology as identified in Attachment C-2 of the ERP Report (LKT-1).

PPA and Contract Information

Modeling reflects PPA capacity, energy, and CoDs shown in Attachment C-1 of the ERP Report (LKT-1). Tri-State's modeling reflected known PPA updates, including:

- Escalante Solar commercial operation date (COD) was advanced from December 2024 to June 2024 based on updated project schedule. Escalante Solar was modeled through December 2043, the end of the Resource Acquisition Period.
- Axial Basin and Dolores Canyon are no longer PPAs and were modeled as Tri-State owned resources.[21]

[20] Tri-State is evaluating the potential to model these opportunities in Phase II of the 2023 ERP.
[21] See Attachment C-3 of the ERP Report (LKT-1). Also see Proceeding No. 23A-0548E.

After scenario modeling began, additional PPA changes occurred:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the Coyote Gulch Solar PPA was terminated, effective October 1, 2023.[22]
- Additionally, due to similar reasons noted above, the price increased from [redacted] for the Spanish Peaks and Spanish Peaks II PPAs. Simultaneous to the price modification, the Spanish Peaks and Spanish Peaks II PPAs were also extended for four additional years, from a 2039 contract end date to 2043 (making them 19-year PPA terms).[23]

SRP Contract

Salt River Project (SRP) is assumed to take at least the contract minimum capacity amount from SPV 3, but if the cost of SPV 3 energy is lower than forecasted market prices, the SRP take can be modeled above the contract minimum, up to the max contract capacity (100 MW).

System Loss Factor

The transmission system loss factor is meant to represent an average of expected transmission losses as Tri-State load in the Western Interconnection is located across multiple BAs and Transmission Provider systems. The transmission loss factor used in the planning and dispatch models was 3.5% in the Wyoming, Western Colorado, and Eastern Colorado planning regions. A portion of transmission system losses are financial, and are recorded in the financial models as a purchase power expense.

Demand-Side Management

Demand Response

For the ECO and WCO planning regions, Tri-State models achievement of the "DR Target." The DR Target[24] requires Tri-State to "…develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load." Tri-State bases its DR modeling on the programs it anticipates launching, which include controls for: water heaters and air conditioners for residential and small commercial settings, irrigation load, and commercial and industrial (C&I) applications. Tri-State also models Low DR for WYO-WNE and NM planning regions,[25] which is generally consistent with internally-forecasted levels of uptake of DR programs.

Modeling the DR Target for ECO and WCO involves the following input assumptions and parameters:

- DR Target of at least 4% MW is a must-take, not a selection in the model.
- There are five different "DR resource" types: (1) Commercial & Industrial (C&I), (2) Irrigation, (3) Residential Battery Energy Storage Systems (BESS), (4) Residential Air Conditioning (A/C), and

[22] The Coyote Gulch Solar PPA was cancelled subsequent to initiation of Phase I scenario modeling, and therefore was included in the modeling, with a July 2026 COD. Replacement capacity will be procured through 2023 ERP Phase II.
[23] These contract modifications occurred subsequent to initiation of Phase I scenario modeling.
[24] See 2020 ERP Phase I Settlement Agreement, section 3.11.8.
[25] "Low DR" is based on the DSM and EE Potential Study completed by MesaPoint Energy for the 2020 ERP, May 8, 2020.

18(5) Residential Water Heaters (WH). Each has different values for Max Capacity, Maximum Daily Energy, Maximum Annual Energy, and Payback Required.

- **Max Capacity** sets the daily maximum output for each DR resource;
- **Maximum Daily Energy (%)** sets the maximum capacity factor for each day, limiting daily output to this input capacity factor;
- **Maximum Storage (MWh)** sets the maximum amount of energy that can be stored at any given time; and
- **Maximum Annual Energy (%)** sets the maximum capacity factor for the year.
- **Payback Required (%)** sets the percentage rate at which the interrupted load requirements need to be replaced.

- DR resource costs assumed for meeting the DR Target for ECO and WCO, both programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements), applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

DR is dispatched by the model by determining the most economical way to dispatch DR thus shifting load while adhering to the hourly constraints and payback requirements in a given hour, day, and season. For example, the C&I DR resource is able to be called on year-round, but only during hours 8-16 (nine hrs/day) up to 14.5 MW in 2030, but only up to 8.6 GWh/yr (6.8% of annual capacity), and only can dispatch six of the nine hours in a given day (6/24 = 25% of Maximum Daily Energy). Also, DR resources are modeled like a battery in that whatever demand energy is curtailed, some amount of payback is required. In the case of the C&I DR resource, a 50% payback is required, so, for example, in year 2030 if it curtails 8.6 GWh/yr, 4.3 GWh/yr is paid back.

Modeling DR resources for WYO-WNE and NM involves the following input assumptions and parameters:

- DR resources can be selected by the model for WYO-WNE and NM.
- All of the five DR resources together are one Project in Encompass with an associated capital cost (CapEx) based on the present value of the lifetime expenditures for that project. If the Project is the most economic choice for meeting system load needs then the Project is selected and the associated Capex is modeled as an expenditure and the DR resource parameters (Max Capacity, etc. noted above) are applied in the modeling.
- The costs associated with the selected DR resources for WYO-WNE and NM, both the programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements) applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

Because much of DR reflects shifts in the time periods when energy is used, financial models – which focus on energy billed to members within a month – show DR energy impacts net of timing shifts.

Energy Efficiency

ECO and WCO regions were modeled to achieve the EE Targets[26] of 0.35% in 2023, 0.5% by 2024, 0.75% by 2025, and 1% by 2030 in incremental annual energy efficiency savings for Colorado Utility Member

[26] *See* 2020 ERP Phase I Settlement Agreement, Section 3.11.9.

system load.[27] See table below for estimated energy equivalents for EE Targets based on the latest load forecast.[28] WYO and NM regions were allowed to select Achievable-Low EE[29] starting in 2025.

Table 9: Colorado Energy Efficiency Targets and GWh Equivalent

Target Year	EE Target (%)	Est. GWh Equivalent
2023	0.35%	39.0
2024	0.50%	145.6
2025	0.75%	59.0
2030	1.00%	73.4

Environmental

Emission and Water Use Rates

Emission rates (lbs/MWh) and water use (gal/MWh)[30] for existing units were updated based on 2022 actual emissions, water use, and net generated MWh for each generator. Emissions rates and water use for generic thermal resources were reviewed and updated by B&V in Spring 2023. Emission rates and water use for innovative technologies were based on industry research and developer specs, where available. Emission and water use rates used for 2023 ERP Phase I modeling are shown in the table below. Also see Attachment C-2 of the ERP Report (LKT-1).

Table 10: Emission and Water Use Rates

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**(gal/MWh)**
LRS 2	2489	1.414	1.693	0.00001	0.126	0.0325	685
LRS 3	2489	1.414	1.693	0.000	0.126	0.0325	685
Craig 1[31]	2388	0.604	2.790	0.0000040	0.104	0.0021	573
Craig 2	2388	0.526	0.801	0.0000038	0.117	0.0019	573
Craig 3	2204	1.332	2.240	0.0000065	0.040	0.0299	573
Springerville 3	2372	0.990	0.857	0.0000043	0.196	0.0325	548

[27] There were two minor inputs to energy efficiency that were incorrectly reflected in calculation of Colorado load for purposes of determining EE Targets in the modeling: 1) Partial Requirements deductions from total load started in 2025 instead of 2026; and 2) deductions for *all* Partial Requirements member elections were deducted from Colorado load requirements for purposes of calculating energy efficiency in the modeling, but should not have included non-Colorado partial requirements. The magnitude of this impact is immaterial, at less than a tenth of a percent.

[28] Page 27 of Tri-State's informational DSM plan filed in Proceeding No. 20A-0528E on September 1, 2022 contained EE Targets forecasted based on Tri-State Colorado system load at that time.

[29] Attachment G-3 of the ERP Report (LKT-1).

[30] Pursuant to Rule 3605(a)(IV)(I).

[31] NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**(gal/MWh)**
Burlington 1	2121	0.063	10.633	*N/A*	0.145	0.0050	10
Burlington 2	2121	0.063	10.895	*N/A*	0.149	0.0051	10
Pyramid 1	1232	0.010	1.394	*N/A*	0.074	0.0213	40
Pyramid 2	1232	0.008	1.127	*N/A*	0.068	0.0205	40
Pyramid 3	1232	0.017	1.285	*N/A*	0.079	0.0184	40
Pyramid 4	1232	0.009	1.147	*N/A*	0.070	0.0207	40
Limon 1	1594	0.009	0.294	*N/A*	0.067	0.0026	32
Limon 2	1594	0.011	0.387	*N/A*	0.079	0.0028	32
Knutson 1	1515	0.011	0.387	*N/A*	0.118	0.0008	17
Knutson 2	1515	0.010	0.329	*N/A*	0.118	0.0008	17
J. M. Shafer	985	0.005	0.725	*N/A*	0.053	0.0465	343
Unspecified Energy Purchases	**Years 2023 - 2029**						
Basin Nebraska	996	0.981	0.822	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY thru 2025	2596	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY 2026-2029	1159	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Market Purchases	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Energy Imbalance	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Gas Expansion Plan Units							
46_5x9RICE	981	0.010	0.180	*N/A*	0.042	0.089	0
40_1x40LM6000	1089	0.011	0.084	*N/A*	0.069	0.027	40
200_1x235_7FA05	1165	0.012	0.090	*N/A*	0.073	0.029	57
Natural Gas CCS	765	0.008	0.046	N/A	0.048	0.019	348
Innovative Tech - Expansion							
Blue Hydrogen w/CCS	59		0.19				570
Green Hydrogen	0		1.06				357
Nuclear SMR	N/A						672
Geothermal EGS/Adv	N/A						100
Non-Emitting Technology with Water Usage	*Note:* Net battery generation is negative; the negative water usage, when applied to negative generation, results in positive overall water usage for non-emitting technology with water usage.						
10 Hour Battery	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	0
Battery - Iron Air	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-24.7
Molten Salt Storage	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-51
Pumped Hydro	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-412

Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction Targets.[32] Also see Attachment B-3 of the ERP Report (LKT-1).

APCD Workbook Inputs and Resource, Market & Contract Emissions Rates

As shown in Attachments D1-D5 to the ERP Report (LKT-1), the APCD Workbooks for each scenario, Tri-State's 2005 carbon emissions baseline reflects adjustments necessary to exclude Member Exits and Partial Requirements contracts from the baseline in relevant years. Details regarding Member Exits and Partial Requirements are described above, see *Load Forecast*.

Additionally, market and contract emissions rates were updated as follows:

- Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates;
- Basin Western Interconnection contract updated to LRS emission rates for 2025, and 2021 eGRID RMPA rate for 2026 to 2029; and
- Market purchase and sales updated to 2021 eGRID RMPA and AZNM rates as applicable.

Social Cost of Carbon

Social Cost of Carbon ("SCoC") is based on the latest values published by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, for calculating the net present value of carbon dioxide emissions, brought back to present value with a 2.5% discount rate.[33] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

Social Cost of Methane

Social Cost of Methane ("SCoM") is based on the latest values published by the IWG on the Social Cost of Greenhouse Gases, for calculating the net present value of methane emissions, brought back to present value with a 2.5% discount rate.[34] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

[32] See 2020 ERP Phase I Settlement Agreement, Sections 3.3.4 and 3.3.5.
[33] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[34] The IWG has not published an update to SCoM values or the discount rate since February 2021.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-62:
NERC Electrochemical Storage Study

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Energy Storage

Impacts of Electrochemical Utility-Scale Battery Energy Storage Systems on the Bulk Power System

February 2021

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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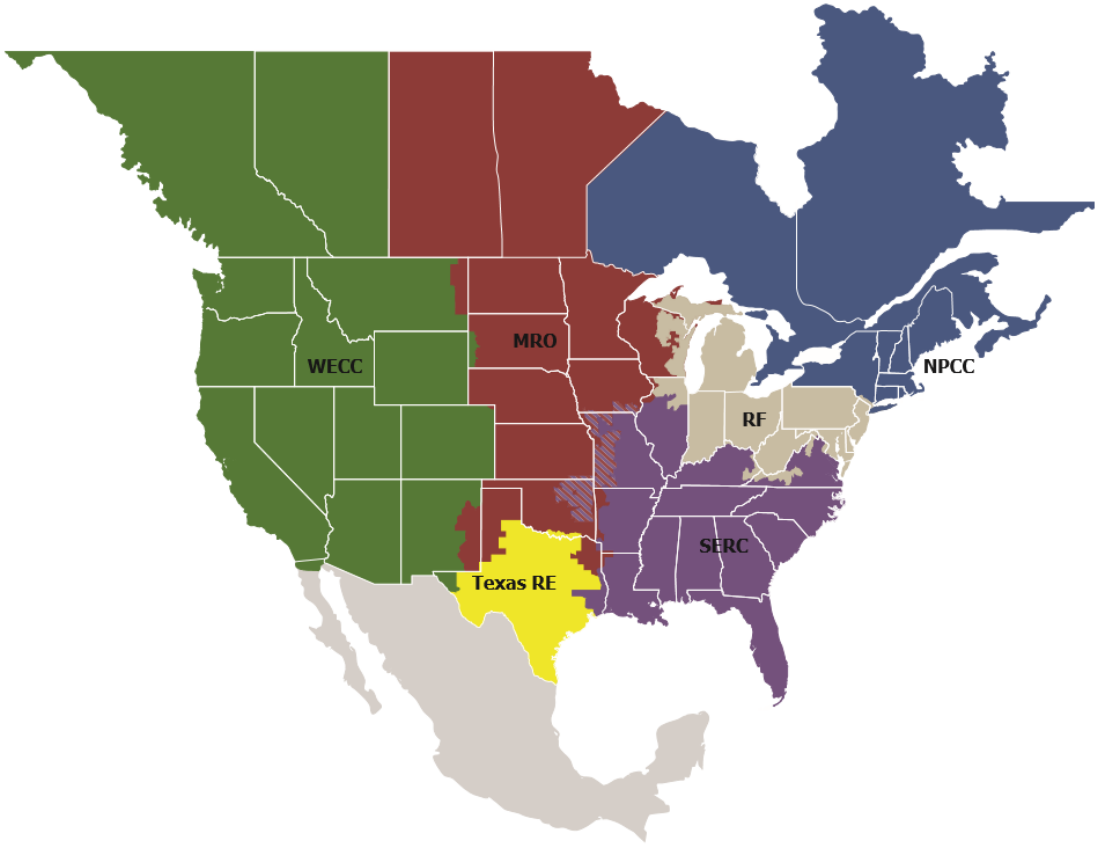
Preface

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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable 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 RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE 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	WECC

Executive Summary

The electricity sector is undergoing significant and rapid changes that present new challenges and opportunities for reliability, security, and resilience. NERC has recently conducted analyses that underscore challenges presented with the acceleration of coal-fired generation retirements and the increased reliance on natural gas. Additionally, NERC continues to note a rapid shift to inverter-based resources (IBRs) that are variable energy resources due to their fuel source (e.g. wind, solar) and have different operating characteristics from traditional synchronous generation. This variability creates potential challenges related to availability that may require additional resources to maintain BPS reliability. NERC has pointed to these topics in past assessments. Furthermore, NERC continues to emphasize the importance of ensuring that these IBRs provide essential reliability services (ERS) to the grid, such as frequency response, ramping, and voltage support. Along with this increase in IBR, primarily from the addition of a large contribution of renewable resources (e.g., wind, solar), there has been an increase in the application of battery energy storage systems (BESS) on the BPS. BESS have the ability to complement IBRs by providing some of the ERS that are important to maintain BPS reliability. Additionally, BESS provide elements of grid support, including providing flexible ramping support, fast frequency response (FFR), addressing the uncertainty of resource availability, and shifting energy to address new peaking conditions.

NERC recently conducted a joint study with WECC that underscored some of the potential benefits BESS can provide for FFR to avert using under frequency load shedding (UFLS) in response to generation losses. Additionally, this assessment confirms projections that BESS will grow significantly across the North American footprint over the next twenty years.

Key Findings: Based on data and information collected for this assessment, NERC identified the following:

- BESS are projected to grow at an increasing pace across the North American footprint as shown in **Figure 2.1**.
- Lithium-ion batteries account for more than 50% of the installed power and energy capacity of large-scale electrochemical batteries. Flow batteries are an emerging storage technology; however, it still constitutes only 2% of the market.
- Advances in technology, decreasing costs, and changes to FERC and other market rules will promote BESS growth.
- As IBRs (primarily from wind and solar resources) continue to grow, BESS can enhance grid reliability by offsetting resource variability and providing ERS, such as voltage support and frequency response. NERC's inverter-based working group (IBRWG) continues to develop appropriate guidelines addressing potential impacts of IBRs.[1]
- A joint NERC/WECC study determined that BESS strategically located provide effective and FFR to avert UFLS.
- Existing NERC standards adequately reflect battery storage as a generator, ensuring that the NERC TPL and MOD standards are applicable to the current number of BESS on the BPS.
- Data on battery storage tends to be non-uniform and lacking in consistency across reporting entities necessitating a need for better reporting mechanisms for BESS data.
- Because battery storage is an emerging technology, the development of utility-scale battery storage has lagged the integration of renewable resources.

Recommendations: Based on the identified Key Findings previously mentioned, NERC has formulated the following recommendations:

[1] IBRWG homepage

- System planners should prepare for a significant increase in the critical mass of BESS across the North American footprint. Planners must ensure that deployed battery storage provides the necessary ERSs to maintain BPS reliability, security, and resilience.
- As regulators provide more incentives for the viability of battery storage to provide capacity and energy, system planners must adequately plan the system for a projected large increase in BESS, understanding the impact of size, location, and operating characteristics on maintaining the reliable operation of the grid.
- The value of battery storage as a complement to variable energy resources, such as wind and solar, should be fully understood by system planners and operators. System planners must conduct adequate studies to determine the dynamic stability impacts of BESS' Interconnection, the capability to provide capacity to meet long-term and contingency reserve margin requirements, and the ability to provide ERS.
- NERC should conduct a detailed analysis of existing NERC Reliability Standards and guidelines to ensure that they adequately provide for a large increase in the critical mass of BESS, conduct a gap analysis to ensure that existing standards are not deficient, and/or identify the need for new standards to reflect the potential large increase in BESS.
- Entities that compile battery data information must enhance both their data collection methods as well as their reporting methods. As energy storage systems become more prolific, accurate and timely data will be essential for both system planners and operators. The Institute of Electrical and Electronics Engineers (IEEE) should update the IEEE Standards to reflect any implications of battery storage systems. The GADS Working Group should ensure that battery storage is accurately reflected in their data capturing protocols.
- The NERC Reliability and Security Technical Committee (RSTC) should form a task force to study the forward-looking implications of BESS and their overall effects on BPS reliability and resilience.

Introduction

NERC, in its mission to maintain the reliability of the BPS, continues to assess the implications on the reliability, security, and resilience from integration of cutting-edge technologies to the electrical grid. Due to the changing nature of the grid and the increasing amount of projected BESS in the future, the industry and regulators must pay more attention to BPS-connected BESS units.

What is a Battery?

The collective contribution of scientists and innovators created our understanding of the forces of electricity, but Alessandro Volta developed the first electrical battery in 1799.[2] This battery, known as the Voltaic Cell, consisted of two plates of different metals immersed in a chemical solution. He discovered that electricity can be generated chemically and made to flow evenly through a conductor in a closed circuit.

The basic power unit inside a battery is a cell, and it consists of three main parts. There are two electrodes (electrical terminals) and a chemical called an electrolyte in between them. The negative electrical terminal is the anode, and the positive electrical terminal is the cathode. Electrolytes allow ions to move between the electrodes and terminals allowing current to flow out of the battery to perform work. For our convenience and safety, these cells are usually packed inside a metal or plastic outer case. The difference between a battery and a cell is simply that a battery consists of two or more cells hooked up so their power adds together (**Figure I.1**).

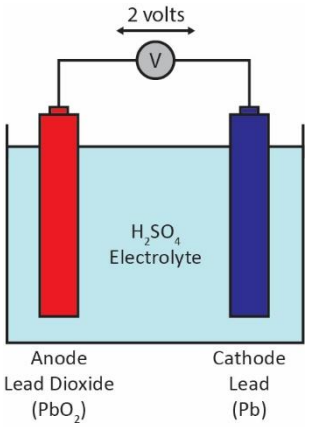


Figure I.1: Schematic of a Battery

Advances in technology and materials have greatly increased the reliability, output, and density of modern battery systems, and economies of scale have dramatically reduced the associated cost. Continued innovation created new technologies, like electrochemical capacitors, which can quickly charge or discharge energy for later use and provide an almost unlimited operational lifespan. Two emerging technologies in electric energy storage are**: Lithium-Ion and Flow** Batteries as described in this report; these two electrochemical technologies offer a more robust and adaptable energy grid, as shown in **Figure I.2**.

The scope of this report will include stand-alone BESS and BESS connected alongside other generation resources.[3] The BESS in scope for this assessment are BPS-connected with a primary emphasis on lithium-Ion and flow batteries. The fastest growing technology is the lithium-Ion market, which is largely driven by the electric vehicle (EV) market.

In recent years, the use of BPS-connected battery energy storage has quadrupled from 214 MW (2014) to 899 MW (2019), and NERC anticipates that the capacity could exceed 3,500 MW by 2023 (**Figure I.3**).

[2] https://ethw.org/Milestones:Volta's_Electrical_Battery_Invention,_1799

[3] This BESS configuration, referred to as hybrid resources, is typically a BESS with solar or a BESS with wind.

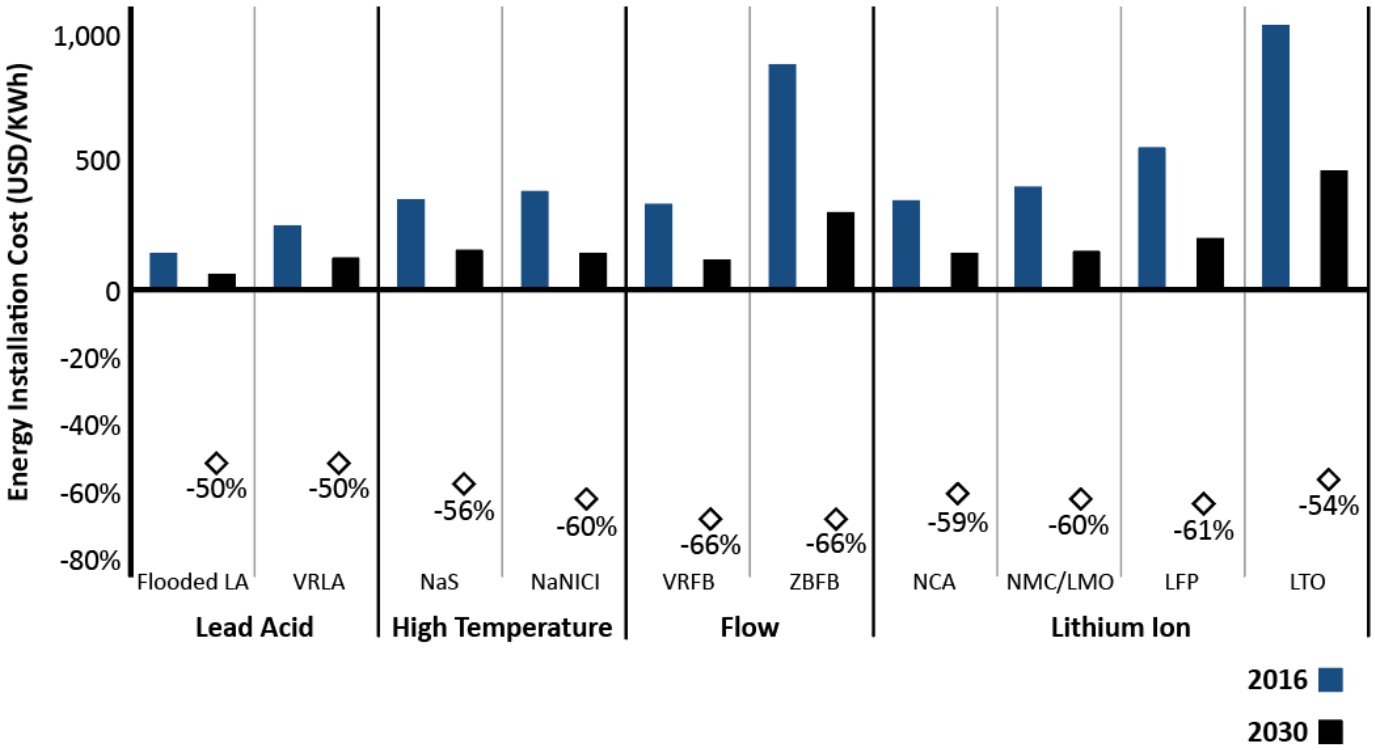


Figure I.2: Energy Installation Costs Central Estimate for Battery Technologies, 2016–2030
(The diamond represents the decrease in installation cost when comparing 2016 to 2030 data)

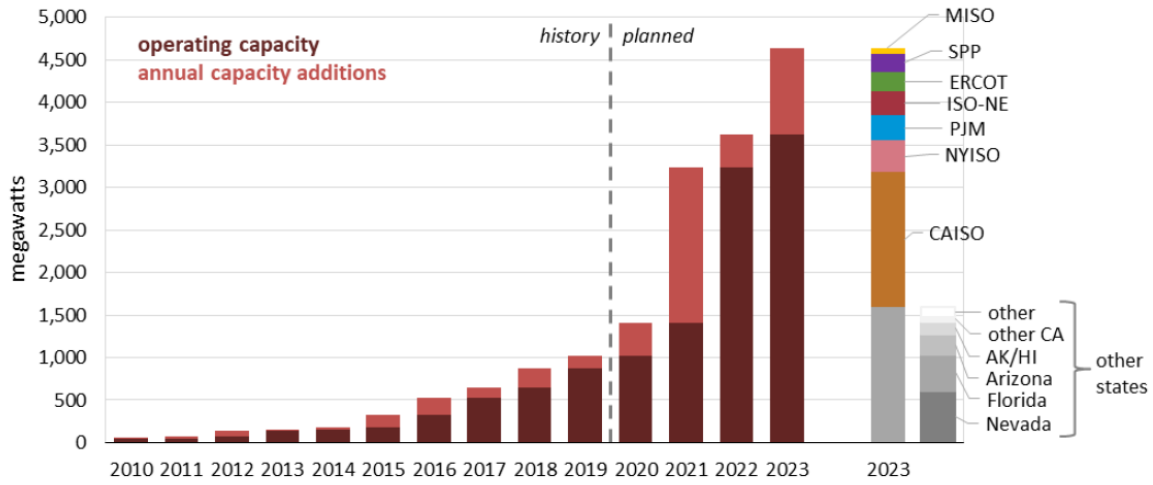


Figure I.3: United States BPS-Connected Battery Energy Storage Power Capacity (July 2020)[4]

One of the major growth areas for BESS is in hybrid systems. An example of a hybrid system is the combination of a wind or solar plant alongside a BESS facility. Internationally, a wind farm in South Australia retains the biggest-battery title at 100 MW/129 MWh, which is enough to supply 30,000 homes for eight hours. The largest battery in the United States and the world is projected to come online in 2021 when Florida Power and Light's 409 MW/900 MWh Manatee (center solar plant) Energy Storage Center becomes operational. Furthermore, Southern California Edison has just

[4] July 2020, U. S Energy Information Administration, Form EIA-806M, Preliminary Monthly Electric Generator Inventory

finalized what analysts called the nation's largest-ever purchase of battery storage in late April 2020, and this mega-battery storage facility is rated at 770 MW/3,080 MWh. The largest battery in Canada is projected to come online in 2021 when Alberta's TransAlta Renewables WindCharger's 60 MW utility-scale battery project becomes operational.[5]

The top four states that have operating or facilities under construction are California, Illinois, West Virginia, and Texas; these four states make up over half of the total installed battery storage in the United States, as shown in **Figure I.4**.

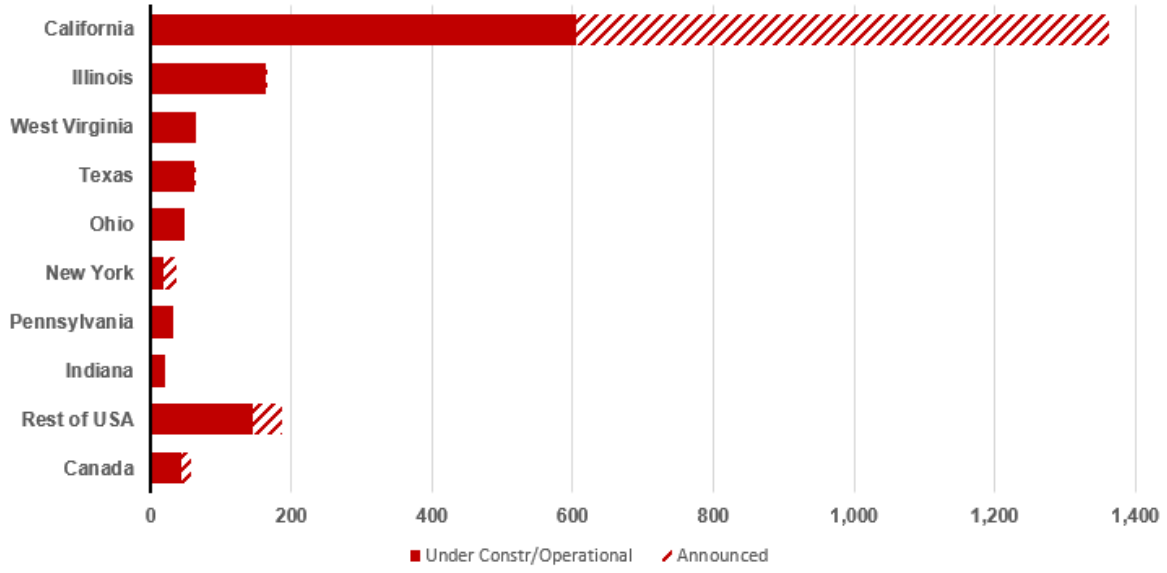


Figure I.4: United States Operating Utility-Scale Battery Storage by State[6]

Figure I.5 shows an electric power profile with its variations during a 24-hour period. In a load-leveling scenario, the BESS charges during periods of low power demand and discharges during periods of high power demand. Overall, the utility would need less capacity to meet this now lowered demand at its peak and could delay the installation of additional generating capacity. Such energy shifts help to regulate the generation and load balance. Energy storage would help to enable the delivery of energy for a limited amount of time when variable renewable energy sources, such as solar photovoltaic (PV) and wind, are not available.

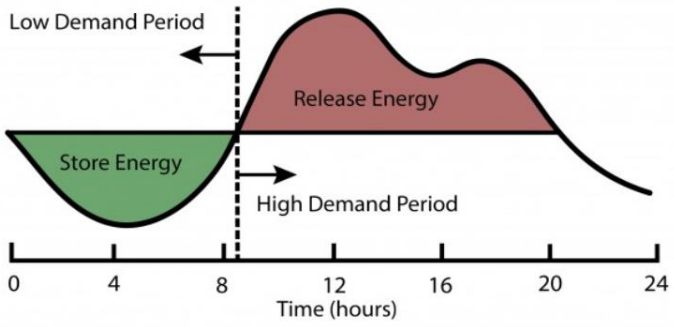


Figure I.5: Daily Energy Storage and Load Leveling[7]

[5] The first 20 MW is operational by December 2020, the final two 20 MW will come online in 2021; https://www.teslarati.com/tesla-canada-biggest-battery-energy-storage-system/

[6] Graph adapted from the DOE website, "DOE Global Energy Storage Database", Energy Storage Exchange, www.energystorageexchange.org.

[7] University of Michigan, http://css.umich.edu/factsheets/us-grid-energy-storage-factsheet

There are other applications and locations for BPS-level BESS. The three main demands that this technology is used for are operating reserves and ancillary services: energy arbitrage, curtailment reduction and load leveling, and peaking capacity.

While the daily energy storage and load-leveling example show a typical BESS applications case, the following sections summarize the most common applications for the growth of BESS in the power industry. These applications will dictate the operational characteristics of BESS.

Key Characteristics and Definitions of BESSs

Storage technologies have a few key characteristics that can be useful for comparison. Some of the key characteristics used by the industry are summarized below. These characteristics can be further defined and customized for each energy storage technologies.

Different battery technologies have an inherent state of charge (SOC), voltage currents, and temperature ranges that when operated within avoids accelerated cell degradation and safety issues.

Definition

A battery energy storage system (BESS) is a term used to describe the entire system, including the battery energy storage device along with any ancillary motors/pumps, power electronics, control electronics, and packaging. Since all electrochemical batteries produce dc current, a BESS typically consists of the following components:

- The dc battery system (batteries, racks, etc.)
- Enclosure(s) with thermal management
- Bi-directional dc/ac inverter
- EMS/system level software controller
- Switchgear/metering/MV step-up transformer, etc.

Rated Power Capacity *(citation, Grid-Scale Battery Storage, FAQ)*

The total possible instantaneous discharge capability, in kilowatts (kW) or megawatts (MW), of the BESS or the maximum rate of discharge that the BESS can achieve that starts from a fully charged state.

Rated Energy Capacity

The amount of energy stored in the battery, in kilowatt-hours (kWh) or megawatt-hours (MWh).

Rated energy capacity can be specified in ac terms (kWh) for complete systems, including energy storage medium, power conversion electronics, and transformers. Alternatively, it can also be specified in dc terms (MWh) when only the battery or energy storage medium is represented or considered. Additionally, vendors will sometimes show a “rating” for kWh in dc without or before considering ac conversion. When this is done, it is critical to remember that the power capacity of the system is normally determined by the capability of the power electronics, not just the energy storage medium, since the ac rating of a battery system may be significantly smaller than the dc rating of the battery component itself, due to the inefficiency of energy conversion.

Some manufacturers will specify a “rated power” but then list a “maximum depth-of-discharge” (DOD) that limits the actual energy available. For some technologies, the energy available may be proportional to the discharge rate and temperature (higher discharge rates typically allow less energy to be removed from the battery).

Storage Duration

Storage duration is the amount of time the energy storage can discharge at the system power capacity before depleting its energy capacity. For example, a rated battery with 1 MW of power capacity and 4 MWh of usable system energy capacity will have a reserve duration of four hours at a specified discharge rate.

Cycle Life

This characteristic is specific to the battery/energy storage medium. Cycle life is the number of times the battery can be discharged and recharged during its useful life over a specific SOC range. Cycle life is often specified as number of cycles to a specific depth of discharge (DOD) since many batteries will have a longer life if discharges are kept shallow. This assumes that cycle life is directionally proportional to DOD and is equivalent to something like 5,000 cycles to 50% DOD or 2,500 cycles to 100% DOD. This may not be the case for some battery types and chemistries. There is an increasing trend to provide warranties based on "energy throughput." This is derived by the summation of the total amount of energy a battery is expected to deliver over its lifetime (e.g., the number of kWh, stored energy delivered by the battery). This term is universal and can be apply to all types of batteries no matter what their degradation mechanism or rate is over time.

Self-discharge

Self-discharge occurs when the stored charge (or energy) of the battery is reduced through internal chemical reactions or without being discharged to perform work for the grid or a customer. Self-discharge, expressed as a percentage of charge lost over a certain period, reduces the amount of energy available for discharge and is an important parameter to consider in batteries intended for longer-duration applications.

State of Charge

SOC, expressed as a percentage, represents the battery's present level of charge and ranges from completely discharged to fully charged. The SOC influences a battery's ability to provide energy or ancillary services to the grid at any given time. Different battery technologies have an inherent SOC range that, when operated within, avoids accelerated cell degradation. The achievable high and low SOC values are specific to a battery chemistry and type.

Round-trip efficiency

Round-trip efficiency, which is measured as a percentage, is a ratio of the energy charged to the battery to the energy discharged from the battery. It represents the total efficiency of the battery system to resupply energy taken from its source, including losses from self-discharge. Although battery manufacturers often refer to the dc-dc efficiency (i.e., round-trip efficiency from the dc charge controller) and do not include the losses due to required subsystems, such as HVAC, natural gas detection, and fire protection. In contrast, ac-ac efficiency (i.e. the round-trip efficiency from the point of interconnection) includes all system losses that are typically more important as it measures the battery as it is charging and discharging from the point of interconnection to the power system, which uses ac (Denholm 2019).

System Life

This is the expected calendar life of the BESS used for its designed purpose and intent, also known as installation life. The system life incorporates the expected service life, degradation mechanism, and rate of all subcomponents for an application or use case. This includes but is not limited to the following: battery, electronics, power conversion, and interconnection equipment. Typically, this term is used only for the battery degradation, which may be a factor of cell corrosion, capacity degradation, life of seals/membranes, or other factors. If designed and installed properly, battery degradation is truly dependent on how an end user operates their system. Battery applications are typically broken up into two categories: energy and power. Energy applications can include time shift, supply capacity, and spinning reserves. Power applications are typically load ramping and/or following voltage support and frequency response. Because energy response typically has a deeper depth of discharge on a consistent basis, these applications have a steeper degradation curve for some chemistries.

Using the battery outside its designed purpose may affect its capabilities and life. Changing or modifying the use case, cycle frequency, DOD, charge/discharge parameters, or rate will affect the warranty of the battery and may exceed the battery or the power electronic capabilities. Entities should contact battery manufacturers and evaluate any effects of changing the use case from the original design before making changes to installations or subcomponents.

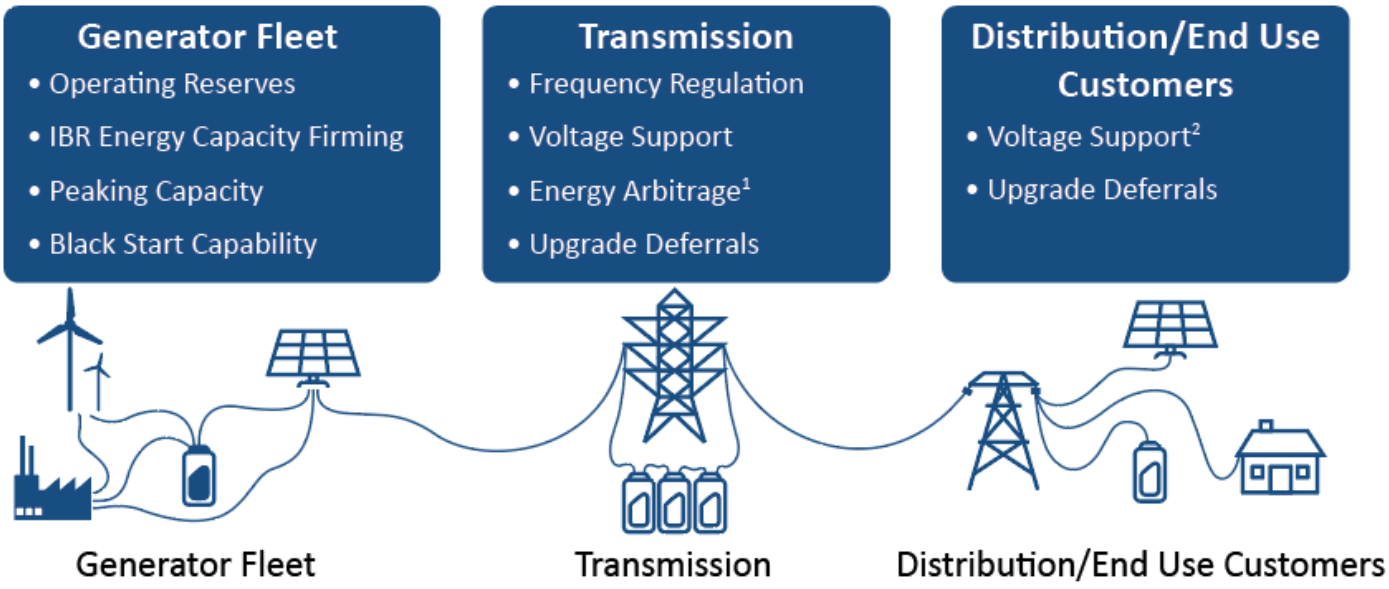
Safety

If used incorrectly, all batteries become a risk and can pose a danger to the equipment and personnel. The higher the energy density of the battery means the more attention to the design, maintenance, and operation of the BESS is required.

Chapter 1: Applications of Battery Energy Storage for the Grid

BESS are an well suited technology to provide short-term grid contingency support (tens of seconds) and long-term energy support/reserve (up to four hours) with the BESS capable of short settling times and the operational flexibility inherent to energy storage. BESS can provide the ERS of frequency regulation, ramping, and voltage support in a manner that can replicate current levels of ERS from synchronous facilities. In addition, BESS can also provide ancillary services with several hours of energy capacity reserve ready for the grid. The main BESS applications in power system generation, transmission, and operation are described in **Figure 1.1.**[8]

Batteries can provide services for system operation and for solar PV and wind generators as well as defer investments in peak generation.



[1] This term is related to the load-leveling term commonly found in nonmarket solutions. They both effectively look to have similar battery performance by shifting energy to different times.

[2] While not commonly used for distribution systems, BESS can perform their voltage support on the distribution system. It is expected that most BESS that provide voltage support will be placed on the transmission system.

Figure 1.1: Main Battery Applications in the Grid[9]

The following section identifies the major reported services BESS are providing.

Operating Reserves and Frequency Regulation

The ability to maintain specified reserves and/or adequate reserves beyond the firm system demand describes the function of operating reserves. Operating reserves consist of attributes like regulation, load following, and contingency reserves (spinning, non-spinning, and supplemental).[10] BESS can provide the regulation and load following capability to supply/absorb additional energy for the unexpected grid energy imbalance, or they can provide ramping capability of the grid during times of major load shifts.[11] With provided flexible ramping capability,

[8] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Utility-scale-batteries_2019.pdf

[9] IBR in **Figure 1.1** are inverter-based resources.

[10] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf

[11] These are typically the morning, afternoon, and evening times that are exacerbated by high solar PV penetration.

BESS can help BAs respond to large ramps during the day and reduce any ramping rate requirement of other resources.

BESS can also provide the grid primary frequency response (PFR). BESS have FFR capability as a full-converter type of power electronic device that, if enabled, allows the BESS to provide a large power injection before most conventional generation. These two functions, PFT and FFR, are short-term reliability services. BESS can also provide longer-duration frequency services with the stored energy that can provide grid the secondary frequency response or tertiary frequency response.

Voltage support

Generating facilities are required to provide reactive power to the grid as called for in NERC's Reliability Standards. BESS can provide the reactive needed to support grid voltage stability on the transmission system. BESS can be a reactive resource to provide local voltage support acting as a transmission asset that similar to shunt reactive devices,[12] such as capacitor, static VAR Compensator (SVC), capacitors, or other power electronic controlled devices. This can occur independently from or in parallel with their frequency regulation service.

Inverter-Based Resources (IBR) Energy Capacity Firming

Renewable energy resources, such as wind plants and solar PV, are variable energy resources as their "fuel source" is inherently variable (wind speed and solar irradiation). BESS can support renewable energy resources by providing energy during times of intermittent or expected unavailability (i.e., at times when the wind speed drops for wind generation or at night for solar PV). The addition of BESS can result in a higher capacity factor for the hybrid system.

Peaking Capacity

BESS can discharge energy at the peak loading conditions to meet the peak demand as well as provide peaking generation capacity replacing the need to use high cost natural gas plants that have historically been dispatched during peak seasons. Furthermore, BESS can ameliorate congestion issues and serve as a substitute for peak shaving.

Energy Arbitrage

BESS can take the advantage of different energy market prices by charging battery during low price hours and discharging during peak price hours.

Transmission and Distribution Upgrade Deferrals

When the peak electricity demand exceeds the existing electricity grid's transmission and distribution capacity, the grid's infrastructure should be upgraded to deliver energy to the end-use customer or demand response options explored. However, these upgrades can be expensive to meet a limitation that may only occur for a few hours of the year.

BESS can help alleviate the peak demand stresses on the system. BESS can reduce grid congestion and improve overall transmission and distribution asset use especially with mobile BESS that can be BESS relocated to new areas when they are no longer needed in the original location.

Blackstart Capability

Following a power system blackout, system blackstart capability serves to provide an initial start-up power supply for the other synchronous generators restoration and re-energize the transmission system without normal grid support. A BESS can be a potential blackstart resource as the stored energy lasts hours and can provide initial start-up power for itself and other generation facilities.

[12] Shunt reactive devices are a parallel pathway to ground in order to provide a service to the electricity grid, typically on managing reactive power. These are different from series-connected resources.

Figure I.2 shows the cumulative installed capacity (MW) for BPS-connected storage systems in the United States in 2019 by the service the systems provide. Operating reserves and ancillary services make up a large portion of these MWs of cumulative installed capacity.

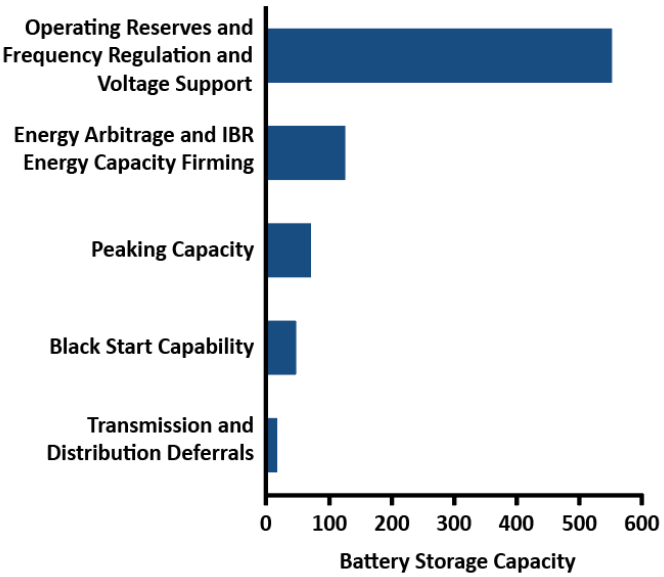


Figure 1.2: United States BPS-Connected Battery Energy Storage Capacity by Service[13]

Status of Rated Power (MW) and Energy (MWh)

The impact that BESS can have on the future sustainable energy grid is substantial. As of September 2020, the United States and Canada had over 37 GW of rated power in energy storage with 90% coming from pumped hydro (**Figure 1.3**). The remaining 10% is from lithium-ion, thermal storage, compressed air, flywheel, lead batteries, and flow batteries. The most dominant electrochemical storage technology is lithium-ion, which accounts for about half the installed rated power.

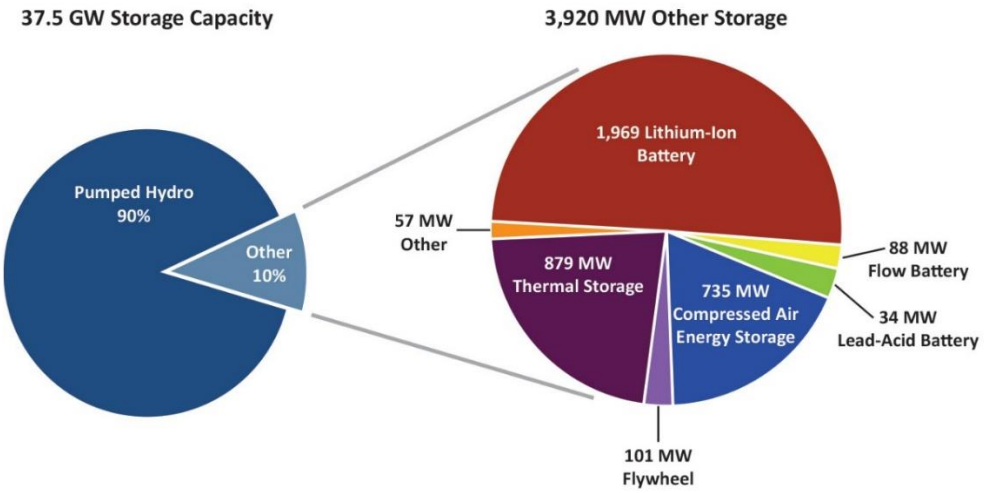
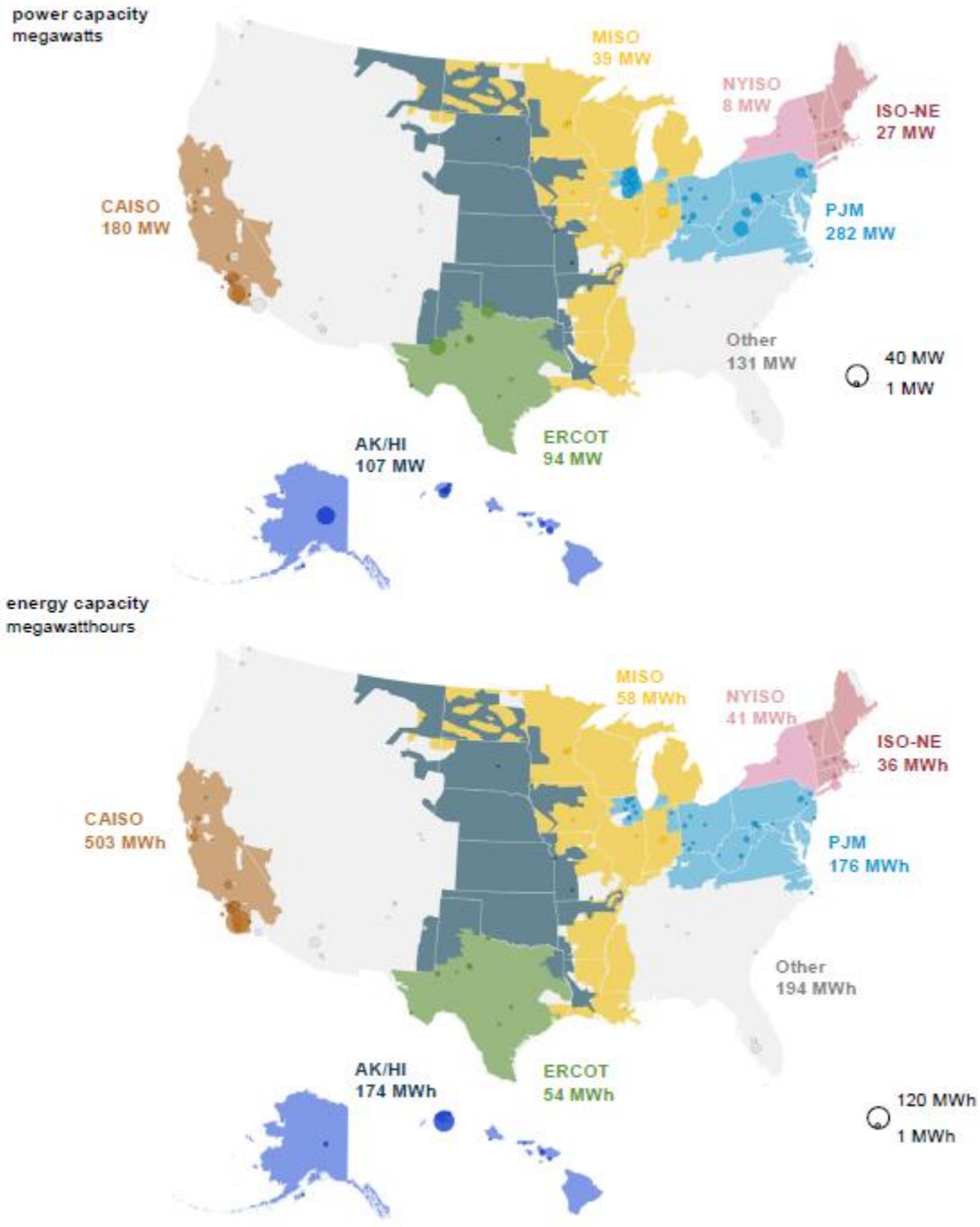


Figure 1.3: Electric Storage Capacity in the United States and Canada, by Type of Storage Technology[14]

[13] https://www.nrel.gov/docs/fy19osti/74426.pdf

[14] Graph adapted from the DOE website, "DOE Global Energy Storage Database," Energy Storage Exchange, www.energystorageexchange.org.

Another view of battery storage technologies across the regulated ISO/RTO markets is shown in **Figure 1.4**. Power capacity (MW) is 282 MW for PJM, 180 MW for CAL-ISO, and 94 MW for ERCOT; the energy capacity (MWh) is 176 MWh for PJM, 503 MWh for CAL-ISO, and 54 MWh for ERCOT.



Sources: U.S. Energy Information Administration, Form EIA-860M, *Preliminary Monthly Electric Generator Inventory;* U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report* Note: Energy capacity data for large-scale battery storage installed in 2018 are based on preliminary estimates.

Figure 1.4: United States Grid-Connected Energy Storage Projects

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

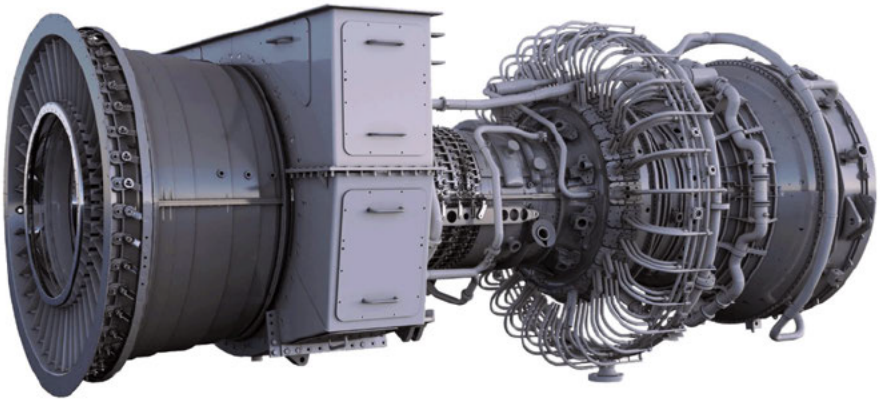
Exhibit 2-63:
GE LM6000 Information

LM6000 aeroderivative gas turbine

A leader in the +40 MW space, the LM6000* has over 40 million operating hours and more than 1,200 units shipped.

View product specifications

Download LM6000 fact sheet



~57 MW	41%	Over 99%	5 min.	100%
SC output	SC efficiency	reliability/availability	start time	H2 capable

Overview

LM6000 power plants

With over 40 million operating hours and more than 1,200 units shipped, GE Vernova's LM6000 aeroderivative gas turbine has more operating experience than any other aeroderivative gas turbine greater in the +40 MW space. The LM6000 offers greater than 99 percent start and operational reliability and over 98 percent availability. Its 5-minute fast start allows operators to differentiate their dispatch capability while a simple two-spool design results in lower overall maintenance costs. Universal and modular packaging gives the LM6000 a smaller footprint and allows for faster installation and commissioning.

Faster power to the grid

Introducing the LM6000VELOX* aeroderivative solution

The new LM6000VELOX aeroderivative solution aims to reduce the installation and commissioning schedule of LM6000 turbines by up to 40%, saving up to 4,000 labor hours. This translates to an expected 90 days I&C schedule. Thanks to multiple enhanced modularity features, the LM6000VELOX aeroderivative solution is ushering in a new era of speed in the energy industry.

GE Vernova's LM6000VELOX aeroderivative solution is available:

- In both simple- and combined-cycle configurations.
- As either a DLE or SAC (water injected) combustor configuration.
- For both 50- and 60-Hertz segments.

See it in action

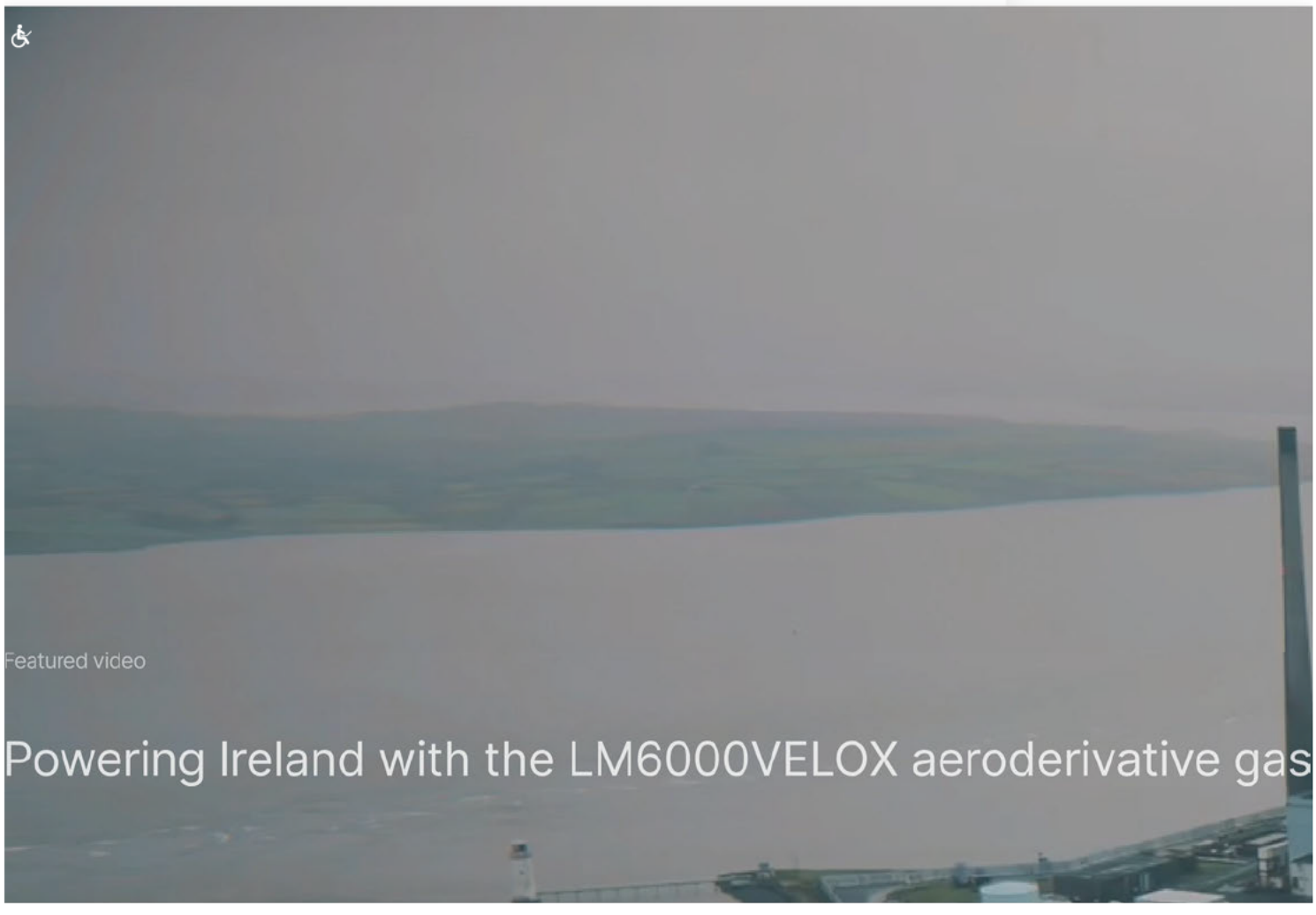
Highlight

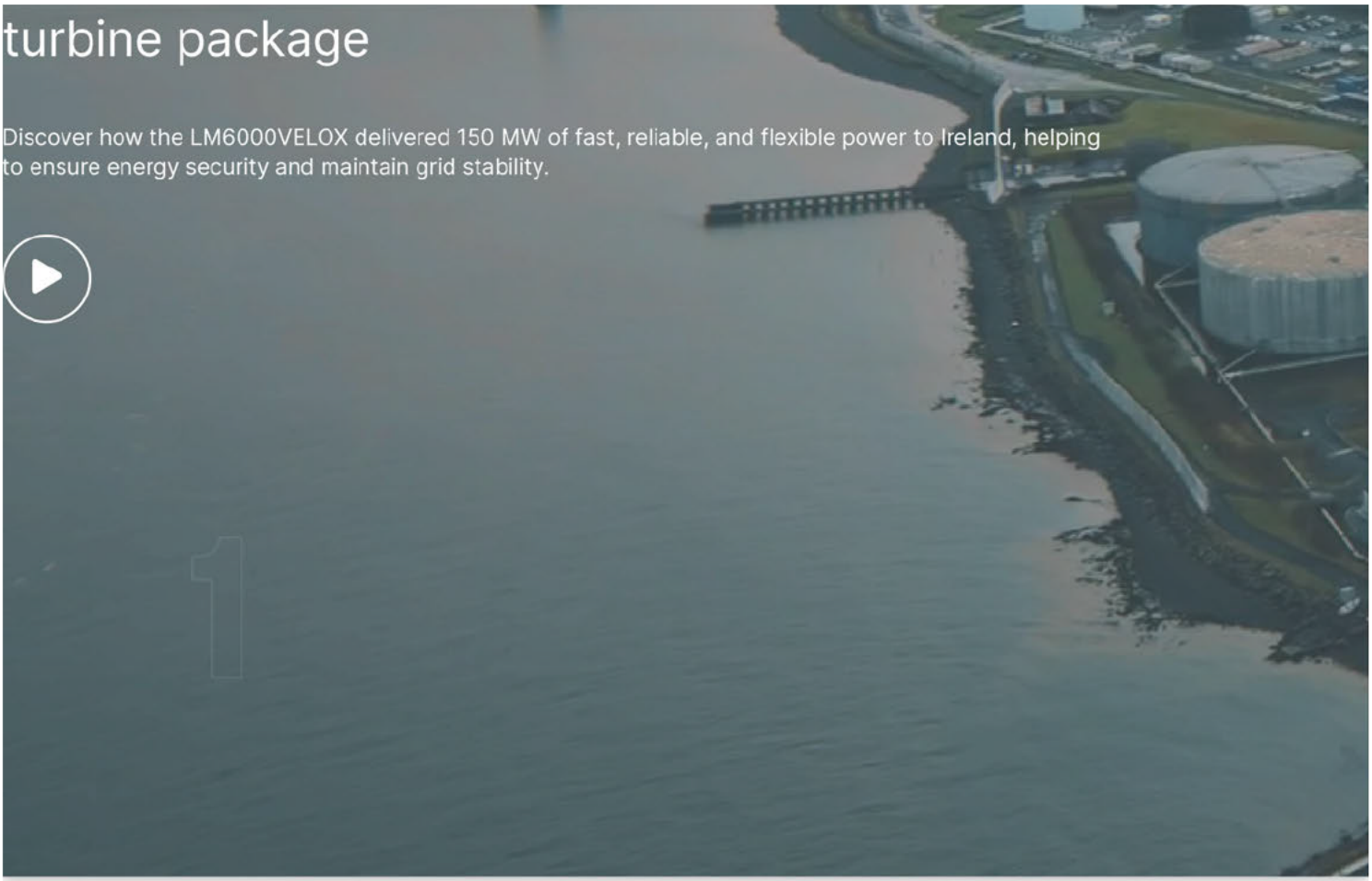
Do you know about the Mark* VIe capabilities?

The Mark VIe is the latest GE Vernova control platform, with just some of its features including:

- Modular, future-ready engineering
- Legacy system integration
- Built-in cybersecurity
- Advanced diagnostics
- Developed for today's fuel demands

Learn more about the Mark VIe solution





Product features

Get to know the LM6000

Fuel flexibility

The LM6000 allows you to operate on a wide variety of fuels—including natural gas, LPG (propane and butane), isopentane, ethanol, diesel, and Coke Oven gas. This means you can quickly switch between fuels to save money, with no interruption in power. The LM6000 is 100% hydrogen capable.

Fast start

Aeros like our LM6000 are built for high cycling capability, which allows customers to get up and running—and on the grid—quickly. With around five minutes to ramp up from start-up to full power, typical medium-speed reciprocating engines have a ramp rate of about 5 MW/min, but aeroderivative gas turbines have a nominal ramp rate of around 50 MW/min, providing a much faster frequency

Spray intercooling (SPRINT*) performance augmentation

Our SPRINT* solution boosts engine performance using a spray intercooling design that increases the mass flow by cooling the air during the compression process. The system is based on an atomized water spray injected through spray nozzles. The water flow rate

control response for better grid support.

is metered, using the appropriate engine control schedules. SPRINT injection points are based on turbine inlet temperature and automatically controlled.

Specifications

Capable, versatile, sustainable power

The LM6000 offers 99%+ start and operational reliability and 98% availability. Its 5-minute fast start allows operators to differentiate their dispatch capability, and its dual-fuel capabilities (gas and diesel) provides fuel flexibility and helps customers meet emissions limits.

Specifications shown are for 50 Hz and 60 Hz.

Simple Cycle—

	LM6000 PC Sprint	LM6000 PF+ Sprint
Net output (MW)	51.1	56.9
Net heat rate (Btu/kWh, LHV)	8595	8328
Net heat rate (kJ/kWh, LHV)	9068	8800
Net efficiency (%, LHV)	39.7%	41.0%

Combined Cycle 1×1+
Combined Cycle 2×1+

LM6000 gas turbines can start up in 5 minutes

*MW output without SPRINT/with SPRINT

NOTE: All ratings are based on ISO conditions and natural gas fuel. Actual performance will vary with project-specific conditions and fuel.

Decarbonization hub

Explore turbine emissions tools & studies

Hydrogen & CO2 emissions calculator

Discover the fuel flow rate needed for hydrogen in gas turbines and explore potential savings from hydrogen use.

Methane slip calculator

Compare unburnt methane amounts released from reciprocating engines vs. turbines and estimate emission reductions.

Aeroderivative gas turbine solutions: A roadmap to 100% hydrogen capability

Get insights on how GE Vernova's advanced gas power technologies drive near-zero carbon, hydrogen solutions, and grid firming.

Navigating the journey to decarbonization & grid stability

Explore how GE Vernova integrates aeroderivative solutions to stabilize renewables and our research green hydrogen potential.

Webinars

Hear from our experts

AI-driven data centers | Aeroderivative gas turbines for munis & co-ops | Can you get more megawatts for your dollar?

Webinar

Bridging the gap: Reliable power for AI-driven data centers

On-demand | Available now

AI is reshaping data center demand. Join GE Vernova, DataVolt and S&P Global to explore how to manage volatility, scale confidently, and build a resilient energy strategy.

Donald Floyd

Sr. Portfolio Manager-Gen AI, GE Vernova Advanced Research

Register to watch now

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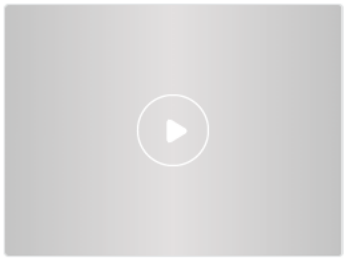
Featured videos

LM6000VELOX: Faster power to the grid

With enhanced speed of installation, the LM6000VELOX can provide fast and reliable energy supply to help stabilize the grid when needed.

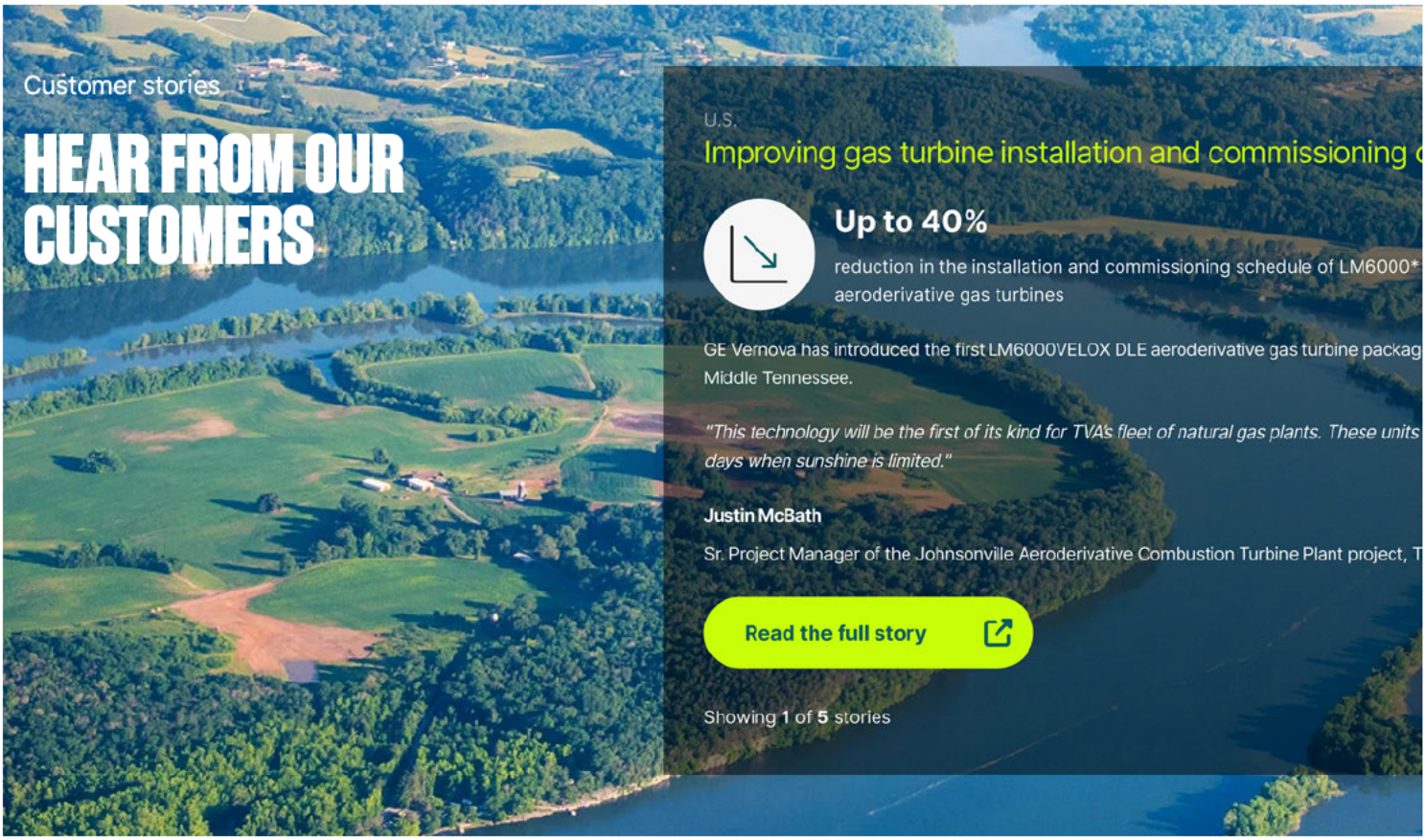


LM6000VELOX DLE package installation

Tennessee Valley Authority (TVA)'s Johnsonville Plant in Middle Tennessee is the site of GE Vernova's first LM6000VELOX DLE package solution.

Keeping Houston's medical center lights on with the LM6000

Discover how TECO and GE Vernova's partnership is driving reliability, availability and efficiency for the largest district cooling system in North America.



Services

Get more from your LM6000 aero turbine

Our services team is prepared to meet your industry-specific requirements and provide more reliable aeroderivative gas turbine services whether you're looking for peaking power, flexible response to immediate grid demands, or simply to keep your operation up and running at a proven 99% rate of reliability.

Upgrades

Our gas turbine upgrade solutions can boost performance and reliability, deliver better efficiency and flexibility, and extend asset life. Whether you need to upgrade your existing engine with our Repower solutions, or improve load balancing, you can explore our gas turbine upgrades tool.

Learn more

Maintenance and repairs

From outages as short as two days—with module and engine exchanges—to customized off-season outages, equipment and engine leasing, upgrades, digital solutions and repairs, our network of global service centers and field service teams combine the highest quality of expertise

and technical aeroderivative gas turbine support with timely, flexible solutions and predictable repair costs.

Learn more

Parts

Reliable plant operations depend on access to flexible parts service. Our global distribution centers are linked to regional supply chains, meaning you've got access to the highest-quality component inventory.

Learn more

Long-term service agreements

Business environments are constantly transforming, but you need to deliver consistent outcomes. By partnering with us for long-term service agreements (LTSAs), you'll be able to realize the full potential of your gas plant.

Learn more

Further reading

Learn more

Explore

- LM6000 gas turbine upgrades
- GE Vernova's LM6000 powering Saudi Arabia's industries
- Aeros vs. reciprocating engines
- Gas turbines for municipalities and cooperatives
- Benefits of cogeneration
- Data center power solutions

Islands and Microgrids

Downloads

LM6000 fact sheet

Aero fuel flexibility white paper

Products

Find the right gas turbine to meet your needs

Whether you're generating; power for entire cities, electrifying your own operations, or are facing an emergency electricity shortage and need power fast, we can act as a versatile gas turbine supplier, ready to quickly provide a range of solutions.

View by type

All | Heavy duty | Aeroderivative

View by frequency

50Hz | 60Hz

View by configuration

Simple | 1×1CC | 2×1CC

9HA	448 - 571 MW	+
9F	294 MW	+
GT13E2	210 MW	+
9E	132 - 147 MW	+
LMS100	112.9 MW	+
6F	88 MW	+
LM6000	51.1 - 57 MW	+
6B	45 MW	+
LM2500	34.5 - 36.3 MW	+
TM2500	34.5 - 34.6 MW	+

Contact us

Want to learn more?

Contact us today

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Steam turbines
Generators
HRSG
Controls / digital
Industries
Applications
Services

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Empowering the data-driven world with reliable, cleaner energy

GE Vernova's Gas Power business helps provide scalable efficient, infrastructure that supports the world's energy demands, including those of hyperscale and colocation data centers. Explore our products, from fuel-flexible turbines to services that keep reliable power flowing worldwide.

Explore our Gas Power data centers solutions

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-64:
Tri-State SPP West Press Release

Benefits of SPP RTO West participation highlighted in filing with Colorado PUC

tristate.coop/benefits-spp-rto-west-participation-highlighted-filing-colorado-puc

06/17/25

- Tri-State requests Colorado Public Utilities Commission finding that SPP RTO is a statutory Organized Wholesale Market and Tri-State's expanded participation in SPP RTO is in the public interest.
- Expanded participation in SPP RTO promotes reliability, affordability and environmental responsibility.

(June 17, 2025, Westminster, Colo.) Following years of collaboration with other regional utilities, transmission providers and stakeholders, Tri-State has filed an application to the Colorado Public Utilities Commission (CoPUC) as the cooperative power supplier plans to expand its participation in the Southwest Power Pool Regional Transmission Organization (SPP RTO) in the West.

Tri-State's application outlines the significant benefits of joining the SPP RTO, under a Federal Energy Regulatory Commission (FERC) approved tariff, as Tri-State and six other Western utilities prepare for full market integration in April 2026. Tri-State's filing marks another milestone in a multi-year effort to expand its market participation to bring increased reliability, affordability, efficiency and responsibility to the region's power grid.

"Grid reliability and resiliency is bolstered with the western expansion of the SPP RTO, as Tri-State serves growing member loads, diversifies our resource portfolio and reduces emissions," said Duane Highley, Tri-State's Chief Executive Officer.

SPP RTO West to deliver market benefits for Tri-State members

The SPP RTO provides Tri-State and its members greater access to:

- **Economic benefits**: An estimated $20 million in annual net benefits for Tri-State alone, as part of more than $200 million in potential annual regional benefits.
- **Efficient dispatch**: Optimized use of regional generation and transmission, and more efficient resource integration, including intermittent renewable energy resources.
- **Transmission system optimization:** Coordinated regional use of transmission assets to meet growing energy demand.
- **Environmental performance**: Ability to meet greenhouse gas reduction requirements more cost-effectively, with robust tracking and reporting mechanisms.
- **Improved generator interconnection**: New interconnection procedures and queue reforms to make integrating new resources more efficient.

“The expansion of the SPP RTO is the most cost-effective pathway to organized market benefit for Tri-State’s members,” said Highley. “Our participation will support our members’ goals for reliability, affordability, and a cleaner energy future, with cost savings shared by all members.”

The SPP RTO West would include a cohort of utilities and transmission providers currently participating in the SPP Western Energy Imbalance Service (WEIS) market—including Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, the Municipal Energy Agency of Nebraska, Platte River Power Authority, and the Western Area Power Administration (WAPA).

Significant Tri-State resources, loads to participate, as regional market reduces seams

FERC approved SPP’s amended tariff in March 2025, enabling SPP to become the first RTO to operate across both the Eastern and Western Interconnections, improving operational flexibility and resiliency across regions.

Tri-State’s owned and contracted resources, transmission and loads in portions of Tri-State’s Colorado, Nebraska and Wyoming Western Interconnection system in the WAPA “WACM” balancing area (BA), which are currently participating in the SPP WEIS market, would transition to the SPP RTO West, including:

- **Resources:** More than 20 generating units, renewable purchase power and contracted resources.
- **Transmission:** More than 3,100 miles of high voltage transmission and more than 200 substations and switching stations.
- **Member Load:** Portions of 23 of Tri-State’s members’ loads, representing 67% percent of gross load across the Tri-State system.

The transition to the SPP RTO West will reduce the number of transmission provider-related seams between transmission providers in Colorado, Wyoming, Montana and Nebraska through the consolidation of seven transmission providers’ tariffs into a SPP RTO common tariff, also reducing the costly “pancaking” of transmission rates. In addition, two BAs will combine to form the SPP West BA. In Colorado, the seam currently between the WACM BA (which becomes part of the SPP West BA) and the Public Service Company of Colorado (Xcel Energy) BA will still exist.

“SPP has successfully shown that it can optimize operations and develop seam agreements between other markets and balancing areas, ” said Highley. “These conversations are already underway for the SPP RTO West.”

Participation in SPP RTO West years in the making

Tri-State has played a foundational role in bringing organized markets to the West, working collaboratively with peer utilities and transmission providers to explore and develop organized market participation frameworks tailored to the needs of Western utilities.

“We greatly value the full benefits of the SPP RTO, including day-ahead, real-time and ancillary services markets, efficient regional transmission planning, reliability coordination, a common transmission tariff and a participatory governance model that help us reduce costs and advance clean energy goals,” said Highley.

In 2015, Tri-State became a member of SPP and placed its Eastern Interconnection transmission facilities under SPP’s tariff. In the Western Interconnection, Tri-State was a founding member of SPP’s WEIS market in 2021. Tri-State has participated in the California Independent System Operator’s Western Energy Imbalance Market in a portion of Wyoming since its inception in 2014, expanding participation into New Mexico in 2021.

In 2020, Tri-State first announced its interest in the western expansion of the SPP RTO, with subsequent resource plan filings and stakeholder engagement processes, maintaining transparency concerning Tri-State’s progress in considering its SPP RTO West participation.

“This effort by our staff, SPP, western utilities, and stakeholders, reflects years of collaboration and commitment to shared goals,” said Highley. “We look forward to further demonstrating the benefits of the market to Colorado regulators and stakeholders.”

Tri-State’s filing seeks a CoPUC finding that participation in SPP RTO is in the public interest and SPP RTO meets the Colorado statutory definition of an Organized Wholesale Market. Colorado regulations signed into law in 2021 require transmission utilities, including Tri-State, to join an organized wholesale market by 2030.

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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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-65:
CDPHE Regulation No. 3

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

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

Outline of Regulation

PART A Concerning General Provisions Applicable to Reporting and Permitting

PART B Concerning Construction Permits

PART C Concerning Operating Permits

PART D Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration

PART E Reserved for Environmental Management Systems

PART F Regional Haze Limits - Best Available Retrofit Technology (BART) and Reasonable Progress (RP)

PART G Statements of Basis, Specific Statutory Authority and Purpose

PART A CONCERNING GENERAL PROVISIONS APPLICABLE TO REPORTING AND PERMITTING

I. Applicability

I.A. The provisions of this Part A shall apply statewide to all sources of air pollutants except as otherwise provided herein.

All sources of air pollutants that have previously obtained an emissions permit (prior to July 1, 1992) or a construction permit, and are subject only to the Part B Construction Permit Program, may choose to reapply for a new construction permit pursuant to Part B of this Regulation Number 3 in order to obtain the operational flexibility provided in Section IV. of this Part A, or to obtain federally enforceable limitations to limit the source's potential to emit ("synthetic minor"). Sources of air pollutants that are subject only to the Part B Construction Permit Program may voluntarily apply for an Operating Permit pursuant to Part C.

Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Technical Secretary of the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Materials incorporated by reference are those editions in existence as of the date of this regulation as promulgated or revised by the Commission and references do not include later amendments to or editions of the incorporated materials.

I.B. Definitions

I.B.1. Administrative Permit Amendment.

I.B.1.a. A permit revision that:

I.B.1.a.(i) Corrects typographical errors;

I.B.1.a.(ii) Identifies a change in the name, address, or phone number of any person identified in the permit, or provides a similar minor administrative change at the source;

I.B.1.a.(iii) Requires more frequent monitoring or reporting by the permittee;

I.B.1.a.(iv) Allows for a change in ownership or operational control of a source where the Division determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division;

I.B.1.b. An administrative permit amendment for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

I.B.2. Administrator

The administrator of the U.S. Environmental Protection Agency (U.S. EPA).

I.B.3. Adverse Environmental Effect

As a term used in the context of regulating hazardous air pollutants, any significant and widespread adverse effect, that may reasonably be anticipated, to wildlife, aquatic life, or other natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental quality over broad areas.

I.B.4. Affected States

All states whose air quality may be affected by issuance of an operating permit, operating permit modification, or operating permit renewal and that are contiguous to Colorado; and/or all states that are within fifty miles of a permitted source.

I.B.5. Affected Unit

A unit that is subject to any acid rain emissions reduction requirement or acid rain emissions limitation pursuant to Title IV of the Federal Act or regulations promulgated there under, in the Code of Federal Regulations Title 40, Part 72.

I.B.6. Air Pollutant

Means carbon monoxide, nitrogen oxides, sulfur dioxide, PM10, PM2.5, total suspended particulates, ozone, volatile organic compounds, lead, all pollutants regulated under Section 111 of the Federal Act (Regulation Number 6), all hazardous air pollutants, and all class I and class II ozone depleting compounds as defined and referenced in Section 602 of the Federal Act.

I.B.7. Allowable Emissions

The emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable or enforceable as a practical matter, permit conditions that restrict the operating rate or hours of operation, or both) and the most stringent of the following:

I.B.7.a. The applicable standards promulgated pursuant to the Federal Act for new source performance or hazardous air pollutants;

I.B.7.b. The applicable Colorado Emission Control Regulation; or

I.B.7.c. The emissions rate specified as a federally enforceable, or enforceable as a practical matter, permit condition, including those with a future compliance date.

I.B.8. Annual Actual Emissions

The actual rate of emissions of a pollutant, excluding excess emissions from a malfunction, or startups and shutdowns associated with a malfunction. Annual actual emissions shall be calculated using the source's actual operating rates, and types of materials processed, stored, or combusted during the calendar year.

I.B.9. Applicable Requirement

Means all of the following as they apply to emissions units in a source subject to operating permit requirements of this regulation (including requirements that have been promulgated or approved by the U.S. EPA through rulemaking at the time of permit issuance but have future effective compliance dates);

I.B.9.a. Any term or condition of any construction permit issued pursuant to Part B of this Regulation Number 3, or any such term or condition as modified by procedures authorized by the operating permit program pursuant to Parts B and C of this Regulation, or any permit issued under Part C or Part D of the Federal Act, except that state-only permit terms or conditions shall remain enforceable solely pursuant to state law;

I.B.9.b. Any standard or other requirement provided for in the state implementation plan;

I.B.9.c. Any standard or other requirement under Section 111 of the Federal Act (New Source Performance Standards), including Section 111(d) of the Federal Act (Standards of Performance for existing sources) (Regulation Number 6);

I.B.9.d. Any standard or other requirement under Section 112 of the Federal Act (hazardous air pollutants, including any requirement concerning accident prevention under Section 112(r)(7) of the Federal Act) (Regulation Number 8) but not including the contents of any risk management plan required under Section 112(r) of the Federal Act;

I.B.9.e. Any requirements for monitoring and compliance assurance monitoring methods and procedures to ensure compliance with permit requirements, including periodic monitoring and testing, and compliance certifications, established pursuant to Sections 504(b) or 114(a)(3) of the Federal Act;

I.B.9.f. Any standards or other requirement under the Code of Federal Regulations Title 40, Part 72 (acid deposition control);

I.B.9.g. Any standard or other requirement governing solid waste incineration;

I.B.9.h. Any standard or other requirement for consumer and commercial products;

I.B.9.i. Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under Title VI of the Federal Act, except where the Administrator has determined such requirement need not be contained in an operating permit (Regulation Number 15);

I.B.9.j. Any national ambient air quality standard or increment or visibility requirement under Part C of Title I of the Federal Act, but only as it would apply to temporary sources permitted pursuant to Part C of this Regulation Number 3.

I.B.10. Carbon Dioxide Equivalent (CO_2e)

A metric used to compare the emissions from various GHG classes based upon their global warming potential (GWP). The CO_2e is determined by multiplying the mass amount of emissions (tons per year), for each GHG constituent by that gas's GWP, and summing the resultant values to determine CO_2e (tons per year). The applicable GWPs codified in 40 CFR Part 98, Subpart A, Table A-1 – Global Warming Potentials are hereby incorporated by reference as in effect as of November 29, 2013, but not including later amendments.

I.B.11. Commence, also Commence Construction

When the owner or operator has obtained all necessary pre-construction approvals or permits required by federal, state, or local air pollution and air quality laws and regulations and has either; (a) begun, or caused to begin, a continuous program of physical onsite construction of the source, or (b) entered into binding agreements or contractual obligation that cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time. The following activities do not require the owner or operator to obtain a permit: 1) planning; 2) site clearing and grading; 3) ordering of equipment and materials; 4) storing of equipment; 5) setting up temporary trailers to house construction management staff and contractor personnel; 6) engineering and design; and 7) geotechnical investigation. In the event that the source does not qualify for issuance of a permit, the owner or operator accepts the financial risk of commencing these activities.

I.B.12. Commencement of Operation

A new source commences operation when it first conducts the activity that it was designed and permitted for (i.e., producing cement or generating electricity).

I.B.13. Construction Permit

Means the same as an emission permit as required under Part B of this regulation as it existed prior to July 1, 1992, and is the permit required under Colorado Revised Statutes Section 25-7-114.2 after July 1, 1992.

I.B.14. Continuous Emissions Monitoring System (CEMS)

All of the equipment that is required to meet the data acquisition and availability requirements of Part D of this Regulation or of a permit issued in accordance with Parts B or C of this regulation, to sample, condition (if applicable), analyze, and provide a record of emissions on a continuous basis.

I.B.15. Continuous Emissions Rate Monitoring Systems (CERMS)

The total equipment required for the determination and recording of the pollutant mass emissions rate (in terms of mass per unit of time).

I.B.16. Continuous Parameter Monitoring System (CPMS)

All of the equipment necessary to meet the data acquisition and availability requirements of Part D of this Regulation, to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O2 or CO2 concentrations), and to record average operational parameter value(s) on a continuous basis.

I.B.17. Criteria pollutants

Those pollutants for which the U.S. EPA has established national ambient air quality standards, including: carbon monoxide, nitrogen dioxide (direct emissions and as a precursor to ozone and PM2.5), sulfur dioxide (direct emissions and as a precursor to PM2.5), PM10, PM2.5, total suspended particulate matter, ozone, volatile organic compounds (as a precursor to ozone), and lead.

For the purposes of Air Pollutant Emission Notice reporting, criteria pollutants shall also include nitrogen oxides, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, municipal waste combustor organics, municipal waste combustor metals, and municipal waste combustor acid gases.

I.B.18. Designated Representative

Means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with Subpart B of Code of Federal Regulations, Title 40, Part 72, to represent and legally bind each owner and operator, as a matter of law, in matters pertaining to the acid rain program. Whenever the term responsible official is used, it shall be deemed to refer to the designated representative with regard to all matters under the acid rain program.

I.B.19. Draft Permit

Means a proposed form of a permit that is released to the public for an opportunity for public comment and hearing, and for affected state review prior to the Division's final decision on a permit application.

I.B.20. Existing Source

An air pollutant source that has been constructed, is in operation, or has received an initial approval of a construction permit prior to the effective date of applicable requirements.

I.B.21. Fugitive Dust

For purposes of this Regulation Number 3, fugitive dust means soil or other airborne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported, or redistributed; except that fugitive dust shall not include any fraction of such soil or other airborne particulate matter that is of a size or substance to adversely affect public health or welfare.

I.B.22. General Permit

Means a single permit issued to cover numerous similar sources.

I.B.23. Greenhouse Gas (GHG)

Means the aggregate group of the following six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These gases are treated in aggregate based on the total carbon dioxide equivalent (CO_2e) as the pollutant GHG. See definition for carbon dioxide equivalent (CO_2e).

For purposes of a GHG PAL, these gases shall not be subject to regulation if the stationary source maintains its total source-wide emissions below the GHG PAL level, meets the requirements of Part D, Section XV., and complies with the PAL permit containing the GHG PAL.

I.B.24. Indirect Source

A facility, building, structure, or installation, or any combination thereof, excluding dwellings, which can reasonably be expected to cause or induce substantial mobile source activity that results in emissions of air pollutants that might reasonably be expected to interfere with the attainment and maintenance of National Ambient Air Quality Standards.

I.B.25. Major Source

Any stationary source or group of stationary sources belonging to the same industrial grouping (see Section I.B.43. of this Part A), that are located on one or more contiguous or adjacent properties and are under common control of the same person (or persons under common control) that:

I.B.25.a. Directly emits, or has the potential to emit considering enforceable controls, in the aggregate, ten tons per year or more of any hazardous air pollutant or twenty-five tons per year or more of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as may be established pursuant to the Federal Act. Emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this provision. Fugitive emissions shall be considered in determining whether a stationary source of hazardous air pollutants is a major source.

I.B.25.b. Directly emits, or has the potential to emit, one hundred tons per year or more of any pollutant subject to regulation. Fugitive emissions shall not be considered in determining whether a source is a major source for purposes of this Section I.B.25.b., unless the source belongs to one of the following categories of stationary sources:

I.B.25.b.(i) Coal cleaning plants (with thermal dryers);

I.B.25.b.(ii) Kraft pulp mills;

I.B.25.b.(iii) Portland cement plants;

I.B.25.b.(iv) Primary zinc smelters;

I.B.25.b.(v) Iron and steel mills;

I.B.25.b.(vi) Primary aluminum ore reduction plants;

I.B.25.b.(vii) Primary copper smelters;

I.B.25.b.(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

I.B.25.b.(ix) Hydrofluoric, sulfuric, or nitric acid plants;

I.B.25.b.(x) Petroleum refineries;

I.B.25.b.(xi) Lime plants;

I.B.25.b.(xii) Phosphate rock processing plants;

I.B.25.b.(xiii) Coke oven batteries;

I.B.25.b.(xiv) Sulfur recovery plants;

I.B.25.b.(xv) Carbon black plants (furnace process);

I.B.25.b.(xvi) Primary lead smelters;

I.B.25.b.(xvii) Fuel conversion plants;

I.B.25.b.(xviii) Sintering plants;

I.B.25.b.(xix) Secondary metal production plants;

I.B.25.b.(xx) Chemical process plants;

I.B.25.b.(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

I.B.25.b.(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

I.B.25.b.(xxiii) Taconite ore processing plants;

I.B.25.b.(xxiv) Glass fiber processing plants;

I.B.25.b.(xxv) Charcoal production plants;

I.B.25.b.(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; or

I.B.25.b.(xxvii) Any other stationary source categories regulated by a standard promulgated as of August 7, 1980 under Section 111 or 112 of the Federal Act, but only with respect to those air pollutants that have been regulated for that category.

I.B.25.c. Meets any of the definitions of major stationary source set forth in Section II.A.25. of Part D of this Regulation Number 3.

I.B.26. Minor Source

Any stationary source that does not qualify as a major source (as defined in Section I.B.25. above).

I.B.27. Mobile Source

Motor vehicles and other sources of air pollution that emit pollutants while moving and that commonly do not remain at one site (one or more contiguous or adjacent properties owned or operated by the same person or by persons under common control), but does not include portable sources.

I.B.28. Modification

Any physical change in, or change in the method of operation of, a stationary source that does not meet the definition of major modification (as defined in Section II.A.23. of Part D of this regulation), and that increases the emission rate of any pollutant for which a federal or state emission standard has been promulgated or that results in the emission of any such pollutant previously not emitted. The following exceptions apply:

I.B.28.a. Routine maintenance, repair, and replacement shall not be considered a physical change;

I.B.28.b. Unless previously limited by enforceable permit terms and conditions, the following shall not be considered to be a change in the method of operation:

I.B.28.b.(i) An increase in the production rate if such increase does not exceed the design capacity of the source and does not lead to emissions in excess of the emission standards;

I.B.28.b.(ii) An increase in the hours of operation that does not lead to emissions in excess of the emission standards.

I.B.28.b.(iii) Use of an alternative fuel or raw material by reason of an order in effect under Sections 2(a) and (b) of the Federal Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), a prohibition under the Federal Power Plan and Industrial Fuel Act of 1978 (or any superseding legislation) or by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act;

I.B.28.b.(iv) Use of an alternative fuel by reason of an order or rule under Section 125 of the Federal Act; or

I.B.28.b.(v) Change in ownership of the source.

I.B.28.c. Emissions resulting from construction and exploration shall be excluded in determining whether a modification will occur. Emissions from ongoing construction, and emissions from natural gas flaring are not considered to be temporary emissions, and are included in determining whether a modification will occur.

I.B.28.d. This definition shall not be used as a definition of major modification or minor permit modification (as defined in Section I.A.2. of Part C of this regulation)-- these are distinct and separate definitions.

I.B.28.e. Any physical change or change in the method of operation at a source with an operating permit issued pursuant to Part C of this Regulation Number 3, that does not constitute a major modification (as defined in Part D, Section II.A.23. of this Regulation Number 3) and that does not trigger new source performance standards or hazardous air pollutant requirements under the Federal Act is not considered to be a modification; except that any such change shall trigger the provisions of Part B, Section III.D.1.a. through III.D.1.g., and Part C, Sections X.A., and Part C Sections XII.A. or XII.B., as appropriate.

for Administrative Permit Amendment see Section I.B.1. of Part A
for Minor Permit Modification, see Section I.A.2. of Part C
for Major Modification, see Section II.A.23. of Part D

for Permit Modification, see Section I.A.3. of Part C
for Permit Revision, see Section I.B.34. of Part A
for Significant Permit Modification, see Section I.A.7. of Part C

I.B.29. New Source

A stationary air pollution source, other than an existing source; or any source that resumes operation after being inactive for more than one year after having been shut down for the purpose of eliminating emissions that violated any applicable emission control regulation or regulation for the control of hazardous air pollutants.

I.B.30. Non-criteria Reportable Pollutants

The list of pollutants set forth in Appendix B and those ozone-depleting compounds listed in Section 602 of the Federal Act.

I.B.31. Non-Road Engine

I.B.31.a. Except as discussed in Section I.B.31.b. of this definition, a non-road engine is an internal combustion engine:

I.B.31.a.(i) In or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers); or

I.B.31.a.(ii) In or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers); or

I.B.31.a.(iii) That, by itself or in or on a piece of equipment is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to wheels, skids, carrying handles, dolly, trailer or platform.

I.B.31.b. An internal combustion engine is not a non-road engine if:

I.B.31.b.(i) The engine is used to propel a motor vehicle or a vehicle used solely for competition, or is subject to standards promulgated under Section 202 of the Federal Act; or

I.B.31.b.(ii) The engine is regulated by a federal New Source Performance Standard promulgated under Section 111 of the Federal Act; or

I.B.31.b.(iii) The engine otherwise included in Section I.B.31.a.(iii) of this definition remains or will remain at a location for more than twelve consecutive months or a shorter period of time for an engine located as a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (i.e., at least two years) and that operates at a single location approximately three months (or more) each year. This Section does not apply to an engine after the engine is removed from the location.

I.B.31.c. (State-only Requirements) Non-road engines not co-located at an existing major source

An operator of a non-road engine as defined in Section I.B.31.a.(iii), above, with a manufacturer's site-rated horsepower of 1,200 or greater, or an aggregation of such non-road engines each with a manufacturer's site-rated horsepower of 1,200 or greater, that operate more than 4,380 hours per year at the same location are subject to the following state-only requirements:

I.B.31.c.(i) Submit an air pollutant emission notice and pay the appropriate fees pursuant to Section VI. of Part A of this regulation;

I.B.31.c.(ii) Submit an application for a site-specific, temporary, non-road engine permit on forms supplied by the Division if the estimated annual actual emissions reported on the Air Pollutant Emission Notice, as required by Section I.B.31.c.(i), are equal to or exceed one hundred tons per year or more of nitrogen oxides, 100 tons per year or more of carbon monoxide, or forty tons per year or more of sulfur dioxide. After receipt and review of a complete application, the Division shall issue a state-only non-road engine permit containing such terms and conditions as are necessary to protect the ambient air quality standards.

I.B.31.c.(iii) The operator of a non-road engine that is exempt based on hours of operation or the annual emissions thresholds described above, must maintain sufficient records to verify that the engine or engines are exempt from the state-only reporting and permit requirements. Such records shall be made available for Division review upon request.

I.B.31.d. (State-only Requirements) Non-road engines co-located at an existing major source of nitrogen oxides or sulfur dioxide

An operator of a non-road engine or aggregation of engines each with a manufacturer's site-rated horsepower of 1,200 or greater, and are non-road engines under Section I.B.31.a.(iii) of this definition, are subject to the following state-only requirements:

I.B.31.d.(i) Submit an air pollutant emission notice and pay the fees required by Section VI. of this Part;

I.B.31.d.(ii) Submit an application for a site-specific, temporary, state-only non-road engine permit on forms supplied by the Division if the estimated annual actual emissions reported on the air pollutant emission notice, as required by Section I.B.29.d.(i), are equal to or exceed forty tons per year or more of nitrogen oxides, one hundred tons per year or more of carbon monoxide, or forty tons per year or more of sulfur dioxide. After receipt and review of a complete application, the Division shall issue a temporary state-only non-road engine permit containing such terms and conditions as are necessary to protect the ambient air quality standards.

I.B.31.d.(iii) The operator of a non-road engine that is 1,200 horsepower or greater, but is exempt on the basis of the annual emissions thresholds described above, must maintain sufficient records to verify that the engine or engines are exempt from the state-only reporting and permit requirements. Such records shall be made available for Division review upon request.

I.B.32. Operating Permit

Unless the context suggests otherwise, any permit or group of permits covering an operating permit source that is issued, renewed, amended or revised pursuant to Part C of this Regulation Number 3.

I.B.33. Operating Permit Source

Any source subject to the permitting requirements of Part C of this regulation.

I.B.34. Permit Revision

Any permit modification, minor permit modification, or administrative permit amendment. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program provided that such increases do not require a permit revision under any other applicable requirement.

I.B.35. Pollution Prevention

Any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants (including fugitive emissions) and other pollutants to the environment prior to recycling, treatment, or disposal. This definition does not include recycling (other than certain “in-process recycling” practices), energy recovery, treatment, or disposal.

I.B.36. Portable Source

A source such as, but not limited to, asphalt batch plants and aggregate crushers that commonly and by usual practice is moved from one site to another. A source will not be considered portable if it remains on one site for more than two years.

I.B.37. Potential to Emit

The maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state enforceable and federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

I.B.38. Predictive Emissions Monitoring System (PEMS)

All of the equipment necessary to monitor process and control device operational parameters (for example, control device secondary voltages and electric currents) and other information (for example, gas flow rate, O2 or CO2 concentrations), and calculate and record the mass emissions rate (for example, lb/hr) on a continuous basis.

I.B.39. Regulated Air Pollutant

Nitrogen oxides or any volatile organic compounds, except as listed in the definition of negligibly reactive volatile organic compounds in the Common Provisions regulation; any pollutant for which a national or state ambient air quality standard has been promulgated; any pollutant that is subject to any standard promulgated under Section 111 of the Federal Act (Regulation Number 6); any class I or II substance subject to a standard promulgated under or established by Title VI of the Federal Act; any pollutant subject to a standard promulgated under Section 112 or other requirements established under Section 112 of the Federal Act, including Sections 112(g), (j), and (r) of the Federal Act; and any pollutant subject to a standard promulgated pursuant to Colorado Revised Statutes Section 25-7-109.3(5)(a), (state-only hazardous air pollutants listed in Section 25-7-109.3(5)(a) are subject to state enforcement only and do not trigger enforcement by the Administrator or by citizens under Section 304 of the Federal Act.)

Once a source becomes subject to the operating permit requirements, regulated air pollutants must be addressed in the permit application and in the permit.

I.B.40. Responsible Official

One of the following:

I.B.40.a. For a corporation: a president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

I.B.40.a.(i) The facilities employ more than two hundred and fifty persons or have gross annual sales or expenditures exceeding twenty-five million dollars (in second quarter 1980 dollars); or

I.B.40.a.(ii) The delegation of authority to such representative is approved in advance by the Division;

I.B.40.b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

I.B.40.c. For a municipality, state, federal, or other public agency; either a principal executive officer, or ranking elected official. For the purposes of this section, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency; or

I.B.40.d. For affected sources:

I.B.40.d.(i) The designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the Federal Act or the regulations, found at Code of Federal Regulations Title 40, Part 72, promulgated there under are concerned; and

I.B.40.d.(ii) The designated representative under Title IV of the Federal Act or the Code of Federal Regulations Title 40, Part 72 for any other purposes under the Code of Federal Regulations Title 40, Part 70.

I.B.41. Schedule of compliance

A schedule of required measures, including an enforceable sequence of actions or operations, leading to compliance with an applicable state implementation plan, emission standard, emission limitation, emission prohibition, or emission control regulation.

I.B.42. State-only Condition

Means any standard, term or condition that is not required by Part C of this regulation (Title V Operating Permits), Part D of this regulation (major New Source Review), Title III (hazardous air pollutants) or Section 111 (New Source Performance Standards) of the Federal Act, is not required to be federally enforceable to participate in the early reductions program, is not required to create a federally enforceable emissions limitation in order to create a synthetic minor source (as defined in Section I.A. of this Part), or is otherwise more stringent than a requirement under the Federal Act.

I.B.43. Stationary Source

Any building, structure, facility, or installation, or any combination thereof belonging to the same industrial grouping that emits or may emit any air pollutant subject to regulation under the Federal Act, that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control. Those emissions resulting directly from an internal combustion engine for transportation purposes or from a non-road engine as defined in Section I.B.29. of this Part shall not be considered a stationary source. Building, structures, facilities, equipment, and installations shall be considered to belong to the same industrial grouping if they belong to the same major groups (i.e., have the same two-digit codes) as described in the Standard Industrial Classification Manual, 1987, but not later amendments. See National Technical Information Service, Order Number PB 87-100012. The manual is available for examination at the office of the Director of the Air Pollution Control Division, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530.

for Affected Source see Section I.A.1. of Part C
for Existing Source, see Section I.B.20. of Part A
for Indirect Source, see Section I.B.24. of Part A
for Major Source, see Section I.B.25. of Part A
for Major Stationary Source, see Section II.A.25. of Part D

for Minor Source, see Section I.B.26. of Part A
for Mobile Source, see Section I.B.27. of Part A
for New Source, see Section I.B.29. of Part A
for Portable Source, see Section I.B.36. of Part A
for Temporary Source, see Section I.B.45. of Part A

I.B.44. Subject to Regulation

For any air pollutant, that the pollutant is subject to either a provision in the Federal Act, or a nationally-applicable regulation codified by the Administrator in Subchapter C of 40 CFR Chapter I of the Federal Act, that requires actual control of the quantity of emissions of the pollutant, and that such a control requirement has taken effect and is operative to control, limit or restrict the quantity of emissions of that pollutant released from the regulated activity, except that:

I.B.44.a. GHG shall not be subject to regulation except as provided in Sections I.B.44.d. through f. of this Part A.

I.B.44.b. For purposes of Section I.B.44.c. through e., the term CO2e of this Part A, shall represent an amount of GHG emitted, and shall be computed as follows:

I.B.44.b.(i) Multiplying the mass amount of emissions (tpy), for each of the six GHGs in the pollutant GHG, by the gas's associated GWP published at Table A-1 to Subpart A of Part 98 of 40 CFR as in effect November 29, 2013, which is hereby incorporated by reference, but not including later amendments. For purposes of this paragraph, prior to July 21, 2014, the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

I.B.44.b.(ii) Sum the resultant value from Section I.B.44.b.(i) of this Part A, for each gas to compute a tpy CO2e.

I.B.44.c. The term emissions increase as used in Sections I.B.44.d. through e. of this Part A, shall mean that both a significant emissions increase (as calculated using the procedures in Section II.A.23 of Part D) and a significant net emissions increase (as defined in Sections II.A.26, and II.A.44 of Part D) occur. For the pollutant GHG, an emissions increase shall be based on tpy CO2e, and shall be calculated assuming the pollutant GHG is a regulated NSR pollutant, and significant is defined as 75,000 tpy CO2e instead of applying the value in Section II.A.44.b. of Part D.

I.B.44.d. Beginning January 2, 2011, the pollutant GHG is subject to regulation concerning major stationary source new source review and prevention of significant deterioration if:

I.B.44.d.(i) The stationary source is a new major stationary source for a regulated NSR pollutant that is not GHG, and also will emit or will have the potential to emit 75,000 tpy CO2e or more; or

I.B.44.d.(ii) The stationary source is an existing major stationary source for a regulated NSR pollutant that is not GHG, and also will have an emissions increase of a regulated NSR pollutant, and an emissions increase of 75,000 tpy CO2e or more.

I.B.44.e. Repealed.

I.B.44.f. If there is a change in federal law that supersedes, or the District of Columbia Circuit Court of Appeals or the United States Supreme Court directs or issues an order, which limits or renders ineffective the regulation of GHG emissions at stationary sources under the New Source Review Prevention of Significant Deterioration(PSD) or Title V provisions of the Federal Act the regulation, GHG emissions under the corresponding programs in this Regulation Number 3 shall be limited or rendered ineffective to the same extent.

I.B.45. Temporary Source

A source in operation for not more than two years in duration unless the Division determines that a longer time period is appropriate.

I.B.46. Uncontrolled Actual Emissions

The annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice form, without consideration of any emission control equipment or procedures.

The Division may allow a source to forego calculating or estimating its uncontrolled actual emissions of hazardous air pollutants upon a showing by the source and a determination by the Division that the creation of such data is unreasonably costly, technically impractical or not reasonably related to information necessary for making regulatory decisions with respect to that source. The Division's final determination may be appealed to the Commission by the source.

I.B.47. Wet Screening Operations

A screening operation at a nonmetallic mineral processing plant that removes unwanted material or that separates marketable fines from the product by a washing process that is designed and operated at all times such that water is an integral part of the process and the product is saturated with water. Screens that use spray bars for the purposes of dust control are not included in this definition.

II. Air Pollutant Emission Notice (APEN) Requirements

II.A. Air Pollutant Emission Notices for New, Modified, and Existing Sources

Except as specifically exempted in Section II.D., no person shall allow emission of air pollutants from, or construction, modification or alteration of, any facility, process, or activity which constitutes a stationary source, except residential structures, from which air pollutants are, or are to be, emitted unless and until an Air Pollutant Emission Notice and the associated Air Pollutant Emission Notice fee has been filed with the Division with respect to such emission. Each such notice shall specify the location at which the proposed emission will occur, the name and address of the persons operating and owning such facility, the nature of such facility, process or activity, an estimate of the quantity and composition of the expected emission and other information as required in the current Air Pollutant Emission Notice form.

II.B. General

II.B.1. Emission Estimate

The Air Pollutant Emission Notice shall include an estimate of the annual actual emissions, including emission controls. The emissions estimate shall be based upon actual test data or, in the absence of such data, upon estimations acceptable to the Division. The following alternative estimate methods, in order of descending acceptability, are acceptable to the Division:

II.B.1.a. Mass balance calculations or a published, verifiable emission factor, whichever is best applied to the source; or

II.B.1.b. Other engineering calculations.

Stack testing or emission monitoring will not be required solely to meet the Air Pollutant Emission Notice reporting requirements.

An owner or operator shall provide a justification to the Division for not using any methods that are higher on the list than the method the owner or operator proposes to use. If none of the above methods are available or applicable to the source, an appropriate method will be determined on a case-by-case basis by the Division, taking into account the provisions of Section II.C.2. of this Part A.

The Division shall make available to all air pollution control authority offices appropriate forms on which the information required by this section shall be submitted.

II.B.2. Air Pollutant Emission Notice Term

An Air Pollutant Emission Notice is valid for a period of five years. The five-year period recommences when a revised Air Pollutant Emission Notice is received by the Division.

II.B.3. APEN Applicability

For the purposes of Air Pollutant Emission Notice applicability, a source will be considered to be an individual emission point, or group of points pursuant to Section II.B.4. of this Part A.

II.B.3.a. Criteria Pollutants

For criteria pollutants, Air Pollutant Emission Notices are required for: each individual emission point in a nonattainment area with uncontrolled actual emissions of one ton per year or more of any individual criteria pollutant (pollutants are not summed) for which the area is nonattainment; each individual emission point in an attainment or attainment/maintenance area with uncontrolled actual emissions of two tons per year or more of any individual criteria pollutant (pollutants are not summed); each individual emission point with uncontrolled actual emissions of lead greater than one hundred pounds per year, regardless of where the source is located.

II.B.3.b. Non-criteria Reportable Pollutants

For non criteria reportable pollutants, Air Pollutant Emission Notices are required for each individual emission point with uncontrolled actual emissions equal to or greater than 250 pounds per year or more of any individual non-criteria reportable pollutant (pollutants are not summed).

II.B.4. Source Grouping

Grouping of multiple emission points on a single Air Pollutant Emission Notice shall be allowed as often as possible, provided the overall goals of receiving accurate and verifiable emissions information are not compromised. The following guidelines shall be used to delineate occasions when grouping can be allowed. These are intended to be used as guidelines only, and specific questions regarding grouping should be directed to the Division.

Multiple pieces of equipment or processes from a single facility may be grouped or associated together and reported on one single Air Pollutant Emission Notice provided the individual sources of emissions meet the following guidelines:

II.B.4.a. All of the aggregated sources have identical source classification codes and emission factors for criteria pollutants;

II.B.4.b. Each of the aggregated sources share a similar location within the facility;

II.B.4.c. Similar sources regulated under the New Source Performance Standards (Regulation Number 6) and non-New Source Performance Standard sources should not be grouped;

II.B.4.d. None of the individual sources is required to monitor emissions through the use of continuous emission monitors;

II.B.4.e. Each of the individual emission points has fuel usage, production, and a consumption level, which are indistinguishable from the other points, which have been grouped on the Air Pollutant Emission Notice;

II.B.4.f. None of the individual sources grouped on the Air Pollutant Emission Notice has previously been issued its own separate emissions permit.

The Division maintains its authority to require individual separate Air Pollutant Emission Notices for any process or activity.

The Division may allow a source to deviate from this emission point grouping criteria upon a showing that an alternative is reasonable and will not compromise the overall goals of receiving accurate and verifiable emissions information.

II.B.5. Air Pollutant Emission Notices and revised Air Pollutant Emission Notices shall be based on calendar years (January through December).

II.B.6. The emissions noted on the current Air Pollutant Emission Notice on file with the Division shall be used for emission fee calculations as described in Section VI. of this Part A.

II.C. Revised Air Pollutant Emission Notices

II.C.1. A revised Air Pollutant Emission Notice shall be filed:

II.C.1.a. Annually whenever a significant change (as defined in Section II.C.2.) in annual actual emissions occurs; or

II.C.1.b. Whenever there is a change in the owner or operator of any facility, process, or activity; or

II.C.1.c. Whenever new control equipment is installed, or whenever a different type of control equipment replaces an existing type of control equipment (revised Air Pollutant Emission Notices are not required for routine maintenance, repair, or replacement of control equipment; or

II.C.1.d. Whenever a permit limitation must be modified; or

II.C.1.e. Before the Air Pollutant Emission Notice expires.

II.C.1.f. A revised Air Pollutant Emission Notice is not required whenever the location of a portable facility, process, or activity is changed, however, the owner or operator of such source must file a relocation notice. Such notice shall be received by the Division at least ten days prior to the change in location. Alternatively, the owner or operator of a portable source may request written approval from the Division to report multiple relocations. Relocation forms are available at the Division offices.

II.C.1.g. A revised Air Pollutant Emission Notice is not required for emergency or backup generators that are ancillary to the main units at electric utility facilities, and that have a permit under Parts C or D of Title I, or Title V of the Federal Act.

II.C.1.h. A revised Air Pollutant Emission Notice is not required for emergency or backup generators for electric power generating facilities that are not ancillary to a main unit at an electric utility facility, and that have a permit containing limits on the physical or operational capacity of the source to emit a pollutant such that the source is not considered to be a major stationary source as defined in Section II.A.25. of Part D of this Regulation Number 3. If an owner or operator of such a source chooses to file a revised Air Pollutant Emission Notice, the Air Pollutant Emission Notice shall list the average of the annual actual emissions for the preceding three years.

II.C.2. Significant change, for the purposes of this section means:

II.C.2.a. For any non-criteria reportable pollutant if the emissions increase by fifty percent or five tons per year, whichever is less, above the level reported on the last Air Pollutant Emission Notice submitted to the Division.

II.C.2.b. For criteria pollutants:

II.C.2.b.(i) For sources emitting less than one hundred tons per year, a change in annual actual emissions, of the individual criteria pollutant less than one hundred tons per year, of five tons per year or more, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(ii) For volatile organic compound and nitrogen oxides sources in ozone nonattainment areas emitting less than one hundred tons of volatile organic compound and nitrogen oxides per year, a change in annual actual volatile organic compound or nitrogen oxide emissions of one ton per year or more or five percent, whichever is greater, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(iii) For sources emitting one hundred tons per year or more, a change in annual actual emissions, of the criteria pollutant above one hundred tons per year, of five percent or fifty tons per year or more, whichever is less, above the level reported on the last Air Pollutant Emission Notice submitted to the Division; or

II.C.2.b.(iv) A change in annual actual emissions, above the level reported on the last Air Pollutant Emission Notice submitted to the Division, of fifty pounds of lead.

II.C.3. Timeframe for Revised Air Pollutant Emission Notice submittals

II.C.3.a. Revised Air Pollutant Emission Notices shall be submitted no later than within thirty days before the five-year term expires.

II.C.3.b. Owners or operators of sources that are required to obtain a permit revision must file a revised Air Pollutant Emission Notice along with a request for permit revision. A revised permit must be obtained before the change at the source occurs.

II.C.3.c. Sources submitting revised Air Pollutant Emission Notices to inform the Division of a change in annual actual emission rates must do so by April 30 of the following year (e.g., a change in emissions in calendar year 1993 must be reported by April 30, 1994).

II.C.3.d. Air Pollutant Emission Notices for changes in control equipment must be submitted before the change occurs); except for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to the requirements in Regulation Number 7, Section XII. For this control equipment, a revised APEN shall be filed once per year, as specified in Section II.C.3.c. of Part A, if any control equipment is added or if control equipment is relocated or removed.

II.C.4. Emissions reported

II.C.4.a. Sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.a., II.C.1.b., or II.C.1.e. must report actual annual emissions. Actual annual emissions for sources utilizing emission control equipment or procedures represent controlled actual annual emissions.

II.C.4.b. Sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.c. or II.C.1.d. must report both uncontrolled actual annual emissions and controlled actual emissions.

II.D. Exemptions from Air Pollutant Emission Notice Requirements

II.D.1. Stationary sources having emission units that are exempt from the requirement to file an Air Pollutant Emission Notice must nevertheless comply with all requirements that are otherwise applicable specifically to the exempted emission units, including, but not limited to: Title V, Prevention of Significant Deterioration, nonattainment New Source Review, opacity limitations, odor limitations, particulate matter limitations and volatile organic compounds controls.

An applicant may not omit any information regarding APEN exempt emission units in any permit application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), or nonattainment New Source Review (Section V., Part D of this Regulation Number 3).

The following sources are exempt from the requirement to file Air Pollutant Emission Notices because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality.

II.D.1.a. Individual emission points in nonattainment areas having uncontrolled actual emissions of any criteria pollutant of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas having uncontrolled actual emissions of any criteria pollutant of less than two tons per year, and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year, regardless of where the source is located.

II.D.1.b. Individual emission points having uncontrolled actual emissions of any individual non-criteria reportable pollutant less than 250 pounds per year.

II.D.1.c. Air conditioning or ventilating systems not designed to remove air pollutants generated by or released from other processes or equipment.

II.D.1.d. Fireplaces used for recreational purposes, inside or outside.

II.D.1.e. Fires and equipment used for noncommercial cooking of food for human consumption, or cooking of food for human consumption at commercial food service establishments, except for char broilers and wood fired equipment (but not including campfires) in PM10 nonattainment areas. Charbroiler shall mean a cooking device in a commercial food service establishment, either gas fired or using charcoal or other fuel, upon which grease drips down upon an open flame, charcoal or embers.

II.D.1.f. Safety flares used to indicate danger to the public.

II.D.1.g. Agricultural operations such as farming, cultivating, harvesting, seasonal crop drying, grain handling operations that are below New Source Performance Standards de minimis levels (including milling and grain elevator operations), and animal feeding operations that are not housed commercial swine feeding facilities as defined in Regulation Number 2, Part B. This exemption does not apply to an agricultural operation that: (1) is a major source (as defined in Section I.B.25. of this part); (2) meets or exceeds the storage capacity thresholds of a federal New Source Performance Standard (Regulation Number 6, Part A); or (3) participates in the early reduction program of the Federal Act, Section 112. Ancillary operations such as fueling stations located at farms or ranches are not exempt from Air Pollutant Emission Notice and permit requirements unless otherwise below the de minimis emission levels contained in this regulation, and are not exempt from other applicable regulation promulgated by the Commission.

II.D.1.h. Emissions from, or construction, or alteration of residential structures, including all buildings or other structures used primarily as a place of residence, and including home heating devices.

II.D.1.i. Laboratories and research & development facilities:

II.D.1.i.(i) Noncommercial (in house) experimental and analytical laboratory equipment that is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories.

II.D.1.i.(ii) Research and development activities that are of a small pilot scale and that process less than ten thousand pounds of test material per year;

II.D.1.i.(iii) Small pilot scale research and development projects less than six months in duration with controlled actual emissions less than five hundred pounds of any criteria pollutant or ten pounds of any non criteria reportable pollutant.

II.D.1.j. Disturbance of surface areas for purposes of land development, that do not exceed twenty-five contiguous acres and that do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil).

II.D.1.k. Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, that uses gaseous fuel, and that has a design rate less than or equal to five million British thermal units per hour. (See definition of fuel burning equipment, Common Provisions Regulation).

II.D.1.l. Internal combustion engines powering portable drilling rigs.

II.D.1.m. Exemption Repealed

II.D.1.n. Chemical storage tanks or containers that hold less than five hundred gallons, and that have an annual average daily throughput of less than twenty-five gallons.

II.D.1.o. Unpaved public and private roadways, except for haul roads located within a stationary source site boundary.

II.D.1.p. Sanding of streets and roads to abate traffic hazards caused by ice and snow.

II.D.1.q. Open burning activities, except that all reporting and permitting requirements that apply to such operations must be followed (see Regulation Number 9).

II.D.1.r. Brazing, soldering, or welding operations, except those that use lead based compounds. All welding that occurs strictly for maintenance purposes is exempt.

II.D.1.s. Street and parking lot striping.

II.D.1.t. Battery recharging areas.

II.D.1.u. Aerosol can usage.

II.D.1.v. Sawing operations, that is ancillary to facility operations, and is not part of the production process.

II.D.1.w. The process of demolition and re bricking of furnaces and kilns. This does not include subsequent operation of such furnaces or kilns.

II.D.1.x. Road and lot paving operations at commercial and industrial facilities, except that asphalt and cement batch plants require Air Pollutant Emission Notices and permits, unless exempt under some other section.

II.D.1.y. Adhesive use that is not related to production.

II.D.1.z. Fire training activities.

II.D.1.aa. Caulking operations that are not part of a production process.

II.D.1.bb. Landscaping and site housekeeping devices equal to or less than ten horsepower in size (lawnmowers, trimmers, snow blowers, etc.).

II.D.1.cc. Fugitive emissions from landscaping activities (e.g., weeding, sweeping).

II.D.1.dd. Landscaping use of pesticides, fumigants, and herbicides.

II.D.1.ee. Exemption Repealed

II.D.1.ff. Emergency events such as accidental fires.

II.D.1.gg. Smoking rooms and areas.

II.D.1.hh. Plastic pipe welding.

II.D.1.ii. Vacuum cleaning systems used exclusively for industrial, commercial, or residential housekeeping purposes.

II.D.1.jj. Beauty salons.

II.D.1.kk. Operations involving acetylene, butane, propane and other flame cutting torches.

II.D.1.ll. Pharmacies.

II.D.1.mm. Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed five thousand gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

II.D.1.nn. Architectural painting, roof coating material and associated surface preparation (except for sandblasting and except for volatile organic compound emissions, associated with surface preparation, above Air Pollutant Emission Notice de minimis levels) for maintenance purposes at industrial or commercial facilities.

II.D.1.oo. Emissions that are not criteria (as defined in Section I.B.17. of this part) or non-criteria reportable pollutants (as defined in Section I.B.30. of this part) (These emissions include methane, ethane, and carbon dioxide).

II.D.1.pp. Janitorial activities and products.

II.D.1.qq. Grounds keeping activities and products.

II.D.1.rr. Sources of odorous emissions that do not utilize emission control equipment for control of odorous emissions. This exemption applies to the odor emissions only. All other emissions are subject to other exemptions set forth in this regulation. This exemption does not exempt any source from the requirements of Regulation Number 2.

II.D.1.ss. Truck and car wash units.

II.D.1.tt. Office emissions, including cleaning, copying, and restrooms.

II.D.1.uu. Exemption Repealed

II.D.1.vv. Electrically operated curing ovens, drying ovens and similar activities, articles, equipment, or appurtenances. This exemption applies to the ovens only, and not to the items being dried in the ovens.

II.D.1.ww. Equipment used exclusively for portable steam cleaning.

II.D.1.xx. Blast cleaning equipment using a suspension of abrasive in water and any exhaust system or collector serving them exclusively.

II.D.1.yy. Commercial laundries (except dry cleaners) that do not burn liquid or solid fuel.

II.D.1.zz. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than sixty thousand gallons, provided the requirements of Regulation Number 7, Section IV. are met, where applicable.

II.D.1.aaa. Storage tanks of capacity less than forty thousand gallons of lubricating oils or used lubricating oils.

II.D.1.bbb. Venting of compressed natural gas, butane or propane gas cylinders, with a capacity of one gallon or less.

II.D.1.ccc. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company owned vehicles where the daily fuel throughput is no more than four hundred gallons per day that is calculated as an annual average. Sources in an ozone attainment/maintenance area must utilize Stage 1 vapor recovery on all tanks greater than 550 gallons capacity, as required by Regulation Number 7, in order to take this exemption.

II.D.1.ddd. Exemption Repealed

II.D.1.eee. Indirect sources are exempt until a permit regulation specific to indirect sources is promulgated by the Commission.

II.D.1.fff. Storage tanks meeting all of the following criteria:

II.D.1.fff.(i) Annual throughput is less than four hundred thousand gallons; and

II.D.1.fff.(ii) The liquid stored is one of the following:

II.D.1.fff.(ii)(A) Diesel fuels 1 D, 2 D, or 4 6;

II.D.1.fff.(ii)(B) Fuel oils #1 through #6;

II.D.1.fff.(ii)(C) Gas turbine fuels 1 GT through 4 GT;

II.D.1.fff.(ii)(D) oil/water mixtures with a vapor pressure equal to or lower than that of diesel fuel (Reid Vapor Pressure of 0.025 pounds per square inch absolute).

II.D.1.ggg. Each individual piece of fuel burning equipment that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour, and that is used solely for heating buildings for personal comfort.

II.D.1.hhh. Natural gas vehicle fleet fueling facilities.

II.D.1.iii. Electric motors driving equipment at non-commercial machining shops.

II.D.1.jjj. Recreational swimming pools.

II.D.1.kkk. Forklifts.

II.D.1.lll. Oil and gas exploration and production operations (well site and associated equipment) shall provide written notice to the Colorado Oil and Gas Conservation Commission of proposed drilling locations prior to commencement of such operations. Air Pollutant Emission Notices are not required until after exploration and/or production drilling, workovers, completions, and testing are finished.

If production will result in reportable emissions, the owner or operator shall file an Air Pollutant Emission Notice with the Division within thirty days after the well completion or recompletion report and log is filed with the appropriate state or federal agency. If production will not occur, or production will not result in reportable emissions, the owner or operator shall submit written notice to the Division indicating that the well was plugged, or that emissions are otherwise not reportable. If production will result in reportable emissions, the owner or operator shall file an Air Pollutant Emission Notice with the Division within thirty days after the report of first production is filed with the appropriate state or federal agency but no later than ninety days following the first day of production.

II.D.1.mmm. Handling equipment and associated activities for glass that is destined for recycling.

II.D.1.nnn. Fugitive emissions of hazardous air pollutants that are natural constituents of native soils and rock (not added or concentrated by chemical or mechanical processes) from underground mines or surface mines unless such source is a major source of hazardous air pollutants under Part C of Regulation Number 3.

II.D.1.ooo. The use of pesticides, fumigants, and herbicides when used in accordance with requirements established under the federal Insecticide, Fungicide and Rodenticide Act as established by the U.S. EPA (United States Code Title 7, Section 136 et seq.).

II.D.1.ppp. Ventilation of emissions from mobile sources operating within a tunnel, garage, or building that are not operating for transportation purposes and are subject to stationary source requirements.

II.D.1.qqq. Non-asbestos demolition.

II.D.1.rrr. Sandblast equipment when the blast media is recycled and the blasted material is collected, including small sandblast glove booths.

II.D.1.sss. Exemption Repealed

II.D.1.ttt. Exemption Repealed

II.D.1.uuu. Surface water storage impoundment of non-potable water and storm water evaporation ponds, with the exceptions of oil and gas production wastewater impoundments (including produced water tanks) containing equal to or more than one percent by volume crude oil on an annual average and commercial facilities that accept oil and gas production wastewater for processing.

II.D.1.vvv. Non-potable water pipeline vents.

II.D.1.www. Steam vents and safety release valves.

II.D.1.xxx. Exemption Repealed

II.D.1.yyy. Seal and lubricating oil systems for steam turbine electric generators.

II.D.1.zzz. Venting of natural gas lines for safety purposes.

II.D.1.aaaa. Chemical Storage Tanks

II.D.1.aaaa.(i) Sulfuric acid storage tanks not to exceed ten thousand five hundred gallons capacity.

II.D.1.aaaa.(ii) Sodium hydroxide storage tanks.

II.D.1.bbbb. Containers, reservoirs, or tanks used exclusively for dipping operations that contain no organic solvents for coating objects with oils, waxes, greases, or natural or synthetic resins.

II.D.1.cccc. Wet screening operations notwithstanding the applicability of the New Source Performance Standards included in the Code of Federal Regulations, Title 40, Part 60, Subpart OOO.

II.D.1.dddd. Non-road engines as defined in Section I.B.31. of this Part A, except certain non-road engines subject to state-only air pollutant emission notice and permitting requirements pursuant to Section I.B.31.c. and I.B.31.d. of this part.

II.D.1.eeee. Exemption Repealed

II.D.1.ffff. Exemption Repealed

II.D.2. An Air Pollutant Emission Notice must be filed for all incinerators.

II.D.3. Air Pollutant Emission Notices are required for emergency and backup generators that are ancillary to the main units at electric utility facilities however, these units may be included on the same Air Pollutant Emission Notice as the main unit.

II.D.4. Any person may request the Division to examine a particular source category or activity for exemption from Air Pollutant Emission Notice or permit requirements.

II.D.4.a. Such requests shall be made separately from the permit application review procedure.

II.D.4.b. Such requests shall include documentation indicating that emissions from the source category or activity have a negligible impact on air quality and public health in Colorado, based on, but not limited to, the following criteria.

II.D.4.b.(i) Emissions from the source or activity are below the Air Pollutant Emission Notice or permit emission de minimis levels set forth in this Regulation Number 3; or

II.D.4.b.(ii) The existing Division emission inventory is sufficient to indicate that the source or activity has a negligible impact; or

II.D.4.b.(iii) For permit exemptions, criteria in Sections II.D.4.b.(i) and/or II.D.4.b.(ii), above, are met, and the source or activity has no applicable requirement that applies to it, and the Division finds that monitoring or record keeping are not necessary.

II.D.4.b.(iv) Exemptions shall not be granted for any source or activity that is subject to any federal applicable requirement. The Division shall determine on a case-by-case basis if sources or activities subject to state only regulations may be granted an exemption.

II.D.4.c. None of the activities submitted as exemption requests to the Division may be taken by a source until the Commission has duly adopted the exemptions as revisions to this Regulation Number 3 and the U.S. EPA has approved the exemption requests.

II.D.5. Commercial (for hire) laboratories whose primary responsibilities are to perform qualitative or quantitative analysis on environmental, clinical, geological, forensic, or process samples may estimate emissions for purposes of Air Pollutant Emission Notice reporting based upon a mass balance calculation utilizing inventory and purchase records of solvents and reagents. Such laboratories may, at their discretion, group emission points if such grouping meets the grouping criteria outlined in this regulation. All inert samples are exempt from Air Pollutant Emission Notice reporting. Emissions from samples subjected to analysis provided to such laboratories for analysis and testing, and by-products that result from sample testing, are exempt from Air Pollutant Emission Notice reporting, provided such samples subjected to analysis are less than five gallons for liquids, or five pounds for solids.

II.D.6. Research and development activities that do not fall within the small scale exemption in Section II.D.1.i. may estimate emissions for purposes of Air Pollutant Emission Notice reporting based upon either a mass balance calculation utilizing inventory and purchase records, or best engineering judgment. Such facilities may file an Air Pollutant Emission Notice or revised Air Pollutant Emission Notice on an annual basis by April 30 of the year following the project's conclusion for each project that is not exempt under Section II.D.1.i., irrespective of Section II.C., herein (revised Air Pollutant Emission Notice requirements), such Air Pollutant Emission Notices shall be filed on a per project basis and shall be based on controlled actual emissions.

III. Administrative Permit Amendment Procedures

III.A. An application for an administrative permit amendment shall be prepared on forms supplied by the Division.

III.B. Within sixty calendar days after receipt of a complete application for an administrative permit amendment the Division shall issue its final determination on such application in accordance with the following:

III.B.1. Deny the application for an administrative permit amendment; or

III.B.2. Grant the application and incorporate any such changes into the permit providing such permit revisions are made pursuant to this Part A, Section III.

III.C. A source may implement the changes addressed in the application for an administrative amendment immediately upon submittal of request, subject to the final determination of the Division.

III.D. As required under the Federal Act, the Division shall transmit to the Administrator a copy of each revised permit made pursuant to an administrative permit amendment under this provision.

III.E. No public notice or review by affected states shall be necessary for permit revisions made pursuant to administrative amendment procedures.

III.F. Administrative permit amendments for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

IV. Operational Flexibility

IV.A. Alternative operating scenarios

No permit revision is required for reasonably anticipated operating scenarios identified by the source in its application for a permit and approved by the Division, provided the permit contains terms and conditions that:

IV.A.1. Require the source, contemporaneously with making a change from one operating scenario to another, to record in a log at the permitted facility a record of the scenario under which it is operating;

IV.A.2. Ensure that the terms and conditions of each such alternative scenario meet all applicable requirements of the state and Federal Act.

IV.A.3. Extend the permit shield to all operating permit terms and conditions under each such operating scenario.

IV.B. Trading based on the permit

If allowed by the applicable state implementation plan, no permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes in emissions that are provided for in the permit. The permit applicant must request such provisions to be included in its permit, and if approved by the Division, the permit shall contain terms and conditions that:

IV.B.1. For operating permits, include all terms required under Section V.C. of Part C;

IV.B.2. Ensure that changes resulting from such increases and decreases in emissions meet all applicable requirements under the state and Federal Acts;

IV.B.3. Extend the permit shield to all operating permit terms and conditions that allow such increases and decreases in emissions.

IV.C. Emissions trading under permit caps

No permit revision shall be required where an applicant requests, and the Division approves such request, for a permit containing terms and conditions allowing for the trading of emissions increases and decreases in the permitted facility. Procedures for such changes are:

IV.C.1. For operating permits, the permit shall contain terms and conditions required pursuant to Section V.C. of Part C;

IV.C.2. The permit applicant shall include in its application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable;

IV.C.3. Any emissions units for which emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trades shall not be included in this provision allowing emissions trading without permit revision;

IV.C.4. The source shall comply with all other applicable requirements.

IV.C.5. The source shall provide a minimum of seven days written notification in advance of the proposed changes to the Division and to the Administrator. The notice must be received by the Division no later than seven days in advance of the proposed changes. The source and the Division shall attach each such notice to their copy of the relevant permit. The notice shall contain:

IV.C.5.a. When the change will occur;

IV.C.5.b. A description of the changes in emissions that will result and how these increases and decreases in emissions will comply with the terms and conditions of the permit;

IV.C.5.c. The permit shield shall extend to all operating permit terms and conditions that allow such increases and decreases in emissions.

IV.C.6. A source shall be allowed to make such change proposed in its notice on the day following the last day of the advance notice described in Section IV.C.5. above, if the Division has not responded nor objected to such changes on or before that day.

V. Certification And Trading Of Emission Reduction Credits Offset And Netting Transactions

V.A. Purpose

This section establishes procedures for the recording of certified emissions reductions and for their use in emission credit transactions. These procedures are intended to:

V.A.1. Promote economic development and lower the cost of meeting pollution control requirements while assuring ambient air quality progress and continued air quality maintenance; and

V.A.2. Encourage development of innovative pollution control methods and technologies.

V.B. Scope

This section applies to any pollutant regulated under the Colorado Air Quality Control Act or the regulations promulgated there under in all attainment, attainment/maintenance, and nonattainment areas of the state. This section does not apply to emissions trading under permit caps in Section IV.C. of Part A.

V.C. Definitions

V.C.1. Alternative compliance methods means the use of emissions reductions credits to meet emissions control requirements in lieu of an applicable control technique guidance method or reasonably available control technology.

V.C.2. Bubble lets existing sources (or groups of sources) increase emissions at one operation in exchange for compensating extra decreases in emissions at another operation. The net result must be equivalent to or better than would have been accomplished using conventional source specific controls.

V.C.3. Certified emissions reduction means a reduction in emissions below the baseline that has been certified by the Division in accordance with the criteria of Section V.E., and that may then be used in an emission credit transaction.

V.C.4. Criteria pollutant means an air pollutant for which a National Ambient Air Quality Standard has been promulgated.

V.C.5. Emission credit transaction means the use of certified emission reduction credits in a bubble, netting or offset transaction or as an alternative compliance method.

V.C.6. Major stationary source means major stationary source as defined in Section II.A.25. of Part D of this regulation.

V.C.7. Net emissions increase means net emissions increase as defined in Section II.A.27. of Part D of this regulation.

V.C.8. Netting is designed to exempt modifications of existing major stationary sources from new source review requirements if the resultant impact does not exceed any of the significant values found in the definition of significant in Section II.A.44. of Part D of this regulation.

V.C.9. Non-inventoried source means any source that has not been recorded on the Division's emission inventory system.

V.C.10. Offset means a transaction in which a certified emissions reduction is used either to avoid causing a violation of an increment in an attainment or attainment/maintenance area, to meet the requirements of Section V.A.3. of Part D of this regulation, regarding the maintenance of reasonable further progress towards attainment of the National Ambient Air Quality Standards in nonattainment areas, or to avoid contributing to visibility or other air quality related values impairment in a Class I area.

V.C.11. Registry means the Division's record of the certification and use of emissions reductions.

V.C.12. Significant means significant as defined in Section II.A.44. of Part D of this regulation.

V.C.13. Surplus means emission reductions not required by current regulations, relied on for state implementation plan planning purposes, and not used to meet any other regulatory requirement.

V.C.14. Open Dust means solid or other air borne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported or redistributed.

V.C.15. Baseline emissions are equal to the product of the:

V.C.15.a. Emission Rate (ER), specified in terms of mass emission per unit of production or throughput (e.g., pounds sulfur dioxide per million British thermal units or pounds of volatile organic compounds per weight of solids applied);

V.C.15.b. Average hourly capacity utilization (CU) e.g., millions of British thermal units per hour or weight of solids applied per hour; and

V.C.15.c. Number of hours of operation (H) during the relevant time period i.e., baseline emissions = ER x CU x H. Net baseline emissions for a bubble are the sum of the baseline emissions of all sources involved in the trade.

V.D. Procedure for Certification of Emissions Reductions and Approval of Transactions

V.D.1. The owner or operator of a source may request the Division to certify any emissions reduction anticipated to occur after the effective date of this section, provided the owner or operator files his application prior to the occurrence of the reduction, at a time at which the source is emitting the baseline emissions of the subject pollutant. Sources that shutdown prior to the application to bank or trade have zero emissions, and therefore no credit is available.

V.D.2. Upon receiving an application for certification, the Division may require the applicant to submit all data and calculations necessary to verify the baseline emissions or the reduction of emissions below the base level including, but not limited to, documentation of operating hours and inputs. The Division may also require the applicant to perform source tests to establish the baseline emissions or the reduction of emissions below the baseline emissions. The Division shall not certify reductions anticipated to occur after the effective date of this regulation until the reductions have occurred and been verified.

V.D.3. The Division shall maintain an emissions reduction registry, in which it shall maintain a record of all certified emissions reductions, and of the use of certified emissions reductions in emission credit transactions. The information contained in such registry shall include the name and address of the owner or operator of the source creating the emissions reduction, the location of the source, its stack parameters, the temperature and velocity of its plume, particle size, the existence of any hazardous pollutants, daily and seasonal emission rates, and any other data that might reasonably be necessary to evaluate future use.

V.D.4. If the Division determines that certification should be granted it shall modify the permit of the applicant to provide that the allowable emissions are equal to the level of current emissions utilized in the calculation of the emissions reduction. The owner or operator of a source not required to obtain a permit by provisions of law other than this section shall be required to apply for and accept a permit as a condition of obtaining a certified emissions reduction. Such permits shall contain only those conditions necessary to ensure the enforcement of the emissions limitations applicable to the source as a result of certification of its emissions reduction.

V.D.5. The amount of the emissions reduction to be certified and entered in the registry shall be calculated as follows:

V.D.5.a. For any emissions reduction that has occurred in an attainment or attainment/maintenance area, the amount of the certified emissions reduction shall be 90 percent of the amount by which emissions have been reduced below the baseline emissions.

V.D.5.b. For any emissions reduction that has occurred in a nonattainment area, the amount of the certified emission reduction shall be 80 percent of the amount by which emissions have been reduced below the baseline emissions.

V.D.5.c. For bubbles in nonattainment areas that need, but lack, approved demonstrations of attainment, i.e., areas with unapproved state implementation plans, a greater discount may be taken. This discount will be based on the area's total baseline emissions, the target emissions for attainment, the emissions for the projected attainment year and the reductions needed to achieve attainment. These values are dynamic and so the discount value may change from year to year but will never be less than 20 percent. These transactions will require a state implementation plan revision.

V.D.6. An application may be filed for approval of the use of a certified emissions reduction in an emissions credit transaction simultaneously with the filing of a certification application, or within seven years after certification has been granted. If the transaction would require the modification of permits held by more than one person, the application shall be jointly submitted by all potentially affected permittees. The Commission shall determine whether to approve all bubble and alternative compliance method transactions, or any offset transactions that, pursuant to Section V.H., require a state implementation plan revision. The Division shall determine whether to approve all netting transactions, or any offset transactions for which no state implementation plan revision is required. The Commission may approve the use of a certified emissions reduction credit as an alternative compliance method in lieu of a specified control technique guidance method or reasonable available control technology.

V.D.7. Applications for certification of emissions reductions and approval of transactions shall be made on forms provided by the Division. Any source applying for approval of an alternative compliance method transaction shall submit to the Division a construction permit application in accordance with Regulation Number 3, Part B, Section III. for the construction or modification, reflecting the source and proposed use of the emissions credit. The application shall contain information sufficient to demonstrate that the criteria set forth in Section V.F. of this Part A are met as well as the criteria for approval of the state implementation plan revision. The Division shall review the application and prepare its preliminary analysis in accordance with Regulation Number 3, Part B, Section III.B. The source requesting approval for the transaction and the state implementation plan revision should be granted, and shall provide with its petition, a copy of the preliminary analysis of the Division. The Division shall not grant initial approval of any such application until the Commission has approved the transaction, the source has met the conditions placed on the transaction by the Commission, and the requirements of all other applicable regulations are met.

V.D.8. Where the owner or operator of a source requests a state implementation plan revision pursuant to this Section V., the Commission shall set a hearing on the proposed revision to be held in accordance with the procedures set forth in Colorado Revised Statutes Section 25-7-119. With respect to applications for certification of emissions reductions, or for approval of any netting transactions, or offset transactions within the Division's jurisdiction under Section V.H.2., the same time limitations for emission permits as found in Part B Section III.B. of this regulation shall apply.

V.D.9. Applicants for certification of an emissions reduction, or for approval of any emission credit transaction, shall be assessed fees for time spent by Division personnel in evaluating such applications in accord with the criteria for assessment of emissions permit fees set forth in Section VI.C. of this Part A. Where more than one person applies for approval of a transaction, all such persons shall be jointly liable for the fees assessed. Applicants shall be responsible for paying such fees regardless of whether the Division approves or denies an application. The costs of Division review of any emissions modeling or other information necessary for the Division to formulate recommendations to the Commission regarding any proposed emission credit transaction shall be included in the costs attributed to the permit application for the source(s) seeking approval of the transaction and shall be paid by the source regardless of whether the emission credit transaction is approved.

V.D.10. The state shall not utilize a certified emissions reduction in making demonstrations of attainment, or reasonable further progress toward attainment of the National Ambient Air Quality Standards, within seven years after the date of certification, or at any time after an application for use of the certified emissions reduction in a transaction has been approved. Where no application has been filed for the approval of the use of a certified emissions reduction within seven years after certification was granted, the state shall subsequently utilize the reduction in making demonstrations of attainment, or reasonable further progress towards attainment of the National Ambient Air Quality Standards. This seven-year period shall be tolled during any time in that there is a pending application before the Division or the Commission for approval of a bubble, netting, or offset transaction based on the certified emissions reduction.

V.D.11. Applications for approval of transactions involving PM10 (fine particulates for Prevention of Significant Deterioration increment consumption), sulfur dioxide, carbon monoxide, lead, and oxides of nitrogen (where visibility impacts are of concern), shall be subject to the following ambient air quality modeling requirements:

V.D.11.a. De minimis: In general modeling is not required to determine the ambient equivalence of trades in which applicable net baseline emissions do not increase and in that the sum of the emissions increases, looking only at the increasing sources, 15 tons per year for PM10, 40 tons per year for sulfur dioxide, 100 tons per year for carbon monoxide, 40 tons per year for nitrogen oxide (where visibility impacts are of concern), or 0.6 tons per year for lead, after applicable control requirements. For purposes of Prevention of Significant Deterioration any increase in PM10 should be modeled.

V.D.11.b. Level 1: In general, modeling to determine ambient equivalence is not required if:

V.D.11.b.(i) The trade does not result in an increase in applicable net baseline emissions;

V.D.11.b.(ii) The relevant sources are located in the same immediate vicinity (within 250 meters) of each other;

V.D.11.b.(iii) An increase in baseline emissions does not occur at the source with the lower effective plume height, as determined under the U.S. EPA approved and Division accepted guidelines, as interpreted in the Code of Federal Regulations Title 40, Subpart 52.343.

V.D.11.b.(iv) No complex terrain is within the area of significant impact (see Figure 1) of the trade or 50 kilometers, whichever is less;

V.D.11.b.(v) Stacks with increasing baseline emissions are sufficiently tall to avoid possible downwash situations, as determined by good engineering practice;

V.D.11.b.(vi) The trade does not involve open dust sources.

V.D.11.c. Level II: Bubble trades that are neither De minimis nor Level I may nevertheless be evaluated for approval based on modeling to determine ambient equivalence limited solely to the impacts of the specific emission sources involved in the trade, if:

V.D.11.c.(i) There is no increase in applicable net baseline emissions;

V.D.11.c.(ii) If the potential change in emissions before and after the trade will not cause a significant increase in pollutant concentrations at any receptor for an averaging time specified in an applicable ambient air quality standard; and

V.D.11.c.(iii) Such an analysis does not predict any increase in ambient concentrations in a Class I or Category I area. However, a bubble will not be approved under Level II where evidence clearly indicates the bubble would create a new violation of an ambient standard or Prevention of Significant Deterioration increment or would delay the planned removal of an existing violation. The change in concentration from the before-trade case to the after-trade case must, in general, be modeled using refined models for each appropriate averaging time for the relevant national ambient air quality standards for each receptor, using the most recent full year of meteorological data. Other techniques may be approved where sources show they equally well protect national ambient air quality standards, applicable Prevention of Significant Deterioration increments, and visibility. For example, in limited circumstances conservative screening models may be acceptable in lieu of refined models. In such cases, use of a full year of meteorological data may not be necessary. Such screening models may be acceptable where: (A) the screening model shows that all the emissions from the stack(s) with increasing emissions would not produce exceedances of the Level II significance values; (B) the stack parameters at the stack(s) with increasing emissions do not change; and (C) the screening model shows that the increase in emissions at the increasing stack(s) would not produce exceedances of these significant values.

In determining significant impact for Level II bubble trades, the Division will use the following significance values to identify trades whose potential ambient impact need not be further evaluated before approval:

8-micrograms/cubic meter (µg/m3) for any twenty-four hour period for PM10;

4-micrograms/cubic meter (µg/m3) for any annual arithmetic mean for PM10;

13-micrograms/cubic meter (µg/m3) for any twenty-four hour period for sulfur dioxide;

46-micrograms/cubic meter (µg/m3) for any three-hour period for sulfur dioxide;

3-micrograms/cubic meter (µg/m3) for any annual period for sulfur dioxide;

575-micrograms/cubic meter (µg/m3) for any eight-hour period for carbon monoxide;

2,300-micrograms/cubic meter (µg/m3) for any one-hour period for carbon monoxide;

0.1 micrograms/cubic meter (µg/m3) for any three-month period for lead. Except that:

V.D.11.c.(iii)(A) For offset transactions, significant impact shall be determined by the values found in the table of significant values in Section VI.D.2. of Part D of this regulation.

V.D.11.c.(iii)(B) Only process fugitive emissions vented through stacks may be approved in a Level II analysis.

V.D.11.c.(iii)(C) Trades involving open dust sources may not be approved in a Level II analysis.

V.D.11.c.(iii)(D) Trades involving complex terrain cannot be approved with a Level II analysis.

V.D.11.d. LEVEL III full dispersion modeling considering all sources affecting the trade's area of impact is required to determine ambient equivalence if applicable net baseline emissions will increase as a result of the trade, or if the trade cannot meet criteria for approval under De Minimis, Level I or Level II.

V.D.11.e. Approved Models:

Modeling: Only U.S. EPA-approved models may be used in banking transactions. Use of non-guideline models will be allowed once they have been approved according to the requirements of Section VIII.A.1. of Part A of this regulation.

V.D.12. Following the certification of an emissions reduction, if the Division determines that certification was granted on the basis of fraud or material misstatement or omission, the Division shall revoke certification of the reduction. Certification shall be revoked only after the owners or operators of the affected sources have received notice and, if requested, a hearing has been conducted. In such cases the Division shall also modify the permit of the source that has used the emissions reduction, so that the permit will contain all conditions that would have applied if the emissions reduction had not been certified initially.

V.E. Criteria for Certification of Emissions Reductions

An emissions reduction shall be certified for use in an emission credit transaction, provided it meets the following criteria:

V.E.1. The emissions reduction shall be surplus. Surplus reductions are those below the baseline emissions. The baseline emissions shall be determined as follows:

V.E.1.a. In attainment and attainment/maintenance areas, the baseline emissions shall be a source's actual emissions of the subject pollutant, or allowable emissions whichever is lower, for the three baseline factors. Reasonably Available Control Technology shall be as set forth in the State implementation plan for the source. Where Reasonably Available Control Technology has not been determined in the state implementation plan for the source, it shall be determined by the Division.

V.E.1.b. In nonattainment areas for which there is a demonstration of attainment of the National Ambient Air Quality Standards approved by the U.S. EPA the baseline emissions shall be actual emissions, provided, however, the baseline emissions shall not exceed reasonably available control technology as defined in the state implementation plan or the level of emissions used by the state in making a demonstration of attainment.

V.E.1.c. In nonattainment areas for which there is not a demonstration of attainment of National Ambient Air Quality Standards approved by the U.S. EPA, the baseline emissions shall be the lower of: 1) the actual emissions, 2) allowable emissions under the state implementation plan or 3) allowable emissions if the source is subject to Reasonably Available Control Technology.

V.E.1.d. Emission rate, capacity utilization and hours of operation must be used to compute pre-trade and post-trade emission levels. Baseline must be established on an annual basis and for all other averaging periods consistent with the relevant National Ambient Air Quality Standards and Prevention of Significant Deterioration increments.

V.E.2. No emissions reduction shall be certified if the Division has relied upon the occurrence of the reduction in demonstrating attainment of the National Ambient Air Quality Standards or reasonable further progress towards attainment, or in establishing a baseline concentration.

V.E.3. Each certified reduction of a pollutant's emissions shall be quantified in the same unit of measurement used in the standard or regulation applicable to the pollutant.

V.E.4. In attainment and attainment/maintenance areas, reductions at major stationary sources that commenced construction after January 1, 1975 may be able to qualify for credit whether such reductions occurred before or after the Prevention of Significant Deterioration baseline triggering date. Other emission reductions (e.g., at minor sources) cannot qualify for credit where the Prevention of Significant Deterioration baseline date is or has been triggered and such reductions occurred prior to the trigger date, unless these reductions are not assumed in the Prevention of Significant Deterioration baselines. Since banked emission reduction credits must be considered to be “In the Air” for all planning purposes, if the baseline date is triggered before banked credits are actually used, such banked credits will be considered as part of the baseline and will not consume increment when used in an emissions trade.

In attainment and attainment/maintenance areas where the Prevention of Significant Deterioration baseline has not been triggered as of the date the permitting authority takes relevant final action on the trading transaction, reductions below current state implementation plan or permit limits generally may be used without special restrictions in bubble or banking transactions, provided they are otherwise creditable and there is assurance that National Ambient Air Quality Standards will not be violated due to any potential increase in actual emissions. However, reductions at sources other than major stationary sources on which construction commenced before January 1, 1975 may not be used to balance increases at such pre 1975 major sources.

V.E.5. Emission reductions achieved by shutting down an existing source or curtailing production or operating hours below baseline levels may be generally credited if such reductions are permanent, quantifiable, and federally enforceable, and if the area has an U.S. EPA-approved attainment plan. In addition, the shutdown or curtailment is creditable only if it occurred on or after the date specified for this purpose in the plan, and if such date is on or after the date of the most recent emissions inventory used in the plan's demonstration of attainment. Where the plan does not specify a cutoff date for shutdown credits, the date of the most recent emissions inventory or attainment demonstration, as the case may be, shall apply. However, in no event may credit be given for shutdowns that occurred prior to August 7, 1977. For purposes of this section a permitting authority may choose to consider a prior shutdown or curtailment to have occurred after the date of its most recent emissions inventory, if the inventory explicitly includes as current existing emissions the emissions from such previously shutdown or curtailed sources.

V.E.5.a. Such reductions may be credited in the absence of an approved attainment demonstration only if the shutdown or curtailment occurred on or after the date the new source permit application is filed, or, if the applicant can establish that the proposed new source is a replacement for the shutdown or curtailed source, and the cutoff date provisions of Section A, above, are met.

V.E.6. No emission reduction credits are allowed from mobile sources unless those sources are subject to ambient impact and new source review permitting.

V.E.7. Reductions down to compliance levels may not qualify for emission reduction credit.

V.E.8. If an existing source commits to switch to a cleaner fuel at some future date, emission reduction credit is allowable only if a permit is conditioned to require use of a specified alternative control measure that would achieve the same degree of emission reduction should the source switch back to a dirtier fuel at some later date. The Division will ensure that adequate long-term supplies of the new fuel are available before granting the reduction credit.

V.E.9. Emission reductions otherwise required by the Federal Act shall not be creditable as emission reductions. Incidental emission reductions that are not otherwise required by the Federal Act are creditable as emission reductions if such emission reductions meet the requirements of Section V. of Part D of this regulation, if applicable and this Section V.

V.E.10. The total tonnage of increased emissions, in tons per year, resulting from a major modification that must be offset in accordance with Section 173 of the Federal Act shall be determined by summing the difference between the allowable emissions (as defined in Section I.B.7. of this part) after the modification and the actual emissions (as defined in Section II.A.1. of Part D) before the modification for each emissions unit.

V.F. Criteria for Approval of all Transactions

The use of an emissions reduction in an emission credit transaction shall be approved only if it meets the following criteria:

V.F.1. The transaction shall involve like pollutants. For toxic or volatile organic compound pollutants, the trade should involve the same degrees of toxicity or photochemical reactivity or else a greater reduction may be required. New or modified major sources of a PM10 precursor can only obtain offsets from emissions reductions in that same PM10 precursor or in PM10. New or modified major sources of PM10 can only obtain offsets from emissions reductions in PM10. The offsets must be greater than one for one and represent a net air quality benefit in the area the source is proposing to locate or modify. (See exception in Section V.H.8.)

V.F.2. No transaction shall be approved if it will result in an increased concentration, at the point of maximum impact, of hazardous air pollutants.

V.F.3. Where a significant fraction of a criteria pollutant stream has been listed as hazardous by the Commission under Regulation Number 8 or the U.S. EPA under United States Code, Title 42, Section 7412 but has not yet been regulated, emissions containing that pollutant from sources within two hundred and fifty meters of each other may only be traded against each other on a greater than one for one basis that assures a net decrease in emissions of the hazardous pollutant.

V.F.4. Hazardous and non-hazardous emissions of the same criteria pollutant may be traded against each other, provided the total emissions containing the hazardous pollutant from the sources involved in the transaction are required to decrease as a result of the transaction.

V.F.5. No transaction may be approved that is inconsistent with any standard established by the Federal Act, the state Act or the regulations promulgated under either, or to circumvent New Source Performance Standards requirements or Best Available Control Technology although the Commission may approve a transaction using a certified emissions reduction credit in lieu of a specified control technique guidance method or reasonably available control technology.

V.F.6. No transaction shall be approved unless either:

V.F.6.a. The source at which the emissions reduction occurred and the source using the emissions reductions are in the same nonattainment area or Prevention of Significant Deterioration baseline area; or

V.F.6.b. The emissions reduction is to be used as an offset to meet the requirements of Section V.A.3. of Part D of this regulation, and the conditions of that section are met for the use of an offset obtained from a source outside the nonattainment area.

V.F.7. Emission reduction credits may not be used to meet applicable technology based requirements for new sources such as New Source Performance Standards, Best Available Control Technology, or Lowest Achievable Emission Rate, although the Commission may approve a transaction using a certified emissions reduction credit in lieu of a specified control technique guidance method or reasonably available control technology.

V.F.8. Trades Involving Open Dust: Sources of particulate emissions may be approved through case by case state implementation plan revisions based on modeled demonstrations of ambient equivalence. Sources proposing such trades must commit, as part of the trade's approval, to:

V.F.8.a. Undertake a post approval monitoring program to evaluate the impact of their control efforts, and

V.F.8.b. Make further enforceable reductions if post trade monitoring indicates initial open dust controls do not produce the predicted air quality results.

V.F.9. The federal land manager must be notified if an emissions trade will take place within one hundred kilometers of a Prevention of Significant Deterioration Class I area. Notification must occur early enough in the review process to allow at least thirty days for the submittal of comments before the trade will be approved by the reviewing authority.

Where a bubble within fifty kilometers of a Prevention of Significant Deterioration Class I area is submitted as a case-by-case state implementation plan revision, the Division may call for additional technical support, beyond the applicable requirements of the modeling screen if deemed necessary to protect air quality in the Class I area.

V.F.10. Effect on Trades of Subsequently-Discovered Clean Air Act Problems: Revisitation Considerations - If ambient violations are discovered in an area where the Division has approved a trade, or if other violations of the act are discovered in that area, sources in the trade should be aware that they are potentially subject to requirements for additional emission reductions, just as are all other sources in the area.

V.F.11. For volatile organic compound and nitrogen oxide trades, pound for pound trades will be considered equal in ambient effect where all sources involved in the trade are in the same control strategy demonstration area (nonattainment area) or if outside that area are sufficiently close to show an equal effect.

V.F.12. For volatile organic compound trades involving surface coating, the emissions must be calculated on a solids applied basis and should specify the maximum time period over which the emissions may be averaged, not to exceed twenty-four hours.

V.F.13. The following trades require a state implementation plan revision:

V.F.13.a. PM10, sulfur dioxide, carbon monoxide or lead trades requiring full-scale dispersion modeling under Level III;

V.F.13.b. PM10, sulfur dioxide, carbon monoxide or lead trades where complex terrain is within the area of the source's significant impact or fifty kilometers, whichever is less, unless the trade does not result in a modification of effective stack heights and the trade otherwise qualifies as De minimis or Level I. The area of significant impact can be determined from Figure 1;

V.F.13.c. Open Dust Trades;

V.F.13.d. Level II trades involving process fugitive PM10, sulfur dioxide , carbon monoxide or lead emissions not discharged through stacks;

V.F.13.e. Trades involving Emission Reduction Credits from mobile sources (see Section V.E.7.);

V.F.13.f. Trades involving sources that are subject of a notice of violation (NOV), noncompliance penalty action or the filing of a judicial complaint;

V.F.13.g. Interstate trades;

V.F.13.h. Volatile organic compound trades with averaging times longer than twenty-four hours;

V.F.13.i. Trades involving work practice and equipment standards;

V.F.13.j. Trades involving negotiated Reasonably Available Control Technology baselines;

V.F.13.k. Trades affecting areas that need but lack approved demonstrations of attainment.

V.F.13.l. Emission credit transactions used as an alternative compliance method.

V.F.14. No emission credit transaction shall be approved unless the terms of the transaction are incorporated in permits applicable to the originating (as applicable) and receiving emissions sources.

V.F.15. Emission credit transactions that require a state implementation plan revision shall be considered by the Commission on a case-by-case basis. The source requesting approval of the transaction has the burden of demonstrating that all the criteria of this Section V.F., are met and of demonstrating that all applicable requirements for approval of the state implementation plan revision has been met.

V.G. Bubble Transactions

V.G.1. An owner or operator of an existing source may apply to the Commission for approval of a state implementation plan revision establishing a bubble. The bubble shall establish new emissions limitations for two or more facilities or operations within the source.

V.G.2. The Commission shall not approve a bubble unless it meets the criteria for approval of Section V.F., and the Division has first certified an emissions reduction at a facility or operation included in the bubble.

V.G.3. As part of the certification process, the amount of allowable emissions shall be reduced at the facility or operation where the emissions reduction has occurred in accord with Section V.D.5. As part of the bubble approval, the Commission may approve an increase in the total allowable emissions at the other facilities or operations covered by the bubble, by an amount not to exceed the amount of the subject certified emissions reduction.

V.G.4. As part of the bubble approval, the Commission may extend compliance deadlines otherwise required by Commission regulations for volatile organic compounds or carbon monoxide emissions, provided the following criteria are met:

V.G.4.a. The applicant must demonstrate to the satisfaction of the Commission that reasonable further progress toward the attainment of the National Ambient Air Quality Standards under the state implementation plan shall be maintained either by:

V.G.4.a.(i) Achievement of emissions reductions earlier than otherwise required by certain facilities or operations covered by the bubble; or

V.G.4.a.(ii) Temporary use of a certified emissions reduction to assure reasonable further progress toward attainment of the National Ambient Air Quality Standards.

V.G.5. If subsequent to the approval of a bubble, the Commission promulgates new regulations or amends existing regulations applicable to a source for which the bubble has been approved, the source shall be required to meet the new or amended regulations, irrespective of the bubble, by either further reducing emissions or using certified emissions reductions as offsets.

V.G.6. Bubble applications in areas that require but lack approved demonstrations of attainment, i.e., non approved state implementation plans, must be accompanied by assurances of consistency with ambient progress and air quality planning goals specified below:

V.G.6.a. The resulting emission limits comply with the reduction requirements of Section V.D.5.c., and the baseline requirements of Section V.E.;

V.G.6.b. The bubble emission limits will be included in any new state implementation plan and associated control strategy demonstration;

V.G.6.c. The bubble will not constrain the Division's ability to obtain any additional emission reductions needed to expeditiously attain and maintain ambient air quality standards;

V.G.6.d. The Division is making reasonable efforts to develop a complete approvable state implementation plan and intends to adhere to the schedule for such development (including dates for completion of emission inventory and subsequent increments of progress) stated in or with the letter formally submitting the bubble.

V.G.7. Bubbles should not increase applicable net baseline emissions. Ordinarily, bubbles may not result in an increase in applicable net baseline emissions. Such a bubble would require a case-by-case state implementation plan revision, and may only be approved based upon a combined Level III and Level II modeling analysis (i.e., an analysis sufficient to show that all applicable requirements of a full Level III analysis are met, and that the bubble would not result in any exceedance of significance values specified for a Level II analysis at any receptor for any averaging time specified in an applicable ambient air quality standard).

V.G.8. Bubbles should not increase emissions of hazardous or toxic air pollutants.

V.H. Offset Transactions

V.H.1. The owner or operator of a source at which an emissions reduction has occurred, and the owner or operator of another source who wishes to use the emissions reduction as an offset, may apply for approval of an offset transaction. In such transactions certified emissions reductions may be applied to avoid causing a violation of an increment in an attainment or attainment/maintenance area, or to meet the requirements of Section V.A.3. of Part D of this regulation. A certified emissions reduction may not be used as an offset for the purpose of complying with an existing applicable emissions control regulation, except for Reasonably Available Control Technology.

V.H.2. The Division shall determine whether to approve an offset transaction in the following cases:

V.H.2.a. Where the source using the emissions reduction would be allowed to increase emissions by less than one hundred tons per year.

V.H.2.b. Where the transaction involves volatile organic compounds or oxides of nitrogen emissions.

V.H.2.c. Where the transaction involves sulfur dioxide, PM10 or carbon monoxide emissions, and all sources involved in the transaction are within two hundred and fifty meters of one another.

V.H.3. Any proposed offset transaction, other than those referred to in Section V.H.2., shall be treated as a request to the Commission for a state implementation plan revision.

V.H.4. Sources of PM10 precursors, sulfur dioxide, nitrogen oxide and carbon monoxide must seek offsets within reasonably close proximity. Sources of nitrogen oxide and volatile organic compounds may seek offsets over a greater area. However, for widely dispersed and volatile organic compound trades, a higher offset may be required.

V.H.5. If the applicant has used his best efforts in seeking the required emission offsets but was unsuccessful, the source may petition for use of some portion of growth allowance. The petition must state the emission increase will not interfere with Reasonably Further Progress and the petitioner is willing to enter into an enforceable program to provide the required emission offset at some future time.

V.H.6. In the absence of an approved attainment demonstration, banked Emission Reduction Credits from shutdowns or curtailments may be used for offsets only if the criteria stated in Section V.E.5.b. of Part A of this regulation are met.

V.H.7. In nonattainment areas with approved demonstrations, banked Emission Reduction Credits may be used for offsets in any trade provided the criteria stated in Section V.E.5.a. of Part A of this Regulation are met.

V.H.8. Interpollutant offsets (other than those offsets discussed above) may be approved by U.S. EPA on a case-by-case basis provided that the applicant demonstrates, on the basis of U.S. EPA-approved methods where possible, that the emissions increases from the new or modified source will not cause or contribute to a violation of an ambient air quality standard. A source's permit application that includes such an interpollutant offset proposal shall not be approved by the Division until there has been an opportunity for public hearing on the proposed emissions trade and until written approval has been received from the U.S. EPA.

V.I. Netting Transactions

V.I.1. Netting may exempt modifications of existing major sources from certain pre-construction permit requirements under new source review, so long as there is no significant net emission increase, as net emissions increase is defined in Section II.A.27. of Part D of this regulation. By netting out, the modifications is not considered major and therefore not subject to pre-construction permit requirements for major modifications as follows:

V.I.1.a. Section VI. of Part D of this regulation, for prevention of significant deterioration;

V.I.1.b. Visibility analysis; and

V.I.1.c. Section V.A. of Part D of this regulation, for nonattainment new source review.

V.I.2. The Division shall grant such an exemption if the emissions reduction qualifies as an Emission Reduction Credit under Regulation Number 3 meets the criteria in Section V.E., for certification, and the difference between the amount of the certified emissions reduction, and the amount of new pollutants to be emitted from the new or modified facility, does not constitute a significant increase of pollutants.

V.I.3. An increase of pollutants shall be considered significant if it equals or exceeds the amounts specified in the definition of significant in Part D of this regulation.

VI. Fees

VI.A. General

VI.A.1. Every person required to obtain a Construction or Operating Permit or to file an Air Pollution Emission Notice shall pay fees as set forth in the following sections. Such fees shall be charged to recover the direct and indirect costs incurred by the Division in processing permit applications, issuing permits, and in conducting a compliance monitoring and enforcement program. Such fees shall apply without regard to whether a permit is issued, denied, withdrawn, or revoked. Fees shall be charged as indicated in Section VI.D. of this part.

VI.B. Permit Processing Fees

VI.B.1. Applicants for a permit shall be assessed total fees that shall be partially determined at the time that the Division makes its decision whether to issue preliminary approval of the permit and partially at the time the Division makes its decision whether to issue final approval.

VI.B.2. The partial fee collected at the time the Division makes its decision whether to issue preliminary approval of the permit shall include the costs associated with the preliminary engineering evaluation, modeling, and analysis of impact on ambient air quality, notice and publication requirements, and such other costs as are required for the aforementioned activities incurred by the Division up to the time of the decision of whether to issue preliminary approval.

VI.B.3. The final fee collected at the time the Division makes its decision of whether to issue final approval shall include the balance of the total of all costs associated with enforcement of any terms and conditions of the emission permit, the supervision of compliance testing, notice and publication requirements, and such other costs as are required for the processing, issuance, and administration of the permit.

VI.B.4. If the Division requires more than thirty hours to process an application, the Division shall inform the owner or operator of the source and provide an estimate of what the actual charges may be, prior to commencing with processing of the application, unless the owner or operator waives this requirement in writing.

VI.B.5. All permit processing fees assessed must be received within thirty days of the date of receipt of the written request therefore. All fees collected under this regulation shall be made payable to the Colorado Department of Public Health and Environment. Construction permits may be issued prior to the Division's receipt of such fees. Failure to pay the permit processing fees within ninety days of the written request for fees may result in late fees or revocation of the permit. Permits issued in accordance with Part C of this regulation may be issued upon approval by the Division of a fee payment schedule.

VI.C. Annual Emissions Fees

VI.C.1. As used in this Section VI., in accordance with Colorado Revised Statute Section 25-7-114.7, regulated air pollutant means:

VI.C.1.a. A volatile organic compound;

VI.C.1.b. Each hazardous air pollutant;

VI.C.1.c. Each pollutant regulated under Section 111 of the Federal Act (New Source Performance Standards), except GHG;

VI.C.1.d. Each pollutant for which a National Ambient Air Quality Standard has been promulgated, except for carbon monoxide; and

VI.C.1.e. Each pollutant regulated under Section 25-7-109, except GHG of the state Act.

VI.C.1.f. The term regulated air pollutant does not include fugitive dust as defined in Section I.B.21. of this Part A, or any fraction thereof.

VI.C.2. Every owner or operator of an air pollution source required to file an Air Pollutant Emission Notice shall pay a nonrefundable annual emissions fee as set forth in Section VI.D.1. of this Part A.

VI.C.3. All annual emissions fees assessed must be received within sixty days of the date of issuance of the written request therefore. All fees collected under this regulation shall be made payable to the Colorado Department of Public Health and Environment.

VI.C.4. In no event shall an owner or operator of a source pay more than a fee based upon total annual emissions of four thousand tons of each regulated air pollutant per source.

VI.D. Fee Schedule

VI.D.1. Annual emission fees and permit processing fees shall be charged in accordance with and in the amounts and limits specified in the provisions of Colorado Revised Statutes Section 25-7-114.7. Annual emission fees for regulated pollutants shall be $22.90 per ton. Annual emission fees for hazardous air pollutants shall be $152.90 per ton. GHG is exempt from the requirement to pay annual emission fees.

VI.D.2. Air Pollutant Emission Notice filing fees shall be charged in accordance with and in the amounts and limits specified in the provisions of Colorado Revised Statutes Section 25-7-114.1.

VII. Confidential Information or Data Contained in Air Pollutant Emission Notices, Permit Applications, or Reports Submitted Pursuant to Part C, Section V.C.6.

VII.A. Upon written request to the Division, any person filing an Air Pollutant Emission Notice or permit application, or submitting reports pursuant to Regulation Number 3, Part C, Sections V.C.6. or V.C.7., may request that information contained in such an Air Pollutant Emission Notice, permit application, or report relating to secret processes or methods of manufacture or production be kept confidential. The written request must identify the basis for the claim that the information relates to secret processes or methods of manufacture or production. All information claimed as confidential must be segregated from the rest of the Air Pollutant Emission Notice, permit application, or report when submitted, with each page clearly marked as "Confidential," "Trade Secret," or other similar marking.

VII.B. The Division will evaluate confidentiality claims based on the written request. The burden of establishing that the information relates to secret processes or methods of manufacture or production is on the claimant. Emission data, as defined in Colorado Revised Statutes Section 25-7-103(11.5), shall not be entitled to confidential treatment notwithstanding this Section VII., or any other law to the contrary. In no event shall an Operating Permit or the compliance certifications submitted pursuant to Section III.B.8. of Part C of this Regulation Number 3 be entitled to confidential treatment. If the Division determines that information requested to be kept confidential is not entitled to confidential treatment, it shall provide written notice of this determination at least three working days prior to making such information available to the public.

VII.C. A request for confidential treatment of information or data submitted to the Division shall be deemed a limited waiver by the applicant of the time constraints contained in Section III.B. of Part B, or Section IV. of Part C of this regulation. Therefore, any delay in the processing of a permit application resulting from the Division's being required to give notice under Section VII.B., hereof, shall not be considered in determining whether the time constraints set forth in this regulation have been met.

VIII. Technical Modeling and Monitoring Requirements

VIII.A. Air Quality Models

VIII.A.1. All estimates of ambient concentrations required under this Regulation Number 3 shall be based on the applicable air quality models, databases, and other requirements generally approved by U.S. EPA and specifically approved by the Division.

If a non-U.S. EPA approved model, such as a wind tunnel study, is proposed, the nature and requirements of such a model should be outlined to the Division at a pre-application meeting. The application will be deemed incomplete until there has been an opportunity for a public hearing on the proposed model and written approval of the U.S. EPA has been received.

VIII.B. Monitoring

VIII.B.1. All monitoring must be performed in accordance with U.S. EPA accepted procedures as approved by the Division.

VIII.B.2. An owner or operator may submit a monitoring program for a proposed source or modification to the Division for review. Within sixty days after such submittal, the Division shall:

VIII.B.2.a. Approve the monitoring program; or

VIII.B.2.b. Specify the changes necessary for approval; otherwise, the monitoring program shall be deemed approved.

VIII.C. Stack Heights

This regulation sets limits for the maximum stack height credit to be used in ambient air quality modeling for the purpose of setting an emission limitation and calculating the air quality impact of a source. It does not limit the actual physical stack height for any source. The following shall not be considered in determining whether an emission limitation is met:

VIII.C.1. Stack height in excess of good engineering practice; or

VIII.C.2. Any other dispersion technique except that the provisions of this Section VIII.C. shall not apply to stack heights in existence or dispersion techniques implemented before December 31, 1970. Sources that were constructed, reconstructed, or for which major modifications were carried out after December 31, 1970, and that are emitting pollutants from such stacks, or using such dispersion techniques, shall be subject to the provisions of this section.

VIII.D. Definitions as used in Section VIII.C.

VIII.D.1. Stack in existence means that the owner or operator had:

VIII.D.1.a. Begun, or caused to begin, a continuous program of physical on site construction of the stack; or

VIII.D.1.b. Entered into binding agreements or contractual obligations that could not be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the stack to be completed in a reasonable time.

VIII.D.2. Dispersion Technique means any technique that attempts to affect the concentration of a pollutant in the ambient air by using that portion of a stack that exceeds good engineering practice stack height, varying the rate of emission of a pollutant according to atmospheric conditions or ambient concentrations of that pollutant, or by increasing final exhaust gas plume rise by manipulating source process parameters, exhaust gas parameters, or combining exhaust gases from several existing stacks into one stack; or other selective handling of exhaust gas streams so as to increase the exhaust gas plume rise. The preceding sentence does not include:

VIII.D.2.a. The reheating of a gas stream, following use of a pollution control system, for the purpose of returning the gas to the temperature at which it was originally discharged from the facility generating the gas stream;

VIII.D.2.b. The merging of exhaust gas streams where:

VIII.D.2.b.(i) The source owner or operator demonstrates that the facility was originally designed and constructed with such merged gas streams;

VIII.D.2.b.(ii) After July 8, 1983, such merging is part of a change in operation at the facility that includes the installation of pollution controls and is accompanied by a net reduction in the allowable emissions of a pollutant. This exclusion from the definition of dispersion techniques shall apply only to the emission limitation for the pollutant affected by such change in operation; or

VIII.D.2.b.(iii) Before July 8, 1985, such merging was part of a change in operation at the facility that included the installation of emissions control equipment or was carried out for sound economic or engineering reasons. Where there was an increase in the emissions limitation or, in the event that no emission limitation was in existence prior to the merging, the reviewing agency shall presume that merging was significantly motivated by intent to gain emissions credit for greater dispersion.

Absent a demonstration by the source owner or operator that merging was not significantly motivated by such intent, the reviewing agency shall deny credit for the effects of such merging in calculating the allowable emissions for the source;

VIII.D.2.c. Smoke management in agricultural or silvicultural prescribed burning programs;

VIII.D.2.d. Episodic restrictions on residential wood burning and open burning; or

VIII.D.2.e. Techniques that increase final exhaust gas plume rise where the resulting allowable emissions of sulfur dioxide from the facility do not exceed five thousand tons per year.

VIII.D.3. Good Engineering Practice Stack Height means the greater of:

VIII.D.3.a. 65 meters; or

VIII.D.3.b. For stacks in existence on January 12, 1979 and for which the owner or operator had obtained all applicable pre-construction permits or approvals required, Hg = 2.5H, provided the owner or operator produces evidence that this equation was actually relied on in establishing an emission limitation; and

VIII.D.3.c. For all other stacks, Hg = H + 1.5L where:

VIII.D.3.c.(i) Hg = good engineering practice stack height measured from the ground level elevation at the base of the stack;

VIII.D.3.c.(ii) H = height of nearby structure(s) measured from the ground level elevation at the base of the stack;

VIII.D.3.c.(iii) L = lesser dimension (height or projected width) of nearby structure(s) provided that the reviewing agency may require the use of a field study or fluid model to verify Good Engineering Practice stack height for the source; or

VIII.D.3.d. The height demonstrated by a fluid model or a field study approved by the reviewing agency, which ensures that the emissions from a stack do not result in excessive concentrations of any air pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, structures, or terrain obstacles.

VIII.D.4. Nearby as applied to good engineering practice is:

VIII.D.4.a. For purposes of applying the formulae provided in Sections VIII.D.3.b. and VIII.D.3.c. in the definition of good engineering practice stack height means that distance up to five times the lesser of the height or the width dimension of a structure, but not greater than 0.8 kilometers (1/2 mile), and

VIII.D.4.b. For conducting demonstrations in Section VIII.D.3. in the definition of good engineering practice means not greater than 0.8 kilometers (1/2 mile), except that the portion of a terrain feature may be considered to be nearby that falls within a distance of up to ten times the maximum height of the feature, not to exceed two miles if such feature achieves a height 0.8 kilometers from the stack that is at least forty percent of the good engineering practice stack height determine by the formula or twenty-six meters, whichever is greater.

VIII.D.5. Excessive concentrations for the purpose of determining good engineering practice, stack height in a fluid model or field study, means:

VIII.D.5.a. For sources seeking credit for stack height exceeding that established by the formulae, a maximum ground level concentration due to emissions from a stack due in whole or part to downwash, wakes, and eddy effects produced by nearby structures or nearby terrain features that individually is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes, or eddy effects and that contributes to a total concentration due to emissions from all sources that is greater than an ambient air quality standard. For sources subject to the prevention of significant deterioration program, an excessive concentration alternatively means a maximum ground level concentration due to emissions from a stack due in whole or part to downwash, wakes, or eddy effects produced by nearby structures or nearby terrain features that individually is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes, or eddy effects and greater than a prevention of significant deterioration increment. The allowable emission rate to be used in making demonstrations shall be prescribed by the new source performance standard that is applicable to the source category unless the owner or operator demonstrates that this emission rate is infeasible. Where such demonstrations are approved by the Division, an alternative emission rate shall be established in consultation with the source owner or operator;

VIII.D.5.b. For sources seeking credit after October 1, 1983 for increases in existing stack heights up to the heights established by the formulae, either:

VIII.D.5.b.(i) A maximum ground level concentration due in whole or part to downwash, wakes or eddy effects as provided in Section VIII.D.5.a. above, except that the emission rate specified by any applicable state implementation plan (or, in the absence of such a limit, the actual emission rate) shall be used; or

VIII.D.5.b.(ii) The actual presence of a local nuisance caused by the existing stack, as determined by the Division; and

VIII.D.5.b.(iii) For sources seeking credit after January 12, 1979 for a stack height determined using the formula, where the Division requires the use of a field study or fluid model to verify good engineering practice stack height; for sources seeking stack height credit after November 9, 1984 based on the aerodynamic influence of cooling towers; and for sources seeking credit after December 31, 1970 based on the aerodynamic influence of structures not adequately represented by the formulae: a maximum ground level concentration due in whole or part to downwash, wakes or eddy effects that is at least forty percent in excess of the maximum concentration experienced in the absence of such downwash, wakes or eddy effects.

APPENDIX A De Minimis Level For Non-Criteria Reportable Pollutants

An Air Pollutant Emission Notice must be filed for each emission point (individual or grouped) that has uncontrolled actual emissions equal to or greater than 250 pounds per year of any non-criteria reportable pollutant listed in Appendix B. As provided in Section II.C.4., sources submitting revised Air Pollutant Emission Notices due to Sections II.C.1.a., II.C.1.b., or II.C.1.e. must report actual annual emissions. Actual annual emissions for sources utilizing emission control equipment or procedures represent controlled actual annual emissions.

If a non-criteria reportable pollutant is not listed in Appendix B, it does not have to be reported unless it is included in a chemical compound group.

Definitions

Point - an individual emission point or a group of individual emission points reported on one Air Pollutant Emission Notice as provided for in Part A, Section II.B.4.

APPENDIX B Non-criteria Reportable Pollutants (Sorted by CAS Number)

Note: HAP means federal, or federal and state hazardous air pollutant

HAPs means state-only hazardous air pollutant

	CAS		**Toxics**
HAP	-		Lindane (all isomers of hexachlorocyclohexane)
	-		Thallium compounds
HAPs	-		Nitrilotriacetic acid, Ca-, Na-, K salts
	-		Ozone depleting compounds (CFC, etc.)
HAP	0		Antimony compounds
HAP	0		Arsenic compounds
HAP	0		Beryllium compounds
HAP	0		Cadmium compounds
HAP	0		Chromium compounds (incl. 6+ compounds, etc.)
HAP	0		Cobalt compounds (as cobalt metal dust and fumes)
HAP	0		Coke Oven Emissions
HAP	0		Cyanide compounds
HAP	0		Fine mineral fibers
HAP	0		Glycol ethers
HAP	0		Lead compounds (except elemental lead)
HAP	0		Manganese compounds
HAP	0		Mercury compounds
HAP	0		Nickel compounds (incl. nickel subsulfide)
HAP	0		Polycyclic Organic Matter

	CAS		Toxics
HAP	0		Radionuclides (including radon)
HAP	0		Selenium compounds
HAP	50000		Formaldehyde
HAP	51285		2,4-Dinitrophenol
HAP	51796		Ethyl carbamate (Urethane)
HAP	53963		2-Acetylaminofluorene
	540885		Tertiary Butyl Acetate
	54115		Nicotine
	54626		Aminopterin
HAPs	55185		N-Nitrosodiethylamine
	55914		Isofluorphate
HAPs	55981		1,4-Butanediol dimethanesulphonate
HAP	56235		Carbon tetrachloride
HAP	56382		Parathion
	56724		Coumaphos
HAP	57147		1,1-Dimethyl hydrazine
	57249		Strychnine
HAP	57578		Propiolactone, beta
HAP	57749		Chlordane
HAP	59892		N-Nitrosomorpholine
HAP	60117		Dimethyl aminoazobenzene
HAP	60344		Methyl hydrazine
HAP	60355		Acetamide
	60413		Strychnine sulfate
	60515		Dimethoate
HAPs	60571		Dieldrin
HAP	62533		Aniline
HAP	62737		Dichlorvos
	62748		Sodium fluoroacetate
HAP	62759		N-Nitrosodimethylamine
HAP	63252		Carbaryl
	64006		Phenol,3-(1-methylethyl)-methylcarbamate
HAP	64675		Diethyl sulfate
	66819		Cyclohexamide
HAP	67561		Methanol (Methyl alcohol)
HAP	67663		Chloroform (Trichloromethane)
HAP	67721		Hexachloroethane
HAP	68122		Dimethylformamide
HAP	71432		Benzene
HAP	71556		1,1,1-Trichloroethane (Methyl chloroform)
	72208		Endrin
HAP	72435		Methoxychlor
HAP	74839		Methyl bromide (Bromomethane)
HAP	74873		Methyl chloride (Chloromethane)
HAP	74884		Methyl iodide (Iodomethane)
	74931		Methyl mercaptan (Methanethiol)
HAP	75003		Ethyl chloride (Chloroethane)
HAP	75014		Vinyl chloride
HAP	75058		Acetonitrile
HAP	75070		Acetaldehyde
HAP	75092		Methylene chloride (Dichloromethane)
HAP	75150		Carbon disulfide

	CAS		**Toxics**
	75183		Dimethyl sulfide (Methyl sulfide)
HAP	75218		Ethylene oxide
HAP	75252		Bromoform
HAP	75343		Ethylidene dichloride (1,1-Dichloroethane)
HAP	75354		1,1-Dichloroethylene (Vinylidene chloride)
HAP	75445		Phosgene
HAP	75558		1,2-Propylenimine (2-Methyl aziridine)
HAP	75569		Propylene oxide
HAP	76448		Heptachlor
HAP	77474		Hexachlorocyclopentadiene
HAP	77781		Dimethyl sulfate
	77816		Tabun
	78342		Dioxathion
	78535		Amiton
HAP	78591		Isophorone
HAP	78875		Propylene dichloride (1,2-Dichloropropane)
	78944		Methyl vinyl ketone (3-butene-2-one)
HAPs	78988		Methylglyoxal
HAP	79005		1,1,2-Trichloroethane
HAP	79016		Trichloroethylene (TCE)
HAP	79061		Acrylamide
HAP	79107		Acrylic acid
HAP	79118		Chloroacetic acid
	79196		Thiosemicarbizide
	79210		Peracetic acid
	79221		Methyl chloroformate
HAP	79345		1,1,2,2-Tetrachloroethane
HAP	79447		Dimethyl carbamoyl chloride
HAP	79469		2-Nitropropane
HAP	80626		Methyl methacrylate
	81812		Warfarin
	82666		Diphacinone
HAP	82688		Pentachloronitrobenzene (Quintobenzene)
HAP	84742		Dibutyl phthalate
HAP	85449		Phthalic anhydride
	86500		Methyl azinphos
	86884		ANTU (alpha-naphthylthiourea)
HAP	87683		Hexachlorobutadiene
HAP	87865		Pentachlorophenol
	88051		Aniline,2,4,6-Trimethyl
HAP	88062		2,4,6-Trichlorophenol
HAP	90040		o-Anisidine
	91087		2,6-Toluene diisocyanate
HAP	91203		Naphthalene
HAP	91225		Quinoline
HAP	91941		3,3-Dichlorobenzidene
HAP	92524		Biphenyl
HAP	92671		4-Aminobiphenyl
HAP	92875		Benzidine (p-Diamino diphenyl)
HAP	92933		4-Nitrobiphenyl
HAP	94757		2,4-D, salts and esters (2,4-Dichlorophenoxyacetic acid)
HAP	95476		o-Xylene

	CAS		Toxics
HAP	95487		o-Cresol
HAP	95534		o-Toluidine
HAP	95807		2,4-Toluene diamine
HAP	95954		2,4,5-Trichlorophenol
HAP	96093		Styrene oxide
HAP	96128		1,2-Dibromo-3-chloropropane
HAP	96457		Ethylene thiourea
HAP	98077		Benzotrichloride
HAP	98828		Cumene
HAP	98862		Acetophenone
	98873		Benzal chloride [(Dichloromethyl)benzene; benzylidenechloride]
HAP	98953		Nitrobenzene
	99989		Dimethyl-p-phenylenediamine
HAP	100027		4-Nitrophenol
HAP	100414		Ethyl benzene (Phenylethane)
HAP	100425		Styrene
HAP	100447		Benzyl chloride, (Chloromethyl)benzene
HAP	101144		4,4-Methylene bis (2-chloroaniline)
HAP	101688		Methylene diphenyl diisocyanate (MDI)
HAP	101779		4,4-Methylenedianiline
HAP	106423		p-Xylene
HAP	106445		p-Cresol
HAP	106467		1,4-Dichlorobenzene
HAP	106503		p-Phenylenediamine
HAP	106514		Quinone
HAP	106887		1,2-Epoxybutane
HAP	106898		Epichlorohydrin (1-Chloro-2,3-epoxypropane)
HAP	106934		Ethylene dibromide (1,2-Dibromoethane)
	106967		Propargyl bromide
HAP	106990		1,3-Butadiene
HAP	107028		Acrolein
HAP	107051		Allyl chloride
HAP	107062		Ethylene dichloride (1,2-Dichloroethane)
	107073		Chloroethanol
HAP	107131		Acrylonitrile
	107153		Ethylene diamine
	107186		Allyl alcohol
HAP	107211		Ethylene glycol
HAP	107302		Chloromethyl methyl ether
	107448		Sarin
	107493		TEPP (Tetraethyldithiopyrophosphate)
HAP	108054		Vinyl acetate
HAP	108101		Methyl isobutyl ketone (MIBK) (Hexone)
	108236		Isopropyl chlorformate
HAP	108316		Maleic anhydride
HAP	108383		m-Xylene
HAP	108394		m-Cresol
HAP	108883		Toluene
HAP	108907		Chlorobenzene
	108918		Cyclohexylamine
HAP	108952		Phenol
	108985		Thiophenol (Phenyl mercaptan)

	CAS		Toxics
	110009		Furan
HAP	110543		Hexane
	110576		Trans 1,4-dichlorobutene
	110894		Piperidine
HAP	111422		Diethanolamine
HAP	111444		Dichloroethyl ether (Bis(2-chloroethyl)ether)
HAP	114261		Propoxur (Baygon)
	115264		Dimefox
HAPs	115286		Chlorendic acid
	115297		Endosulfan
	115902		Fensulfothion
	116063		Aldicarb (Temik)
HAPs	117102		Chrysazin (Dorbane)
HAP	117817		Bis(2-ethylhexyl) phthalate (DEHP) (Dioctyl phthalate)
HAP	118741		Hexachlorobenzene
	119380		Isopropylmethylpyrazolyl dimethylcarbamate (Isolan)
HAP	119904		3,3-Dimethoxybenzidine
HAP	119937		3,3'-Dimethyl benzidine
HAP	120809		Catechol
HAP	120821		1,2,4-Trichlorobenzene
HAP	121142		2,4-Dinitrotoluene
HAP	121448		Triethylamine
HAP	121697		N,N-Diethyl aniline (N,N-Dimethylaniline)
	122145		Fenitrothion
HAPs	122601		Phenyl glyceryl ether (3 phenoxy 1,2 propanediol)
HAP	122667		1,2-Diphenylhydrazine
HAP	123319		Hydroquinone
HAP	123386		Propionaldehyde
	123739		Crotonaldehyde (E)
HAP	123911		1,4-Dioxane (1,4-Diethyleneoxide)
	126987		Methacrylonitrile
HAP	126998		Chloroprene (2-Chloro-1,3-butadiene)
HAP	127184		Perchloroethylene (Tetrachloroethylene)
	129066		Warfarin sodium
HAP	131113		Dimethyl phthalate
	131522		Sodium pentachlorophenate
HAPs	132274		2-Biphenylol sodium salt
HAP	132649		Dibenzofurans
HAP	133062		Captan
HAP	133904		Chloramben (3-amino-2,5-dichloro benzoic acid)
	140761		Pyridine, 2-methyl-5-vinyl
HAP	140885		Ethyl acrylate
	141662		Dicrotophos
	144490		Fluoracetic acid
	149746		Dichloromethylphenylsilane
HAP	151564		Ethylene imine (Aziridine)
	152169		Diphosphoramide, octamethyl
HAP	156627		Calcium cyanamide
	297789		Isobenzan
	297972		Thionazin (O,O-Diethyl-O-(2-pyrazinyl)phosphorothioate)
	298000		Parathion-methyl
	298022		Phorate

	CAS		**Toxics**
	298044		Disulfoton
HAP	302012		Hydrazine
HAPs	309002		Aldrin
	315184		Mexacarbate
HAP	334883		Diazomethane
	359068		Fluoroacetyl chloride
	371620		Ethylene fluorohydrin
HAP	463581		Carbonyl sulfide
	465736		Isodrin
	470906		Chlorfenvinfos
	505602		Mustard gas (Dichlorodiethyl sulfide)
	509148		Tetranitromethane
HAP	510156		Chlorobenzilate (ethyl-4,4'-dichlorobenzilate)
HAP	532274		2-Chloroacetophenone
	534076		Bis(chloromethyl)ketone
HAP	534521		4,6-Dinitro o-cresol, and salts
	535897		Crimidine
	538078		Ethyl bis (2-chloroethyl)amine
HAP	540841		2,2,4-Trimethylpentane
	541537		Dithiobiuret
HAP	542756		1,3-Dichloropropene
HAP	542881		Bischloromethyl ether
	542905		Ethylthiocyanate
	555771		Tris(2-chloroethyl)amine
	556616		Methyl isothiocyanate
	563122		Ethion
HAP	584849		2,4-Toluene diisocyanate
HAP	593602		Vinyl bromide
HAPs	615532		N-nitroso-N-methylurethane
HAP	624839		Methyl isocyanate
	624920		Methyl disulfide
	625558		Isopropyl formate
	640197		Fluoroacetamide
	644644		Dimetilan
	675149		Cyanuric fluoride
HAP	680319		Hexamethylphosphoramide
HAP	684935		N-nitroso-N-methylurea
	732116		Phosmet
	786196		Carbophenothion
	814686		Acrylyl chloride
HAP	822060		Hexamethylene-1,6-diisocyanate
	919868		Demeton-s-methyl
HAPs	924163		N-Nitroso-di-n-butylamine
	944229		Fonofos
	947024		Phosfolan
	950107		Mephosfolan
	950378		Methidathion
	991424		Norbormide
HAP	1120714		1,3-Propane sultone
	1122607		Nitrocyclohexane
	1314847		Zinc phosphide
HAP	1319773		Cresylic acid/Cresols

	CAS		**Toxics**
HAP	1330207		Xylene (and mixed isomers)
HAP	1332214		Asbestos
HAP	1336363		Polychlorinated biphenyls (PCBs) (Aroclors)
	1397940		Antimycin A
HAPs	1402682		Aflatoxins
	1420071		Dinoterb
	1464535		Diepoxybutane
	1563662		Carbofuran
HAP	1582098		Trifluralin
HAP	1634044		MTBE (Methyl tertiary butyl ether)
	1642542		Diethylchlorophosphate
HAP	1746016		2,3,7,8-TCDD (Dioxin)
	1910425		Paraquat
	1982474		Chloroxuron
	2001958		Valinomycin
	2032657		Methiocarb
	2074502		Paraquat methosulfate
HAPs	2475458		Disperse Blue 1
	2497076		Oxydisulfoton
	2524030		Dimethylphosphorochloridothioate
	2540821		Formothion
	2631370		Promecarb
	2642719		Ethyl azinphos
HAPs	2646175		CI Solvent Orange 2
	2778043		Endothion
HAP	3547044		DDE (Dichlorodiphenyldichloroethylene)
	3689245		Sulfotep
	3691358		Chlorophacinone
	3734972		Amiton oxalate
	3735237		Methyl phenkapton
	3878191		Fuberidazole
	4098719		Isophorone diisocyanate
	4170303		Crotonaldehyde
	4301502		Fluenetil
	4835114		Hexamethylenediamine, N,N-dibutyl
	5836293		Coumatetralyl
	7446119		Sulfur trioxide
HAP	7550450		Titanium tetrachloride
HAPs	7644410		1,4-Dichloro-2-butene
HAP	7647010		Hydrochloric acid (Hydrogen chloride)
HAP	7664393		Hydrogen fluoride (Hydrofluoric acid)
	7664417		Ammonia
	7664939		Sulfuric acid
	7697372		Nitric acid
HAP	7723140		Phosphorous
	7726956		Bromine
	7782414		Fluorine
HAP	7782505		Chlorine
	7783064		Hydrogen sulfide
	7786347		Mevinphos
HAP	7803512		Phosphine
HAP	8001352		Toxaphene (Camphechlor)

	CAS		Toxics
	8065483		Demeton
	10265926		Methamidophos
	10294345		Boron trichloride
	10311849		Dialifor
	13071799		Terbufos
	13171216		Phosphamidon
	13194484		Ethoprophos (Ethoprop)
	13494809		Tellurium
	16752775		Methomyl
	17702577		Formparanate
	19287457		Diborane
	20859738		Aluminum phosphide
	21548323		Fosthietan
	21609905		Leptophos
	21923239		Chlorthiophos
	22224926		Fenaminophos (Fenamiphos)
	23135220		Oxamyl
	23422539		Formotanate hydrochloride
	23505411		Pirimifos-ethyl
	24934916		Chlormephos
	28347139		Xylylene dichloride
	28772567		Bromodiolone
	53558251		Pyriminil
HAPs	60153493		3-(N-Nitrosomethylamine) (Propionitrile)
HAPs	64091914		Ketone, 3-pyridyl-3-(N-methyl-N-nitrosoamino) propyl
HAPs	108171262		Chlorinated paraffins (C12, 60% chlorine)

PART B CONCERNING CONSTRUCTION PERMITS

I. Applicability

I.A. The provisions of this Part B shall apply statewide. All sources that did not commence construction or operation prior to February 1, 1972, are required to have a construction permit except as specified in Section II.

II. General Requirements For Construction Permits

II.A. General Considerations

II.A.1. Except where specifically authorized by the terms of this Regulation Number 3, no person shall commence construction of any stationary source or modification of a stationary source without first obtaining or having a valid construction permit from the Division.

II.A.2. Any permit that has been issued pursuant to a prior regulation of the Commission, with respect to a project or the operation thereof, shall continue in full force and effect for the purpose for that it was originally issued, unless this current regulation no longer requires such permit, in that case the permit can be rescinded upon request of the owner or operator of the permitted source.

II.A.3. Any orders or decisions of the Division shall be final upon issuance, according to Section III.F.3. of this Part B.

II.A.4. Construction permits for criteria pollutants, GHG and hazardous air pollutants shall be issued based on the production/process rate requested in the Air Pollutant Emission Notice submitted with the permit application or as requested in the application. The emission rate associated with the requested production/process rate shall be a permit condition. For permits to limit the potential to emit criteria, pollutants, GHG or hazardous air pollutants the Division may modify the production/process rate, hours of operation or other requested permit conditions in order to create state-only or federally and practically enforceable permit conditions; provided, however, that the applicant may decline to accept such modifications and elect instead to forego limits on its potential to emit or pursues any right of appeal or other available alternative. For details regarding permits to limit the potential to emit hazardous air pollutants see Regulation Number 8, Part E, Section IV.

II.A.5. Construction permits are required for hazardous air pollutants if:

II.A.5.a. The source is subject to Colorado Maximum Achievable Control Technology or Generally Available Control Technology.

II.A.6. Owners or operators of sources that have valid operating permits in accordance with Part C of this regulation may construct or modify such source without obtaining a construction permit prior to construction or modification, provided the construction or modification qualifies for a minor permit modification or for operational flexibility, and the applicable provisions as set forth in Sections X., XI., or XII. of Part C are met. In addition, all applicable requirements that are related to construction permit approval and that are set forth in Sections III.D.1.a. through III.D.1.g. of this Part B remain in effect.

II.A.7. A source that is voluntarily applying for a permit to create state-only or federally enforceable permit conditions, as appropriate, to limit the potential to emit criteria, pollutants, GHG or hazardous air pollutants may request to obtain such limits in a construction permit.

II.B. Transfer or Assignment of Ownership

If transfer or assignment of ownership or operation of an air pollution emission source permitted pursuant to this Part B is anticipated, the prospective owner or operator shall apply to the Division on Division supplied administrative permit amendment forms for reissuance of the existing permit. Section III. of Part A of this regulation governs the administrative permit amendment procedures required for transfer or assignment of ownership.

In accordance with the provisions of this section, the permit shall be reissued upon completion of the transfer or assignment if the applicant certifies that no change is contemplated that might constitute a new or modified air pollution source. In no event shall the new owner or operator of a source that was subject to the requirements of these regulations prior to the transfer or assignment be relieved of the obligation to comply with such requirements by reason of a transfer. Such transfers are subject to all applicable permit processing and inspection fees.

If a company is changing its name only, the owner or operator shall apply to the Division, on Division supplied administrative permit amendment forms, for reissuance of the existing permit. Section III. of Part A, governs the administrative permit amendment procedures required for identifying a change in name. If all other procedures and information as stated in the last submitted Air Pollutant Emission Notice(s) remains unchanged, only one Air Pollutant Emission Notice need be submitted for each stationary source, indicating the name change.

No administrative permit amendment for transfer or assignment of ownership of a source shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage and liability between the current and new permittee is received by the Division.

II.C. Portable Sources

A permitted portable source (e.g., asphalt plants, crushers, etc.) shall have its permit number permanently and prominently displayed on each major component of equipment that is a part of that portable source.

II.D. Exemption from Construction Permit Requirements

Permit exemptions taken under this section do not affect the applicability of any State or Federal regulations that are otherwise applicable to the source.

An applicant may not omit any information regarding APEN or permit exempt emission units in any application if such information is needed to determine the applicability of Title V (Part C of this Regulation Number 3), Prevention of Significant Deterioration (Section VI. of Part D of this Regulation Number 3), or Nonattainment New Source Review (Section V. of Part D of this Regulation Number 3).

II.D.1. The following sources are exempt because by themselves, or cumulatively as a category, they are deemed to have a negligible impact on air quality:

II.D.1.a. Those sources exempted from the filing of Air Pollutant Emission Notices in Section II.D. of Part A, of this regulation.

II.D.1.b. Containers, reservoirs, or tanks used exclusively for dipping operations for coating objects with oils, waxes, greases, or natural or synthetic resins containing no organic solvents.

II.D.1.c. Stationary Internal Combustion Engines that:

II.D.1.c.(i) Are power portable drilling rigs; or

II.D.1.c.(ii) Are emergency power generators that operate no more than two hundred and fifty hours per year; or

II.D.1.c.(iii) Have uncontrolled actual emissions less than five tons per year or manufacturer's site-rated horsepower of less than fifty.

II.D.1.d. The collection, transmission, liquid treatment, and solids treatment processes at domestic wastewater treatment works, or treatment facilities that treat only domestic type wastewater, except for combustion processes.

II.D.1.e. Each individual piece of fuel burning equipment, other than smokehouse generators, that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour.

II.D.1.f. Gasoline stations located in ozone attainment areas, except for stations located in the Denver 1-hour ozone attainment/maintenance area.

II.D.1.g. Surface mining activities that mine seventy thousand tons or fewer of product material per year. A fugitive dust control plan is required for such sources. Crushers, screens and other processing equipment activities are not included in this exemption.

II.D.1.h. Composting piles, however, all odor requirements of Regulation Number 2 must be met.

II.D.1.i. Commercial and product quality control laboratory equipment.

II.D.1.j. Fires and equipment used for noncommercial cooking of food for human consumption and for cooking of food for human consumption at commercial food service establishments.

II.D.1.k. Petroleum industry flares, not associated with refineries, combusting natural gas containing no hydrogen sulfide except in trace (less than five hundred parts per million weight) amounts, approved by the Colorado Oil and Gas Conservation commission and having uncontrolled emissions of any pollutant of less than five tons per year.

II.D.1.l. Crude oil truck loading equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year.

II.D.1.m. Oil and gas production wastewater impoundments (including produced water tanks) containing less than one percent by volume crude oil on an annual average, with the exception of commercial facilities that accept oil and gas production wastewater for processing.

II.D.1.n. Exemption Repealed.

II.D.2. Facilities located in a nonattainment area for any criteria pollutant for which the area is nonattainment; with total facility uncontrolled actual emissions (potential emissions at actual operating hours) that are less than the following amounts:

II.D.2.a. Two tons per year volatile organic compounds.

II.D.2.b. One ton per year PM10.

II.D.2.c. One ton per year PM2.5.

II.D.2.d. Five tons per year total suspended particulate.

II.D.2.e. Five tons per year carbon monoxide.

II.D.2.f. Five tons per year sulfur dioxide.

II.D.2.g. Five tons per year nitrogen oxides.

II.D.2.h. Two hundred pounds per year lead.

For purposes of calculating total facility uncontrolled actual emissions, only those individual (or grouped) emission points requiring Air Pollutant Emission Notices are to be considered.

II.D.3. Facilities located in attainment or attainment/maintenance areas for all criteria pollutants with total facility uncontrolled actual emissions less (potential emissions at actual operating hours) than the following amounts:

II.D.3.a. Five tons per year volatile organic compounds.

II.D.3.b. Five tons per year PM10.

II.D.3.c. Five tons per year PM2.5.

II.D.3.d. Ten tons per year total suspended particulate.

II.D.3.e. Ten tons per year carbon monoxide.

II.D.3.f. Ten tons per year sulfur dioxide.

II.D.3.g. Ten tons per year nitrogen oxides.

II.D.3.h. Two hundred pounds per year lead.

For purposes of calculating total facility uncontrolled actual emissions, only those individual (or grouped) emission points requiring Air Pollutant Emission Notices are to be considered.

II.D.4. Facilities that emit any other criteria pollutant that is not listed in Sections II.D.2. and II.D.3., above (fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds, and municipal waste combustor emissions), with total facility uncontrolled actual emissions of such pollutants that are less than two tons per year.

II.D.5. When a facility that was previously exempt from permit requirements exceeds one of the permit de minimis levels stated in Sections II.D.2. through II.D.4., above, due to the addition of new emission points, the Division will issue either a facility-wide permit for all non-grandfathered emission units above Air Pollutant Emission Notice de minimis levels, or individual emission permits for those emission units.

II.D.6. All incinerators require a permit as stated in Regulation Number1, Section III.B.1.

II.D.7. Oil and gas exploration and production operations that are addressed under Section II.D.1.lll. of this Regulation Number 3, Part A, and that are required to obtain a construction permit, are not required to file an application for a construction permit until they are required to file an Air Pollutant Emission Notice, as set forth in Section II.D.1.lll. The application shall include a list of all applicable requirements, and how the requirements will be met until a construction permit is issued.

II.D.8. Any person may request the Division to add source categories to the permit exemption list, in accordance with the procedures set forth in Section II.D.4. of Part A of this regulation.

II.D.9. Sources with a valid operating permit are not required to obtain a construction permit prior to commencing construction or modification, as set forth in Section II.A.6. of this Part B.

III. Construction Permit Review Procedures

III.A. Option for Pre Application Meeting

Prior to submitting an application for a permit, an applicant may request and, if so requested, the Division shall grant, a pre-application meeting with the applicant. At such meeting, the Division shall advise the applicant of the applicable permit requirements, including the information, plans, specifications and the data required to be furnished with the permit application.

III.B. Application for a Construction Permit

III.B.1. An application for a Construction Permit shall be prepared on forms currently supplied by the Division.

III.B.2. Applications for Construction Permits, and modifications to Construction Permits, must include an Air Pollutant Emission Notice.

III.B.3. Applications shall be signed by a person legally authorized to act on behalf of the applicant. The applicant shall furnish all information and data required by the Division to evaluate the permit application and to make its preliminary analysis in accordance with Section III.B.5. of this part.

III.B.4. An application for a Construction Permit will not be deemed to be complete until all information and data required to evaluate the application have been submitted to the Division. Within sixty calendar days after the receipt of an application or any supplemental information timely requested by the Division, the Division will give notice to the applicant if and in what respect the application is incomplete. If the Division fails to notify an applicant that the application is incomplete within sixty calendar days of receipt of the original application or receipt of the requested supplemental information, the application shall be deemed to have been complete as of the day of receipt by the Division of the application or the last submitted supplemental information, whichever is later.

III.B.5. Except for applications for sources subject to the requirements of Section VI. of Part D of this regulation (Prevention of Significant Deterioration), the Division shall prepare its preliminary analysis within sixty calendar days after receipt of a complete permit application. The preliminary analysis allows the Division to determine whether the new source will, at date of commencement of operation, comply with:

III.B.5.a. All applicable emission control regulations,

III.B.5.b. Applicable regulations for the control of hazardous pollutants,

III.B.5.c. Requirements of the nonattainment and attainment programs (Sections V. and VI. of Part D), and

III.B.5.d. Any applicable ambient air quality standards and all applicable regulations.

The preliminary analysis shall indicate what impact, if any, the new source will have (as of the projected date of commencement of operation) on all areas (attainment, attainment/maintenance, nonattainment, unclassifiable), within the probable area of influence of the proposed source. If so requested on the permit application form, a copy of this preliminary analysis shall be forwarded to the applicant postmarked no later than fifteen calendar days after the completion of the preliminary analysis.

When the preliminary analysis includes modeling, the model used shall be an appropriate one given the topography, meteorology and other characteristics of the region that the source will impact. Use of any non-guideline model requires U.S. EPA approval under Section VIII.A. of Part A of this regulation.

III.C. Public Comment and Hearing Requirements

III.C.1. The following sources, unless exempted in Section III.C.2., below, are subject to public comment:

III.C.1.a. Sources with projected controlled annual emissions of any pollutant for which an ambient air quality standard has been designated, where such emissions will be greater than twenty five tons per year if the source is located in a nonattainment area, fifty tons per year if the source is located in an attainment or attainment/maintenance area, or two hundred pounds per year of lead (for any area of the state).

III.C.1.b. Sources for which preliminary analysis indicates a possible violation of Commission Regulation Number 2 (odor emissions).

III.C.1.c. For hazardous air pollutants if:

III.C.1.c.(i) The source is subject to Federal National Emission Standards for Hazardous Air Pollutants,

III.C.1.c.(ii) The source is subject to Federal or Colorado Maximum Achievable Control Technology or Generally Available Control Technology standards, or

III.C.1.c.(iii) The source is voluntarily applying for permit conditions to limit the source's potential to emit hazardous air pollutants.

III.C.1.d. Sources subject to Sections V. or VI. of Part D of this regulation that are attempting to obtain a federally enforceable limit on the potential to emit of the source in order to avoid other requirements.

III.C.1.e. Sources submitting an application for a BART determination or BART alternative pursuant to Regulation Number 3, Part F.

III.C.2. The following sources are generally not required to be subject to public comment, unless the Division determines that public comment is warranted pursuant to Section III.C.3. below:

III.C.2.a. Sources of six months duration or less, except that public comment shall be required for all major sources of hazardous pollutants without regard to the duration of the operation of such source unless specifically exempted below.

III.C.2.b. Demolition projects, even if asbestos materials are present, provided that all the requirements of Regulation Number 8 are followed for any and all materials suspected of containing asbestos.

III.C.2.c. Construction or modification of sources in accordance with the minor modification and operational flexibility provisions of Sections X., XI., and XII. of Part C of this regulation are subject to the public participation requirements of Part C.

III.C.3. Sources for which a permit is required, but for which public comment is not required by Sections III.C.1., III.C.2.a., or III.C.2.b., above, are exempt from public comment requirements unless the Division determines that public comment is warranted. In making such determinations, the Division shall take into consideration the duration of the operation, its location, the nature and projected amount of emissions, anticipated public concern, and other relevant factors.

III.C.4. When public comment is required by Section III.C.1., or when the Division determines, pursuant to Section III.C.3., that an application warrants public comment, the Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located, or by such other means necessary to assure notice to the affected public, that may include posting of such notice on the publicly accessible portion of the Division's web site. The Division shall cause a copy of the application, the preliminary analysis, and the draft permit to be filed with the county clerk for each county in which the source is, or will be located. The Division shall send written or electronic notice to persons requesting notice of permit applications that are subject to public notice requirements. For sources applying for a permit to limit the potential to emit criteria pollutants or federal hazardous air pollutants, the Division shall send a copy of the public notice and the draft permit to the U.S. EPA Administrator for comment. The Division shall also send a copy of the final permit approval to the U.S. EPA Administrator for comment. The newspaper notice or other such means of notice shall contain all of the following information in Sections III.C.4.a. through III.C.4.e., below:

III.C.4.a. The location and nature of the proposed project or activity for which a construction permit application has been filed.

III.C.4.b. The locations where the application and preliminary analysis are available for public inspection.

III.C.4.c. That comments concerning the ability of the proposed project or activity to comply with the applicable standards and regulations of the Commission are solicited from any interested person.

III.C.4.d. That the Division will receive and consider public comments for thirty calendar days after such publication.

III.C.4.e. The Division's preliminary determination of approval, conditional approval, or disapproval of the application.

III.D. Construction Permit Review Requirements

III.D.1. Requirements applicable to all construction permit applications (except that processing timeframes of combined construction/operating applications shall be as set forth in Part C, Section IV., of this Regulation Number 3). Within thirty calendar days following the completion of the Division's preliminary analysis for applications not subject to the public comment, within thirty calendar days following the period for public comment for applications subject to public comment, or if a public comment hearing is held, within thirty calendar days following such hearing, the Division shall grant the permit if it finds that:

III.D.1.a. The proposed source or activity will meet all applicable emission control regulations and regulations for the control of hazardous air pollutants;

III.D.1.b. As applicable, the proposed source or activity will meet the requirements of the attainment program as outlined in Section V. of Part D of this regulation, if any;

III.D.1.c. The proposed source or activity will not cause an exceedance of any National Ambient Air Quality Standards;

III.D.1.d. The source or activity will meet any applicable ambient air quality standards and all applicable regulations;

III.D.1.e. As applicable, the proposed source or modification will meet the requirements of the prevention of significant deterioration program of Section VI. of Part D of this regulation.

[Provided however, that the Division shall not deny a permit for failure of the proposed source to meet any applicable requirement of the state implementation plan where (1) there is pending an application for a revision to the state implementation plan pursuant to Colorado Revised Statute, Section 25-7-305 (Alternative Emission Reduction) that, if adopted, would require the Division to grant the permit and (2) the applicant waives the time constraints on the Division to act on its application until the Commission has issued its final decision on the request for a state implementation plan revision and the U.S. EPA has acted on the proposed revision to the state implementation plan. In such circumstances, the Division shall delay its decision on the permit application until after final action on the request for revision of the state implementation plan (including action by the U.S. EPA)];

III.D.1.f. The fees required in Section VI. of Part A of this regulation have been paid;

III.D.1.g. Permit approval shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the state implementation plan and any other requirements under local, state, or federal law.

III.D.2. RACT Requirements for new or modified Minor Sources (including new or modified minor emissions units at major stationary sources) of volatile organic compounds, carbon monoxide, nitrogen oxides, sulfur dioxide, and PM10 in nonattainment and attainment/maintenance areas:

III.D.2.a. Minor sources in designated nonattainment or attainment/maintenance areas that are otherwise not exempt pursuant to Section II.D. of this Part, shall apply Reasonably Available Control Technology for the pollutants for which the area is nonattainment or attainment/maintenance.

III.D.2.b. In the Denver Metropolitan PM10 attainment/maintenance area, for any new minor source with a potential to emit forty tons per year or more of nitrogen oxides or sulfur dioxide, or a modification of an existing minor source with a net emissions increase of forty tons per year or more of nitrogen oxides or sulfur dioxide, the source will install Reasonably Available Control Technology.

III.E. Permit Terms and Conditions

The Division shall include such terms and conditions in any permit as it deems necessary for the proposed project or activity to qualify for the permit.

III.F. Denial or Revocation of the Construction Permit

III.F.1. If the Division determines that a source cannot comply with the provisions of Part B, Section III.D., of this regulation, the Division shall issue its written denial of the permit application stating the reasons for such denial. Any Division denial of a permit shall become final upon mailing of the denial notice to the applicant by certified mail. The applicant may appeal the Division's final denial of a permit as provided in Section III.F.3., below.

III.F.2. Any applicant for a construction permit shall advise the Division in writing of any refusal to accept any permit condition imposed by the Division within twenty calendar days after receipt of the permit. Such refusal shall be deemed a denial of the permit application.

III.F.3. If the Division denies a permit, imposes conditions upon a permit that are contested by the applicant, revokes a permit, or requires a permit from a source that may qualify for an exemption, the applicant or owner or operator of a source may request a hearing before the Commission for review of the Division's action. The request for a hearing must be filed with the Commission within thirty days after the issuance of the permit, denial or revocation. The hearing shall be heard in accordance with the provisions of Section VI. of the Commission's Procedural Rules, Colorado Revised Statute Sections 25-7-114.5(8), and 25-7-119, (Colorado Air Pollution Prevention and Control Act) and Section 24-4-105, (State Administrative Procedure Act).

III.F.4. Initial Approval Expiration

III.F.4.a. An initially approved permit shall expire if the owner or operator of the source for which the permit was issued: (i) does not commence construction or operation of the source within eighteen months after either the date of issuance of the permit or the date on which such construction or activity was scheduled to commence as set forth in the permit, whichever is later; (ii) discontinues construction for a period of eighteen months or more; or (iii) does not complete construction within a reasonable time of the estimated completion date.

III.F.4.b. Upon a showing of good cause by the permittee, the Division may grant extensions of the permit not to exceed eighteen months per extension. Construction or operation shall commence or be resumed within a reasonable period of time from the granting of the extension. In determining what constitutes good cause or a reasonable period of time, the Division shall consider the degree of construction already completed, the amount invested or legally committed to the project, whether an extension would prevent (e.g., through reservation of a Prevention Significant Deterioration increment) economic development in the affected area, general economic conditions, the health of the community as it affects the ability of the permittee to proceed, and other relevant factors. The Division shall notify the Commission of any requested extensions and the reason given for each request.

III.G. Final Permit Approval

III.G.1. Unless prior and mutually acceptable arrangements have been made, the applicant shall give notice to the Division within fifteen calendar days after the date on which commencement of operation takes place.

III.G.2. Within 180 calendar days after commencement of operation, the source shall demonstrate to the Division compliance with the terms and conditions of the initial approval construction permit. The Division may inspect the source to determine whether or not the operating terms and conditions of the initial approval construction permit have been satisfied. At the end of 180 days, the Division must revoke the construction permit; or, continue the construction permit if applicable; or, notify the owner or operator that the source has demonstrated compliance with the construction permit.

III.G.3. Before final approval of the permit is granted, the Division may require the applicant to conduct and pay for performance tests in accordance with methods approved by the Division. A test protocol shall be submitted to the Division for review and approval at least thirty days prior to testing. The Division may monitor such tests and may, at its expense, conduct its own performance tests.

III.G.4. For sources that submit an application for an operating permit pursuant to Part C of this Regulation Number 3, including any application for a permit modification or permit renewal, prior to issuance of a final approval construction permit, upon demonstration by the source of compliance with all terms and conditions of the construction permit or a satisfactory final approval inspection, as required pursuant to this Section III.G., the Division may elect to either issue a final approval construction permit or allow the initial approval construction permit to continue in full force and effect. The Division shall provide written notice to the permittee of its election.

III.G.5. If the Division determines that the terms and conditions of the permit have been satisfied, the Division shall issue in writing its final permit approval to the applicant, or shall incorporate the terms and conditions into an operating permit issued in accordance with Part C of this regulation. Otherwise, the Division shall revoke the permit.

III.G.6. Final approval may be issued at the same time as initial approval for temporary sources of duration of one month or less.

III.G.7. Prior to issuance of final approval, the applicant shall furnish:

III.G.7.a. An operating and maintenance plan for all control equipment and control practices; and

III.G.7.b. A proposed record keeping format for demonstrating compliance on an ongoing basis.

III.H. Permit Cancellation

Whenever an owner or operator wishes to cancel a permit, the owner or operator shall notify the Division, using forms provided by the Division.

III.I. General Construction Permits

III.I.1. The Division may issue a general construction permit covering numerous similar sources to a source that would otherwise be required to obtain a construction permit pursuant to this Part B. Any general construction permit shall comply with all applicable requirements, including notice and opportunity for public participation where warranted for such sources. The Division may issue a general construction permit in accordance with one or more of the following considerations:

III.I.1.a. The control equipment utilized by the sources;

III.I.1.b. The design characteristics of the sources;

III.I.1.c. The operational variability of the sources;

III.I.1.d. The location of the sources.

III.I.2. A source shall not perform any of the following without first obtaining a valid general construction permit from the Division pursuant to this provision, or a valid construction permit as otherwise required pursuant to Section III. of this Part B:

III.I.2.a. Commence construction or modify any building, facility, structure, or installation;

III.I.2.b. Install any machine, equipment, or other device;

III.I.2.c. Commence the conduct of any such activity;

III.I.2.d. Commence performance of any combinations thereof; or

III.I.2.e. Commence operations of any of the same that will or do constitute a new stationary source.

III.I.3. Administration

III.I.3.a. General construction permits may be issued, modified, revoked and reissued, or terminated in accordance with the provisions of this regulation.

III.I.3.b. Sources shall submit applications to be covered under the general construction permit on forms provided by the Division.

III.I.3.c. Individual Permit Requirements

III.I.3.c.(i) The Division may require any source authorized by a general construction permit to apply for and obtain an individual permit. Cases where an individual permit may be required include, but are not limited to, the following:

III.I.3.c.(i)(A) A change has occurred in the availability of control technology or practices for the control or abatement of air pollutants applicable to the source; or

III.I.3.c.(i)(B) Circumstances have changed since the time of the request to be covered so that the source is no longer appropriately controlled under the general construction permit.

III.I.3.c.(ii) Any source authorized by a general construction permit may request to be excluded from the coverage of the general construction permit by applying for an individual permit, as provided for under this regulation, Parts A and B.

III.I.3.c.(iii) When the Division issues an individual permit to a source otherwise subject to a general construction permit, the applicability of the general construction permit to the individual permittee is automatically terminated on the effective date of the individual permit.

III.I.3.c.(iv) A source excluded from a general construction permit solely because it already has an individual permit may request that the individual permit be revoked, and that it be covered by the general construction permit. Upon revocation of the individual permit, the general construction permit shall apply to the source.

III.I.3.c.(v) In determining whether an individual permit is required, the Division may consider the compliance history and current compliance status of the source.

III.I.4. The Division shall review the application and certify or deny the request based on criteria specified in the general construction permit established by the Division for that type of source.

III.I.5. General construction permits shall include conditions necessary to ensure the sources will meet all applicable requirements.

III.I.6. General construction permits issued by the Division may include the following requirements, as appropriate and as specified in each permit:

III.I.6.a. An operating and maintenance plan for all control equipment and control practices;

III.I.6.b. A record keeping format for demonstrating compliance;

III.I.6.c. Monitoring methods to assure compliance; and

III.I.6.d. Alternative operating scenarios that include specific monitoring, record keeping, and reporting methods that will assure compliance with the permit conditions.

III.I.7. All general construction permits shall undergo statewide public notice. If a source wants to be covered under a general construction permit, the source must apply within the time period specified in the public notice.

PART C CONCERNING OPERATING PERMITS

I. Applicability

The provisions of this Regulation Number 3, Part C shall apply statewide to all sources of air pollutants that are required to obtain an operating permit as specified in Section II. The provisions of this Part C shall also apply, except as otherwise provided herein, to those minor sources of air pollutants that voluntarily choose to obtain an operating permit.

I.A. DEFINITIONS

I.A.1. Affected Source

(acid deposition program) A source of air pollutants that includes one or more fossil fuel fired combustion devices subject to emission reduction requirements or limitations under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, or under the state Act.

I.A.2. Minor Permit Modification

Any revisions to an operating permit issued by the Division that meets the criteria of Sections X. or XI. of this Part C.

I.A.3. Permit Modification

Any revision to an operating permit issued by the Division that cannot be accomplished under the administrative permit amendment procedures set forth in Section III. of Part A of this regulation, or the minor permit modification procedures set forth in Sections X. or XI. of this Part C. A permit modification for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations, Title 40, Part 72.

I.A.4. Permit Shield

Where a source operates in compliance with all operating permit terms and conditions, the source shall be deemed in compliance with the state and Federal Acts where the permit includes all applicable requirements of such acts, specifically states that other identified provisions are not applicable, and states that the permit shield applies. The permit shield does not apply to terms and conditions that become applicable to the source subsequent to permit issuance. The permit shield shall not alter or affect the provisions of Colorado Revised Statutes Sections 25-7-112 or 25-7-113, Section 303 of the Federal Act, the applicable requirements of the acid rain program, consistent with Section 408(a) of the Federal Act, or the ability of the Administrator to obtain information from a source pursuant to Section 114 of the Federal Act; nor shall the permit shield affect the liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

I.A.5. Renewal of an Operating Permit

The process by which a permit is reissued at the end of its term.

I.A.6. Section 502(b)(10) Changes

Changes that contravene an express permit term. Such changes do not violate applicable requirements or contravene federally enforceable permit terms and conditions that are monitoring (including test methods), record keeping, reporting, or compliance certification requirements.

I.A.7. Significant Permit Modification

All operating permit modifications that do not qualify as minor permit modifications or as administrative permit amendments. At a minimum, a significant permit modification shall include:

I.A.7.a. Any change that causes a significant increase in the rate of emissions as described by any permit term or condition;

I.A.7.b. Any change that is considered a modification under Title I of the Federal Act;

I.A.7.c. Any change that requires or changes a case-by-case determination of an emission limitation or other standard;

I.A.7.d. Any change that requires or changes a source specific determination for temporary sources of ambient impacts;

I.A.7.e. Any change that requires or changes a visibility or increment analysis;

I.A.7.f. Every significant change in existing monitoring permit terms or conditions; and

I.A.7.g. Every relaxation of reporting or record keeping permit terms or conditions.

I.A.7.h. Every change that seeks to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

I.A.7.h.(i) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the Federal Act; and

I.A.7.h.(ii) An alternative emissions limit approved pursuant to regulations promulgated under Section 112(i)(5) of the Federal Act

I.A.7.i. The establishment of a Plant-wide Applicability Limitation (PAL) in accordance with Section XVII. of Part D of this regulation.

I.A.7.j. All significant permit modifications shall be processed using the procedures set forth in Part C of Regulation Number 3 for combined Construction/Operating Permit issuance. Such source may choose to obtain a construction permit pursuant to Part B and shall subsequently meet the operating permit requirements of Part C.

II. General Requirements for Operating Permits

II.A. General Considerations

II.A.1. Except where specifically authorized by the terms of this Regulation Number 3, Part C, no person shall operate any of the following sources without first obtaining an operating permit in accordance with the provisions of this regulation.

II.A.1.a. Any affected source;

II.A.1.b. Any major source; with the exception of those sources that would be major based only on total suspended particulates emissions

II.A.1.c. Any source required to have a permit pursuant to the prevention of significant deterioration program of Part C, Title I, of the Federal Act;

II.A.1.d. Any source required to have a permit pursuant to the program for the attainment and maintenance of national ambient air quality standards or Part D of Title I of the Federal Act; and

II.A.1.e. Any solid waste incineration unit that is a distinct operating unit of any facility that combusts any solid waste material from commercial or industrial establishments or the general public (including single residences, hotels, and motels). Such term does not include: (1) incinerators or other units required to have a permit under United States Code Title, 42, Section 6925 of the Solid Waste Disposal Act; (2) materials recovery facilities (including primary or secondary smelters) which combust waste for the primary purpose of recovering metals; (3) qualifying small power production facilities, as defined in United States Code Title 16, Section 769(17)(C), or qualifying cogeneration facilities, as defined in United States Code Title 16, Section 796(18)(B), of the Federal Power Act, that burn homogenous waste for the production of electric energy or in the case of qualifying cogeneration facilities that burn homogeneous waste for the production of electric energy and steam or forms of useful energy (such as heat) that are used for industrial, commercial, heating, or cooling purposes; or (4) air curtain incinerators provided that such incinerators only burn wood wastes, yard wastes and clean lumber and that such air curtain incinerators comply with any applicable opacity limitations. Operating permits for solid waste incineration units shall be obtained within thirty-six months of promulgation of a new source performance standard applicable to such units, or by November 15, 1994, whichever is later.

II.A.1.f. Any source designated by the Administrator and the Commission as requiring an operating permit.

II.A.1.g. A source is not required to obtain an operating permit solely because it is subject to regulation or requirements pursuant to Section 112(r) of the Federal Act.

II.A.2. Any construction permit that has been issued pursuant to Regulation Number 3, Part B, with respect to a source that is subject to the operating permit requirements of this Part C, shall continue in full force and effect until such time as the operating permit is issued for such source, if the source has filed a timely and complete operating permit application. If a complete operating permit application has been timely filed with the Division by the source in accordance with the provisions of Section III., below, the source will not be subject to an enforcement action for operating the source without an operating permit. No source subject to an operating permit may operate after the time it is required to file a timely and complete application except in compliance with a previously issued operating permit and as set forth in Section II.B., below. A previously issued construction permit shall not constitute a defense for operating a source in violation of the requirement to have an operating permit.

II.A.3. Any orders or decisions of the Division shall be final upon issuance.

II.B. Application Shield

A timely and complete application for an operating permit under the provisions of this Part C shall operate as a defense to an enforcement action for the source's failure to have an operating permit until the Division or the Commission makes a final determination on the permit application. This defense to an enforcement action shall not apply if, subsequent to the completeness determination required by Section IV.B.1. of this Part C, the applicant fails to submit by the deadline specified in writing by the Division any additional information identified as necessary to process the application, or to otherwise supplement its application in accordance with the provisions of Sections IV.B.3. and IV.B.4. of this Part C. This defense to an enforcement action shall not be available to an applicant that files a fraudulent application. Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted to the Division.

II.C. Transfer or assignment of ownership

If transfer or assignment of ownership or operation of an air pollution emission source permitted pursuant to the operating permit requirements of this Part C of Regulation Number 3 is anticipated, the prospective owner or operator shall apply to the Division, on Division supplied administrative permit amendment forms, for reissuance of the existing permit. Part A, Section III. governs the administrative permit amendment procedures required for transfer or assignment of ownership of a source subject to the operating permit requirements. No administrative permit amendment shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

II.D. Portable Sources

A portable source that conducts the same or similar type activity at multiple temporary locations throughout the state may be issued a single operating permit under this Part C, provided that the operation involves at least one change in location of the source during the five year permit term. Portable sources must notify the Division at least ten days in advance of each change in location. The owner or operator of a portable source must demonstrate that all applicable requirements will be met at all locations at which the source will operate before an operating permit authorizing operations at the multiple locations will be issued. Sources subject to the acid rain provisions of Title IV of the Federal Act shall not constitute portable sources.

II.E. Insignificant Activities and Exemptions from Operating Permit Requirements

Sources that are otherwise required to obtain an operating permit are not required to include insignificant activities from the following list in their operating permit applications, except as otherwise provided below.

None of the exemptions listed below, including emission de minimis levels, shall apply if by taking such exemption a source would avoid any specific federal or state applicable requirement, including, but not limited to, New Source Performance Standards, Regulation Number 7, Prevention of Significant Deterioration (Section VI., Part D of this Regulation Number 3), nonattainment New Source Review requirements (Section V. Part D of this Regulation Number 3), Title III, National Emission Standards for Hazardous Air Pollutants, Title V, and Colorado Maximum Achievable Control Technology or Generally Available Control Technology . (If the potential to emit, taking into account full design rate and continuous operation, triggers Prevention of Significant Deterioration or New Source Review requirements, the source must submit an Air Pollutant Emission Notice and apply for the appropriate permit, or must apply for a permit to limit the physical or operational capacity of the source such that the source is not considered to be a major source as defined in Section I.B.25. of Part A of this regulation.).

Sources otherwise required to obtain an operating permit are required to include a list of insignificant activities in their permit applications if the insignificant activities are listed in Sections II.E.1. and II.E.2., or marked with an asterisk in Section II.E.3. The asterisk denotes an insignificant activity source category based on the size of the activity, emissions levels from the activity or the production rate of the activity. The owner or operator of individual emission points marked with an asterisk in Section II.E.3., below, must maintain sufficient record keeping verifying that the exemption applies. Such records shall be made available for Division review upon request.

The following sources are exempt from the requirement to obtain an operating permit pursuant to this Part C:

II.E.1. Sources subject to regulation or requirements pertaining to standards of performance for new residential wood heaters pursuant to Regulation Number 6; or

II.E.2. Sources subject to regulation or requirements pertaining to national emissions standards for hazardous air pollutants for asbestos in the course of demolition and renovation pursuant to Regulation Number 8.

II.E.3. Certain categories of sources and activities which are considered to be insignificant contributors to air pollution as listed below. A source solely comprised of one or more of these activities are not required to obtain an operating permit pursuant to this regulation, unless the source's emissions trigger the major source threshold as defined in Section I.B.25. of Part A of this Regulation Number 3 (definition of major source):

II.E.3.a. *Individual emission points in nonattainment areas having uncontrolled actual emissions of any criteria pollutant (as defined in Section I.B.17. of Part A of this Regulation Number 3) of less than one ton per year, and individual emission points in attainment or attainment/maintenance areas having uncontrolled actual emissions of any criteria pollutant of less than two tons per year, and each individual emission point with uncontrolled actual emissions of lead less than one hundred pounds per year, regardless of where the source is located.

II.E.3.b. Individual emission points of non criteria reportable pollutants having uncontrolled actual emissions less than the de minimis levels as determined following the procedures set forth in Appendix A.

II.E.3.c. Air conditioning or ventilating systems not designed to remove air pollutants generated by or released from other processes or equipment.

II.E.3.d. Fireplaces used for recreational purposes, inside or outside.

II.E.3.e. Fires and equipment used for noncommercial cooking of food for human consumption, or cooking of food for human consumption at commercial food service establishments, except for char broilers and wood fired equipment (but not including campfires) in PM10 nonattainment areas. Charbroiler shall mean a cooking device in a commercial food service establishment, either gas fired or using charcoal or other fuel, upon which grease drips down upon an open flame, charcoal or embers.

II.E.3.f. Flares used to indicate danger to the public.

II.E.3.g. Agriculture operations such as farming, cultivating and harvesting, seasonal crop drying, grain handling operations that are below New Source Performance Standards de minimis levels (including milling and grain elevator operations), and animal feeding operations that are not housed commercial swine feeding facilities as defined in Regulation Number 2, Part B. This exemption does not apply to an agricultural operation that: (1) is a major source (Regulation Number 3, Part A, Section I.B.25.); (2) meets or exceeds the storage capacity thresholds of a federal New Source Performance Standards (Regulation Number 6, Part A); or (3) participates in the early reduction program of the Federal Act, Section 112. Ancillary operations such as fueling stations located at farms or ranches are not exempt from Air Pollutant Emission Notice and permit requirements unless otherwise below the de minimis emission levels contained in this regulation, and are not exempt from other applicable regulations promulgated by the Commission.

II.E.3.h. Emissions from, or construction, or alteration of residential structures, including all buildings or other structures used primarily as a place of residence, and including home heating devices.

II.E.3.i. Research laboratories

II.E.3.i.(i) Noncommercial (in house) experimental and analytical laboratory equipment that is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories.

II.E.3.i.(ii) *Research and development activities that are of a small pilot scale and that process less than ten thousand pounds of test material per year;

II.E.3.i.(iii) *Small pilot scale research and development projects less than six months in duration with controlled actual emissions less than five hundred pounds of any criteria pollutant or ten pounds of any non criteria reportable pollutant.

II.E.3.j. *Disturbance of surface areas for purposes of land development, that do not exceed twenty-five contiguous acres and that do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil).

II.E.3.k. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, that uses gaseous fuel, and that has a design rate less than or equal to five million British thermal units per hour. (See definition of fuel burning equipment in the Common Provisions Regulation).

II.E.3.l. Internal combustion engines powering portable drilling rigs.

II.E.3.m. *Petroleum industry flares, not associated with refineries, combusting natural gas containing no hydrogen sulfide except in trace amounts (less than five hundred parts per million weight), approved by the Colorado Oil and Gas Conservation Commission and having uncontrolled emissions of any pollutant of less than five tons per year.

II.E.3.n. *Chemical storage tanks or containers that hold less than five hundred gallons, that have an annual average throughput less than twenty-five gallons per day, and are not associated with either oil and gas production wastewater or commercial facilities that accept oil production wastewater for processing.

II.E.3.o. Unpaved public and private roadways, except for haul roads located within a stationary source site boundary.

II.E.3.p. Sanding of streets and roads to abate traffic hazards caused by ice and snow.

II.E.3.q. Open burning activities, except that all reporting and permitting requirements that apply to such operations must be followed (see Regulation Number 9).

II.E.3.r. Brazing, soldering, or welding operations that use lead based compounds. All welding that occurs strictly for maintenance purposes is exempt.

II.E.3.s. Street and parking lot striping.

II.E.3.t. Battery recharging areas.

II.E.3.u. Aerosol can usage.

II.E.3.v. Sawing operations that are ancillary to facility operations and are not part of the production process.

II.E.3.w. The process of demolition and re-bricking of furnaces and kilns. This does not include subsequent operation of such furnaces or kilns.

II.E.3.x. Road and lot paving operations at commercial and industrial facilities, except that asphalt and cement batch plants require Air Pollutant Emission Notices and permits, unless exempt under some other section.

II.E.3.y. Adhesive use that is not related to production.

II.E.3.z. Fire training activities.

II.E.3.aa. Caulking operations that are not part of a production process.

II.E.3.bb. *Landscaping and site housekeeping devices equal to or less than ten horsepower in size (lawnmowers, trimmers, snow blowers, etc.).

II.E.3.cc. Fugitive emissions from landscaping activities (e.g., weeding, sweeping).

II.E.3.dd. Landscaping use of pesticides, fumigants, and herbicides.

II.E.3.ee. *Crude oil loading truck equipment at exploration and production sites where the loading rate does not exceed 10,000 gallons of crude oil per day averaged on an annual basis. Condensate truck loading equipment at exploration and production sites that splash fill less than 6750 barrels of condensate per year or that submerge fill less than 16308 barrels of condensate per year.

II.E.3.ff. Emergency events such as accidental fires.

II.E.3.gg. Smoking rooms and areas.

II.E.3.hh. Plastic pipe welding.

II.E.3.ii. Vacuum cleaning systems used exclusively for industrial, commercial, or residential housekeeping purposes.

II.E.3.jj. Beauty salons.

II.E.3.kk. Operations involving acetylene, butane, propane and other flame cutting torches.

II.E.3.ll. Pharmacies.

II.E.3.mm. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed five thousand gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers.

II.E.3.nn. Architectural painting, roof coating material and associated surface preparation (except for sandblasting and except for volatile organic compound emissions, associated with surface preparation, above Air Pollutant Emission Notice de minimis levels) for maintenance purposes at industrial or commercial facilities.

II.E.3.oo. Emissions of air pollutants that are not criteria or non-criteria reportable pollutants (see Sections I.B.17. and I.B.30. of Part A of this regulation). These emissions include methane, ethane and carbon dioxide.

II.E.3.pp. Janitorial activities and products.

II.E.3.qq. Grounds keeping activities and products.

II.E.3.rr. Sources of odorous emissions that do not utilize emission control equipment for control of odorous emissions. This exemption applies to the odor emissions only. All other emissions are subject to other exemptions set forth in this regulation. This exemption does not exempt any source from the requirements of Regulation Number 2.

II.E.3.ss. Truck and car wash units.

II.E.3.tt. Office emissions, including cleaning, copying, and restrooms.

II.E.3.uu. *Oil production wastewater (produced water tanks), containing less than one percent by volume annual average crude oil, except for commercial facilities that accept oil production wastewater for processing.

II.E.3.vv. Electrically operated curing ovens, drying ovens and similar activities, articles, equipment, or appurtenances. This exemption applies to the ovens only, and not to the items being dried in the ovens.

II.E.3.ww. Equipment used exclusively for portable steam cleaning.

II.E.3.xx. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system or collector serving them exclusively.

II.E.3.yy. Commercial laundries (except dry cleaners) that do not burn liquid or solid fuel.

II.E.3.zz. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than sixty thousand gallons, provided the requirements of Regulation Number 7, Section IV. are met, where applicable.

II.E.3.aaa. Storage tanks of capacity less than forty thousand gallons of lubricating oils or waste lubricating oils.

II.E.3.bbb. *Venting of compressed natural gas, butane or propane gas cylinders, with a capacity of one gallon or less.

II.E.3.ccc. *Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than four hundred gallons per day, averaged annually. Sources in an ozone attainment/maintenance area must utilize Stage 1 vapor recovery on all tanks greater than five hundred and fifty gallons capacity, as required by Regulation Number 7, in order to take this exemption.

II.E.3.ddd. Exemption Repealed.

II.E.3.eee. Indirect sources are exempt until a (permit) regulation specific to indirect sources is promulgated by the Commission.

II.E.3.fff. *Storage tanks meeting all of the following criteria:

II.E.3.fff.(i) Annual throughput is less than four hundred thousand gallons; and

II.E.3.fff.(ii) The liquid stored is one of the following:

II.E.3.fff.(ii)(A) Diesel fuels 1-D, 2-D, or 4-6;

II.E.3.fff.(ii)(B) Fuel oils #1 - #6;

II.E.3.fff.(ii)(C) As turbine fuels 1 - GT through 4 - GT;

II.E.3.fff.(ii)(D) An oil/water mixture with a vapor pressure less than or equal to that of diesel fuel (Reid vapor pressure of .025 psia).

II.E.3.ggg. Each individual piece of fuel burning equipment that uses gaseous fuel, and that has a design rate less than or equal to ten million British thermal units per hour, and that is used solely for heating buildings for personal comfort.

II.E.3.hhh. Natural gas vehicle fleet fueling facilities.

II.E.3.iii. Electric motors driving equipment at non-commercial machining shops.

II.E.3.jjj. Recreational swimming pools.

II.E.3.kkk. Forklifts.

II.E.3.lll. Handling equipment and associated activities for glass that is destined for recycling.

II.E.3.mmm. Containers, reservoirs, or tanks used exclusively for dipping operations, that contain no organic solvents, for coating objects with oils, waxes, greases, or natural or synthetic resins.

II.E.3.nnn. Stationary Internal Combustion Engines that:

II. E.3.nnn.(i) Are power portable drilling rigs; or

II. E.3.nnn.(ii) Are emergency power generators that operate no more than two hundred fifty hours per year; or

II. E.3.nnn.(iii) Have uncontrolled actual emissions less than five tons per year or manufacturer's site-rated horsepower of less than fifty

II.E.3.ooo. The collection, transmission, liquid treatment, and solids treatment processes at domestic wastewater treatment works, or treatment facilities that treat only domestic type wastewater, except for combustion processes.

II.E.3.ppp. Gasoline stations located in ozone attainment areas.

II.E.3.qqq. *Surface mining activities that mine seventy thousand tons or fewer of product material per year. A fugitive dust control plan is required for such sources. Crushers, screens and other processing equipment activities are not included in this exemption.

II.E.3.rrr. Composting piles, however, all odor requirements of Regulation Number 2 must be met.

II.E.3.sss. Fugitive emissions of hazardous air pollutants that are natural constituents of native soils and rock (not added or concentrated by chemical or mechanical processes) from underground mines or surface mines unless such source is a major source of hazardous air pollutants under Part C of this Regulation Number 3.

II.E.3.ttt. The use of pesticides, fumigants, and herbicides when used in accordance with requirements established under the federal Insecticide, Fungicide and Rodenticide Act as established by the U.S. EPA (United States Code Title 7, Section 136 et seq.).

II.E.3.uuu. Ventilation of emissions from mobile sources operating within a tunnel, garage, or building that are not operating for transportation purposes and are subject to stationary source requirements,.

II.E.3.vvv. Non-asbestos demolition.

II.E.3.www. Sandblast equipment when the blast media is recycled and the blasted material are collected.

II.E.3.xxx. Stationary internal combustion engines:

II.E.3.xxx.(i) *Less than or equal to 175 horsepower which operate less than 1,450 hours per year.

II.E.3.xxx.(ii) *Greater than 175 horsepower and less than or equal to 300 horsepower which operate less than 850 hours per year.

II.E.3.xxx.(iii) *Greater than 300 horsepower and less than or equal to 750 horsepower which operate less than 340 hours per year.

II.E.3.yyy. Surface water storage impoundment of non-potable water and storm water evaporation ponds, with the exceptions of impoundment of oil and gas production wastewater (including produced water tanks) containing equal to or more than one percent by volume crude oil on an annual average and commercial facilities that accept oil and gas production wastewater for processing.

II.E.3.zzz. Non-potable water pipeline vents.

II.E.3.aaaa. Steam vents and safety release valves.

II.E.3.bbbb. Exemption Repealed.

II.E.3.cccc. Seal and lubricating oil systems for steam turbine electric generators.

II.E.3.dddd. Venting of natural gas lines for safety purposes.

II.E.3.eeee. Chemical storage tanks

II.E.3.eeee.(i) *Sulfuric acid storage tanks not to exceed ten thousand five hundred gallons capacity.

II.E.3.eeee.(ii) *Sodium hydroxide storage tanks.

II.E.3.ffff. Wet screening operations notwithstanding the applicability of the New Source Performance Standards included in the Code of Federal Regulations, Title 40, Part 60, Subpart OOO.

II.E.3.gggg. *Any condensate storage tank with a production rate of 730 barrels per year or less or condensate storage tanks that are manifold together with a production rate of 730 barrels per year or less that are owned and operated by the same person, and are located at exploration and production sites.

II.F. Sources that are not required by this Part C to obtain an operating permit may elect to apply for, and may be issued, an operating permit. Any such permit issued must contain terms and conditions sufficient to satisfy the requirements of this regulation.

II.G. All federally enforceable terms and conditions in an operating permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator, as well as citizens pursuant to United States Code Title 42, Section 7604.

III. Operating Permit Application Requirements

III.A. Option for pre application meeting

Prior to submitting an application for a permit an applicant may request and, if so requested, the Division shall grant, a pre application meeting with the applicant. At such meeting, the Division shall advise the applicant of the applicable permit requirements, including the information, plans, specifications and the data required to be furnished with the permit application, based on the best information available from the applicant at the time. Failure of the Division to identify all requirements and information does not exempt the source from compliance with applicable requirements or these regulations.

III.B. Application for operating permit and combined construction/operating permit applications

III.B.1. An application for an operating permit shall be prepared on forms supplied by the Division that meet all the requirements of the Federal Act. Applicants shall submit sufficient copies of their applications for provision of copies to the Administrator, affected states and county clerks as required by Sections V.B.5., VI., and IX. of this Part C.

III.B.2. Each source required to obtain an operating permit pursuant to Section III. of this Part C, for the first time, shall submit an application for such a permit no later than twelve months after the source becomes subject to the operating permit requirement. A source that becomes subject to the operating permit program by operation of law, such as the adoption of new legal requirements, shall submit an application for an operating permit within twelve months of the effective date of such new legal requirements unless otherwise specified by the requirements. A new source or an existing source that modifies in a way that renders it newly subject to the operating permit requirements, shall submit a complete application for an operating permit within twelve months of commencing operation, except as otherwise provided herein. Modifications made to a source with an operating permit, through a permit issued under Part B of this regulation shall apply for a modification to their operating permit within twelve months of startup. A new source (including any significant modification), shall meet the applicable requirements of Part B.

III.B.3. Reserved.

III.B.4. Reserved.

III.B.5. All other major sources existing on January 1, 1995 shall submit their operating permit applications unless otherwise notified by the Division.

III.B.6. Each source subject to an operating permit shall submit an application for renewal of the operating permit at least twelve months, but not more than eighteen months, prior to the expiration of the operating permit. All of the provisions governing the application for and issuance of operating permits are applicable to applications for renewal of operating permits, except that an application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application. The Division may choose to issue a draft renewal or proposed renewal permit specifying only those portions that will be revised, supplemented, or deleted, incorporating the remaining permit terms by reference. All requirements for compliance plans, compliance schedules and compliance certifications found in Sections III.B.7., III.B.8., and III.C.8. through III.C.13. of this Part C, are applicable to the entire operating permit upon renewal.

III.B.7. A source required to obtain a construction permit pursuant to Part B of this Regulation Number 3 may submit an application for a combined construction permit and operating permit on a standard application form supplied by the Division prior to commencing construction, modification, installation or commencement of any activities or operations for which a construction permit is required pursuant to Part B. In accordance with the provisions of Part B, a source applying for a combined construction/operating permit cannot construct before issuance of a permit.

III.B.8. Applications shall be signed by a responsible official who shall also sign the compliance certification on the application. The compliance certification shall include: (a) a certification of compliance with all applicable requirements; (b) a statement of methods used for determining compliance, including a description of monitoring, record keeping, and reporting requirements and test methods; (c) a schedule for submission of compliance certifications during the permit term not less than annually, or more frequently as specified by the terms and conditions of the permit; (d) a statement indicating the source's compliance status with any applicable compliance assurance monitoring and compliance certification requirements; (e) if applicable to a source, a statement indicating the source has properly registered its risk management plan required pursuant to Section 112(r) of the Federal Act. Compliance certifications for state only conditions shall be separate from compliance certifications required under the Federal Act, and shall only be required for sources of such state only conditions seeking the operational flexibility provisions of Sections X., XI., and XII. of this Part C. Sources seeking protection under the terms of the permit shield for such state only conditions, or sources of state only conditions are otherwise required to obtain an operating permit pursuant to the state Act.

III.B.9. Each application form, report and compliance certification submitted pursuant to this regulation shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

III.C. Complete applications

The applicant shall furnish all information and data required by the Division to evaluate the permit application and to make its preliminary analysis in accordance with Section IV. of this Part C including, but not limited to:

III.C.1. Identifying information, including company name and address (or plant name and address if different from the company name), owner's name and agent, and telephone number and name of plant site manager/contact;

III.C.2. A description of the source's processes and products (by standard industrial classification code) including any associated with alternate scenarios identified by the source;

III.C.3. The following emission-related information:

III.C.3.a. All emissions of pollutants for which the source is major, and all emissions of regulated air pollutants. A permit application shall describe all emissions of regulated air pollutants emitted from any emissions unit, except where such units are exempted under Section II.E. of this Part C, and all additional information related to the emissions of pollutants sufficient to verify which requirements are applicable to the source and other information necessary to collect any permit fees owed pursuant to Section VI. of Part A of this regulation;

III.C.3.b. Identification and description of all points of emissions described in Section III.C.3.a., above, in sufficient detail to establish the basis for fees and applicability of requirements of the Federal Act;

III.C.3.c. Emissions rate in tons per year and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method;

III.C.3.d. The following information to the extent it is needed to determine or regulate emissions: fuels, fuel use, raw materials, production rates, and operating schedules;

III.C.3.e. Identification and description of air pollution control equipment and compliance monitoring devices or activities;

III.C.3.f. Limitations on source operation affecting emissions or any work practice standards, where applicable, for all regulated air pollutants at the source;

III.C.3.g. Other information required by any applicable requirement, including information related to stack height limitations developed pursuant to United States Code Title 42, Section 7423 (Part A, Section VIII. of this Regulation Number 3); and

III.C.3.h. Calculations on which the information required in Sections III.C.3.a. through III.C.3.g. are based.

III.C.4. The following air pollution control requirements:

III.C.4.a. Citation and description of all applicable requirements, and

III.C.4.b. Description of, or reference to, any applicable test method for determining compliance with each applicable requirement.

III.C.5. Other specific information that may be necessary to implement and enforce other applicable requirements of the Federal Act or of this Section III., or to determine the applicability of such requirements.

III.C.6. An explanation of any proposed exemptions from otherwise applicable requirements.

III.C.7. Additional information as determined to be necessary by the Division to define alternative operating scenarios identified by the source pursuant to Section IV.A. of Part A of this regulation, or to define permit terms and conditions implementing Section XII. of this Part C.

III.C.8. A compliance plan which contains: (a) a description of the compliance status of the source with respect to all applicable requirements; (b) for applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements; (c) for applicable requirements that will become effective during the permit term, a statement that the source will meet the requirements on a timely basis; and (d) for requirements for which the source is not anticipated to be in compliance at the time of permit issuance, a narrative description of how the source will achieve compliance with such requirements.

III.C.9. A compliance schedule which contains: (a) for applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements; or (b) for applicable requirements that will become effective during the permit term, a statement that the source will meet the requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy the provision, unless a more detailed schedule is expressly required by the applicable requirement; and (c) a schedule of compliance for sources that are not anticipated to be in compliance at the time of permit issuance. This schedule shall include a schedule of enforceable remedial milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance. This compliance schedule shall be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

III.C.10. A schedule for submission of progress reports no less frequently than every six months for sources required having a schedule of compliance to remedy a violation.

III.C.11. The compliance plan content requirements specified in this section shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, with regard to the schedule and method(s) the source will use to achieve compliance with the acid rain emissions limitations.

III.C.12. Data necessary to allow the Division to determine whether the source complies with:

III.C.12.a. All applicable emission control regulations;

III.C.12.b. Applicable regulations for the control of hazardous air pollutants;

III.C.12.c. Requirements of the nonattainment and attainment programs, Sections V. and VI. of Part D of this regulation; and

III.C.12.d. Any applicable ambient air quality standards (for temporary sources and new or modified sources applying for a combined construction/operating permit only). When the data includes modeling, the model used shall be an appropriate one given the topography, meteorology, and other characteristics of the region that the source will impact; and

III.C.12.e. All applicable regulations.

III.C.13. Copies of Air Pollutant Emission Notices on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

III.D. Operating Permit Renewal

In submitting an application for renewal of an operating permit issued under these regulations, a source may identify terms and conditions in its previous permit that remain unchanged and incorporate by reference those portions of its existing permit and the permit application and any permit amendments or modification applications that describe products, processes, operations, and emissions to which those terms and conditions apply. The source must identify specifically and list which portions of its previous permit and/or applications that are incorporated by reference. In addition, a renewal application must contain:

III.D.1. Information for those products, processes, operations, and emissions, in accordance with the provisions of this Part C, that:

III.D.1.a. Are not addressed in the existing permit;

III.D.1.b. Are subject to applicable requirements that are not addressed in the existing permit; or

III.D.1.c. Are permit terms and conditions that differ from those in the existing permit.

III.D.2. A compliance plan, schedule, and certification requirements for the entire permit in accordance with this Part C.

III.E. A major source may comply with this section through any one of the following methods:

III.E.1. The source may obtain a single permit for all relevant emission points located within a contiguous or adjacent area under common control (whether or not falling under the same two digit standard industrialized code);

III.E.2. The source may obtain separate permits for separate emission points or groups of emission points, or

III.E.3. The Division may issue a permit covering one or more emission points eligible for coverage under a general permit and the source may obtain a separate permit or permits for emission points not eligible for such coverage.

III.F. The acid rain portions of permit applications shall be made on nationally standardized forms pursuant to regulation promulgated by the Administrator at Code of Federal Regulations Title 40, Part 72.

IV. Processing Of Applications

IV.A. Standards for application determinations

The Division shall evaluate operating permit applications and combined construction/operating permit applications. The evaluation of permit applications shall consider, for the construction permit portion, whether operation of the proposed new source at the date of start-up, and for operating permits whether the permitted emissions, will comply with all applicable emissions control regulations, regulations for the control of hazardous air pollutants, applicable ambient air quality standards and regulations, requirements for the prevention of significant deterioration of air quality that is better than the National Ambient Air Quality Standards, and nonattainment and attainment/maintenance area requirements. The submittal of a complete application shall not affect the requirement that any source have a construction permit pursuant to Part B of this Regulation Number 3, except as otherwise required herein.

IV.B. Completeness determinations

IV.B.1. An application for an operating permit or a combined construction permit/operating permit, will not be deemed to be complete until all information and data required to evaluate the application have been submitted to the Division. Within sixty calendar days after the receipt of an application or any supplemental information requested by the Division, the Division will give notice to the applicant if and in what respect the application is incomplete. If the Division fails to notify an applicant that the application is incomplete within sixty calendar days of receipt of the original application or receipt of the requested supplemental information, the application shall be deemed to have been complete as of the day of receipt by the Division of the application or the last submitted supplemental information, whichever is later, for the purposes specified in Section II.B. of this Part C (concerning the application shield). Nothing herein precludes the Division from requesting further information about the source in order to process the permit application. If the Division concludes that the application is not complete, it shall inform the applicant of the additional information that must be submitted prior to consideration of the application. No completeness determination shall be required for applications for administrative or minor permit modification procedures under Section III. of Part A of this regulation, or Sections X. and XI. of this Part C.

IV.B.2. The Division shall review each application submitted to determine whether it is complete. An application shall be deemed to be complete when it contains the information required by Sections III.B., III.C., and III.D. of this Part C in sufficient detail for the Division to evaluate the subject source and the permit application, to determine all applicable requirements and to calculate all applicable fees.

IV.B.3. A source shall supplement its permit application to correct or update information provided in its initial submission as soon as it becomes aware of any omissions or incorrect information submitted or to address changes made to the source after submission of the application, but prior to public notice as provided in Section VI. of this Part C.

IV.B.4. A source shall supplement its permit application to address any requirements that become applicable to the source after the date the source submitted its application, but prior to issuance of a draft permit.

IV.C. Permit application processing timeframes

For operating permit applications, or for combined construction and operating permit applications, the Division shall approve or disapprove the permit application within eighteen months of receipt of a complete application. Permit processing timeframes for operating permit applications for affected sources under the acid rain provisions shall be governed by Code of Federal Regulations Title 40, Part 72. If a timely and complete application is filed, but the Division fails to issue or deny a renewal operating permit prior to expiration of the operating permit for which a source is seeking renewal, the previously issued operating permit, and all of its terms and conditions, shall not expire until the renewal operating permit is issued and any previously extended permit shield continues in full force and operation.

To the extent feasible, applications shall be acted upon in the order received except that priority shall be given to taking final action on applications for construction or modification under Title I, Parts C and Part D, of the Federal Act. Final action on such applications shall be taken within twelve months following receipt of a complete application.

IV.D. Requests for additional information

If, after an application is deemed complete, the Division determines that additional information is necessary to evaluate or take final action on an application, the Division shall request necessary information in writing and set a reasonable deadline for response. Additional information submitted within the deadline will be evaluated by the Division. If the applicant fails to provide the requested information or does not meet the deadline, the source's ability to operate without a permit shall terminate on the date of the deadline as provided in Section II.B. of this Part C.

V. Operating Permit Issuance, Renewals And Modifications

V.A. Except as provided below, the Division shall not issue, reissue or renew an operating permit until the source has obtained a final approval construction permit for all emission units pursuant to Regulation Number 3, Part B, Section III.G. However, nothing in this section shall preclude the Division from issuing, reissuing, or renewing an operating permit if the holder of an initial approval construction permit has not commenced operation of the new construction or modification authorized by that construction permit.

When the source has not demonstrated compliance with the terms of an initial approval construction permit as required pursuant to Regulation Number 3, Part B, Section III.G., or has not obtained a final approval construction permit as required above, the Division may issue, reissue or renew an operating permit under the following circumstances:

V.A.1. If the source has not demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G., and the source is not anticipated to be in compliance at the time of the operating permit issuance with any of the terms or conditions of the initial approval construction permit, the operating permit must contain a compliance plan and compliance schedule that meets the requirements of this Part C, Sections III.C.8., III.C.9., and III.C.10., with respect to those permit term(s). In that instance, the deviation reporting required under this Part C, Section V.C.7.b. may, at the Division’s discretion, serve as the demonstration required pursuant to Regulation Number 3, Part B, Section III.G. and no final approval construction permit will be issued; or

V.A.2. If the source has not demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G., and the source anticipates being in compliance at the time of the operating permit issuance with all of the terms or conditions of the initial approval construction permit, the Division can elect to allow the initial approval construction permit to continue in full force and effect pursuant Regulation Number 3, Part B, Section III.G.4. In that instance, the first deviation report after permit issuance as required under this Part C, Section V.C.7.b. may, at the Division's discretion, serve as the demonstration required pursuant to Regulation Number 3, Part B, Section III.G., and no final approval construction permit will be issued; or

V.A.3. If the source has demonstrated compliance under the provisions of Regulation Number 3, Part B, Section III.G. but not yet received a final approval construction permit, the Division may, at its discretion, elect to either issue a final approval construction permit or allow the initial approval construction permit to continue in full force and effect. The Division shall provide written notice to the permittee of its election.

V.B. An operating permit, permit modification or permit renewal shall be issued only upon a determination by the Division that the following criteria have been met:

V.B.1. The Division has received a complete application for a permit, permit modification, or permit renewal;

V.B.2. Public comment and hearing requirements, except for modifications qualifying for minor permit modification procedures or administrative permit revisions;

V.B.3. Requirements for notifying and responding to affected states pursuant to Section IX. of this Part C. This section is not applicable to minor sources that voluntarily apply for an operating permit for purposes of Sections X., XI., and XII., unless the source is required to have federally enforceable emissions limitations to be considered a minor source, nor to major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state-only conditions under the state Act;

V.B.4. Permit conditions provide for compliance with all applicable requirements and the requirements of this Regulation Number 3; and

V.B.5. The Administrator has received a copy of the proposed permit and has not objected to its issuance within forty-five days of receipt of the proposed permit and all necessary supporting information. This section is not applicable to minor sources that voluntarily apply for an operating permit for purposes of Sections X., XI., and XII., unless the source is required to have federally enforceable emissions limitations to be considered a minor source, nor to major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state only conditions under the state Act.

V.B.6. The Administrator's objection to permit issuance shall be based on a determination that the proposed permit will not be in compliance with applicable requirements or requirements of Code of Federal Regulations Title 40, Part 70. Any such objection shall include a statement of the Administrator's reasons for objecting and a description of the terms and conditions that the permit must include to respond to the objection. Failure of the Division to do any of the following shall also constitute grounds for an objection by the Administrator:

V.B.6.a. Failure to comply with the provisions of Section V.F. of this Part C for submission of copies of permit applications, proposed permits, and final permits to the Administrator;

V.B.6.b. Failure to comply with the provisions of Section IX. of this Part C for review by affected states;

V.B.6.c. Failure to submit any information to the Administrator necessary to review adequately the proposed permit; or

V.B.6.d. Failure to comply with the provisions of Section VI. of this Part C for public participation.

V.B.7. If the Division fails, within ninety days after an objection by the Administrator, to revise and submit a proposed permit in response to the objection, the Administrator will issue or deny the permit in accordance with the requirements of the federal program promulgated under Title V of the Federal Act.

V.B.8. The permit applicant has paid all applicable hourly fees as set forth in Part A, Section VI. of this Regulation Number 3.

V.C. An operating permit shall contain, at a minimum, the following:

V.C.1. Emissions limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance, including:

V.C.1.a. The permit shall specify and reference the origin of and authority for each term and condition, and identify any difference in form as compared to the applicable requirement upon which the term or condition is based; and

V.C.1.b. The permit shall state that, where an applicable requirement of the Federal Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Federal Act, Code of Federal Regulations Title 40, Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable; and

V.C.1.c. If allowed by the state implementation plan, an alternative emissions limitation that is at least as stringent as an applicable requirement may be substituted for an applicable requirement as a permit term or condition, so long as the permit containing such equivalency determination contains provisions to ensure that any resulting emissions limitation is quantifiable, accountable, enforceable and based on replicable procedures.

V.C.2. The permit term shall be five years.

V.C.3. The effective date and termination date of the permit shall be specifically identified in the permit.

V.C.4. A statement of all monitoring and related record keeping and reporting requirements shall be specifically identified in the permit.

V.C.5. Each permit shall contain the following requirements with respect to monitoring:

V.C.5.a. All emissions monitoring and analysis procedures or test methods required under the applicable requirements, including any required procedures and methods for compliance assurance monitoring and compliance certification requirements;

V.C.5.b. Where the applicable requirement does not require periodic testing or instrumental or non-instrumental monitoring, periodic monitoring, or record keeping, sufficient to yield reliable data for the relevant time period that are representative of the source's compliance with the permit as required to be reported pursuant to Section V.C.16.e. of this Part C. Such monitoring requirements shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirements.

V.C.5.c. As necessary, requirements concerning the use, maintenance and, where appropriate, installation of monitoring equipment or methods.

V.C.6. Each permit shall incorporate all applicable record keeping requirements and require, where applicable, the following:

V.C.6.a. Records of required monitoring information, which includes the following:

V.C.6.a.(i) Date, place, as defined in the permit, and time of sampling or measurements;

V.C.6.a.(ii) Date(s) on which analyses were performed;

V.C.6.a.(iii) The company or entity that performed the analysis;

V.C.6.a.(iv) The analytical techniques or methods used;

V.C.6.a.(v) The results of such analysis; and

V.C.6.a.(vi) The operating conditions as existing at the time of sampling or measurement.

V.C.6.b. The retention of records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. The applicant may, with the Division's approval, maintain any of the above records in a computerized form. Sources must retain records of all required monitoring data and support information for the most recent twelve month period, as well as compliance certifications for the past five years on site at all times. A source shall make available for Division review all other records of required monitoring data and support information required to be retained by a source upon forty-eight hours advance notice by the Division.

V.C.6.c. A permittee may request confidential treatment for information in any report submitted under this section pursuant to the limitations and procedures set forth in Section VII. of Part A of this Regulation Number 3.

V.C.7. Each permit shall incorporate all applicable reporting requirements, and shall require the following:

V.C.7.a. Submittal of all reports of any required monitoring at least every six months except as otherwise required on a more frequent basis pursuant to compliance assurance monitoring rules or other applicable requirements. The Division may approve alternative reporting formats and schedules proposed by an applicant consistent with the requirements of this section, allowing for coordination with other reporting requirements for that source. All instances of deviations from any permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official consistent with Section III.B.8. of this Part C;

V.C.7.b. Prompt reporting of deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. Each permit shall contain a definition of prompt reporting in relation to the degree and type of deviation likely to occur and the applicable requirements. Generally "prompt" reporting shall entail reporting as required in Section V.C.7.a., above, requiring submission of reports of deviations from permit requirements at least every six months, except as otherwise specified by the Division in the permit. Prompt reporting, for this purpose, does not constitute an exception to the requirements of Section VII. relating to reporting of emergency events for the purpose of avoiding enforcement actions.

V.C.8. A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds under Title IV of the Federal Act or the regulations promulgated there under at Code of Federal Regulations Title 40, Part 72.

V.C.9. State only permit terms and conditions shall be listed separately on the operating permit. All procedural requirements of this Part C may apply to such state only conditions, except as otherwise required by the state Act, in order for sources to obtain the permit shield and all operational flexibility provisions. The permit shall also contain a specific designation as not being federally enforceable any state only terms and conditions included in the permit that are not required under the Federal Act or under any of its applicable requirements. A source may choose to obtain a separate construction permit pursuant to Part B for such state only requirements, except as otherwise required under the state Act;

V.C.10. A severability clause that demands the continued validity of the various permit requirements in the event of a challenge to any portion of the permit;

V.C.11. Provisions stating the following permit terms and conditions:

V.C.11.a. The permittee must comply with all conditions of the permit issued under this Part C. Any permit noncompliance relating to federally enforceable terms or conditions constitutes a violation of the Federal Act, as well as the state Act and this regulation. Any permit noncompliance relating to state only terms or conditions constitutes a violation of the state Act and this regulation, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under Section 304 of the Federal Act. Any such violation of the Federal Act, the state Act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

V.C.11.b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit;

V.C.11.c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in Sections X. and XI. of this Part C;

V.C.11.d. The permit does not convey any property rights of any sort, or any exclusive privilege;

V.C.11.e. The permittee shall furnish to the Division, within a reasonable time specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim;

V.C.12. A requirement that the permittee shall pay to the Division all applicable fees required by the state Act and regulations.

V.C.13. A provision that no permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit;

V.C.14. Terms and conditions for reasonably anticipated operating scenarios identified by the source in its application for a permit and approved by the Division, in accordance with Section IV.A. of Part A of this regulation.

V.C.15. Terms and conditions, if the permit applicant requests them, for the trading of emissions increases and decreases in the permitted facility, in accordance with Section IV.B. of Part A.

V.C.16. The following elements with respect to compliance:

V.C.16.a. Consistent with Sections III.B.7., III.B.8., III.C.8. through III.C.13., and V.C.4. through V.C.7. of this Part C, compliance, certification, testing, monitoring, reporting, and record keeping requirements sufficient to assure compliance with the terms and conditions of the permit. Any document (including reports) required by an operating permit shall contain a certification by a responsible official that meets the requirements of Section III.B.8. of this Part C;

V.C.16.b. Inspection and entry requirements that require, upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Division or any authorized representative to perform the following:

V.C.16.b.(i) Enter upon the permittees premises where an operating permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

V.C.16.b.(ii) Have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

V.C.16.b.(iii) Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit. The permittee shall provide, as part of its permit application, a list of any specialized safety equipment which may be necessary for use by an inspector; and

V.C.16.b.(iv) Any sampling or monitoring of substances or parameters at reasonable times for the purpose of assuring compliance with the permit or applicable requirements;

V.C.16.c. A schedule of compliance consistent with Section III.C. of this Part C;

V.C.16.d. Progress reports consistent with an applicable schedule of compliance and Section III.C. of this Part C, to be submitted at least semiannually or at a more frequent period if so specified in the applicable requirement or by the Division. Such progress reports shall contain the following:

V.C.16.d.(i) Dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

V.C.16.d.(ii) An explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

V.C.16.e. Requirements for compliance certification with terms and conditions contained in the permit, including emission limitations, standards, or work practices. Permits shall include each of the following:

V.C.16.e.(i) The frequency (which shall not be less than annually or such more frequent periods as specified in the applicable requirement or by the Division) of submission of compliance certifications;

V.C.16.e.(ii) In accordance with Sections V.C.4. through V.C.7. of this Part C, a means of monitoring the compliance of the source with its emissions limitations, standards and work practices;

V.C.16.e.(iii) A requirement that the compliance certification include the following:

V.C.16.e.(iii)(A) The identification of each permit term and condition that is the basis of the certification;

V.C.16.e.(iii)(B) The compliance status;

V.C.16.e.(iii)(C) Whether compliance was continuous or intermittent;

V.C.16.e.(iii)(D) The method(s) used for determining the compliance status of the source, currently and over the reporting period, consistent with Sections V.C.4. through V.C.7. of this Part C; and whether the data collection using the methods referenced for compliance certification provide continuous or intermittent data; and

V.C.16.e.(iii)(E) Such other facts as the Division may require to determine the compliance status of the source.

V.C.16.e.(iv) A requirement that all compliance certifications shall be submitted to the Administrator as well as to the Division. This requirement shall not apply to sources subject to the operating permit requirements solely due to state only conditions pursuant to the state Act;

V.C.16.e.(v) Any additional requirements for compliance assurance monitoring and compliance certification;

V.C.16.e.(vi) Such other provisions as the Division may require.

V.C.17. If a source is required to develop and register a risk management plan pursuant to Section 112(r) of the Federal Act, the permit shall only refer to such plan and state the source's compliance with such registration requirement. The content of the risk management plan will not be incorporated as a permit term.

V.D. The permit shield shall extend to applicable requirements that are included and specifically identified in the permit. Upon request, the Division shall include in the permit a determination identifying specific requirements that do not apply to the source. The source shall specify in its permit application for such a determination the requirements as to which the determination is requested. The permit shall state that the permit shield applies to any requirements so identified. A request for a determination to extend the shield to requirements deemed applicable to the source may be made either in the original permit application or in a subsequent application for a permit modification.

V.E. If the Division denies a permit, imposes conditions on a permit that are contested by the applicant, revokes a permit, or requires a permit from a source that may qualify for an exemption, the applicant or owner or operator of the source may request a hearing before the Commission in accordance with the Commission’s Procedures for Adjudications. The request for a hearing must be filed with the Commission within thirty days after the issuance of the permit, denial or revocation. The hearing shall be held in accordance with Colorado Revised Statute Sections 25-7-119 and 24-4-105 and the Commission’s Procedures for Adjudications.

V.F. The Division shall submit to the Administrator a copy of each permit application (including any application for permit modification), each proposed permit, and each final operating permit.

VI. Public Participation Requirements

VI.A. Except for modifications qualifying for administrative permit amendments, minor permit modification procedures and operational flexibility provisions, as described in Sections X., XI., and XII. of this Part C, Sections III. and IV. of Part A, and except for applications for coverage under general operating permits as described in Section VIII. of this Part C, all permit proceedings, including initial permit issuance, significant modifications, re-openings and renewals, and are subject to public notice, comment and opportunity for public hearing requirements. A minor source voluntarily applying for an operating permit is not subject to the public participation requirements of this Part C unless the source is required to have a federally enforceable emission limitation to be considered a (synthetic) minor source. Minor sources that are not synthetic minors and major sources of Colorado-only Hazardous Air Pollutants subject to the operating permit requirements solely due to state-only conditions shall be subject to the public participation requirements where warranted in accordance with the provisions of Part B of this Regulation Number 3.

VI.B. The Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located or in a State publication designed to give general public notice, and by such other means if necessary to assure notice to the affected public, which may include posting of such notice on the publicly accessible portion of the Division's web site. The Division shall cause a copy of the preliminary analysis and application to be filed with the county clerk for each county in which the source is or will be located. The Division shall send written or electronic notice to the applicant, to persons requesting notice of permit applications that are subject to public notice requirements, and to affected states. The newspaper notice or other State publication shall contain the information listed below in VI.B.1. through VI.B.9. The Division's web site notice shall contain all the following information in Sections VI.B.1. through VI.B.15.:

VI.B.1. The name and address of the permittee;

VI.B.2. The name and address of the affected facility;

VI.B.3. The Division's name and address;

VI.B.4. The activity or activities proposed in the permit application;

VI.B.5. The emissions change involved in any permit modification;

VI.B.6. The name, address, and telephone number of a Division staff contact from whom interested persons may obtain additional information, including copies of the permit draft, the application, all relevant supporting materials, the compliance plan, the monitoring and compliance certification report, and all other materials available to the Division that are relevant to its permit decision;

VI.B.7. Information regarding scheduling of any public comment hearing if one is requested;

VI.B.8. That the Division will receive and consider public comments for thirty calendar days after such publication;

VI.B.9. The Division's preliminary determination of approval, conditional approval, or disapproval of the application;

VI.B.10. That any interested person may submit a written request for a public comment hearing to be held by the Commission to receive comments regarding the concerns listed in Sections VI.B.11. through VI.B.15., below, the sufficiency of the preliminary analysis, and whether the Division should approve or deny the permit application. Any written request for a public comment hearing must be submitted to the Division within thirty days of publication;

VI.B.10.a. Written requests for a public comment hearing shall be directed to the Air Pollution Control Division's office at 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530;

VI.B.10.b. Requests shall: (i) identify the individual or group applying; (ii) state his or her address and phone number; (iii) state the reasons for the request; (iv) state the manner in which the person is affected by the proceedings; and (v) provide an explanation of why the person's interests are not already adequately represented.

VI.B.11. That comments concerning the ability of the proposed activity to comply with applicable requirements are solicited from any interested person;

VI.B.12. That comments are solicited on the air quality impacts of the source or modification;

VI.B.13. That comments are solicited on alternatives to the source or modification;

VI.B.14. That comments are solicited on the control technology required;

VI.B.15. That comments are being solicited on any other appropriate air quality considerations.

VI.C. Within fifteen calendar days after the preparation of the preliminary analysis for those applications subject to the requirements of this Part C, the Division shall forward to the applicant written notice of the applicant's right to a public comment hearing with respect to the application pursuant to Section VII. of the Commission’s Procedural Rules.

VI.D. A public comment hearing request pursuant to Section VI.B. of this Part C must be transmitted by the Division to the Commission, along with the complete permit application, the preliminary analysis, the draft permit, and any written comments received by the Division within five days after the end of the thirty-day comment period. At least thirty days prior to the date set for the public comment hearing, the notice of public comment hearing, the preliminary analysis and the draft permit shall be posted on the Division’s web site. No substantive revisions shall be made to the draft permit during the thirty days prior to the public comment hearing. The applicant may submit, within ten days following the close of the public comment period, a response to any comments made. Nothing herein shall impede the Division's ability to meet required processing timeframes or other required time periods contained in this regulation.

VI.E. The Commission shall hold a public comment hearing within sixty days of its receipt of the request for a hearing pursuant to Section VI.B. or VI.C. of this Part C, unless such greater time is agreed to by the applicant and the Division. The Division shall appear at the public comment hearing in order to present the permit application. At least thirty days prior to such hearing, notice thereof shall be mailed by the Commission to the applicant, and to any interested person who submitted a request for a public hearing, printed in a newspaper of general distribution in the area of the proposed source or modification, and submitted for public review with the county clerk for each county in which the source or modification is or will be located.

VI.F. The Division shall maintain a record of the commenter and of the issues raised during the public comment and public hearing process for a period of five years.

VI.G. The Division shall notify the Administrator and any affected state, in writing, of any refusal to accept all recommendations for the proposed permit that the affected state submitted during the public or affected state review period, as well as reasons for such refusal.

VI.H. If the Administrator does not object in writing to the issuance of any proposed permit within forty-five days of receipt of the proposed permit, any person may petition the Administrator within sixty days of expiration of the Administrator's forty-five day review period to make such objection. Any such petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period as provided for in Section VI.B. of this Part C, unless the petitioner demonstrates that it was impracticable to raise such objections within that period, or unless the grounds for such objection arose after such period

VI.H.1. A petition for review does not stay the effectiveness of a permit or its requirements if the permit was issued after the end of the forty-five day review period and prior to an U.S. EPA objection.

VI.H.2. If, pursuant to a petition filed under this Section VI.H., the U.S. EPA objects to the issuance of a permit prior to its issuance, the Division shall not issue the permit until the U.S. EPA's objection has been resolved.

VI.H.3. If, pursuant to a petition filed under this Section VI.H., the U.S. EPA objects to the issuance of a permit after it has been issued by the Division, the Administrator may modify, terminate, or revoke such permit and the Division may thereafter issue only a revised permit that satisfies the U.S. EPA's objection.

VI.H.4. In no event will any proceeding under this Section VI.H. cause a source to be in violation of the requirement to have submitted a timely and complete application.

VII. Emergency Provisions

VII.A. An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of god, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

VII.B. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section VII.C. are met. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

VII.C. The affirmative defense for an emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

VII.C.1. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

VII.C.2. The permitted facility was at the time being properly operated;

VII.C.3. During the period of the emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

VII.C.4. The permittee submitted oral notice of the emergency to the Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirement of Section V.C.7.b. of this Part C. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

VII.C.5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

VIII. General Operating Permits

VIII.A. The Division may, after notice and opportunity for public participation provided under Section VI. of this Part C, issue a general permit covering numerous similar sources that would otherwise be required to obtain an operating permit pursuant to this Part C. Any general permit shall comply with all requirements applicable to other operating permits and shall identify criteria by which sources may qualify for the general permit. For sources that qualify, the Division shall grant the conditions and terms of the general permit. Notwithstanding the permit shield, a source shall be subject to enforcement action for operation without an operating permit if the source is later determined not to qualify for the conditions and terms of the general permit. General permits are not authorized for affected sources under the acid rain program unless otherwise provided in regulations promulgated under Title IV of the Federal Act. A general permit may be issued for the following purposes:

VIII.A.1. To establish terms and conditions to implement applicable requirements for a source category;

VIII.A.2. To establish terms and conditions to implement applicable requirements in lieu of reopening the permit to incorporate additional applicable requirements pursuant to Section XIII of this Part C;

VIII.A.3. To establish terms and conditions for new requirements that apply to sources with existing permits, so long as no terms or conditions of the existing permit are being violated;

VIII.A.4. To establish federally enforceable caps on emissions from sources in a specified category.

VIII.A.5. The Division may issue a general permit if it finds that:

VIII.A.5.a. There are several permittees, permit applicants, or potential permit applicants who have the same or substantially similar operations, emissions, activities, or facilities;

VIII.A.5.b. The permittees, permit applicants, or potential permit applicants emit the same type of regulated air pollutants;

VIII.A.5.c. The operations, emissions, activities, or facilities are subject to the same or similar standards, limitations, and operating requirements; and

VIII.A.5.d. The operations, emissions, activities, or facilities are subject to the same or similar monitoring, record keeping, and reporting requirements.

VIII.B. A general permit developed under this section shall identify criteria by which sources may qualify for the general permit. After a general permit has been developed, any eligible source may submit an application to be covered under the permit.

VIII.C. An application for coverage under a general permit shall identify the source and provide information sufficient to demonstrate that it falls within the source category covered by the general permit, together with all information necessary to determine qualification for, and to assure compliance with, the general permit including a compliance plan in accordance with Section III.C.8. of this Part C.

VIII.D. A final action approving a request for coverage under a general permit shall not be subject to judicial review. A source may seek judicial review of a final action denying coverage under a general permit.

VIII.E. If some, but not all, of a source's operations, activities, and emissions are eligible for coverage under one or more general permits, the source may apply for and receive coverage under the general permits for the operations, activities, and emissions that are so eligible. If the source is required under Section II. of this Part C to obtain an operating permit addressing the remainder of its operations, activities, and emissions, it may apply for, and receive, an operating permit that addresses specifically those items not covered by general permits. In such a case, the source's operating permit shall identify all operations, activities, and emissions that are subject to general permits and incorporate those general permits by reference.

VIII.F. Sources that would qualify for a general permit must apply to the Division for coverage under the terms of the general permit or must apply for an operating permit under Section III. of this Part C. without repeating the public participation procedures required under Section VI. of this Part C, the Division may grant a source's request for authorization to operate under a general permit. Such a grant shall not be a final permit action for purposes of judicial review.

VIII.G. Upon granting of the general permit by the Division, the source must keep a copy of the permit on-site at all times.

VIII.H. A general operating permit shall not be issued to a major source where issuance of a general permit would cause a violation of any applicable requirement in any other operating permit held by the source, or where issuance of a general operating permit operates to allow the source to avoid a modification under Title I of the Federal Act.

VIII.I. A source may commence operations under the general operating permit sixty days after submitting its application for a general operating permit unless notified by the Division within that time period that additional information is required to determine whether the source qualifies for a general operating permit. Nothing herein precludes the Division from requesting additional information after sixty days have elapsed since the source's submission of a general operating permit application.

VIII.J. The application shield shall become effective upon the source's submission of a complete application, in accordance with Section II.B. of this Part C.

VIII.K. The permit shield shall become effective upon issuance of the general operating permit by the Division.

VIII.L. The general operating permits, as developed by the Division, shall be required to undergo review by the Administrator, affected states and the public, as set forth in Sections V.B., VI., and IX. of this Part C every five years.

IX. Review By Affected States

IX.A. The Division shall give notice of each draft-operating permit to any affected state on or before the time that the Division provides public notice under Section VI. of this Part C, except where the requirements for timing of notices are different pursuant to Sections X., X.I., and XII. of this Part C.

IX.B. The Division shall notify the U.S. EPA and any affected state in writing of any refusal by the Division to accept all recommendations for the proposed permit that the affected state submitted during the public or affected state review period. Said notice will include the Division's reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements.

X. Minor Permit Modification Procedures

X.A. Minor permit modification procedures may be used only for those permit modifications that:

X.A.1. Do not violate any applicable requirement;

X.A.2. Do not involve significant changes to existing monitoring, reporting, or record keeping requirements in a permit;

X.A.3. Do not require or change a case-by-case determination of an emission limitation or other standard or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

X.A.4. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

X.A.4.a. A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the Federal Act, including but not limited to modifications under Part 2 of the state Act (prevention of significant deterioration), Part 3 of the state Act (attainment), or New Source Performance Standards (Regulation Number 6);

X.A.4.b. An alternative emissions limit approved pursuant to regulations promulgated under Colorado Revised Statute Section 25-7-109.3 or Section 112(i)(5) of the federal Act (Regulation Number 8);

X.A.5. Are excepted from the definition of permit modification in Section I.A.3. of Part C.

X.A.6. Are not otherwise required by the Division to be processed as a significant modification.

X.B. Notwithstanding Sections X.A.5.and XI. (group processing criteria), minor permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other approved approaches, to the extent that such minor permit modification procedures are otherwise provided for in the state implementation plan promulgated pursuant to the state Act.

X.C. An application for a minor permit modification shall be prepared on forms supplied by the Division.

X.D. Applications shall meet the requirements of an application for an operating permit as set forth in Commission Regulation Number 3, Part C, Section III., and be signed by a responsible official. The applicant shall furnish all information and data required by the Division to evaluate the minor permit modification application, and shall include the following:

X.D.1. A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

X.D.2. The sources suggested draft permit;

X.D.3. Certification by a responsible official that the proposed modification meets the criteria for use of minor permit modification procedures and a request that such procedures be used; and

X.D.4. Completed forms supplied by the Division for the Division to use to notify the Administrator and affected states.

X.D.5. Data necessary to allow the Division to determine whether the source complies with:

X.D.5.a. All applicable emission control regulations;

X.D.5.b. Applicable regulations for the control of hazardous air pollutants;

X.D.5.c. Requirements of the nonattainment and attainment programs (Sections V. and VI. of Part D of this regulation); and

X.D.5.d. Any applicable ambient air quality standards and all applicable regulations. When the data includes modeling, the model used shall be an appropriate one given the topography, meteorology, and other characteristics of the region, which the source will impact;

X.D.6. Copies of Air Pollutant Emission Notice(s) on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

X.E. An application for a minor permit modification will not be deemed to be complete until all information and data (including any required ambient air impact analysis in accordance with Section VIII. of Part A) required to evaluate the application have been submitted to the Division.

X.F. Within five working days of receipt of a complete minor permit modification application, the Division shall send a copy of the notice completed pursuant to Section X.D.4., above, to the Administrator.

X.G. Within five working days of receipt of a complete minor permit modification application, the Division shall send a copy of the notice completed pursuant to Section X.D.4., above, to affected states. Notice to affected states shall not be required for minor sources that voluntarily apply for an operating permit to obtain the operational flexibility set forth in this Part C. The Division shall notify the Administrator and any affected state of any refusal by the Division to accept all recommendations for the proposed revised permit under the minor permit modification procedures that the affected state submitted during its review period. The Division shall include in such notice its reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements under the state or Federal Act. Notice to affected states and to the Administrator is not required for minor modifications involving state only conditions.

X.H. Within ninety calendar days of receipt of a complete application for minor permit modification, or fifteen calendar days after the end of the Administrator's forty five day review period, whichever is later, the Division shall:

X.H.1. Issue the minor permit modification as proposed;

X.H.2. Deny the minor permit modification application;

X.H.3. Determine that the requested modification does not meet the minor permit modification criteria and should be reviewed under the significant modification procedures; or

X.H.4. Revise the draft minor permit modification and transmit to the Administrator the new proposed minor permit modification as required in this Regulation Number 3, Part C, Section V.B.5.

X.I. A source shall be allowed to make the changes proposed in its application for minor permit modification immediately after it files such application. If the source elects to make such changes, and until the Division issues its final determination in accordance with Sections X.H.1. through X.H.4., above, the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time, the source does not need to comply with existing permit terms and conditions it seeks to modify, but if the source fails to comply with its proposed permit terms and conditions during this period, the existing permit terms and conditions it seeks to modify shall be fully enforceable by the Division.

X.J. The permit shield shall not extend to minor permit modifications.

X.K. A permit modification for purposes of the acid rain portion of a permit shall be governed by regulations promulgated under Title IV of the Federal Act, found at Code of Federal Regulations Title 40, Part 72.

XI. Procedures For Group Processing Of Minor Permit Modification Applications

XI.A. Group processing of applications for modifications eligible for minor permit modification processing may be used only for those permit modifications that:

XI.A.1. Meet the requirements of Part C, Sections X.A.1. through X.A.6., above, for minor permit modification procedures; and

XI.A.2. That collectively is below the lowest threshold level as set forth below:

XI.A.2.a. Ten percent of the emissions allowed by the permit for the emissions unit for which the change is requested; or

XI.A.2.b. Twenty percent of the applicable definition of major source; or

XI.A.2.c. Five tons per year, whichever is less.

XI.B. An application shall be filed with the Division for each change the source proposes to make, describing the change and the new emissions resulting from the change and notifying the Division that the source intends to request group processing of such minor modification applications in accordance with Section XI.C.4., below. An application for group processing of minor permit modifications shall be prepared on forms supplied by the Division.

XI.C. Applications shall meet the requirements of an application for an operating permit as set forth in Commission Regulation Number 3, Part C, Section III., and be signed by a responsible official. The applicant shall furnish all information and data (including any required ambient air impact analysis in accordance with Section VIII. of Part A of this regulation) required by the Division to evaluate the minor permit modification application and shall include the following:

XI.C.1. A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs;

XI.C.2. The sources suggested draft permit;

XI.C.3. Certification by a responsible official that the proposed modification meets the criteria for use of group processing procedures and a request that such procedures be used;

XI.C.4. A list of the source's other pending applications awaiting group processing, and a determination of whether the requested modification, aggregated with these other applications, equals or exceeds the threshold set under Sections XI.A.2.a. through XI.A.2.c. of this Part C;

XI.C.5. Certification by a responsible official that the source has notified the U.S. EPA of the proposed modification. Such notification need only contain a brief description of the requested modification;

XI.C.6. Copies of Air Pollutant Emission Notice(s) on file with the Division indicating production/process rates for which the operating permit is to be evaluated, or, if Air Pollutant Emission Notice(s) have not been previously filed, a new Air Pollutant Emission Notice(s) shall be submitted in accordance with Part A, Section II. The Air Pollutant Emission Notice fee will not be charged for submission of copies of current Air Pollutant Emission Notice(s) previously filed with the Division.

XI.C.7. Completed forms for the permitting authority to use to notify the Administrator and affected states. Notice to affected states is not required for minor sources voluntarily applying for an operating permit to obtain the operational flexibility set forth in this Part C. Notice to affected states and the Administrator is not required for group processing of minor modifications involving state only conditions.

XI.C.8. As provided for in the state implementation plan, minor permit modifications made pursuant to this Section XI. will not trigger the procedural requirements otherwise applicable for modifications pursuant to Part B of this regulation.

XI.D. On a quarterly basis, or within five business days of receipt of an application demonstrating that the aggregate of a source's pending applications equals or exceeds the thresholds set forth in Section XI.A.2., whichever is earlier, the Division shall promptly notify the Administrator and affected states. A source shall only be allowed to aggregate its increased emissions caused by changes made in accordance with this Section XI. during each five-year permit term, except that any aggregation of emissions that equals or exceeds the thresholds set forth in Section A.2. shall trigger the procedural requirements set forth in this Section XI. All aggregation of emissions not addressed through the procedures set forth in this Section XI. shall be incorporated into the operating permit upon renewal.

The Division shall promptly notify the Administrator and any affected state of any refusal by the Division to accept all recommendations for the proposed revised permit under the group processing of minor permit modifications that the affected state submitted during its review period. The Division shall include in such notice the reasons for not accepting any such recommendation. The Division is not required to accept recommendations that are not based on applicable requirements under the state or Federal Acts.

XI.E. Within one hundred and eighty calendar days of receipt of a complete application for group processing of minor permit modifications under this Section XI., or fifteen calendar days after the end of the Administrator's forty-five days review period, whichever is later, the Division shall:

XI.E.1. Issue the minor permit modification as proposed;

XI.E.2. Deny the minor permit modification application;

XI.E.3. Determine that the requested modifications do not meet the minor permit modification criteria and should be reviewed under the significant modification procedures; or

XI.E.4. Revise the draft minor permit modification and transmit to the Administrator the new proposed minor permit modification.

XI.F. A source shall be allowed to make the changes proposed in its application for group processing of minor permit modifications immediately after it files such application. If the source elects to make such changes, and until the Division issues its final determination in accordance with Sections XI.E.1. through XI.E.4. above, the source must comply with both the applicable requirements governing the change and the proposed permit terms and conditions. During this time, the source does not need to comply with existing permit terms and conditions it seeks to modify, but if the source fails to comply with its proposed permit terms and conditions during this period, the existing permit terms and conditions it seeks to modify shall be fully enforceable by the Division.

XI.G. The permit shield shall not extend to minor permit modifications made pursuant to the group processing procedures in this Section XI.

XII. Operational Flexibility

XII.A. Section 502(b)(10) changes

XII.A.1. No permit revision is necessary for changes within a permitted facility, if the changes are excepted from the definition of modification in Part A, Section I.B.28. of this Regulation Number 3, and the changes do not exceed the emissions allowable under the permit, whether expressed therein as a rate of emissions or in the terms of total emissions, and provided that notice is provided to the Division as set forth below:

XII.A.1.a. For each such change, the facility shall provide the Administrator and the Division with a minimum of seven days' written notification in advance of the proposed changes. The notice must be received by the Division no later than seven days in advance of the proposed changes. The source, the Division, and the Administrator shall attach each such notice to their copy of the relevant permit;

XII.A.1.b. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable because of the change;

XII.A.1.c. A source shall be allowed to make such change proposed in its notice on the day following the last day of the advance notice described in this section if the Division has not responded nor objected to the proposed change on or before that day; and

XII.A.1.d. The permit shield shall not apply to any changes made pursuant to this section. If subsequent changes cause the facility's operations and emissions to revert to those anticipated in the operating permit, the permittee resumes compliance with the terms and conditions of the permit, and has provided the Division and Administrator with a minimum of seven days' advance notice of such changes in accordance with the provisions of Section XII.A.1.a., above, the permit shield may be reinstated in accordance with the terms and conditions stated in the operating permit.

XII.A.2. Changes made pursuant to this Section XII.A. shall be incorporated into the operating permit at the time of renewal, at which time the permit shield shall apply.

XII.B. Off Permit Changes

No permit revision shall be necessary for changes within a permitted facility, not otherwise addressed or prohibited in the permit or in the provisions of this Section XII.B., governing off permit changes. This provision shall apply to changes, which are excepted from the definition of permit modification in Section I.A.3. of this Part C, or if such changes are subject to requirements of Title IV of the Federal Act (acid rain program). As provided for in the state implementation plan, changes made pursuant to this Section XII.B. shall not trigger the procedural requirements contained in Part B of this regulation for obtaining a construction permit.

XII.B.1. Each such change shall meet all applicable requirements and shall not violate any existing permit term or condition.

XII.B.2. The source must provide contemporaneous written notice to the permitting authority and the Administrator of each such change, except for changes that have been determined to be insignificant by the Commission pursuant to regulation. Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change. A revised Air Pollutant Emission Notice shall be submitted in accordance with the provisions of Part A, Section II., along with the written notice required in this Section XII.B.2.

XII.B.3. The permit shield shall not apply to any such change made pursuant to this Section XII.B.

XII.B.4. The source shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from those changes, including any other data necessary to show compliance with applicable ambient air quality standards.

XII.B.5. Changes made pursuant to this Section XII.B. shall be incorporated into the operating permit at the time of renewal.

XIII. Reopening For Cause Of Permits Issued Pursuant To Part C

XIII.A. A permit issued pursuant to Part C of this Commission Regulation Number 3, shall be reopened and revised under any of the following circumstances:

XIII.A.1. Additional applicable requirements become applicable to a major source with a remaining permit term of three or more years. Such reopening shall be completed no later than eighteen months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended, or if a general permit is obtained to address the new requirement pursuant to Section VIII.A.2. of this Part C;

XIII.A.2. Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the permit;

XIII.A.3. The Division or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;

XIII.A.4. The Division or the Administrator determines that the permit must be revised or revoked to assure compliance with the applicable requirements;

XIII.A.5. Permit reopening and reissuance shall be processed using the procedures set forth in Sections III., IV., and V. of this Part C for permit issuance and permit renewal;

XIII.A.6. Proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists; and

XIII.A.7. Reopening under this section of Part C shall not be initiated before notice of such intent is provided to the source by the Division at least thirty days in advance of the date that the permit is to be reopened. The Division may provide a shorter time period within which to give notice in the case of an emergency.

XIII.B. The Division shall extend the permit shield to those parts of the permit that have been changed pursuant to the reopening and reissuance proceedings of this section of Part C.

XIII.C. A source may choose to have its operating permit renewed during any proceeding for reopening the permit under this section, provided a complete application is submitted pursuant to Part C.

XIV. Compliance Assurance Monitoring

The regulations promulgated by the U.S. EPA listed in Section XIV.A.1., below, are hereby incorporated by reference by the Commission and made a part of the Colorado Commission regulations. Materials incorporated by reference are those in existence as of the date indicated and do not include later amendments. The material incorporated by reference is available for public inspection during regular business hours at the Office of the Commission, located at 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Parties wishing to inspect these materials should contact the Technical Secretary of the Commission, located at the office of the Commission.

XIV.A.1. Air Pollution Control, Monitoring, Operating Permits, Reporting and Record Keeping Requirements: Compliance Assurance Monitoring, Code of Federal Regulations Title 40, Parts 64 and 70.6, October 22, 1997 (62 FR 54900).

Air Pollution Control, Monitoring, Operating Permits, Reporting and Record keeping Requirements: Compliance Assurance Monitoring, Code of Federal Regulations Title 40, Parts 64, 70.6 and 71.6, October 22, 1997 (62 FR 54900).

PART D CONCERNING MAJOR STATIONARY SOURCE NEW SOURCE REVIEW AND PREVENTION OF SIGNIFICANT DETERIORATION

I. Applicability

I.A. General Applicability

I.A.1. This Part D shall apply to any new or existing major stationary source.

Any new major stationary source or major modification, to which the requirements of this Part D apply, shall not begin actual construction in a nonattainment, attainment, or unclassifiable area unless a permit has been issued containing all applicable state and federal requirements.

I.A.2. Except as otherwise provided in Section XV. of this Part D, and consistent with the definition of major modification (Section II.A.23. of this part), a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases - a significant emissions increase (as defined in Section II.A.45. of this part), and a significant net emissions increase (as defined in Sections II.A.27. and II.A.44. of this part). The project is not a major modification if it does not cause a significant emissions increase. If the project causes a significant emissions increase, then the project is a major modification only if it also results in a significant net emissions increase.

I.A.3. The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being constructed or modified, according to Sections I.B.1. through I.B.3. of this part. The procedure for calculating (before beginning actual construction) whether a significant net emissions increase will occur at the major stationary source (i.e., the second step of the process) is contained in the definition of Net Emissions Increase (Section II.A.27. of this part). Regardless of any such preconstruction projections, a major modification results if the project causes a significant emissions increase and a significant net emissions increase.

I.B. Applicability Tests

I.B.1. Actual-to-projected-actual applicability test for projects that only involve existing emissions units.

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in Section II.A.38. of this part) and the baseline actual emissions (as defined in Sections II.A.4.a. and II.A.4.b. of this part, as applicable), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.2. Actual-to-potential test for projects that only involve construction of a new emissions unit(s).

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in Section I.B.37. of Part A of this regulation) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in Section II.A.4. of this part) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.3. Hybrid test for projects that involve multiple types of emissions units.

A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods specified in Sections I.B.1. through I.B.3. of this part as applicable with respect to each type of emissions unit, equals or exceeds the significant amount for that pollutant (as defined in Section II.A.44. of this part).

I.B.4. An owner or operator of a major stationary source who conducts the actual-to-projected-actual test for a project that requires a minor permit modification in accordance with Section X. of Part C, requires a significant permit modification in accordance with Section I.A.3. of Part C, a modification as defined in Section I.B.28. of Part A or that requires a minor source permit under Part B shall submit a permit application including:

I.B.4.a. All calculations and supporting documentation used to determine baseline actual emissions of each emissions unit affected by the project;

I.B.4.b. All calculations and supporting documentation used to determine projected actual emissions of each existing emissions unit affected by the project;

I.B.4.c. A determination of that portion of each existing unit's emissions following the project that the unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions and that are unrelated to the project, including any increased utilization due to product demand growth; and,

I.B.4.d. Any other information requested by the Division that may be needed to determine if a major modification will occur at each emissions unit affected by the project.

The information submitted in accordance with Section I.B.4.a. through I.B.4.d., above, shall be incorporated into an appendix to the major stationary source's Title V Operating permit or as a permit note in the construction permit.

The requirement that the owner or operator of a major stationary source who conducts the actual-to-projected-actual test for a project that requires a minor permit modification submit information in accordance with Sections I.B.4.a. through I.B.4.d., as set out in this Subsection I.B.4., shall not be federally enforceable and shall not be incorporated into the state implementation plan.

I.C. For any major stationary source requesting, or operating under, a Plant-wide Applicability Limitation (as defined in Section II.A.35.) for a regulated NSR pollutant, the major stationary source shall comply with the requirements of Section XV. of this part.

II. Definitions

II.A. The following definitions apply specifically to the provisions contained in this Part D.

II.A.1. Actual Emissions

The actual rate of emission of a regulated NSR pollutant from an emissions unit, determined as follows:

II.A.1.a. Actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive twenty-four month period that precedes the particular date and is representative of normal unit operation. A different period may be used if it is more representative of normal unit operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored or combusted or actual emission data during the selected time period;

II.A.1.b. The Division may presume that source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit only if actual emissions cannot be determined pursuant to Section II.A.1.a., above;

II.A.1.c. For any emissions unit that has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

II.A.1.d. This definition shall not apply for calculating whether a significant emissions increase has occurred, or for establishing a PAL under Section XV. of Part D of this regulation. Instead, Sections II.A.38. and II.A.4. of this part shall apply for these purposes.

II.A.2. Actuals PAL

For a major stationary source, means a PAL based on the baseline actual emissions (as defined in Sections II.A.4.a. through II.A.4.d. of this part) of all emissions units (as defined in the Common Provisions regulation) at the source that emit or have the potential to emit the PAL pollutant. For a GHG-only source, actuals PAL means a PAL based on the baseline actual emissions (as defined in Sections II.A.4.e. and II.A.4.f.) of all emissions units (as defined in Section II.A.13.b.) at the source that emit or have the potential to emit GHGs.

II.A.3. Air Quality Related Value

Any value of an area that may be affected by a change in air quality. Examples include flora, fauna, soil, water, visibility, cultural, and odor.

II.A.4. Baseline Actual Emissions

The rate of emissions, in tons per year, of a regulated NSR pollutant.

II.A.4.a. For any existing electric utility steam generating unit (as defined in Section II.A.14. of this part), baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the five year period immediately preceding when the owner or operator begins actual construction of the project. The Division shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

II.A.4.a.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.a.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.a.(iii) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive twenty-four month period may be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive twenty-four month period can be used for each regulated NSR pollutant.

II.A.4.a.(iv) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by Section II.A.4.a.(ii).

II.A.4.b. For an existing emissions unit (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the ten year period immediately preceding either the date the owner or operator begins actual construction of the project, or the date a complete permit application is received by the Division for a permit required under this Part D, except that the ten year period shall not include any period earlier than November 15, 1990.

II.A.4.b.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.b.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above an emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.b.(iii) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had the major stationary source been required to comply with such limitations during the consecutive twenty-four month period. However, if an emission limitation is part of a maximum achievable control technology standard contained in Part E of Regulation Number 8, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan.

II.A.4.b.(iv) For a regulated NSR pollutant, when a project involves multiple emissions units, only one consecutive twenty-four month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive twenty-four month period can be used for each regulated NSR pollutant.

II.A.4.b.(v) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required under Sections II.A.4.b.(ii) and II.A.4.b.(iii) of this part.

II.A.4.c. For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit (as defined in Section I.B.37. of Part A of this regulation).

II.A.4.d. For a PAL for a major stationary source, the baseline actual emissions shall be calculated for existing electric utility steam generating units in accordance with the procedures contained in Section II.A.4.a., for other existing emissions units in accordance with the procedures contained in Section II.A.4.b., and for a new emissions unit in accordance with the procedures contained in Section II.A.4.c.

II.A.4.e. For a GHG PAL means the average rate, in tons per year CO2e or tons per year GHG, as applicable, at which the emissions unit actually emitted GHGs during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins construction of the project, or the date a complete permit application is received by the Division for a permit required under this Part D or by the Division for a permit required by a plan, whichever is earlier.

II.A.4.f. For any existing electric utility steam generating unit (as defined in Section II.A.14. of this part), baseline actual emissions for a GHG PAL means the average rate, in tons per year CO2e or tons per year GHG, at which the unit actually emitted the pollutant during any consecutive twenty-four month period selected by the owner or operator within the five year period immediately preceding when the owner or operator begins actual construction of the project. The Division shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

II.A.4.f.(i) The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions.

II.A.4.f.(ii) The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive twenty-four month period.

II.A.4.f.(iii) The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the stationary source must currently comply, had such stationary source been required to comply with such limitations during the consecutive 24-month period.

II.A.4.f.(iv) The average rate shall not be based on any consecutive twenty-four month period for which there is inadequate information for determining annual GHG emissions and for adjusting this amount if required by Sections II.A.4.a.(ii) and II.A.4.a.(iii).

II.A.5. Baseline Area

II.A.5.a. Any intrastate area (and every part thereof) designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Federal Act in which the major source or major modification establishing the minor source baseline date would construct or would have an air quality impact for the pollutant for which the baseline date is established, as follows: equal to or greater than one microgram/cubic meter (1 µg/m3) (annual average) for SO2, NO2, or PM10; or equal to or greater than 0.3 µg/m3) (annual average) for PM2.5.

II.A.5.b. Area redesignations under Section 107(d)(1)(A)(ii) or (iii) of the Federal Act cannot intersect or be smaller than the area of impact of any major stationary source or major modification that:

II.A.5.b.(i) Establishes a minor source baseline date, or

II.A.5.b.(ii) Is subject to this Part D, and would be constructed in the same state as the state proposing the redesignation.

II.A.5.c. Any baseline area established originally for the total suspended particulate increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that such baseline area shall not remain in effect if the permit authority rescinds the corresponding minor source baseline date in accordance with Section II.A.26.c.

II.A.6. Baseline Concentration

The ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and shall include:

II.A.6.a. The actual emissions representative of sources in existence on the applicable minor source baseline date, except as otherwise provided in this definition; and

II.A.6.b. The allowable emissions from major stationary sources that commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.

II.A.6.c. The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):

II.A.6.c.(i) Actual emissions from any major stationary source on which construction commenced after the major source baseline date; and

II.A.6.c.(ii) Actual emission increases and decreases at any stationary source occurring after the minor source baseline date.

II.A.7. Begin Actual Construction

Initiation of physical on-site construction activities on an emissions unit that are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipe work, and construction of permanent storage structures. With respect to a change in the method of operation, this term refers to those on-site activities other than preparatory activities that mark the initiation of the change.

II.A.8. Best Available Control Technology (BACT)

An emission limitation (including a visible emissions standard) based on the maximum degree of reduction of each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the Division or Commission, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of the best available control technology result in emissions of any pollutant that would exceed emissions allowed by the applicable standards in the Code of Federal Regulations, Title 40, Parts 60 and 61 (Regulation Number 6, Part A, and Regulation Number 8, Part A) as in effect on the effective date of this clause, but not including later amendments, unless such amendments are specifically incorporated by reference in accordance with the provisions of Colorado Revised Statutes Section 24-4-103 (12.5). Information as to the availability of such standards may be obtained from the Director, Air Pollution Control Division, Colorado Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530.

If the Division or Commission determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, it may instead prescribe designs, equipment, work practices, operational standards or combination thereof, to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means that achieve equivalent results.

II.A.9. Clean Coal Technology

Any technology, including technologies applied at the pre-combustion, combustion, or post-combustion stage, at a new or existing facility that will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990.

II.A.10. Clean Coal Technology Demonstration Project

A project using funds appropriated under the heading “Department of Energy-Clean Coal Technology,” up to a total amount of $2.5 billion for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the U.S. EPA. The federal contribution for a qualifying project shall be at least twenty percent of the total cost of the demonstration project.

II.A.11. Complete

In reference to an application for a major NSR permit, an application that contains all the information necessary for processing the application. Designating an application complete for purposes of permit processing does not preclude the Division from requesting or accepting any additional information.

II.A.11.a. At a minimum, a complete application for a permit to construct a major source or major modification subject to the requirements of this Part D shall include:

II.A.11.a.(i) All monitoring data required pursuant to this regulation and an analysis of ambient air quality in accordance with Section VI.A.3. of this part;

II.A.11.a.(ii) The impact analysis required by Section VI.A.2. of this part, a written summary of the data inputs to the model, and a topographic presentation of the resultant concentrations of each pollutant modeled for each applicable ambient standard or Prevention of Significant Deterioration increment within the impact area of the source;

II.A.11.a.(iii) A report of the regulatory status of the model pursuant to Section VIII.A.1. of Part A;

II.A.11.a.(iv) A demonstration that the proposed technological system of continuous emission reduction that is to be used will enable such source to comply continuously with the standards of performance that are to apply to such source and that the emission inputs to the model for the impact analysis are equivalent to the emissions allowed by such standards of performance;

II.A.11.a.(v) A description of the devices or systems that will be installed to monitor the emissions of each pollutant that will be emitted in significant amounts, maintaining such devices or systems, and the schedule and format for reporting the results of such emission monitoring to the Division;

II.A.11.a.(vi) The additional impact analysis required by Section VI.A.6. of this part, any demonstration of facts needed to establish a claim by the applicant to qualify for any exemption or exclusion under Section VI.B. of this part;

II.A.11.a.(vii) A schedule of construction in accordance with Section III.G.2. of Part B;

II.A.11.a.(viii) An additional copy of the application for the federal land manager of each affected Class 1 area, for the U.S. EPA, for the county Commissioner, and for public notice (county clerk). Two additional copies shall be submitted for interested public groups.

II.A.12. Construction

Any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) that would result in a change in actual emissions

II.A.13. Emissions Unit

II.A.13.a. Any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric steam-generating unit as defined in Section II.A.14. of this part. For purposes of this Part D, there are two types of emissions units described in Section II.A.13.a.(i) and II.A.13.a.(ii), below.

II.A.13.a.(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emissions unit first operated.

II.A.13.a.(ii) An existing emissions unit is any emissions unit that does not meet the requirements in Section II.A.13.a.(i), above. A replacement unit (as defined in Section II.A.41. of this part) is an existing emissions unit.

II.A.13.b. With respect to GHGs means any part of a stationary source that emits or has the potential to emit GHGs. For purposes of Section XV., there are two types of emissions units:

II.A.13.b.(i) A new emissions unit is any emissions unit that is (or will be) newly constructed and that has existed for less than two years from the date such emissions unit first operated.

II.A.13.b.(ii) An existing emissions unit is any emissions unit that does not meet the requirements in Section II.A.13.b.(i).

II.A.14. Electric Utility Steam Generating Unit

Any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electrical output capacity and more than twenty-five megawatts electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

II.A.15. Federal Land Manager (FLM)

With respect to any lands of the United States, the secretary of the department with authority over such lands.

II.A.16. GHG-only source

Any existing stationary source that emits or has the potential to emit GHGs in the amount equal to or greater than the amount of GHGs on a mass basis that would be sufficient for a new source to trigger permitting requirements for GHGs under Part D, Section II.A.25. and the amount of GHGs on a CO2e basis that would be sufficient for a new source to trigger permitting requirements for GHGs under Part A, Section I.B.44. at the time the PAL permit is being issued, but does not emit or have the potential to emit any other non-GHG regulated NSR pollutant at or above the applicable major source threshold. A GHG-only source may only obtain a PAL for GHG emissions under Part D, Section XV.

II.A.17. High Terrain

Any area having an elevation nine hundred feet or more above the base of the stack of a source.

II.A.18. Hydrocarbon Combustion Flare

Either a flare used to comply with an applicable new source performance standard or maximum achievable control technology standard (including uses of flares during startup, shutdown, or malfunction permitted under such standard), or a flare that serves to control emissions of waste streams comprised predominately of hydrocarbons and containing no more than 230 mg/dscm hydrogen sulfide.

II.A.19. Innovative Control Technology

Any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or non-air quality environmental impacts.

II.A.20. Low Terrain

Any area other than high terrain.

II.A.21. Lowest Achievable Emissions Rate (LAER)

For any source, the more stringent rate of emissions based on the following:

II.A.21.a. The most stringent emission limit contained in any state implementation plan for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limits are not achievable; or

II.A.21.b. The most stringent emission limitation that is achieved in practice by such class or category of source. In no event shall application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source performance standard (Regulation Number 6).

II.A.22. Major Emissions Unit

II.A.22.a. Any emissions unit that emits or has the potential to emit one hundred tons per year or more of the PAL pollutant in an attainment area; or

II.A.22.b. Any emissions unit that emits or has the potential to emit the PAL pollutant in an amount that is equal to or greater than the major stationary source threshold (as defined in Section II.A.25. of this part) for the PAL pollutant for nonattainment areas.

II.A.22.c. For a GHG PAL issued on a CO2e basis, any emissions unit that emits or has the potential to emit equal to or greater than the amount of GHGs on a CO2e basis that would be sufficient for a new source to trigger permitting requirements under paragraph Part A, Section I.B.44. at the time the PAL permit is being issued.

II.A.23. Major Modification

Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source.

II.A.23.a. Any significant emissions increase from any emissions units or net emissions increase at a major stationary source that is significant for volatile organic compounds or NOx shall be considered significant for ozone.

II.A.23.b. In the Denver Metropolitan PM10 nonattainment area, any net emission increase that is significant for sulfur dioxide or nitrogen oxides shall be considered significant for PM10.

II.A.23.c. A physical change or change in the method of operation shall not include routine maintenance, repair, and replacement.

II.A.23.d. A physical change or change in the method of operation, unless previously limited by any enforceable or federally enforceable permit condition that was established after January 6, 1975 for sources in attainment or unclassifiable areas and after December 21, 1976 for sources in nonattainment areas, shall not include:

II.A.23.d.(i) Use of an alternative fuel or raw material by reason of an order in effect under Sections 2(a) and (b) of the Federal Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation), a prohibition under the Power Plant and Industrial Fuel Use Act of 1978 (or any superseding legislation) or by reason of a natural gas curtailment plan in effect pursuant to the Federal Power Act;

II.A.23.d.(ii) Use of an alternative fuel because of an order or rule under Section 125 of the Federal Act;

II.A.23.d.(iii) Use of an alternative fuel at a steam-generating unit to the extent that the fuel is generated from municipal solid waste;

II.A.23.d.(iv) Use of an alternative fuel or raw material that:

II.A.23.d.(iv)(A) the stationary source in a nonattainment area was capable of accommodating prior to December 21, 1976, unless such change would be prohibited under a federally enforceable permit condition, or

II.A.23.d.(iv)(B) the stationary source in an attainment or unclassifiable area was capable of accommodating prior to January 6, 1975 unless such change would be prohibited under a federally enforceable permit condition, or

II.A.23.d.(iv)(C) the source is approved to use under any permit issued under this Regulation Number 3.

II.A.23.d.(v) An increase in the production rate, unless such change would be prohibited under a federally enforceable permit condition;

II.A.23.d.(vi) An increase in the hours of operation, unless such increase would be prohibited under a federally enforceable permit condition; or

II.A.23.d.(vii) Any change in ownership of a stationary source.

II.A.23.d.(viii) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, if the project complies with:

II.A.23.d.(viii)(A)The Colorado State Implementation Plan, and

II.A.23.d.(viii)(B)Other requirements necessary to attain and maintain the National Ambient Air Quality Standards during the project and after it is terminated.

II.A.23.d.(ix) For major stationary sources in attainment areas:

II.A.23.d.(ix)(A) The installation or operation of a permanent clean coal technology demonstration project that constitutes re-powering, provided that the project does not result in an increase in the potential to emit of any regulated pollutant emitted by the unit. The exemption shall apply on a pollutant-by-pollutant basis.

II.A.23.d.(ix)(B) The reactivation of a very clean coal fired electric utility steam generating unit.

II.A.23.d.(x) The reactivation of a very clean coal fired electric utility steam generating unit.

II.A.23.e. This definition shall not apply with respect to a particular regulated NSR pollutant when the major stationary source is complying with the requirements under Section XV. of this Part D for a PAL for that pollutant. Instead, the definition in Section II.A.31. of this part shall apply.

II.A.23.f. Emissions caused by indirect sources of pollution, emissions from internal combustion engines on any vehicle, and emissions resulting from temporary construction or exploration activities shall be excluded in determining whether a major modification will occur.

Emissions from on-going construction are not considered to be temporary emissions, and are included in determining whether a major modification will occur.

Fugitive emissions from the listed sources in Section II.A.25.a. and any other stationary source category that, as of August 7, 1980 was regulated under Sections 111 or 112 of the Federal Act (as adopted in Regulations Nos. 6, Part A, and 8, Parts A and E) shall, to the extent quantifiable, be considered in calculating the potential to emit of the modification.

II.A.24. Major Source Baseline Date

II.A.24.a. In the case of PM10 and sulfur dioxide, January 6, 1975;

II.A.24.b. In the case of nitrogen dioxide, February 8, 1988; and

II.A.24.c. In the case of PM2.5, October 20, 2010.

II.A.25. Major Stationary Source

II.A.25.a. For the purpose of determining whether a source in an attainment or unclassifiable area is subject to the requirements of this Part D, major stationary source means:

II.A.25.a.(i) Any of the following stationary sources of air pollutants that emits, or has the potential to emit, one hundred tons per year or more of any regulated NSR pollutant:

II.A.25.a.(i)(A) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input

II.A.25.a.(i)(B) Coal cleaning plants (with thermal dryers)

II.A.25.a.(i)(C) Kraft pulp mills

II.A.25.a.(i)(D) Portland cement plants

II.A.25.a.(i)(E) Primary zinc smelters

II.A.25.a.(i)(F) Iron and steel mill plants

II.A.25.a.(i)(G) Primary aluminum ore reduction plants

II.A.25.a.(i)(H) Primary copper smelters

II.A.25.a.(i)(I) Municipal incinerators capable of charging more than 250 tons of refuse per day

II.A.25.a.(i)(J) Hydrofluoric, sulfuric, and nitric acid plants

II.A.25.a.(i)(K) Petroleum refineries

II.A.25.a.(i)(L) Lime plants

II.A.25.a.(i)(M) Phosphate rock processing plants

II.A.25.a.(i)(N) Coke oven batteries

II.A.25.a.(i)(O) Sulfur recovery plants

II.A.25.a.(i)(P) Carbon black plants (furnace process)

II.A.25.a.(i)(Q) Primary lead smelters

II.A.25.a.(i)(R) Fuel conversion plants

II.A.25.a.(i)(S) Sintering plants

II.A.25.a.(i)(T) Secondary metal production plants

II.A.25.a.(i)(U) Chemical process plants

II.A.25.a.(i)(V) Fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input

II.A.25.a.(i)(W) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels

II.A.25.a.(i)(X) Taconite ore processing plants

II.A.25.a.(i)(Y) Glass fiber processing plants

II.A.25.a.(i)(Z) Charcoal production plants

II.A.25.a.(ii) Notwithstanding the stationary source size specified in Section II.A.25.a.(i), any stationary source that emits, or has the potential to emit, two hundred and fifty tons per year or more of any regulated NSR pollutant.

II.A.25.b. For the purpose of determining whether a source in a nonattainment area is subject to the requirements of Section V. of this part, and whether a source in an attainment area affecting a nonattainment area is subject to the requirements of Section VI.D. of this part, major stationary source means any stationary source of air pollutants that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant for which the area is nonattainment, except where the lower emissions thresholds in Sections II.A.25.b.(i)-(vi) apply. Additionally, a source causing or contributing to a violation of a national ambient air quality standard for any pollutant regulated under Section 110 of the Federal Act shall be considered a major stationary source when it has the potential to emit one hundred tons per year or more of that pollutant. The source will be considered to cause or contribute to a violation where the source exceeds the significance levels in the table under Section VI.D.2. of this Part D. Such source is subject to the requirements of Section VI. of this Part D.

II.A.25.b.(i) Fifty tons per year or more of volatile organic compounds or nitrogen oxides in any serious ozone nonattainment area.

II.A.25.b.(ii) Fifty tons per year or more of volatile organic compounds in any ozone transport region, except for any severe or extreme ozone nonattainment area.

II.A.25.b.(iii) Twenty five tons per year or more of volatile organic compounds or nitrogen oxides in any severe ozone nonattainment area.

II.A.25.b.(iv) Ten tons per year or more of volatile organic compounds or nitrogen oxides in any extreme ozone nonattainment area.

II.A.25.b.(v) Fifty tons per year or more of carbon monoxide in any serious carbon monoxide nonattainment area, where stationary sources significantly contribute to carbon monoxide levels.

II.A.25.b.(vi) Seventy tons per year or more of PM10 in any serious PM10 nonattainment area.

II.A.25.c. Major stationary source includes any physical change that would occur at a stationary source not otherwise qualifying as a major stationary source under Sections II.A.25.a and II.A.25.b. of this part, if the change would constitute a major stationary source by itself.

II.A.25.d. A major stationary source that is major for volatile organic compounds or NOx shall be considered major for ozone, except that emissions of negligibly reactive volatile organic compounds, as defined in the Common Provisions, shall not be included in the determination of major stationary source status for ozone.

II.A.25.e. The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this section whether it is a major stationary source, unless the source belongs to one of the categories of stationary sources listed in Section II.A.25.a.(i) or any other stationary source category which, as of August 7, 1980, is regulated under Section 111 or 112 of the Federal Act.

II.A.25.f. Emissions caused by indirect air pollution sources (as defined in Section I.B.24. of Part A of this regulation), emissions from internal combustion engines on any vehicle, and emissions resulting from temporary activities, such as construction or exploration, shall be excluded in determining whether a source is a major stationary source. Emissions from ongoing construction are not considered to be temporary emissions and are included in determining whether a major modification will occur.

II.A.25.g. A major stationary source in the Denver Metro PM10 attainment/maintenance area that is major for sulfur dioxide or nitrogen oxides shall be considered major for PM10.

II.A.26. Minor Source Baseline Date

II.A.26.a. The earliest date after the trigger date that a major stationary source or a major modification subject to the requirements of Section VI. of this Part D submits a complete application under the relevant regulations. The trigger date is:

II.A.26.a.(i) In the case of PM10 and sulfur dioxide, August 7, 1977;

II.A.26.a.(ii) In the case of nitrogen dioxide, February 8, 1988; and

II.A.26.a.(iii) In the case of PM2.5, October 20, 2011.

II.A.26.b. The baseline date is established for each pollutant for which increments or other equivalent measures have been established if:

II.A.26.b.(i) The area in which the proposed source or modification would construct is designated as attainment or unclassifiable under Sections 107(d)(1)(A)(ii) or (iii) of the Federal Act for the pollutant on the date of its complete application under Section VI. of this part; and

II.A.26.b.(ii) In the case of a major stationary source the pollutant would be emitted in significant amounts, or, in the case of a major modification, there would be a significant net emissions increase of the pollutant.

II.A.26.c. Any minor source baseline date established originally for the Total Suspended Particulates increments shall remain in effect and shall apply for purposes of determining the amount of available PM10 increments, except that the Division may rescind any such minor source baseline date where it can be shown, to the satisfaction of the Division, that the emissions increase from the major stationary source, or the net emissions increase from the major modification, responsible for triggering that date did not result in a significant amount of PM10 emissions.

II.A.27. Net Emissions Increase

II.A.27.a. With respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero:

II.A.27.a.(i) The increase in emissions from a particular physical change or change in the method of operation at a stationary source calculated pursuant to Sections I.A.2. through I.A.3., and I.B. of this Part D; and

II.A.27.a.(ii) Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. Baseline actual emissions for calculating increases and decreases under this paragraph shall be determined as provided in the definition of baseline actual emissions, except that paragraphs II.A.4.a.(iii) and II.A.4.b.(iv) of this Part D shall not apply.

II.A.27.b. Contemporaneous - an increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs within five years prior to the date that the increase from the particular change occurs.

II.A.27.c. An increase or decrease in actual emissions is creditable only if:

II.A.27.c.(i) It occurs within five years before the date that the increase or decrease occurs; and

II.A.27.c.(ii) The Division has not relied on it in issuing a permit for the source under Regulation Number 3, Part D, or the U.S. EPA has not relied on it in issuing a permit under Title I, Part C of the Federal Act, which permit is in effect when the increase in actual emissions from the particular change occurs; and

II.A.27.c.(iii) In order to establish a baseline emissions rate, the owner or operator must submit an Air Pollutant Emission Notice to the Division prior to the increase or decrease indicating actual emissions (as defined in Section II.A.1. of this of part) and the owner or operator must submit a revised Air Pollutant Emission Notice to the Division within one year after the increase or decrease occurs, or

II.A.27.c.(iv) The owner or operator provides credible, demonstrable evidence to the Division of what actual emissions were before making the increase or decrease and what they were after making the increase or decrease.

II.A.27.d. An increase or decrease in actual emissions of sulfur dioxide, particulate matter, or nitrogen oxides that occurs before the applicable minor source baseline date is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available. With respect to particulate matter, only PM10 emissions can be used to evaluate the net emissions increase for PM10 and only PM2.5 emissions can be used to evaluate the net emissions increase for PM2.5.

II.A.27.e. An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

II.A.27.f. A decrease in actual emissions is creditable only to the extent that:

II.A.27.f.(i) The Division has not relied on it in issuing any permit under this Part D, or has not relied on it in demonstrating attainment or reasonable further progress:

II.A.27.f.(ii) The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

II.A.27.f.(iii) It is enforceable as a practical matter at and after the time that actual construction on the particular change begins; and

II.A.27.f.(iv) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

II.A.27.g. An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed one hundred and eighty days.

II.A.27.h. Section II.A.1.a. of this part shall not apply for determining creditable increases and decreases after a change.

II.A.27.i. The organic compounds referenced in the common provisions definition of negligibly reactive volatile organic compounds are neither counted as reactive volatile organic compounds in determining significant ozone increases nor creditable against an increase in emissions of any volatile organic compound.

II.A.27.j. Creditable Decreases for Fuel Switching.

Generally, for credit to be given for the emissions reduction in potential to emit or actual emissions resulting from a physical change or change in method of operation of a major stationary source occurring on or after the effective date of this rule, an Air Pollutant Emission Notice reporting such reduction must be filed within one year after the reduction occurs unless an extension is requested by the source and approved by the Division due to uncertainty as to the permanence of such reduction. At the time credit for any reduction is requested, such reduction must be enforceable. Such reductions must be enforceable through permit conditions or source specific state implementation plan revisions.

II.A.28. Nonattainment Major New Source Review (NSR) Program

A major stationary source preconstruction permit program that has been approved by the Administrator and incorporated into this Regulation Number 3, Part D. Any permit issued under the program is a major NSR permit.

II.A.29. PAL Effective Date

Generally means the date of issuance of the PAL permit. However, the PAL effective date for an increased PAL is the date any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

II.A.30. PAL Effective Period

The period beginning with the PAL effective date and ending ten years later.

II.A.31. PAL Major Modification

Notwithstanding Part A, Section I.B.44. and Part D Sections II.A.22 and II.A.26. (the definitions for subject to regulation, major modification, and net emissions increase), any physical change in or change in the method of operation of the PAL source that causes it to emit the PAL pollutant at a level equal to or greater than the PAL.

II.A.32. PAL Minor Source

Any stationary source that does not meet the definition of major stationary source in Part D, Section II.A.25. at the time the PAL is issued.

II.A.33. PAL Permit

The Operating Permit issued in accordance with this Part D that establishes a PAL for a major stationary source or a GHG-only source.

II.A.34. PAL Pollutant

The pollutant for which a PAL is established at a major stationary source or a GHG-only source. For a GHG-only source, the only available PAL pollutant is greenhouse gases.

II.A.35. Plant-wide Applicability Limitation (PAL)

An emission limitation expressed on a mass basis in tons per year, or expressed in tons per year CO2e for a CO2e-based GHG emission limitation, for a pollutant at a major stationary source or GHG-only source that is enforceable as a practical matter and established source-wide in accordance with Section XV. of this Part D.

II.A.36. Prevention of Significant Deterioration (PSD) Permit

Any permit that is issued in accordance with Section VI. of this Part D.

II.A.37. Project

A physical change in, or change in the method of operation of, an existing major stationary source.

II.A.38. Projected Actual Emissions

II.A.38.a. The maximum annual rate, in tons per year, at which an existing emissions unit at a major stationary source is projected to emit a regulated NSR pollutant in any one of the five years (twelve-month period) following the date the unit resumes regular operation after the project, or in any one of the ten years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

II.A.38.b. In determining the projected actual emissions under Section II.A.38.a., above, before beginning actual construction, the owner or operator of the major stationary source:

II.A.38.b.(i) Shall consider all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans; and

II.A.38.b.(ii) Shall include fugitive emissions to the extent quantifiable, and emissions associated with startups, shutdowns, and malfunctions; and

II.A.38.b.(iii) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions under Section II.A.4. of this part D and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

II.A.38.b.(iv) In lieu of using the method set out in Sections II.A.38.b.(i) through II.A.38.b.(iii), may elect to use the emissions unit's potential to emit, in tons per year, as defined in Section I.B.37. of Part A of this regulation.

II.A.39. Reactivation of Very Clean Coal-fired Electric Utility Steam Generating Unit

Any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

II.A.39.a. Has not been in operation for the two year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of the enactment;

II.A.39.b. Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than eighty-five percent and a removal efficiency for particulates of no less than ninety-eight percent;

II.A.39.c. Is equipped with low-nitrogen oxide burners prior to the time of commencement of operations following reactivation; and

II.A.39.d. Is otherwise in compliance with the requirements of the Federal Act.

II.A.40. Regulated NSR Pollutant

II.A.40.a. Nitrogen oxides or any volatile organic compound;

II.A.40.b. Any pollutant for which a national ambient air quality standard has been promulgated;

II.A.40.c. Any pollutant that is a constituent or precursor of a general pollutant listed under Sections II.A.40.a. or II.A.40.b., above,(e.g. volatile organic compounds and oxides of nitrogen are precursors for ozone) provided that such a constituent or precursor pollutant may only be regulated under NSR as part of regulation of the general pollutant. Precursors for the purposes of New Source Review are the following:

II.A.40.c.(i) Nitrogen oxides or any volatile organic compound are precursors to ozone;

II.A.40.c.(ii) Sulfur dioxide is a precursor to PM2.5;

II.A.40.c.(iii) Nitrogen oxides are precursors to PM2.5.

II.A.40.d. Any pollutant, except for GHG, that is subject to ny standard promulgated under Section 111 of the Federal Act, (see II.A.40.e. for GHG);

II.A.40.e. Any pollutant that otherwise is subject to regulation under the Federal Act as defined in Section I.B.44. or Part A;

II.A.40.f. Notwithstanding Sections II.A.40.a. through II.A.40.e. of this Part D, the term regulated NSR pollutant shall not include any or all hazardous air pollutants either listed in Section 112 of the Federal Act (that have not been delisted pursuant to Section 112(b)(3) of the Federal Act) or Appendix B of this regulation, unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under Section 108 of the Federal Act.

II.A.40.g. PM2.5 emissions and PM10 emissions shall include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperatures. On or after January 1, 2011, such condensable particulate matter shall be accounted for in applicability determinations and in establishing emissions limitations for PM2.5 and PM10 in PSD permits. Compliance with emission limitations for PM2.5 and PM10 issued prior to this date shall not be based on condensable particulate matter unless required by the terms and conditions of the permit or the applicable implementation plan. Applicability determinations made prior to this date without accounting for condensable particulate matter shall not be considered in violation of this section.

II.A.41. Replacement Unit

An emissions unit for which all the criteria listed in Sections II.A.41.a. through II.A.41.d. are met. No creditable emission reductions shall be generated from shutting down the existing emissions unit that is replaced.

II.A.41.a. The emissions unit is a reconstructed unit within the meaning of Code of Federal Regulations Title 40, Section 60.15(b)(1), or the emissions unit completely takes the place of an existing emissions unit.

II.A.41.b. The emissions unit is identical to or functionally equivalent to the replaced emissions unit.

II.A.41.c. The replacement does not alter the basic design parameters of the process unit.

II.A.41.d. The replaced emissions unit is permanently removed from the major stationary source, otherwise permanently disabled, or permanently barred from operation by a permit that is enforceable as a practical matter. If the replaced emissions unit is brought back into operation, it shall constitute a new emissions unit.

II.A.42. Repowering

II.A.42.a. Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990.

II.A.42.b. Repowering shall also include any oil and/or gas-fired unit that have been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

II.A.43. Secondary Emissions

Emissions that occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this Part D, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification that causes the secondary emissions. Secondary emissions include emissions from any offsite support facility that would not otherwise be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions that come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

II.A.44. Significant

II.A.44.a. Unless the context otherwise requires, a significant rate of emissions in tons per year is defined as a value that would equal or exceed any of the following:

Carbon monoxide: 100 tons per year

Nitrogen Oxides: 40 (nitric oxide + nitrogen dioxide) tons per year

Sulfur dioxide: 40 tons per year

Particulate matter: 25 tons per year particulate matter emissions or, 15 tons per year of PM10 emissions

PM10 - Precursors in the Denver Metropolitan PM10 attainment/maintenance area: 40 tons per year for each individual precursor (nitrogen oxides or sulfur oxides)

PM2.5: 10 tons per year of direct PM2.5 emissions; 40 tons per year of sulfur dioxide emissions; or 40 tons per year of nitrogen dioxide emissions

Ozone: 40 tons per year of volatile organic compounds or nitrogen oxides

Lead: 0.6 tons per year

Fluorides: 3 tons per year

Sulfuric acid mist: 7 tons per year

Hydrogen sulfide: 10 tons per year

Total reduced sulfur (including hydrogen sulfide): 10 tons per year

Reduced sulfur compounds (including hydrogen sulfide): 10 tons per year

Municipal Waste Combustor Organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans): 3.2 x 10-6 megagrams per year (3.5 x 10-6 tons per year)

Municipal Waste Combustor Metals (measured as particulate matter): 14 megagrams per year (15 tons per year)

Municipal Waste Combustor Acid Gases (measured as sulfur dioxide and hydrogen chloride): 36 megagrams per year (40 tons per year)

Municipal Solid Waste Landfill Gases (measured as non-methane organic compounds): 45 megagrams per year (50 tons per year)

In a serious or severe ozone nonattainment area: 25 tons per year of volatile organic compounds or nitrogen oxides

In an extreme ozone nonattainment area: any increase of volatile organic compounds or nitrogen oxides

II.A.44.b. Significant means, in reference to a net emissions increase or the potential of a source to emit a regulated NSR pollutant that this definition does not list, any emissions rate, except that this definition shall not apply to hazardous air pollutants listed in or pursuant to Section 112 of the Federal Act.

II.A.44.c. Notwithstanding the significant emission rates above, significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification, that would construct within ten kilometers of a Class I area, and have an impact on such area equal to or greater than one microgram/cubic meter ((g/m3) (twenty-four hour average).

II.A.45. Significant Emissions Increase

For a regulated NSR pollutant, an increase in emissions that is significant (as defined in Section II.A.44. of this Part D) for that pollutant.

II.A.46. Significant Emissions Unit

II.A.46.a. An emissions unit that emits or has the potential to emit a PAL pollutant in an amount that is equal to or greater than the significant level (as defined in Section II.A.44. of this Part D or in the Federal Act, whichever is lower) for that PAL pollutant, but less than the amount that would qualify the unit as a major emissions unit (as defined in Section II.A.22. of this part).

II.A.46.b. For a GHG PAL issued on a CO2e basis, significant emissions unit means any emissions unit that emits or has the potential to emit GHGs on a CO2e basis in amounts equal to or greater than the amount that would qualify the unit as small emissions unit as defined in Section II.A.47, but less than the amount that would qualify the unit as a major emissions unit as defined in Section II.A.22.

II.A.47. Small Emissions Unit

II.A.47.a. An emissions unit that emits or has the potential to emit the PAL pollutant in an amount less than the significant level for that PAL pollutant (as defined in Section II.A.34. of this Part D or in the Federal Act, whichever is lower).

II.A.47.b. For a GHG PAL issued on a CO2e basis, small emissions unit means an emissions unit less than the amount of GHGs on a CO2e basis defined as significant for the purposes of Part A, Section I.B.46.c. at the time the PAL permit is being issued.

II.A.48. Temporary Clean Coal Technology Demonstration Project

A clean coal technology demonstration project that is operated for a period of five years or less, and that complies with the state implementation plan and other requirements necessary to attain and maintain the National Ambient Air Quality Standards during the project and after it is terminated.

III. Permit Review Procedures

III.A. Major stationary sources subject to the requirements of this Part D must apply for and obtain a Construction Permit in accordance with the procedures and requirements in Part B or an Operating permit in accordance with the procedures and requirements in Part C.

III.B. The Division shall complete the processing of applications (including any requested public hearing) for sources subject Sections VI. and VII. of this Part D within twelve months of receipt of a complete application.

IV. Public Comment Requirements

IV.A. When public comment is required, or when the Division determines that an application warrants public comment in accordance with Section III.C.3. of Part B of this regulation, the Division shall, within fifteen calendar days after the preparation of the preliminary analysis, cause public notice of the application to be published in a newspaper of general distribution in the area in which the proposed project or activity is or will be located, and by such other means as necessary to assure notice to the affected public, which may include posting of such notice on the publicly accessible portion of the Division's web site, and cause a copy of the application, the preliminary analysis and the draft permit to be filed with the county clerk for each county in which the source is, or will be, located. The Division shall send written or electronic notice to persons requesting a notice of permit applications for the type of source or geographic area.

IV.A.1. For sources subject to the provisions of Sections V. and VI. of this part, a copy of all the materials the applicant submitted, and a copy or summary of other materials, if any, considered in making the preliminary analysis shall be filed with the county clerk for each county in which the source is or will be located. In addition, for sources subject to the provisions of Sections V. and VI., a copy of the written or electronic notice of public comment shall be sent to the applicant, the U.S. EPA Administrator, and to officials and agencies having cognizance over the location where the proposed construction would occur, including any other state or local air pollution control agencies and any state, Indian governing body or Federal Land Manager whose lands may be affected by emissions from the source or modification.

IV.A.2. Additionally, for permit applications subject to the requirements of this Part D, the notice shall contain the following information:

IV.A.2.a. That comments are solicited on an innovative technological system for pollution control if proposed by the applicant and that a hearing by the Commission will be held on such system if requested by any interested person;

IV.A.2.b. That comments are solicited on the air quality impacts of the source or modification;

IV.A.2.c. That comments are solicited on alternatives to the source or modification;

IV.A.2.d. That any interested person may submit a written request for a public comment hearing to be held pursuant to Section VII. of the Commission's Procedural Rules to receive comments regarding the foregoing concerns, the sufficiency of the preliminary analysis, and whether the Division should approve or deny the permit application; and

IV.A.2.e. The degree of increment consumption that is expected from the source or modification.

IV.A.3. Within fifteen calendar days after the preparation of the preliminary analysis for those applications subject to the requirements of this Part D, the Division shall forward to the applicant written notice of the applicant's right to a public comment hearing with respect to the application pursuant to Section VII. of the Commission's Procedural Rules.

IV.A.4. A hearing request pursuant to Section IV.A.2.a. of this Part D, regarding innovative control, must be transmitted by the Division to the Commission within twenty days after its receipt.

IV.A.5. A hearing request pursuant to Section IV.A.2.d. of this Part D must be transmitted by the Division to the Commission, along with the complete permit application, the preliminary analysis, the draft permit, and any written comments received by the Division within five days after the end of the thirty-day comment period. At least thirty days prior to the date set for the public comment hearing, the notice of public comment hearing, the preliminary analysis and the draft permit shall be posted on the Division's web site. No substantive revisions shall be made to the draft permit during the thirty days prior to the public comment hearing.

IV.A.6. The Commission shall hold a public comment hearing within sixty days of its receipt of the request for such hearing pursuant to Section IV.A.2. of this Part D (unless such greater time is agreed to by the applicant and the Division), but at least sixty days after receipt by any Federal Land Manager of notice and the permit application required pursuant to Section XIII.A. of this Part D. The Division shall appear at the public comment hearing in order to present the permit application. At least thirty days prior to such hearing, notice thereof shall be mailed by the Commission to the applicant, to any interested person who submitted a request for a public hearing and to any Federal Land Manager given notice pursuant to Section XIII.A., printed in a newspaper of general distribution in the area of the proposed source or modification, and submitted for public review with the county clerk for each county in which the source or modification is or will be located. Except as provided herein and in the notice, such hearings will be conducted pursuant to the Act, the Procedural Rules of the Air Quality Control Commission and the State Administrative Procedure Act, Colorado Revised Statutes, Section 24-4-101 et seq.

IV.A.7. Within fifteen days after the Division makes a final decision on an application subject to the requirements of this Part D, the Division shall make available for public inspection the decision and all public comments with the county clerk for each county where the pre-construction information was made available.

V. Requirements Applicable to Nonattainment Areas

V.A. Major Stationary Sources.

For any new major stationary source or major modification, the Division shall grant a permit if it determines that the following conditions in Sections V.A.1. through V.A.6., as well as those in Section III.D.1. of Part B of this regulation, will be met:

V.A.1. The proposed source will achieve the lowest achievable emission rate for the specific source category.

V.A.2. The applicant has certified that all other existing major stationary sources owned, operated, or controlled by the applicant (or any entity controlling, controlled by, or under the common control with the applicant) in Colorado are in compliance with the requirements of the State implementation plan and the federally approved state implementation plan, or are subject to and in compliance with an enforceable compliance schedule, or a federally enforceable compliance schedule.

V.A.3. Prior to the date of commencement of operations, the ratio of total actual emission reductions compared to the emissions increase (offsets) shall be at least one for one (1:1), unless an alternative ratio is provided for the applicable nonattainment area as identified in Section V.A.3.a., below.

V.A.3.a. Offset Ratios

V.A.3.a(i) For ozone nonattainment areas that are subject to subpart 2, part D, title I of the Federal Act, the offset ratio of total actual emission reductions of VOC to the emissions increase of VOC shall be as follows:

V.A.3.a(i)(a) In any marginal nonattainment area for ozone – at least 1.1:1;

V.A.3.a(i)(b) In any moderate nonattainment area for ozone – at least 1.15:1;

V.A.3.a(i)(c) In any serious nonattainment area for ozone – at least 1.2:1;

V.A.3.a(i)(d) In any severe nonattainment area for ozone – at least 1.3:1; or

V.A.3.a(i)(e) In any extreme nonattainment area for ozone – at least 1.5:1.

V.A.3.a.(ii) For all areas within an ozone transport region that is subject to subpart 2, part D, title 1 of the Federal Act, and that are not designated as serious, severe or extreme and are subject to subpart 1, part D, title 1 of the Federal Act – at least 1.15:1.

V.A.3.a.(iii) For ozone nonattainment areas that are subject to subpart 1, part D, title I of the Federal Act, including 8-hour ozone nonattainment areas subject to 40 CFR, Part 51, Section 51.902(b), the ratio of total actual emissions reductions of VOC to the emissions increase of VOC shall be at least 1:1.

V.A.3.b. Offsets must be obtained from existing sources (whether or not under the same ownership) within the nonattainment area for each pollutant, or its precursors, for which the area is nonattainment. Offsets must represent reasonable further progress towards attainment of the National Ambient Air Quality Standards when considered in connection with other new and existing sources of emissions. In addition, offsets for PM10, PM2.5, sulfur oxides, and carbon monoxide must show, through atmospheric modeling, a positive net air quality benefit in the area affected by the emissions. Provided, however, that offsets meeting the requirements of this Section V.A.3. may also be obtained from existing sources outside the nonattainment area if the applicant demonstrates:

V.A.3.b.(i) A greater air quality benefit may thus be achieved, or sufficient offsets are not available from sources within the nonattainment area; and

V.A.3.b.(ii) The other area has an equal or higher nonattainment classification than the area in which the source is located; and

V.A.3.b.(iii) Emissions from such other area contribute to a violation of the National Ambient Air Quality Standard in the nonattainment area in which the source is located.

V.A.3.b.(iv) With respect to offsets obtained from outside the nonattainment area, the Division may increase the ratio of the required offsets to new emissions the greater the distance such offsets are from the new or modified source.

V.A.3.c. Offsets must be for the same regulated NSR pollutant, except that offset requirements for direct PM2.5 emissions or PM2.5 precursors may be satisfied by offsetting reductions in direct PM2.5 emissions or emissions of any PM2.5 precursor identified under Section II.A.40. of Part D.

V.A.4. The permit application shall include an analysis of alternative sites, sizes, production processes and environmental control techniques for such proposed source that demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.

V.A.5. Offsets for which emission reduction credit is taken must be enforceable through permit conditions or source specific state implementation plan revisions.

V.A.6. The applicant will demonstrate that emissions from the proposed source will not adversely impact visibility in a Class I area. This demonstration shall be reviewed by the Federal Land Manager and any determination made by the Federal Land Manager shall be considered in the Division's decision to grant the permit. If an adverse impact, as described in Section XIV.E., is predicted by the Division, the permit application will be denied. Federal Land Manager involvement shall follow the same procedures as stated in Section XIII.A. of this Part D. The demonstration will be performed using either techniques described in the latest version of the U.S. EPA document entitled “Workbook for Estimating Visibility Impairment” or other techniques approved by the Division.

V.A.7. Applicability of Certain Nonattainment Area Requirements

V.A.7.a. Any major stationary source in a nonattainment area is subject to the requirements of Section V.A. of this Part D.

V.A.7.b. The requirements of Section V.A. shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980 on the capacity of the source or modification to otherwise emit a pollutant, such as a restriction on hours of operation.

V.A.7.c. The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a project that is not a part of a major modification and the owner or operator elects to use the method specified in Sections II.A.38.b.(i) through II.A.38.b.(iii) of this Part D for calculating projected actual emissions.

V.A.7.c.(i) Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

V.A.7.c.(i)(A) A description of the project;

V.A.7.c.(i)(B) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

V.A.7.c.(i)(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under Section II.A.38.b.(iii) of this part and an explanation for why such amount was excluded, and any netting calculations, if applicable.

V.A.7.c.(ii) If the emissions unit is an existing electric utility steam generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in Section V.A.7.c.(i) to the Division. Nothing in this Section V.A.7.c.(ii) shall be construed to require the owner or operator of such a unit to obtain any determination from the Division before beginning actual construction.

V.A.7.c.(iii) The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions units identified in Section V.A.7.c.(i)(B); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

V.A.7.c.(iv) If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Division within sixty days after the end of each year during which records must be generated under Section V.A.7.c.(iii) setting out the unit's annual emissions during the calendar year that preceded submission of the report.

V.A.7.c.(v) If the unit is an existing unit other than an electric utility steam generating unit, the owner or operator shall submit a report to the Division if the annual emissions, in tons per year, from the project identified in Section V.A.7.c.(i), exceed the baseline actual emissions (as documented and maintained pursuant to Section V.A.7.c.(i)(C)) by a significant amount (as defined in Section II.A.44. of this part) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Section V.A.7.c.(i)(C). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

V.A.7.c.(v)(A) The name, address and telephone number of owner or operator of the major stationary source;

V.A.7.c.(v)(B) The annual emissions as calculated pursuant to Section V.A.7.c.(iii); and

V.A.7.c.(v)(C) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

V.A.7.d. The owner or operator of the source shall make the information required to be documented and maintained pursuant to Section V.A.7.c. available for review upon request for inspection by the Division or the general public.

V.A.8. Exemptions from certain nonattainment area requirements:

V.A.8.a. The following are exempt from the major stationary source criteria of Section V.A.3. of this part.

V.A.8.a.(i)(A) Portable sources that will relocate outside a nonattainment area in less than one year.

V.A.8.a.(i)(B) Each pilot plant that operates an aggregate of less than six months.

V.A.8.a.(i)(C) Construction phases of a new or modified building, facility, structure, or installation. These may, at the discretion of the Division, exceed a period of one year.

V.A.8.a.(i)(D) Other temporary processes or activities of less than one year in duration.

V.A.8.a.(i)(E) Sources undergoing fuel switches as required by federal order if the Division determines that:

V.A.8.a.i(E)(1) The applicant has used best efforts in seeking the required emission offsets but was unsuccessful;

V.A.8.a.i(E)(2) All available emission offsets were obtained; and,

V.A.8.a.i(E)(3) The applicant will continue to seek emission offsets as they become available.

VI. Requirements applicable to attainment and unclassifiable areas and pollutants implemented under Section 110 of the Federal Act (Prevention of Significant Deterioration Program).

VI.A. Major Stationary Sources and Major Modifications.

The requirements of this Section VI. shall apply to any major stationary source and any major modification with respect to each pollutant regulated under the Act and the Federal Act that it would emit, except as this Regulation Number 3 would otherwise allow.

For any new major stationary source or major modification proposing to construct in any area in Colorado designated under Section 107 (d) of the Federal Act as attainment or unclassifiable for any criteria pollutant as of the date of submittal of a complete application under this Regulation Number 3, or for pollutants implemented under Section 110 of the Federal Act, the Division shall grant a permit if it determines that the following requirements, in addition to those in Section III.D.1. of Part B of this regulation, have been or will be met:

VI.A.1. Control Technology Review.

VI.A.1.a. A new major stationary source shall apply Best Available Control Technology for each pollutant regulated under the Act or Federal Act that it would have the potential to emit in significant amounts.

VI.A.1.b. A major modification shall apply best available control technology for each pollutant regulated under the Act or Federal Act for which there would be a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation of the unit.

VI.A.1.c. For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than eighteen months prior to commencement of construction of each independent phase of the project. The review will be conducted in a timely manner that will allow the owner or operator to proceed with scheduled construction of the source. During the review, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

VI.A.2. Source Impact Analysis. The owner or operator of the proposed source or modification shall demonstrate to the Division that allowable emission increases from the proposed source or modification in conjunction with all other applicable emissions increases or reductions (including secondary emissions) will not cause or contribute to concentrations of air pollutants in the ambient air in violation of either Section VI.A.2.a. or b.

VI.A.2.a. Any state or national ambient air quality standard in any baseline area or air quality control region; or

VI.A.2.b. Any applicable maximum allowable increase over the baseline concentration in any area.

VI.A.2.c. Reserved

VI.A.3. Pre-construction Monitoring and Analysis

VI.A.3.a. An analysis of ambient air quality in any area that would be affected by the proposed major stationary source or major modification shall be performed for each pollutant regulated under the Act or Federal Act that the source or modification would emit or have the potential to emit in a significant amount, or for which there would be a significant net emissions increase.

VI.A.3.b. With respect to any such regulated pollutant for which no national ambient air quality standard exists and for which there is an acceptable method for the monitoring of that pollutant, the analysis shall contain such air quality monitoring data as the Division determines are necessary to assess ambient air quality for that pollutant in any area that emissions of that pollutant would affect.

VI.A.3.c. With respect to any such pollutant for which a national ambient air quality standard does exist, the analysis shall contain continuous air quality monitoring data gathered for purposes of determining whether emissions of that pollutant would cause or contribute to a violation of the applicable standard or any maximum allowable increase.

VI.A.3.d. In general, the continuous air quality monitoring data that are required under Section VI.A.3.c., or the pre-application monitoring of air quality related values required by Section XIII.B. of this part, shall have been gathered over a period of one year and shall represent the year preceding receipt of the application, except that, if the Division determines that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year (but not to be less than four months), the data that are required shall have been gathered over at least that shorter period.

VI.A.3.e. The owner or operator of a proposed major stationary source or major modification of volatile organic compounds who satisfies all conditions of the Code of Federal Regulations Title 40, Part 51, Appendix S, Section IV. (but not including conditions resulting from amendments after July 1, 1991 and not including Section IV. B. of Appendix S) may provide post-approval monitoring data for ozone in lieu of providing pre-construction data as required under Section VI.A.3.a. (Information on obtaining the Code of Federal Regulations Title 40, Part 51, Appendix S, Section IV. is available from the Director, Air Pollution Control Division, 4300 Cherry Creek Drive South, Denver, Colorado, 80246-1530.)

VI.A.4. Post-Construction Monitoring. At its discretion, the Division may require that the owner or operator of a major stationary source or major modification conduct post-construction ambient monitoring for a period up to one year. The Division may also require additional monitoring beyond the one year period if such monitoring is necessary to determine the effect emissions from the stationary source or modification have, or may have, on air quality in any area. The monitoring of air quality related values or sensitive receptors required by Section XIII.B. of this part, shall be for such time as is necessary to determine the effect emissions from the source or modification will have on the air quality related values or sensitive receptors.

Post-construction monitoring requirements will be permit conditions.

VI.A.5. Operation of Monitoring Stations. The owner or operator of a major stationary source or major modification shall use the U.S. EPA accepted procedures for ambient monitoring as approved by the Division during the operation of monitoring stations for purposes of satisfying the requirements of Sections VI.A.3. and VI.A.4., above.

VI.A.6. Additional Impact Analysis. For each pollutant that is regulated under the Act or the Federal Act, and for which the source or modification would emit in significant amounts (as defined in Section II.A.44. of this part) or for which there would be a significant net emissions increase, the owner or operator shall provide an analysis of the impairment to visibility, water, soils, and vegetation that would occur as a result of the emissions of such pollutant from the source or modification and general commercial, residential, industrial, and other growth associated with the source or modification. The analysis of impairment to water will not be used in the determination of best available control technology. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value. The additional impact analysis will include the effects on air quality related values as stated in Section XIII.B. of this part, if applicable.

The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

VI.B. Applicability of Certain PSD Requirements.

VI.B.1. The requirements of Section VI.A. do not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant:

VI.B.1.a. The source or modification is subject to Part 3 of the Act and Section V. of this part, and the source or modification would not impact any area designated as attainment or unclassifiable for that pollutant; or

VI.B.1.b. The emissions from the source or modification would not be significant; or

VI.B.1.c. The source or modification is a portable stationary source that has previously received a permit under requirements equivalent to those contained in Section VI.A. of this part if:

VI.B.1.c.(i) The source proposes to relocate and emissions of the source at the new location would be temporary;

VI.B.1.c.(ii) The emissions from the source would not exceed its allowable emissions;

VI.B.1.c.(iii) The emissions from the source would impact no Class I area and no area where an applicable increment is known to be violated; and

VI.B.1.c.(iv) Reasonable notice identifying the proposed new location and the probable duration of operation at the new location and a revised Air Pollutant Emission Notice is given to the Division prior to the relocation. Such notice and revised Air Pollutant Emission Notice shall be given to the Division not less than ten days in advance of the proposed relocation unless a different time duration is previously approved by the Division.

VI.B.2. The requirements contained in Sections VI.A.2. through VI.A.4. of this part do not apply:

VI.B.2.a. To a proposed major stationary source or major modification with respect to a particular pollutant, if the emissions would be from a temporary source, modification or activity, such as construction or exploration, and would not have an impact on air quality in any Class I area or an area where an applicable increment is known to be violated; or

VI.B.2.b. As they relate to any maximum allowable increase for a Class II area, to a modification of a major stationary source that was in existence on March 1, 1978, if the net increase in allowable emissions of each pollutant subject to regulation, excluding GHG, under the Act from the modification after the application of best available control technology would be less than fifty tons per year.

VI.B.3. The Division may exempt a proposed major stationary source or major modification from the requirements of Sections VI.A.3. through VI.A.5. of this part, with respect to monitoring for a particular pollutant if:

VI.B.3.a. The emissions of the pollutant from the new stationary source or the net emissions increase of the pollutant from the modification would cause air quality impacts, in any area, less than the following:

VI.B.3.a.(i) Carbon monoxide - 575 µg/m^3, 8-hour average;

VI.B.3.a.(ii) Nitrogen dioxide - 14 µg/m^3, annual average;

VI.B.3.a.(iii) Particulate Matter - PM10 -- 10 µg/m^3, 24-hour average; PM2.5 – 0 µg/m^3, 24-hour average;

VI.B.3.a.(iv) Sulfur dioxide - 13 µg/m^3, 24-hour average;

VI.B.3.a.(v) Lead - 0.1 µg/m^3, 3-month average;

VI.B.3.a.(vi) Fluorides - 0.25 µg/m^3, 24-hour average;

VI.B.3.a.(vii) Total reduced sulfur - 10 µg/m^3, 1-hour average;

VI.B.3.a.(viii) Hydrogen sulfide - 0.2 µg/m^3, 1-hour average;

VI.B.3.a.(ix) Reduced sulfur compounds - 10 µg/m^3, 1-hour average; or

VI.B.3.b. The existing concentrations of the pollutant in the area that the source or modification would affect are less than the concentrations listed in this section; or

VI.B.3.c. For ozone, the emissions increase or net emissions increase of volatile organic compounds or nitrogen oxides from the source or modification would be less than 100 tons per year; or

VI.B.3.d. The pollutant is not referred to in this Section VI.B.3.a.; or

VI.B.3.e. The source or modification was subject to Section VI., with respect to PM2.5, as in effect before July 15, 2008, and the owner or operator submitted an application for a permit under this Section VI.A. of Part D before that date consistent with EPA recommendations to use PM10 as a surrogate for PM2.5, and the Division subsequently determines that the application as submitted was complete with respect to the PM2.5 requirements then in effect, as interpreted by EPA in the memorandum entitled “Interim Implementation of New Source Review Requirements for PM2.5” (October 23, 1997). Instead, the requirements of Section VI.A. of this Part D, as interpreted in the aforementioned memorandum, that was in effect before July 15, 2008 shall apply to such source or modification.

VI.B.4. The requirements of this Part D shall apply at such time that any stationary source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforceable limitation that was established after August 7, 1980, on the capacity of the source or modification to otherwise emit a pollutant such as a restriction on hours of operation.

VI.B.5. The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) in circumstances where there is a project that is not a part of a major modification and the owner or operator elects to use the method specified in Sections II.A.38.b.(i) through II.A.38.b.(iii) of this Part D for calculating projected actual emissions.

VI.B.5.a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

VI.B.5.a.(i) A description of the project;

VI.B.5.a.(ii) Identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

VI.B.5.a.(iii) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded under Section II.A.38.b.(iii) of this part, and an explanation for why such amount was excluded, and any netting calculations, if applicable.

VI.B.5.b. If the emissions unit is an existing electric utility steam-generating unit, before beginning actual construction, the owner or operator shall provide a copy of the information set out in Section VI.B.5.a. to the Division. Nothing in this Section VI.B.5.b. shall be construed to require the owner or operator of such a unit to obtain any determination from the Division before beginning actual construction.

VI.B.5.c. The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in Section VI.B.5.a.(ii); and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of ten years following resumption of regular operations after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

VI.B.5.d. If the unit is an existing electric utility steam generating unit, the owner or operator shall submit a report to the Division within sixty days after the end of each year during which records must be generated under Section VI.B.5.c. setting out the unit's annual emissions during the calendar year that preceded submission of the report.

VI.B.5.e. If the unit is an existing unit other than an electric utility steam-generating unit, the owner or operator shall submit a report to the Division if the annual emissions, in tons per year, from the project identified in Section VI.B.5.a. exceed the baseline actual emissions (as documented and maintained pursuant to Section VI.B.5.a.(iii)) by a significant amount (as defined in Section II.A.44. of this part) for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection as documented and maintained pursuant to Section VI.B.5.a.(iii). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

VI.B.5.e.(i) The name, address and telephone number of the major stationary source;

VI.B.5.e.(ii) The annual emissions as calculated pursuant to Section VI.B.5.c.; and

VI.B.5.e.(iii) Any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

VI.B.6. The owner or operator of the source shall make the information required to be documented and maintained pursuant to Section VI.B.5. available for review upon request for inspection by the Division or the general public.

VI.B.7. A stationary source or modification may apply the applicable maximum allowable increases for total suspended particulate matter as in effect on the date of the permit application, in meeting the requirements of Section VI.A.2. of this part, if the following requirements are met:

VI.B.7.a. The owner or operator of the source or modification submitted an application for a permit under Regulation Number 3 before the provisions for maximum allowable increases for PM10 took effect; and

VI.B.7.b. The Division determines that the application as submitted, before the date that the maximum allowable increases for PM10 took effect, was complete.

VI.C. Notice to the U.S. EPA.

The Division shall transmit to the Administrator of the U. S. EPA a copy of each permit application relating to a major stationary source or major modification subject to this regulation, and provide notice of every action related to the consideration of such permit.

VI.D. Major Stationary Sources in attainment areas affecting nonattainment areas.

VI.D.1. For any new major stationary source or major modification that is proposed to be constructed in an area designated under Section 107(d) of the Federal Act as attainment or unclassifiable for a particular pollutant and the emissions of such pollutant from which would significantly affect ambient air quality in an area designated as nonattainment for such pollutant, the Division shall grant a permit if it determines that one or both of the following conditions, as well as those in Section III.D.1. of Part B and Section VI.A. of this Part D will be met:

VI.D.1.a. The proposed source or modification will meet the requirements of Sections V.A.1. and V.A.2. of this part, and obtain sufficient emission reductions of such pollutant in the nonattainment area to offset that portion of its emissions of such pollutant that affect the nonattainment area. Offsets may be obtained from outside the nonattainment area as provided in Section V.A.3. of this part; or

VI.D.1.b. The proposed source or modification will achieve an emissions rate that will ensure that the emissions of such pollutant from the source or modification will not significantly affect ambient air quality in the nonattainment area.

VI.D.2. Ambient air quality will be deemed to be significantly affected if, but for any offsets, the applicable significance level set forth in the following table would be exceeded in the nonattainment area.

TABLE OF SIGNIFICANCE LEVELS

Pollutant	**Averaging Time**				
	Annual	**24-Hour**	**8-Hour**	**3-Hour**	**1-Hour**
SO_2	1.0 µg/m^3	5 µg/m^3		25 µg/m^3	
PM10	1.0 µg/m^3	5 µg/m^3			
PM2.5	0.3 µg/m^3	1.2 µg/m^3			
NO_2	1.0 µg/m^3				
CO			500 µg/m^3		2000 µg/m^3

VI.D.3. Any new major stationary source or major modification subject to this section that will emit or cause a net emissions increase in volatile organic compounds or oxides of nitrogen shall demonstrate to the satisfaction of the Division that its emissions will not affect any ozone nonattainment area or shall obtain offsets as required in Section VI.D.1., above.

VI.D.4. Emission offsets for PM10, sulfur dioxide, and carbon monoxide, must show, through air quality modeling, a positive net air quality benefit in the portion of the nonattainment area affected by emissions from the proposed source or modification.

VII. Negligibly Reactive Volatile Organic Compounds (NRVOCs)

VII.A. The negligibly reactive volatile organic compounds referenced in the Common Provisions definition of negligibly reactive volatile organic compounds are considered to be of negligible photochemical reactivity and are neither counted as reactive volatile organic compounds in determining volatile organic compound emission contributions to an increase in ozone nor used as volatile organic compound emission offsets or other volatile organic compound emission trading credits against volatile organic compounds not listed in the common provisions negligibly reactive volatile organic compound definition.

VII.B. Negligibly reactive volatile organic compounds may be substituted for volatile organic compounds and the resulting decrease in volatile organic compound emissions, if otherwise creditable, may be used for offset, banking or other emission trading credit.

VIII. Area Classifications

VIII.A. The following areas in Colorado shall be Class I areas and may not be redesignated:

VIII.A.1. National Parks

VIII.A.1.a. Rocky Mountain

VIII.A.1.b. Mesa Verde

VIII.A.2. National Wilderness Areas

VIII.A.2.a. Black Canyon of the Gunnison

VIII.A.2.b. Eagle's Nest

VIII.A.2.c. Flattops

VIII.A.2.d. Great Sand Dunes

VIII.A.2.e. La Garita

VIII.A.2.f. Maroon Bells - Snowmass

VIII.A.2.g. Mount Zirkel

VIII.A.2.h. Rawah

VIII.A.2.i. Weminuche

VIII.A.2.j. West Elk

VIII.B. All other areas of Colorado, unless otherwise specified by Act of Congress or the Colorado legislature, or the Commission pursuant to Section IX. are designated Class II; provided, however that in the following areas as they existed on August 7, 1977 (maps available from the Division), the increase allowed in sulfur dioxide concentrations over the baseline concentration shall be the same as the increase established by Section 163(b) of the Federal Act for Class I areas, except that such allowable increases may not be allowed if a Federal Land Manager should make an adverse impact determination under Section XIII.C. with which the Division concurs and except that such allowable increases, may be exceeded by compliance with the provisions of Sections XIII.D., XIII.E., or XIII.F.:

VIII.B.1. National Monuments

VIII.B.1.a. Florissant Fossil Beds

VIII.B.1.b. Colorado

VIII.B.1.c. Dinosaur

VIII.B.1.d. Great Sand Dunes (those portions not included as National Wilderness Areas in Section VIII.A.2.)

VIII.B.2. Forest Service Primitive Areas

VIII.B.2.a. Uncompahgre Mountain

VIII.B.2.b. Wilson Mountain

VIII.B.3. Lands administered by the Federal Bureau of Land Management in the Gunnison Gorge Recreation Area as of October 27, 1977. All areas designated Class II under this section may be redesignated as provided in Section IX. of this part.

VIII.B.4. National Parks

Black Canyon of the Gunnison (those portions not included as National Wilderness Areas in Section VIII.A.2.)

VIII.C. The following areas may be redesignated only as Class I or II.

VIII.C.1. An area that exceeds ten thousand acres in size and is a national monument, a national primitive area, a national preserve, a national recreational area, a national wild and scenic river, a national wildlife refuge, a national lakeshore; and

VIII.C.2. A national park or national wilderness area established after August 7, 1977, that exceeds ten thousand acres in size.

VIII.D. The Commission recognizes out of state Class I areas that have been listed in the Federal Register (44 Fed. Reg. 69124). Emissions from sources in Colorado shall not violate any standard in these areas.

IX. Redesignation

IX.A. Except as otherwise provided in this section or Section VIII. of this part, the Commission may redesignate any area in Colorado as Class I, Class II or Class III as herein provided. The Commission will provide notice to the General Purpose Unit of local government in an area where the maximum allowable increase is being approached.

IX.B. The Commission shall review and consider a request for redesignation by any person.

IX.C. The Commission shall not set a hearing date on a proposed redesignation until the following have been completed:

IX.C.1. A complete description of the area proposed for redesignation;

IX.C.2. A detailed statement of the circumstances that support the proposed redesignation;

IX.C.3. A prediction of the costs and benefits for the affected population from the proposed redesignation;

IX.C.4. A technical analysis of expected impacts on ambient air quality in adjacent or nearby areas;

IX.C.5. Comments, or evidence of an opportunity for submission of comments, by all appropriate regional planning agencies and councils of government organizations, affected municipalities and other affected political subdivisions; and

IX.C.6. An analysis of the relationship of the proposed redesignation with applicable county or regional development plans, including but not limited to, comprehensive area wide plans and 208 water quality plans.

IX.D. The Commission shall provide sixty day notice prior to a public hearing, including notice to other states, Indian governing bodies and Federal Land Managers whose lands may be affected by a proposed redesignation, of any proposed redesignation, and conduct public hearings on such proposed redesignation in or near areas within Colorado that may be affected by such proposed redesignation, including at least one public hearing within or as near as is practicable to the area to be redesignated. At least thirty days prior to any such public hearings, the Commission shall make available for public inspection a discussion of the reasons for the proposed redesignation, including a satisfactory description and analysis of the health, environmental, economic, and societal and energy effects of the proposed redesignation. The notice announcing any public hearings shall contain appropriate notification of the availability of such discussion.

IX.E. Prior to the issuance of notice respecting the proposed redesignation of an area that includes any federal lands, the Commission shall provide written notice to the appropriate Federal Land Manager and afford adequate opportunity (not in excess of sixty days) to confer with the Commission respecting the notice of proposed redesignation and to submit written comments and recommendations with respect to such notice of proposed redesignation. In redesignating any area with respect to which any Federal Land Manager had submitted written comments and recommendations, the Commission shall publish a list of any inconsistency between such redesignation and such comments and recommendations and an explanation of such inconsistency (together with the reasons for making such redesignation against the recommendation of the Federal Land Manager).

IX.F. All redesignations, except any established by an Indian governing body, shall be specifically approved; (1) by the governor, after consultation with the appropriate committees of the legislature, if it is in session, or with the leadership of the legislature, if it is not in session, and (2) by resolutions or ordinances enacted by the general purpose units of local government representing a majority of the residents of the area to be redesignated.

IX.G. No area may be redesignated if such redesignation would cause or contribute to concentrations of any air pollutant in any other area that exceed any maximum allowable increase or maximum allowable concentration permitted under the classification of such area.

IX.H. Lands within the exterior boundaries of reservations of federally recognized Indian tribes may be redesignated only by the appropriate Indian governing body.

IX.I. Any redesignation shall constitute a revision to the Colorado State Implementation Plan and shall be submitted for approval to the Administrator of the U.S. EPA.

IX.J. Any redesignation or denial of a proper request for redesignation made pursuant to this Section IX. shall be subject to judicial review in accord with Colorado Revised Statute Section 25-7-120.

IX.K. Any area other than an area to which Sections VIII.A. or VIII.C. refer to may be redesignated as Class III if any major stationary source or major modification could receive a permit only if the area in question were redesignated as Class III, and any material submitted as part of that application were available, insofar as was practicable, for public inspection prior to any public hearing on redesignation of any area as Class III.

X. Air Quality Limitations

X.A. Ambient Air Increments

X.A.1. The maximum allowable increases over the baseline concentration for sulfur dioxide, PM10, PM2.5 or nitrogen dioxide except as provided in Section VIII.B. of this part, are:

X.A.1.a. For any Class I area:

PM2.5 (µg/m^3)	
Annual arithmetic mean	1
Twenty-four hour maximum	2
PM10 (µg/m^3)	
Annual arithmetic mean	4
Twenty-four hour maximum	8
Sulfur dioxide (µg/m^3)	
Annual arithmetic mean	2
Twenty-four hour maximum	5
Three hour maximum	25
Nitrogen dioxide (µg/m^3)	
Annual arithmetic mean	2.5

X.A.1.b. For any Class II area:

PM2.5 (µg/m^3)	
Annual arithmetic mean	4
Twenty-four hour maximum	9
PM10 (µg/m^3)	
Annual arithmetic mean	17
Twenty-four hour maximum	30
Sulfur dioxide (µg/m^3)	
Annual arithmetic mean	20
Twenty-four hour maximum	91
Three hour maximum	512
Nitrogen dioxide (µg/m^3)	
Annual arithmetic mean	25

X.A.1.c. For any Class III area:

PM2.5 (µg/m^3)	
Annual arithmetic mean	8
Twenty-four hour maximum	18
PM10 (µg/m^3)	
Annual arithmetic mean	34
Twenty-four hour maximum	60
Sulfur dioxide (µg/m^3)	
Annual arithmetic mean	40
Twenty-four hour maximum	182
Three hour maximum	700
Nitrogen dioxide (µg/m^3)	
Annual arithmetic mean	50

X.A.2. The maximum allowable increases over the baseline concentration for any other air pollutant shall be the same as those increases established pursuant to Section 165(a) of the Federal Act.

X.A.3. For any period other than an annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one location.

X.A.4. Periodic Review

X.A.4.a. The Division shall, on a periodic basis, review the adequacy of this Regulation Number 3 for preventing significant deterioration of air quality. Within thirty days after any information becomes available and there is cause to believe that an applicable increment is being violated, the Division shall present the cause for such belief to the Commission.

X.A.4.b. If the Commission concurs that there is cause to believe that an increment is being violated, it shall hold a hearing to determine whether an increment violation exists. The hearing shall be held pursuant to the procedures of Colorado Revised Statute Section 25-7-119. Notice should be given by first class mail to permitted sources that can be reasonably identified as emitting the pollutant in violation and affecting the area of violation.

X.A.4.c. Should the Commission determine that an increment violation exists, the Division shall review all sources affecting the area of increment violation and ensure that all such sources comply with all applicable permit conditions, and state and local regulations. Within thirty days after completing such a review, the Division shall recommend revisions, if necessary, to the Commission to correct the violation. Upon receipt of recommended revisions from the Division, the Commission shall as soon as practicable act to revise this regulation as it deems necessary.

X.A.5. Increment Consumption Restriction

X.A.5.a. No new major stationary source or major modification shall individually consume more than seventy-five percent of an applicable increment.

X.A.5.a.(i) Applicants may request a hearing before the Commission to request a waiver of this restriction. The hearing shall be heard in accordance with the provisions of Colorado Revised Statute Sections 25-7-114 (4)(h), 25-7-119 (Colorado Air Pollution Prevention and Control Act), and Colorado Revised Statute 24-4-105 (State Administrative Procedure Act).

X.A.5.a.(i)(A) The Commission shall not set a hearing date for a waiver request until submittal of comments, or evidence of an opportunity for submittal of comments by all appropriate regional planning agencies and councils of government organizations, affected municipalities and other affected political subdivisions has occurred.

X.A.5.a.(i)(B) Ambient Air Limits. No concentrations of a pollutant shall exceed a national ambient air quality standard or a state ambient air standard where no national ambient air quality standard has been established.

XI. Exclusions From Increment Consumption

XI.A. The following concentrations are excluded in determining compliance with a maximum allowable increase:

XI.A.1. Concentrations attributable to the increase in emissions from stationary sources that have converted from the use of petroleum products, natural gas, or both by an order in effect under Sections 2(a) and (b) of the federal "Energy Supply and Environmental Coordination Act of 1974" (or any superseding legislation) over the emissions from such sources before the effective date of such an order, but not more than five years after the effective date of such an order.

XI.A.2. Concentrations attributable to the increase in emissions from sources that have converted from using natural gas by reason of a natural gas curtailment plan in effect pursuant to the Federal "Power Act" over the emissions from such sources before the effective date of such plan, but not more than five years after the effective date of the plan.

XI.A.3. Concentrations of particulate matter attributable to an increase in emissions from construction or other temporary emission-related activities of new or modified sources.

XI.A.4. Concentrations attributable to the temporary increase in emissions of sulfur dioxide, or particulate matter, or nitrogen oxides from stationary sources that are affected by revisions of the Colorado State Implementation Plan that are approved by the Administrator of the U.S. EPA and that provide:

XI.A.4.a. The time period of such temporary increase in emissions is not renewable and may not exceed two years in duration, unless a longer time is approved by the Division and the U.S. EPA;

XI.A.4.b. Such temporary increase in emissions shall not impact a Class I area or an area where an applicable increment is known to be violated or cause or contribute to the violation of a national ambient air quality standard; and

XI.A.4.c. Emission limitations shall be in effect at the end of the time period specified in the plan revision that will ensure that the emissions levels from stationary sources affected by the plan revision will not exceed those levels occurring from such sources before the plan revision was approved by the U.S. EPA.

XII. Innovative Control Technology

XII.A. An owner or operator of a proposed major stationary source or major modification otherwise subject to the requirements of Section VI. of this Part D may request the Division to grant a waiver from the Best Available Control Technology requirements and to approve a system of innovative control technology, in order to encourage the use of such technology.

XII.B. The Division or the Commission may, with the consent of the governor(s) of other affected states, grant a waiver from the Best Available Control Technology requirements of Section VI.A.1. of this part necessary for the employment of innovative control technology and determine that the source or modification may employ such system if:

XII.B.1. The proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function;

XII.B.2. The owner or operator agrees to achieve a level of continuous emissions reduction greater than or equivalent to that, which would have been required under Section VI.A.1. by a date specified by the Division. Such date shall not be later than four years from the time of startup or seven years from permit issuance;

XII.B.3. The source or modification would meet the requirements of Sections VI.A.1. and VI.A.2. based on the emissions rate that the stationary source employing the system of innovative control technology would be required to meet on the date specified by the Division;

XII.B.4. The source or modification would not, before the date specified by the Division under Section XII.B.2., above;

XII.B.4.a. Cause or contribute to any violation of an applicable national ambient air quality standard; or

XII.B.4.a.(i) Impact any area where an applicable increment is known to be violated; or

XII.B.5. All other applicable requirements including those for public participation have been met.

XII.B.6. The provisions of Section VIII. of this part (relating to Class I areas) have been satisfied with respect to all periods during the life of the source or modification.

XII.C. The Division shall withdraw any approval to employ a system of innovative control technology made under this section, if:

XII.C.1. The proposed system fails by the specified date to achieve the required continuous emissions reduction rate; or

XII.C.2. The proposed system fails before the specified date so as to contribute to an unreasonable risk to public health, welfare, or safety; or

XII.C.3. The Division decides at any time that the proposed system is unlikely to achieve the required level of control or to protect the public health, welfare, or safety.

XII.D. If a source or modification fails to meet the required level of continuous emissions reduction within the specified time period, or if the approval is withdrawn in accordance with Section XII.C., above, the Division may allow the source or modification up to an additional three years to meet the requirement for the application of best available control technology through use of a demonstrated system of control.

XIII. Federal Class I Areas

XIII.A. Within twenty days of receipt of a permit application for a new major stationary source or major modification that may affect visibility or air quality related values in any Federal Class I area, the Division shall transmit a copy of the application to all affected Federal Land Managers and consult with them as to its completeness in its analysis and monitoring (if required) of air quality related values. If the Division receives advance notification of a permit application of a source that may affect visibility or air quality related values, it will notify all affected Federal Land Managers within thirty days of such notification. The Division will consider any analysis performed by a Federal Land Manager that indicates there will be an adverse impact on visibility or air quality related values if such analysis is received within thirty days after the Federal Land Manager receives a copy of the complete application. If the Division disagrees with the Federal Land Manager, any notices for public comment or of a public hearing on the application will explain the disagreement or state where the explanation can be obtained.

XIII.B. In addition to the general impact analysis required by Section VI.A.6. of this part, any source that will have or is likely to have an impact on any designated Class I area may be required to conduct monitoring to establish the condition of and the impact on air quality related values in such Class I area(s) both prior to completing an application for a permit to construct and during the construction and operation of such source.

XIII.B.1. If monitoring is required, the source shall conduct a private monitoring program. However, if monitoring is being conducted by any other existing source or government agency, the new source may enter into a joint monitoring program with that source or agency. All monitoring programs must be approved in advance by the Division.

XIII.B.2. Pre-application monitoring may include the monitoring of not more than three air quality related values or sensitive receptors of air quality related values specified by the Division after consultation with the Federal Land Manager. The air quality related values or sensitive receptor(s) selected must be important to the affected Class I area, and there must be cause to believe that monitoring of the air quality related values or sensitive receptors will provide a basis for evaluating effects to the relevant air quality related values.

XIII.B.3. Monitoring during construction and operation may only be required for the sensitive receptors specified for pre-application monitoring, unless new information becomes available that demonstrates a significant economic or technological advantage of monitoring a different sensitive receptor, and it is acceptable to the source owner or operator.

XIII.B.4. Monitoring of air quality related values or sensitive receptors of air quality related values may only be required if:

XIII.B.4.a. Monitoring methods are reasonably available and research and development of monitoring methods are unnecessary;

XIII.B.4.b. The major effect on the air quality related values or sensitive receptor would reasonably be predicted to be a result of the applicant's individual emissions or of the applicant's emissions in combination with any person's emissions with whom the applicant may be required to conduct joint monitoring; and

XIII.B.4.c. It is economically reasonable for the source to conduct such monitoring.

XIII.C. Sources Impacting Federal Class I Area - Additional Requirements. Federal Land Managers may present to the Division, after its preliminary analysis required under Section III.B. of Part B of this regulation, a demonstration that the emissions from the proposed source or modification would have an adverse impact on the air quality related values (including visibility) of any federal mandatory Class I lands, notwithstanding that the change in air quality resulting from emissions from such source or modification would not cause or contribute to concentrations that would exceed the maximum allowable increases for a Class I area. If the Division concurs with such demonstration, or in the event the Federal Land Manager fails to perform an adverse impact analysis and the Division determines that there is an adverse impact on visibility, or the Division determines that a demonstration of no adverse impact is in error, the Division shall not issue the permit.

XIII.D. Class I Variances. The owner or operator of a proposed major stationary source or major modification may demonstrate to the satisfaction of the Federal Land Manager that the emissions from such source or modification would not have an adverse impact on the air quality related values (including visibility) of Class I lands under the Federal Land Manager's jurisdiction, notwithstanding that the change in air quality resulting from emissions from such source or modification would cause or contribute to concentrations that would exceed the maximum allowable increases for a Class I area. If the Federal Land Manager concurs with such demonstration and so certifies to the Division, the Division or the Commission may, provided that applicable requirements are otherwise met, issue the permit with such emission limitations as may be necessary to assure that emissions of sulfur dioxide, and PM10, PM2.5 and nitrogen oxides would not exceed the following maximum allowable increases over the minor source baseline concentration for such pollutants.

Maximum allowable increase	
Particulate matter	
PM2.5, Annual arithmetic mean	4 µg/m^3
PM2.5, Twenty-four hour maximum	9 µg/m^3
PM10, Annual arithmetic mean	17 µg/m^3
PM10, Twenty-four hour maximum	30 µg/m^3
Sulfur dioxide	
Annual arithmetic mean	20 µg/m^3
Twenty-four hour maximum	91 µg/m^3
Three hour maximum	325 µg/m^3
Nitrogen dioxide	
Annual arithmetic mean	25 µg/m^3

XIII.E. Sulfur Dioxide Variance by Governor

XIII.E.1. The owner or operator of a proposed major stationary source or major modification that cannot be approved under Section XIII.D., above, may demonstrate to the governor that the source or modification cannot be constructed by reason of any maximum allowable increase for sulfur dioxide for periods of twenty-four hours or less, applicable to any Class I area and, in the case of the federal mandatory Class I areas, that a variance under this section would not have an adverse affect on the air quality related values of the area (including visibility).

XIII.E.2. The governor, after consideration of the Federal Land Manager's recommendation (if any) and subject to his concurrence, may grant, after notice and an opportunity for a public hearing, a variance from such maximum allowable increase.

XIII.E.3. If such variance is granted, the Division may issue a permit to such source or modification in accordance with Section XIII.G., below, if the applicable requirements of Regulation Number 3 are otherwise met.

XIII.F. Variance by the Governor with the President's Concurrence

XIII.F.1. The recommendations of the governor and the Federal Land Manager shall be transferred to the president in any case where the governor recommends a variance with which the Federal Land Manager does not concur.

XIII.F.2. If the president approves the variance, the Division may issue a permit in accordance with Section XIII.G., below, if the applicable requirements of Regulation Number 3 are otherwise met.

XIII.G. Emission Limitations for Presidential and Gubernatorial Variance. In the case of a permit to be issued under Sections XIII.E. and XIII.F., the source or modification shall comply with emission limitations as may be necessary to assure that emissions of sulfur dioxide from the source or modification would not (during any day on that the otherwise applicable maximum allowable increases are exceeded) cause or contribute to concentrations that would exceed the following maximum allowable increases over the baseline concentration assure that such emissions would not cause or contribute to concentrations that exceed the otherwise applicable maximum allowable increases for periods of exposure of twenty-four hours or less for more than eighteen days, not necessarily consecutive, during any annual period:

Maximum Allowable Increase (µg/m3)

Period of Exposure	**Terrain Areas**	
	Low	**High**
24-hour maximum	36	62
3-hour maximum	130	221

XIV. Visibility

XIV.A. Purpose

This section assures reasonable progress towards the national goal of preventing future, and remedying existing, visibility impairment in Class I areas, where such impairment results from man-made air pollution.

XIV.B. Applicability

This section applies to all Class I areas and to sources in Colorado the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area (even if the area is in another state).

XIV.C. Definitions

For purposes of this Section XIV.

XIV.C.1. Adverse impact on visibility means for the purpose of Section XIV.E. visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Class I area. Any determination shall be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with times of visitor use of the Class I area, and the frequency and timing of natural conditions that reduce visibility.

XIV.C.2. Best Available Retrofit Technology means an emission limitation achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation shall be established on a case-by-case basis 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, the remaining useful life of the source, and the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

XIV.C.3. Existing stationary facility means any of the stationary sources of air pollutants defined in Sections I.B.19., I.B.24. through I.B.27., I.B.36., and I.B.43. of Part A, Section I.A.1.(c) of Part C, and Section II.A.24. of Part D of this regulation, including any reconstructed source that was not in operation prior to August 7, 1962, and had commenced construction on or before August 7, 1977, and has the potential to emit two hundred and fifty tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable shall be counted.

XIV.C.4. Long-term strategy means a ten to fifteen year plan for making reasonable progress toward the national goal specified in Section XIV.A. of this part.

XIV.C.5. Natural conditions include naturally occurring phenomena that reduce visibility as measured in terms of visual range, contrast, or coloration.

XIV.C.6. Reasonably attributable means attributable by visual observation or any other technique the state deems appropriate.

XIV.C.7. Significant impairment means, for purposes of Section XIV.D.2.c., visibility impairment, that interferes with the management, protection, preservation or enjoyment of the visitor's visual experience of the Class I area.

XIV.C.8. Visibility impairment means any humanly perceptible change in visibility (visual range, contrast, coloration) that would have existed under natural conditions.

XIV.C.9. Class I area means an area listed in Section VIII.A. of this part and any area that may be redesignated to Class I in the future.

XIV.D. Existing Impairment

XIV.D.1. The Federal Land Manager or the Division may, at any time, certify to the Division director that visibility impairment exists in any Class I area. The Division may also certify that visibility impairment exists in any Class I area without the concurrence of the Federal Land Manager.

XIV.D.2. Each existing stationary facility located in Colorado to which the cause of or contribution to visibility impairment in any Class I area is reasonably attributable, shall

apply for and obtain from the Division a permit that requires the installation and operation of Best Available Retrofit Technology. The facility shall install and operate Best Available Retrofit Technology as expeditiously as practicable but in no case later than five years after permit issuance.

XIV.D.2.a. For fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts, Best Available Retrofit Technology shall be determined pursuant to "Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities" (U.S. EPA Publication Number 450/3-80-009b, 1980), and state of the art information available at the time of Best Available Retrofit Technology analysis. Pursuant to Colorado Revised Statute Section 24-4-103 (12.5), the document referenced in this section is available for public inspection during normal working hours, or copies are available for cost, from the technical secretary of the Commission, 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. This Regulation Number 3 does not include later amendments to or editions of the referenced documents.

XIV.D.2.b. Should technological or economic limitations make the application of Best Available Retrofit Technology as previously defined infeasible; the state may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, as representing Best Available Retrofit Technology. Where a facility is subject to Section XIV.D.2.a., due to technological limitations, the facility shall install and operate Best Available Retrofit Technology as previously defined when new technology for control of the pollutant becomes reasonably available provided: 1) the pollutant is emitted by the existing facility; 2) controls representing Best Available Retrofit Technology for the pollutant have not previously been required under this section; and 3) the impairment of visibility in any Class I area is reasonably attributable to the emissions of that pollutant.

XIV.D.2.c. Any existing stationary facility required to install and operate Best Available Retrofit Technology under this section may apply to the Division and the U.S. EPA Administrator for an exemption.

XIV.D.2.c.(i) An application under this section must include all available documentation relevant to the impact of the source's emissions on visibility in any Class I area and a demonstration by the existing stationary facility that it does not or will not by itself or in combination with other sources, emit any air pollutant that may be reasonably anticipated to cause or contribute to a significant impairment of visibility in any Class I area.

XIV.D.2.c.(ii) Any fossil fuel fired power plant with a total generating capacity of 750 megawatts or more may receive an exemption from Best Available Retrofit Technology only if the owner or operator of such power plant demonstrates to the satisfaction of the Division that such power plant is located at such a distance from all Class I areas that such power plant does not or will not by itself or in combination with other sources emit any air pollutant that may reasonably be anticipated to cause or contribute to significant impairment of visibility in any such Class I area.

XIV.D.2.c.(iii) The existing stationary facility must give prior written notice to all affected Federal Land Managers of any application for exemption.

XIV.D.2.c.(iv) The Federal Land Manager may provide an initial recommendation or comment on the disposition of such application. Such recommendation, where provided, must be part of the exemption application. This recommendation is not to be construed as the concurrence required under Section XIV.D.2.c.(iv).

XIV.D.2.c.(v) After notice and opportunity for public hearing, before the Commission, the Division may grant or deny the exemption.

XIV.D.2.c.(vi) An exemption granted by the Division under this section will be effective only upon concurrence by all affected Federal Land Managers.

XIV.D.2.c.(vii) Any determination shall be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of the visibility impairment, and how these factors correlate with time of visitor use of the Class I area, and the frequency and timing of natural conditions that reduce visibility.

XIV.D.2.d. The Division shall process any application for a permit required by Section XIV.D.2., above, or any application for exemption under Section XIV.D.2.b., according to the time constraints stated in Part B, Section III.B. of this regulation. All applications for permits or exemptions will be subject to public notice and public hearing requirements applicable to sources subject to the provisions of Section VI. of this part. Processing fees will be charged to the applicant to recover actual costs incurred by the Division as stated in Section VI. of Part A of this Regulation Number 3.

XIV.E. New Source Review

Applicants for new major stationary sources and major modifications shall demonstrate that the proposed source will not have an adverse impact on visibility in a Class I area as required by Sections V.A.6., VI.A.6., and XIII. of this part.

XIV.F. Long-term Strategy

XIV.F.1. The Commission shall review and revise, if appropriate, the long-term strategy every five years.

XIV.F.1.a. During the long-term strategy development and review process, the Commission shall consult with the Federal Land Managers.

XIV.F.1.b. A public hearing shall be held upon request of any interested person. The state shall provide written notification to each affected Federal Land Manager and other affected states at least sixty days prior to holding any public hearing.

XIV.F.1.c. The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available on September 1, at least every fifth year following the submittal of the previous report and consistent with the federal five-year Regional Haze reporting schedule. The report shall include an assessment of:

XIV.F.1.c.(i) The progress achieved in remedying existing impairment of visibility in any Class I area;

XIV.F.1.c.(ii) The ability of the long-term strategy to prevent future impairment of visibility in any Class I area;

XIV.F.1.c.(iii) 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;

XIV.F.1.c.(iv) Additional measures, including the need for state implementation plan revisions, that may be necessary to assure reasonable progress toward the national visibility goal;

XIV.F.1.c.(v) The progress achieved in implementing Best Available Retrofit Technology and meeting other schedules set forth in the long-term strategy;

XIV.F.1.c.(vi) The impact of any exemption granted under Section XIV.D.2.c.; and,

XIV.F.1.c.(vii) The need for Best Available Retrofit Technology to remedy existing impairment in an integral vista declared since plan approval.

XIV.G. Public Land Emission Inventories

XIV.G.1. Federal Public Lands

XIV.G.1.a. For the purposes of this Section XIV.G., federal land management agency means a federal agency that owns and manages at least 50,000 acres of federal land in Colorado.

XIV.G.1.b. Federal land management agencies shall submit to the Commission emission inventories by December 31, 2001 and no less frequently than every five years thereafter.

XIV.G.1.c. The inventory shall include the sources listed in Section XIV.G.3.b. of this regulation and emissions of criteria pollutants, including surrogates or precursors for such pollutants, from activities in Colorado or other states that may affect any mandatory class I federal area in Colorado by reducing visibility in such area.

XIV.G.2. Colorado State Public lands

XIV.G.2.a. The Division shall submit to the Commission emission inventories for all state land management agencies including the State Land Board, the Department of Agriculture, and the Department of Natural Resources by July 1, 2002 and no less frequently than every five years thereafter.

XIV.G.2.b. The inventory shall include the sources listed in Section XIV.G.3.b. of this regulation and emissions of criteria pollutants, including surrogates or precursors for such pollutants, from activities in Colorado that may affect any mandatory Class I federal area in Colorado by reducing visibility in such area.

XIV.G.3. Public Land Emission Inventory Requirements

XIV.G.3.a. The inventory shall include both current emissions and projected future emissions, over at least a five-year period.

XIV.G.3.b. The following sources on public lands shall be included in the inventory:

XIV.G.3.b.(i) Stationary source emissions, based on existing air pollution emission notices filed with the Division;

XIV.G.3.b.(ii) Mobile sources utilizing state lands, excluding state and federal highways;

XIV.G.3.b.(iii) Paved and unpaved roads;

XIV.G.3.b.(iv) Fires on public lands from all sources; and

XIV.G.3.b.(v) Biogenic sources, including emissions from flora and fauna.

XIV.G.4. Public Hearings

Not later than December 31, 2002, and no less frequently than every five years thereafter, a public hearing before the Commission shall be conducted to approve the public land emission inventories.

XV. Actuals PALs

XV.A. Applicability.

XV.A.1. At the request of an owner or operator, the Division may approve the use of an actuals PAL, including for GHGs on either a mass basis or a CO2e basis, in a Title V permit for any existing major stationary source or any existing GHG-only source that has operated for at least two years if the PAL meets the requirements in Sections XV.A. through XV.L. The term “PAL” shall mean “actuals PAL” throughout Section XV. of this part.

XV.A.2. Any physical change in or change in the method of operation of a major stationary source or a GHG-only source that maintains its total source-wide emissions below the PAL level, meets the requirements in Sections XV.A. through XV.L., and complies with the PAL permit:

XV.A.2.a. Is not a major modification for the PAL pollutant;

XV.A.2.b. Is not subject to the major NSR review procedures in Sections I.B., V., and VI. of this part;

XV.A.2.c. Is not subject to the provisions in Section V.A.5.b. of this part (restrictions on relaxing enforceable emission limitations that the major stationary source used to avoid applicability of the major NSR program); and

XV.A.2.d. Does not make GHGs subject to regulation as defined in Part A, Section I.B.44.

XV.A.3. Except as provided under Section XV.A.2.c. above, a major stationary source or a GHG-only source shall continue to comply with all applicable Federal or State requirements, emission limitations, and work practice requirements that were established prior to the effective date of the PAL.

XV.B. Permit application requirements.

As part of a permit application requesting a PAL, the owner or operator of a major stationary or a GHG-only source source shall submit the following information to the Division for approval (in addition to the information required by Part C of this Regulation):

XV.B.1. A list of all emissions units at the source designated as small (as defined in Section II.A.47. of this part), significant (as defined in Section II.A.46. of this part), and major (as defined in Section II.A.22. of this part) based on their potential to emit, and identifying each as such. In addition, the owner or operator of the source shall indicate which, if any, Federal or State applicable requirements, emission limitations or work practices apply to each unit.

XV.B.2. Calculations of the baseline actual emissions for each emissions unit listed in Section XV.B.1. above (with supporting documentation). Baseline actual emissions are to include emissions associated not only with operation of the unit, but also emissions associated with startup, shutdown and malfunction.

XV.B.3. The calculation procedures that the major stationary source owner or operator proposes to use to convert the monitoring data to monthly emissions and annual emissions based on a twelve-month rolling total for each month as required by Section XV.M.1.

XV.B.4. As part of a permit application requesting a GHG PAL, the owner or operator of a major stationary source or a GHG-only source shall submit a statement by the source owner or operator that clarifies whether the source is an existing major source as defined in Sections II.A.24.a. and II.A.24.b. or a GHG-only source as defined in Section XV.P.1.

XV.C. General requirements for establishing PALs.

XV.C.1. A PAL may be established at a major stationary source or a GHG-only source, provided that, at a minimum, the requirements in Sections XV.C.1.a. through XV.C.1.g. below are met.

XV.C.1.a. The PAL shall impose an annual emission limitation expressed on a mass basis in tons per year, or expressed in tons per year CO2e, that is enforceable as a practical matter, for the entire major stationary source or GHG-only source. For each month during the PAL effective period after the first twelve months of establishing a PAL, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the monthly emissions of the PAL pollutant from each emissions unit under the PAL for the previous twelve consecutive months is less than the PAL (a rolling twelve-month total). For each month during the first eleven months from the PAL effective date, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the preceding monthly emissions of the PAL pollutant for each emissions unit under the PAL is less than the PAL.

XV.C.1.b. The PAL shall be established in a PAL permit section of an operating permit issued pursuant to Part C of this regulation that meets the public participation requirements in Section XV.D.

XV.C.1.c. The PAL permit shall contain all the requirements of Section XV.F.

XV.C.1.d. The PAL shall include fugitive emissions, to the extent quantifiable, from all emissions units that emit or have the potential to emit the PAL pollutant at the major stationary source or GHG-only source.

XV.C.1.e. Each PAL shall regulate emissions of only one pollutant.

XV.C.1.f. Each PAL shall have a PAL effective period of ten years.

XV.C.1.g. The owner or operator of the major stationary source or GHG-only source with a PAL shall comply with the monitoring, recordkeeping, and reporting requirements provided in Sections XV.K. through XV.N. for each emissions unit under the PAL throughout the PAL effective period.

XV.C.2. At no time (during or after the PAL effective period) are emissions reductions of a PAL pollutant, which occur during the PAL effective period, creditable as decreases for purposes of offsets under Section V. unless the level of the PAL is reduced by the amount of such emissions reductions and such reductions would be creditable in the absence of the PAL.

XV.D. Public participation requirement for PALs.

PALs for existing major stationary sources or GHG-only sources shall be established, renewed, or increased in accordance with the significant modification provisions set forth in Section I.A.7.of Part C of this regulation. The Division shall provide the public with notice of the proposed approval of a PAL permit and a thirty-day period for submittal of public comment.

XV.E. Setting the ten-year actuals PAL level.

XV.E.1. Except as provided in Sections XV.E.4. and XV.E.6., the actuals PAL level for a major stationary source or GHG-only source shall be established as the sum of the baseline actual emissions (as defined in Section II.A.4. of this Part D or, for GHGs in Section XV.P.2.) of the PAL pollutant for each emissions unit at the source, plus an amount equal to the applicable significant level for the PAL pollutant under Section II.A.44. of this part, or under the Federal Act, whichever is lower.

XV.E.2. When establishing the actuals PAL level for a PAL pollutant, only one consecutive twenty-four month period may be used to determine the baseline actual emissions for all existing emissions units. However, a different consecutive twenty-four month period may be used for each different PAL pollutant.

XV.E.3. Emissions associated with units that were permanently shut down after this twenty-four month period must be subtracted from the PAL level.

XV.E.4. For newly constructed units (which do not include modifications to existing units) on which actual construction began after the twenty-four month period, in lieu of adding the baseline actual emissions as specified in Section XV.E.1., above, the emissions must be added to the PAL level in an amount equal to the potential to emit of the units.

XV.E.5. The Division shall specify a reduced PAL level(s) (in tons/yr) in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or State regulatory requirement(s) that the Division is aware of prior to issuance of the PAL permit. For instance, if the source owner or operator will be required to reduce emissions from industrial boilers in half from baseline emissions of 60 ppm NOx to a new rule limit of 30 ppm, then the permit shall contain a future effective PAL level that is equal to the current PAL level reduced by half of the original baseline emissions of such unit(s).

XV.E.6. For CO2e based GHG PAL, the actuals PAL level shall be established as the sum of the GHGs baseline actual emissions (as defined in Section XV.P.2.) of GHGs for each emissions unit at the source, plus an amount equal to the amount defined as "significant" on a CO2e basis for the purposes of Part A, Section I.B.44.c. at the time the PAL permit is being issued.

XV.E.6.a. When establishing the actuals PAL level for a CO2e-based PAL, only one consecutive 24-month period must be used to determine the baseline actual emissions units.

XV.E.6.b. Emissions associated with units that were permanently shut down after this 24-month period must be subtracted from the PAL level.

XV.E.6.c. The Division shall specify a reduced PAL level in tons per year CO2e in the PAL permit to become effective on the future compliance date(s) of any applicable Federal or state regulatory requirement(s) that the Division is aware of prior to issuance of the PAL permit.

XV.F. Contents of the PAL permit.

The PAL permit shall contain, at a minimum, the information in Sections XV.F.1. through XV.F.11.

XV.F.1. The PAL pollutant and the applicable source-wide emission limitation in tons per year CO2e.

XV.F.2. The PAL permit effective date and the expiration date of the PAL (PAL effective period).

XV.F.3. Specification in the PAL permit that if a major stationary source or a GHG-only source owner or operator applies to renew a PAL in accordance with Section XV.I. before the end of the PAL effective period, then the PAL shall not expire at the end of the PAL effective period. It shall remain in effect until a revised PAL permit is issued by the Division.

XV.F.4. A requirement that emission calculations for compliance determination purposes include emissions from startups, shutdowns and malfunctions.

XV.F.5. A requirement that, once the PAL expires, the major stationary source or GHG-only source is subject to the requirements of Section XV.H.

XV.F.6. The calculation procedures that the major stationary source or GHG-only source owner or operator shall use to convert the monitoring data to monthly emissions and annual emissions based on a twelve-month rolling total for each month as required by Section XV.M.1.

XV.F.7. A requirement that the major stationary source or GHG-only source owner or operator monitors all emissions units in accordance with the provisions under Section XV.K.

XV.F.8. A requirement to retain the records required under Section XV.M. on site. Such records may be retained in an electronic format.

XV.F.9. A requirement to submit the reports required under Section XV.N. by the required deadlines.

XV.F.10. Any other requirements that the Division deems necessary to implement and enforce the PAL.

XV.F.11. A permit for a GHG PAL issued to a GHG-only source shall also include a statement denoting that GHG emissions at the source will not be subject to regulation under Part A, Section I.B.44. as long as the source complies with the PAL.

XV.G. Reopening of the PAL permit.

XV.G.1. During the PAL effective period, the Division shall reopen the PAL permit to:

XV.G.1.a. Correct typographical/calculation errors made in setting the PAL or reflect a more accurate determination of emissions used to establish the PAL.

XV.G.1.b. Reduce the PAL if the owner or operator of the major stationary source creates creditable emissions reductions for use as offsets under Section V.A.3. of this Part D.

XV.G.1.c. Revise the PAL to reflect an increase in the PAL as provided under Section XV.J.

XV.G.2. The Division has discretion to reopen the PAL permit to:

XV.G.2.a. Reduce the PAL to reflect newly applicable Federal requirements (for example, NSPS) with compliance dates after the PAL effective date.

XV.G.2.b. Reduce the PAL consistent with any other requirement, that is enforceable as a practical matter, and that the Division may impose on the major stationary source or GHG-only source.

XV.G.2.c. Reduce the PAL if the Division determines that a reduction is necessary to avoid causing or contributing to a NAAQS or PSD increment violation, or to an adverse impact on an air quality related value that has been identified for a Federal Class I area by a Federal Land Manager and for which information is available to the general public.

XV.G.3. Except for the permit reopening in Section XV.G.1.a. for the correction of typographical/calculation errors that do not increase the PAL level, all other reopenings shall be carried out in accordance with the public participation requirements of Section XV.D.

XV.H. Expiration of a PAL.

Any PAL that is not renewed in accordance with the procedures in Section XV.I. shall expire at the end of the PAL effective period, and the requirements in Sections XV.H.1. through XV.H.5. shall apply.

XV.H.1. Each emissions unit (or each group of emissions units) that existed under the PAL shall comply with an allowable emission limitation under a revised permit established according to the procedures in Sections XV.H.1. through XV.H.5. of this part.

XV.H.1.a. Within the time frame specified for PAL renewals in Section XV.I.2., the major stationary source or GHG-only source shall submit a proposed allowable emission limitation for each emissions unit (or each group of emissions units, if such a distribution is more appropriate as determined by the Division) by distributing the PAL allowable emissions for the major stationary source or GHG-only source among each of the emissions units that existed under the PAL. If the PAL had not yet been adjusted for an applicable requirement that became effective during the PAL effective period, as required under Section XV.I.5., such distribution shall be made as if the PAL had been adjusted.

XV.H.1.b. The Division shall determine whether and how the PAL allowable emissions will be distributed and issue a revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as the Division determines is appropriate.

XV.H.2. Each emissions unit(s) shall comply with the allowable emission limitation on a twelve-month rolling total basis. The Division may approve the use of monitoring systems (source testing, emission factors, etc.) other than CEMS, CERMS, PEMS or CPMS to demonstrate compliance with the allowable emission limitation.

XV.H.3. Until the Division issues the revised permit incorporating allowable limits for each emissions unit, or each group of emissions units, as required under Section XV.H.1.a., the source shall continue to comply with a source-wide, multi-unit emissions cap equivalent to the level of the PAL emission limitation.

XV.H.4. Any physical change or change in the method of operation at the major stationary source or GHG-only source will be subject to the major NSR requirements if such change meets the definition of major modification in Section II.A.23. of this Part D.

XV.H.5. The major stationary source or GHG-only source owner or operator shall continue to comply with any State or Federal applicable requirements that may have applied either during the PAL effective period or prior to the PAL effective period except for those emission limitations that had been established pursuant to Sections V.A.7.b. and VI.B.4. of this part, but were eliminated by the PAL in accordance with the provisions in Section XV.A.2.c.

XV.I. Renewal of a PAL.

XV.I.1. The Division shall follow the procedures specified in Section XV.D. in approving any request to renew a PAL for a major stationary source or GHG-only source, and shall provide both the proposed PAL level and a written rationale for the proposed PAL level to the public for review and comment. During such public review, any person may propose a PAL level for the source for consideration by the Division.

XV.I.2. Application deadline.

A major stationary source or GHG-only source owner or operator shall submit a timely application to the Division to request renewal of a PAL. A timely application is one that is submitted at least twelve months prior to, but not earlier than eighteen months from, the date of PAL permit expiration. This deadline for application submittal is to ensure that the permit will not expire before the permit is renewed. If the owner or operator of a major stationary source or GHG-only source submits a complete application , including any additional information requested by the Division, to renew the PAL within this time period, then the PAL shall continue to be effective until the revised permit with the renewed PAL is issued.

XV.I.3. Application requirements.

The application to renew a PAL permit shall contain the information required in Sections XV.I.3.a. through XV.I.3.d., below.

XV.I.3.a. The information required in Sections XV.B.1. through XV.B.3. of this part.

XV.I.3.b. A proposed PAL level.

XV.I.3.c. The sum of the potential to emit of all emissions units under the PAL (with supporting documentation).

XV.I.3.d. Any other information the owner or operator wishes the Division to consider in determining the appropriate level for renewing the PAL.

XV.I.4. PAL adjustment.

In determining whether and how to adjust the PAL, the Division shall consider the options outlined in Sections XV.I.4.a. and XV.I.4.b. However, in no case may any such adjustment fail to comply with Section XV.I.4.c.

XV.I.4.a. If the emissions level calculated in accordance with Section XV.E. is equal to or greater than eighty percent of the PAL level, the Division may renew the PAL at the same level without considering the factors set forth in Section XV.I.4.b.; or

XV.I.4.b. The Division may set the PAL at a level that it determines to be more representative of the source's baseline actual emissions, or that it determines to be appropriate considering air quality needs, advances in control technology, anticipated economic growth in the area, desire to reward or encourage the source's voluntary emissions reductions, or other factors as specifically identified by the Division in its preliminary analysis or technical review document.

XV.I.4.c. Notwithstanding Sections XV.I.4.a. and XV.I.4.b. above,

XV.I.4.c.(i) If the potential to emit of the major stationary source or GHG-only source is less than the PAL, the Division shall adjust the PAL to a level no greater than the potential to emit of the source; and

XV.I.4.c.(ii) The Division shall not approve a renewed PAL level higher than the current PAL, unless the major stationary source or GHG-only source has complied with the provisions of Section XV.J. (increasing a PAL).

XV.I.5. If the compliance date for a State or Federal requirement that applies to the PAL source occurs during the PAL effective period, and if the Division has not already adjusted for such requirement, the PAL shall be adjusted at the time of PAL permit renewal or Title V permit renewal, whichever occurs first.

XV.J. Increasing a PAL during the PAL effective period.

XV.J.1. The Division may increase a PAL emission limitation only if the major stationary source or GHG-only source complies with the provisions in Sections XV.J.1.a. through XV.J.1.d. below.

XV.J.1.a. The owner or operator of the major stationary source or GHG-only source shall submit a complete application to request an increase in the PAL limit for a PAL major modification. Such application shall identify the emissions unit(s) contributing to the increase in emissions so as to cause the major stationary or GHG-only source's emissions to equal or exceed its PAL.

XV.J.1.b. As part of this application, the major stationary source or GHG-only source owner or operator shall demonstrate that the sum of the baseline actual emissions of the small emissions units, plus the sum of the baseline actual emissions of the significant and major emissions units assuming application of BACT equivalent controls, plus the sum of the allowable emissions of the new or modified emissions unit(s) exceeds the PAL. The level of control that would result from BACT equivalent controls on each significant or major emissions unit shall be determined by conducting a new BACT analysis at the time the application is submitted, unless the emissions unit is currently required to comply with a BACT or LAER requirement that was established within the preceding ten years. In such a case, the assumed control level for that emissions unit shall be equal to the level of BACT or LAER with which that emissions unit must currently comply.

XV.J.1.c. The owner or operator obtains a major NSR permit for all emissions unit(s) identified in Section XV.J.1.a., regardless of the magnitude of the emissions increase resulting from them (that is, no significant levels apply). These emissions unit(s) shall comply with any emissions requirements resulting from the major NSR process (for example, BACT or LAER), even though they have also become subject to the PAL or continue to be subject to the PAL.

XV.J.1.d. The PAL permit shall require that the increased PAL level shall be effective on the day any emissions unit that is part of the PAL major modification becomes operational and begins to emit the PAL pollutant.

XV.J.2. The Division shall calculate the new PAL as the sum of the allowable emissions for each modified or new emissions unit, plus the sum of the baseline actual emissions of the significant and major emissions units (assuming application of BACT equivalent controls as determined in accordance with Section XV.J.1.b.), plus the sum of the baseline actual emissions of the small emissions units.

XV.J.3. The PAL permit shall be revised to reflect the increased PAL level pursuant to the public notice requirements of Section XV.D. of this part.

XV.K. Monitoring requirements for PALs.

XV.K.1. General Requirements.

XV.K.1.a. Each PAL permit shall contain enforceable requirements for the monitoring system that accurately determines plant-wide emissions of the PAL pollutant in terms of mass per unit of time or CO2e per unit of time. Any monitoring system authorized for use in the PAL permit must be based on sound science and meet generally acceptable scientific procedures for data quality and manipulation. Additionally, the information generated by such system must meet minimum legal requirements for admissibility in a judicial proceeding to enforce the PAL permit.

XV.K.1.b. The PAL monitoring system must employ one or more of the four general monitoring approaches meeting the minimum requirements set forth in Sections XV.K.2.a. through XV.K.2.d. and must be approved by the Division.

XV.K.1.c. Notwithstanding Section XV.K.1.b., you may also employ an alternative monitoring approach that meets the requirements of Section XV.K.1.a. if approved by the Division.

XV.K.1.d. Failure to use a monitoring system that meets the requirements of this Section renders the PAL invalid.

XV.K.2. Minimum Performance Requirements for Approved Monitoring Approaches.

The following are acceptable general monitoring approaches when conducted in accordance with the minimum requirements in Sections XV.K.3. through XV.K.9:

XV.K.2.a. Mass balance calculations for activities using coatings or solvents;

XV.K.2.b. CEMS (as defined in Section I.B.14. of Part A);

XV.K.2.c. CPMS or PEMS (as defined in Sections I.B.16. and I.B.38., respectively, of Part A); and

XV.K.2.d. Published, verifiable emission factors

XV.K.3. Mass Balance Calculations.

An owner or operator using mass balance calculations to monitor PAL pollutant emissions from activities using coating or solvents shall meet the following requirements:

XV.K.3.a. Provide a demonstrated means of validating the published content of the PAL pollutant that is contained in or created by all materials used in or at the emissions unit;

XV.K.3.b. Assume that the emissions unit emits all of the PAL pollutant that is contained in or created by any raw material or fuel used in or at the emissions unit, if it cannot otherwise be accounted for in the process; and

XV.K.3.c. Where the vendor of a material or fuel, which is used in or at the emissions unit, publishes a range of pollutant content from such material, the owner or operator must use the highest value of the range to calculate the PAL pollutant emissions unless the Division determines there is site-specific data or a site-specific monitoring program to support another content within the range.

XV.K.4. CEMS.

An owner or operator using CEMS to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.4.a. CEMS must comply with applicable Performance Specifications found in the Code of Federal Regulations Title 40, Part 60, Appendix B, and Part 75; and

XV.K.4.b. CEMS must sample, analyze and record data at least every fifteen minutes while the emissions unit is operating.

XV.K.5. CPMS or PEMS.

An owner or operator using CPMS or PEMS to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.5.a. The CPMS or the PEMS must be based on current site specific data demonstrating a correlation between the monitored parameter(s) and the PAL pollutant emissions across the range of operation of the emissions unit; and

XV.K.5.b. Each CPMS or PEMS must sample, analyze, and record data at least every fifteen minutes, or at another less frequent interval approved by the Division, while the emissions unit is operating.

XV.K.6. Emission factors.

An owner or operator using emission factors to monitor PAL pollutant emissions shall meet the following requirements:

XV.K.6.a. All emission factors shall be adjusted, if appropriate, to account for the degree of uncertainty or limitations in the factors' development;

XV.K.6.b. The emissions unit shall operate within the designated range of use for the emission factor, if applicable; and

XV.K.6.c. If technically practicable, the owner or operator of a significant emissions unit that relies on an emission factor to calculate PAL pollutant emissions shall conduct validation testing to determine a site-specific emission factor within six months of PAL permit issuance, unless the Division determines that testing is not required.

XV.K.7. A source owner or operator must record and report maximum potential emissions without considering enforceable emission limitations or operational restrictions for an emissions unit during any period of time that there is no monitoring data, unless another method for determining emissions during such periods is specified in the PAL permit.

XV.K.8. Notwithstanding the requirements in Sections XV.K.3. through XV.K.7., where an owner or operator of an emissions unit cannot demonstrate a correlation between the monitored parameter(s) and the PAL pollutant emissions rate at all operating points of the emissions unit, the Division shall, at the time of permit issuance:

XV.K.8.a. Establish default value(s) for determining compliance with the PAL based on the highest potential emissions reasonably estimated at such operating point(s); or

XV.K.8.b. Determine that operation of the emissions unit during operating conditions when there is no correlation between monitored parameter(s) and the PAL pollutant emissions is a violation of the PAL.

XV.L. Re-validation.

All data used to establish the PAL pollutant must be re-validated through performance testing or other scientifically valid means approved by the Division. Such testing must occur at least once every five years after issuance of the PAL.

XV.M. Recordkeeping requirements.

XV.M.1. The PAL permit shall require an owner or operator to retain a copy of all records necessary to determine compliance with any requirement of Section XV. of this part and of the PAL, including a determination of each emissions unit's twelve-month rolling total emissions, for five years from the date of such record.

XV.M.2. The PAL permit shall require an owner or operator to retain a copy of the following records for the duration of the PAL effective period plus five years:

XV.M.2.a. A copy of the PAL permit application and any applications for revisions to the PAL; and

XV.M.2.b. Each annual certification of compliance pursuant to Part C of this regulation, and the data relied on in certifying the compliance.

XV.N. Reporting and notification requirements.

The owner or operator shall submit semi-annual monitoring reports and prompt deviation reports to the Division in accordance with the requirements of the applicable Title V permit and Section V.C.7. of Part C of this regulation. The reports shall meet the requirements in Sections XV.K.11.a. through XV.K.11.c. below.

XV.N.1. Semi-Annual Report.

The semi-annual report shall be submitted to the Division within thirty days of the end of each reporting period. This report shall contain the information required by the Title V permit, Section V.C.7.a. of Part C of this regulation, and Sections XV.N.1.a. through XV.N.1.g., below.

XV.N.1.a. The identification of owner and operator and the permit number.

XV.N.1.b. Total annual emissions (expressed on a mass-basis in tons per year, or expressed in tons per year CO2e) based on a twelve-month rolling total for each month in the reporting period recorded pursuant to Section XV.K.10.a.

XV.N.1.c. All data relied upon, including, but not limited to, any Quality Assurance or Quality Control data, in calculating the monthly and annual PAL pollutant emissions shall be made available upon request by the Division.

XV.N.1.d. A list of any emissions units modified or added to the major stationary source or GHG-only source during the preceding six-month period.

XV.N.1.e. The number, duration, and cause of any deviations or monitoring malfunctions (other than the time associated with zero and span calibration checks), and any corrective action taken.

XV.N.1.f. A notification of a shutdown of any monitoring system, whether the shutdown was permanent or temporary, the reason for the shutdown, the anticipated date that the monitoring system will be fully operational or replaced with another monitoring system, whether the emissions unit(s) monitored by the monitoring system continued to operate, and calculations of emissions from those units as provided by Section XV.K.7. of this part.

XV.N.1.g. A signed statement by the responsible official (as defined in Section I.B.40. of Part A of this regulation) certifying the truth, accuracy, and completeness of the information provided in the report.

XV.N.2. Deviation report.

The major stationary source or GHG-only source owner or operator shall promptly submit reports of any deviations or exceedance of the PAL requirements, including periods where no monitoring is available. A report submitted pursuant to Section V.C.7.b. of Part C of this regulation shall satisfy this reporting requirement. The deviation reports shall be submitted within the time limits prescribed by Section V.C.7.b. of Part C. The reports shall contain the following information:

XV.N.2.a. The identification of owner and operator and the permit number;

XV.N.2.b. The PAL requirement that experienced the deviation or that was exceeded;

XV.N.2.c. Emissions resulting from the deviation or the exceedance; and

XV.N.2.d. A signed statement by the responsible official (as defined in Section I.B.40. of Part A of this regulation) certifying the truth, accuracy, and completeness of the information provided in the report.

XV.N.3. Re-validation results

The owner or operator shall submit to the Division the results of any revalidation test or method within three months after completion of such test or method.

XV.O. If any provision of this Section, or the application of such provision to any person or circumstance, is held invalid, the remainder of this Section, or the application of such provision to persons or circumstances other than those as to which it is held invalid, shall not be affected thereby.

PART E RESERVED FOR ENVIRONMENTAL MANAGEMENT SYSTEMS

Reserved for Environmental Management Systems

PART F REGIONAL HAZE LIMITS - BEST AVAILABLE RETROFIT TECHNOLOGY (BART) AND REASONABLE PROGRESS (RP)

The provisions of Section VI (Regional Haze Determinations) and VII (MRR) of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan. All other Sections of Regulation 3, Part F are State-Only.

The provisions of Part 51, Appendix Y, Title 40, of the Code of Federal Regulations (CFR), promulgated by the U.S. Environmental Protection Agency listed in this Section are hereby incorporated by reference by the Air Quality Control Commission and made a part of the Colorado Air Quality Control Commission Regulations as modified by the following Regulation Number 3, Part F. Materials incorporated by reference are those in existence as July 6, 2005 and do not include later amendments. The material incorporated by reference is available for public inspection during regular business hours at the Office of the Commission, located at 4300 Cherry Creek Drive South, Denver, Colorado 80246. The material incorporated by reference is also available through the United States Government Printing Office, online at www.gpo.gov/fdsys. Parties wishing to inspect these materials should contact the Technical Secretary of the Commission, located at the Office of the Commission.

I. Applicability

The provisions of this regulation apply to existing stationary facilities (BART eligible sources), as defined in Section II.I. of this regulation, as well as to Reasonable Progress (RP) sources.

II. Definitions

II.A. Adverse impact on visibility

Means visibility impairment that interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

II.B. Available Technology

Means that a technology is licensed and available through commercial sales.

II.C. Applicable Technology

Means a commercially available control option that has been or may soon be deployed on the same or a similar source type or a technology that has been used on a pollutant-bearing gas stream that is the same or similar to the gas stream characteristics of the source.

II.D. Average Cost Effectiveness

Means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). For the purposes of calculating average cost effectiveness, baseline annual emissions means a realistic depiction of anticipated annual emissions for the source. The source or the Division may use state or federally enforceable permit limits or estimate the anticipated annual emissions based upon actual emissions from a representative baseline period.

II.E. BART Alternative

Means an alternative measure to the installation, operation, and maintenance of BART that will achieve greater reasonable progress toward national visibility goals than would have resulted from the installation, operation, and maintenance of BART at BART-eligible sources within industry source categories subject to BART requirements.

II.F. BART-eligible source

Means an existing stationary facility as defined in Section II.I.

II.G. Best Available Retrofit Technology (BART)

Means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, 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.

II.H. Deciview

Means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index=$10 \ln_e (b_{ext}/10\ Mm^{-1})$

Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

II.I. Existing stationary facility

Means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any visibility impairing air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

II.I.1. Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input that generate electricity for sale

II.I.1.a. Boiler capacities shall be aggregated to determine the heat input of a plant

II.I.1.b. Includes plants that co-generate steam and electricity and combined cycle turbines

II.I.2. Coal cleaning plants (thermal dryers)

II.I.3. Kraft pulp mills

II.I.4. Portland cement plants

II.I.5. Primary zinc smelters

II.I.6. Iron and steel mill plants

II.I.7. Primary aluminum ore reduction plants

II.I.8. Primary copper smelters

II.I.9. Municipal incinerators capable of charging more than 250 tons of refuse per day

II.I.10. Hydrofluoric, sulfuric, and nitric acid plants

II.I.11. Petroleum refineries

II.I.12. Lime plants

II.I.13. Phosphate rock processing plants

Includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants

II.I.14. Coke oven batteries

II.I.15. Sulfur recovery plants

II.I.16. Carbon black plants (furnace process)

II.I.17. Primary lead smelters

II.I.18. Fuel conversion plants

II.I.19. Sintering plants

II.I.20. Secondary metal production facilities

Includes nonferrous metal facilities included within Standard Industrial Classification code 3341, and secondary ferrous metal facilities in the category “iron and steel mill plants.”

II.I.21. Chemical process plants

Includes those facilities within the 2-digit Standard Industrial Classification 28, including pharmaceutical manufacturing facilities

II.I.22. Fossil-fuel boilers of more than 250 million BTUs per hour heat input

II.I.22.a. Individual boilers greater than 250 million BTU/hr, considering federally enforceable operational limits

II.I.22.b. Includes multi-fuel boilers that burn at least fifty percent fossil fuels

II.I.23. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels

II.I.23.a. 300,000 barrels refers to total facility-wide tank capacity for tanks put in place after August 7, 1962 and in existence on August 7, 1977

II.I.23.b. Includes gasoline and other petroleum-derived liquids.

II.I.24. Taconite ore processing facilities

II.I.25. Glass fiber processing plants

II.I.26. Charcoal production facilities

Includes charcoal briquette manufacturing and activated carbon production

II.J. Incremental Cost Effectiveness

Means the comparison of the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) = [(Total annualized costs of control option) - (Total annualized costs of next control option)] ÷ [(Next Control option annual emissions) - (control option annual emissions)]

II.K. In existence

Means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

II.L. In operation

Means engaged in activity related to the primary design function of the source.

II.M. Integral vista

Means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

II.N. Natural conditions

Means naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

II.O Plant

Means all emissions units at a stationary source.

II.P. Visibility-Impairing Air Pollutant

Includes the following:

II.P.1. Sulfur dioxide (SO2),

II.P.2 Nitrogen oxides (NOx) and

II.P.3. Particulate matter. (PM10 will be used as the indicator for particulate matter. Emissions of PM10 include the components of PM2.5 as a subset.).

III. Sources required to Perform a BART Analysis

Each source that the Division determines is BART-eligible and subject to BART shall complete a BART analysis under Section IV. The Division shall provide written notice to each source determined to be subject to BART. Within twenty calendar days of the mailing of such notice a source may appeal such determination to the Commission by filing a petition for a hearing with the Commission. Any such hearing shall be subject to Section VI. of the Procedural Rules.

III.A. Determining Potential to Emit for a BART Source

For the purposes of determining whether the potential to emit of an existing stationary source is greater than 250 tpy the potential emissions of visibility impairing pollutants from the existing stationary source shall include the emissions from all BART-eligible units which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (*i.e.*, which have the same two-digit code) as described in the Standard Industrial Classification Manual.

III.B. Identification of sources subject to BART

III.B.1. Identification of sources subject to BART shall be performed in accordance with EPA's guidelines for BART determinations under the regional haze rule 40 CFR Part 51, Appendix Y. A BART-eligible source described in Section III.A, above, is subject to BART unless valid air quality dispersion modeling demonstrates that the source will not cause or contribute to visibility impairment in any Class I area.

III.B.1.a. A single source that is responsible for a 1.0 deciview change or more is considered to “cause” visibility impairment in any Class I area.

III.B.1.b. A single source that is responsible for a 0.5 deciview change or more is considered to “contribute” visibility impairment in any Class I area.

III.B.1.c. A single source is exempt from BART if the 98th percentile daily change in visibility, as compared against natural background conditions, is less than 0.5 deciviews at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

III.B.2. The Division will perform air quality dispersion modeling for each source identified as BART-eligible, for all visibility impairing pollutants, for class I areas. The modeling results will be provided to each source.

IV. BART Analysis

IV.A. Presumptive BART for Coal Fired Power Plants

IV.A.1. Plants with a Generating Capacity of 750 MW or Greater

BART-eligible coal fired power plants with a generating capacity of 750 MW or GREATER is presumed to be able to meet the presumptive limits. Regardless of whether or not a unit can meet the presumptive BART limits the source must complete a BART analysis.

IV.A.2. Other Coal Fired Power Plants

The Division shall use the presumptive BART limits of section IV.A.3. as guidelines and may establish a BART level for the unit either above or below the presumptive BART level based on the BART determination.

IV.A.3. Coal-Fired Electric Generating Units

IV.A.3.a. Sulfur Dioxide

Coal-Fired Electric Generating Units: 95 percent reduction or 0.15 lb SO2/mmBTU.

IV.A.3.b. Nitrogen Oxides

Unit Type	Coal Type	NO_X limit (lb/mm BTU)
Dry bottom Wall fired	Bituminous Sub-bituminous Lignite	0.39 0.23 0.29
Tangential Fired	Bituminous Sub-bituminous Lignite	0.28 0.15 0.17
Cell Burners	Bituminous Sub-bituminous	0.40 0.45
Dry-turbo-fired	Bituminous Sub-bituminous	0.32 0.23
Wet-bottom tangential-fired	Bituminous	0.62

IV.B. Each source subject to BART pursuant to Section III shall submit a BART application for a construction permit, which shall include a BART analysis, a proposal for BART at the source and a justification for the BART proposal to the Division by August 1, 2006.

IV.B.1. The BART analysis must include, at a minimum:

IV.B.1.a. A list of the demonstrated and potentially applicable retrofit control options for the units subject to BART. Sources are not required to evaluate control options, which are less effective than the controls currently installed on the BART subject source or unit.

IV.B.1.b. A discussion of the technical feasibility of each of the technologies identified in Section IV.B.1.a. This discussion should include an analysis of whether the proposed technology is available and applicable. If the source determines that a technology is not technically feasible the discussion shall include a factual demonstration that the option is not commercially available or that unusual circumstances preclude its application to the emission unit.

IV.B.1.c. A ranking of all the technically feasible technologies identified in Section IV.B.1.b. The ranking shall take into account various emission performance characteristics of the technologies. The technologies should be ranked from lowest emissions to highest emissions for each pollutant and each emissions unit. The ranking should include a discussion of pollution control equipment in use at the unit, including upgrading existing equipment if technically feasible.

IV.B.1.d. An evaluation of the impacts of the technically feasible BART options. The impact evaluation shall include:

IV.B.1.d.(i). An estimate of the Average Cost Effectiveness of each of the control technologies identified as technically feasible in Section IV.B.1.b. This analysis shall specify the emissions unit being controlled, the design parameters for the emission controls and cost estimates based on those design parameters. The remaining useful life of the source or unit may be taken into account in the cost of the technologies. The remaining useful life is the difference between: (1) The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year); and (2) The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation. The analysis must also include the energy and non-air quality environmental impacts of control options.

IV.B.1.d.(ii). An analysis of the incremental cost effectiveness. Before a control technology can be eliminated the source shall evaluate the incremental cost effectiveness in combination with the total cost effectiveness in order to justify elimination of a control option.

IV.B.1.d.(iii). An evaluation of the visibility impacts for each BART option according to modeling guidance provided by the Division.

IV.B.1.d.(iv). An evaluation of non-air quality impacts. The non-air quality impacts may include water use increases, solid waste disposal, or other adverse environmental impacts.

IV.B.1.d.(v). An evaluation of the energy impacts. The energy impact analysis should look at the energy requirements of the control technology and any energy penalties or benefits associated with the control. The analysis should also consider direct energy consumption and may address concerns over the use of locally scarce fuels or the use of locally or regionally available coal.

IV.B.1.d.(v).(1). The energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment.

IV.B.1.e. An evaluation and justification of the proposed averaging time to evaluate compliance with the proposed emission limitations.

IV.B.1.f. Coal-fired power plants may, in their discretion, include in the BART analysis an evaluation of representative characteristics (including nitrogen content) of coal from sources they reasonably expect to use, to the extent such characteristics tend to result in higher NOx emissions than coals of the same classification from alternative sources. The analysis also may consider whether a particular BART limit might lead the power plant not to use coal from a particular mine due to such coal characteristics, and the extent to which such a decision might result in economic disruption or unemployment at the mine or in nearby communities.

IV.B.1.g. Sources subject to a MACT standard may limit the analysis for those pollutants covered by the MACT to a discussion of new technologies that have become available since the promulgation of the MACT.

IV.B.2. Sources with a potential to emit of less than 40 tons per year of SO2 and NOx and less than 15 tpy of PM10 may exclude those pollutants from the BART determination.

IV.B.3. Selecting a best alternative

The source shall submit a proposal for BART at the source or unit(s), including a justification for selecting the technology proposed. The justification shall be based on the following factors: (1) the technology available; (2) the costs of compliance; (3) the energy and non-air environmental impacts of compliance; (4) any pollution control equipment in use at the source or unit(s); (5) the remaining useful life of the source or unit(s) and; (6) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

IV.B.4. Schedules to comply with BART emissions limits

IV.B.4.a. The technology analysis shall include a schedule to comply with BART or a BART alternative as expeditiously as practicable following EPA approval of the state implementation plan for regional haze that incorporates such BART requirements. The source must comply with BART or BART alternative emissions limits no later than 5 years after approval of the state implementation plan by EPA for regional haze.

IV.B.4.b. A source or unit subject to BART may implement a BART alternative in lieu of BART if such BART alternative is authorized by the Division.

IV.C. BART Alternative

As an alternative to BART for a source or sources, the Division may approve a BART Alternative. If the Division approves source grouping as a BART Alternative, only sources (including BART-eligible and non-BART eligible sources) within the same source category (as defined by SIC or NAICS code) within the same airshed may be grouped together.

IV.C.1. If a Source (s) proposes a BART Alternative, the resultant emissions reduction and visibility impacts must be compared with those that would result from the BART options evaluated for the source(s).

IV.C.2. Source (s) proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation.

IV.D. Emission limits

IV.D.1. Coal-Fired Electric Generating Units

Compliance with the emission limitation is determined on a 30-day rolling average basis for SO2 and NOx, or may be determined by the Division based on the BART analysis submitted by the source. The emission limit shall be included in the facility's permit.

IV.D.2. Other Sources Subject to BART

The Division will establish emission limits with averaging times consistent with established reference methods and include the limit in the facility's permit.

IV.E. A source that has installed BART for regional haze or implemented a Division approved BART alternative for regional haze is exempted from the imposition of further controls pursuant to regional haze BART with respect to those pollutants that are controlled through BART or the BART alternative for Regional Haze and is exempted from the imposition of further controls necessary for reasonable progress during the first reasonable progress planning period. Sources may be subject to additional controls or emission reductions based on reasonable progress requirements in planning periods beyond the first planning period under the regional haze State Implementation Plan.

IV.F. Division Review and Approval

IV.F.1. The Division shall review and approve, disapprove or amend the proposed BART technology or BART alternative, including the emission limit, schedule for compliance for the facility, and averaging period. The Division shall consider additional information both submitted and not submitted by the source that is deemed relevant. The Division shall submit its BART determination to the Commission for review and approval.

IV.F.2. If two or more sources are grouped together pursuant to Section IV.C. the Division shall establish recordkeeping and reporting requirements sufficient to determine that the sources meet the BART alternative emission limits.

IV.F.3. Any source seeking to modify the BART determination for that facility must submit a new BART analysis for review by the Division.

V. Challenge of Division BART Determinations and Enforceable Agreements.

V.A. Persons affected or aggrieved by a BART determination may challenge the decision of the Commission pursuant to Article 4 of Title 24, C.R.S.

VI. Regional Haze Determinations

VI.A. BART Determinations

VI. A.1. The provisions of this Section VI.A of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.A.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

BART Determinations for Colorado Sources

Unit	NOx Emission Limit	SO2 Emission Limit	Particulate Emission Limit
CENC Unit 4	0.37 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0 lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu

CENC Unit 5	0.19 lb/MMBtu (30-day rolling average) or 0.26 lb/MMBtu Combined Average for Units 4 and 5 (30-day rolling average)	1.0lb/MMBtu (30-day rolling average)	0.07 lb/MMBtu
Craig Unit 1	*	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Craig Unit 2	0.08 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

*Refer to VI.D. for requirements

Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Comanche Unit 1	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Comanche Unit 2	0.20 lb/MMBtu (30-day rolling average) 0.15 lb/MMBtu (combined annual average for units 1 & 2)	0.12 lb/MMBtu (individual unit 30-day rolling average) 0.10 lb/MMBtu (combined annual average for units 1 & 2)	0.03 lb/MMBtu
Hayden Unit 1	0.08lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

Hayden Unit 2	0.07 lb/MMBtu (30-day rolling average)	0.13 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 5	0.31 lb/MMBtu (30-day rolling average)	0.26 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 6	0.31lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Martin Drake Unit 7	0.29 lb/MMBtu (30-day rolling average)	0.13lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
CEMEX – Lyons Kiln	255.3 lbs/hr (30-day rolling average) 901.0 tons/year (12-month rolling average)	25.3 lbs/hr (12-month rolling average) 95.0 tons/yr (12-month rolling average)	0.275 lb/ton of dry feed 20% opacity
CEMEX – Lyons Dryer	13.9 tons/yr	36.7 tons/yr	22.8 tons/yr 10% opacity

VI.A.3. Each source listed in the above tables must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than five years after EPA approval of Colorado's state implementation plan for regional haze, which was January 30, 2013 with the exception of Craig Unit 1, or relevant component thereof. Each source listed in the above tables must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.A.4. Except for Craig Unit 1, the sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the BART portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.B. Reasonable Progress Determinations

VI.B.1. The provisions of this Section VI.B of Regulation Number 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.B.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits:

RP Determinations for Colorado Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Rawhide Unit 101	0.145 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
CENC Unit 3	246 tons per year (12-month rolling total)	1.2 lb/MMBtu	0.07 lb/MMBtu
Nixon	0.21 lb/MMBtu (30-day rolling average)	0.11 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu
Clark Units 1 & 2 Shutdown 12/31/2013	Shutdown 12/31/2013	Shutdown 12/31/2013	Shutdown 12/31/2013
Holcim - Florence Kiln	2.73 lbs/ton clinker (30-day rolling average) 2,086.8 tons/year	1.30 lbs/ton clinker (30-day rolling average) 721.4 tons/year	246.3 tons/year

Nucla	0.5 lb/MMBtu (30-day rolling average)*	0.4 lb/MMBtu (30-day rolling average)	0.03 lb/MMBtu

*Refer to VI.E. for requirements

RP Determinations for Colorado Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate Emission Limit**
Craig Unit 3	0.28 lb/MMBtu (30-day rolling average)	0.15 lb/MMBtu (30-day rolling average)	0.013 lb/MMBtu filterable PM 0.012 lb/MMBtu filterable PM10
Cameo Shutdown 12/31/2011	Shutdown 12/31/2011	Shutdown 12/31/2011	Shutdown 12/31/2011

VI.B.3. Each source listed in the above table must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than December 31, 2017, except for Nucla. Each source listed in the above table must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained.

VI.B.4. Except for Nucla, the sources shall submit to the Division a proposed compliance schedule within sixty days after EPA approves the RP portion of the Regional Haze SIP. The Division shall publish these proposed schedules and provide for a thirty-day public comment period following publication. The Division shall publish its final determinations regarding the proposed schedules for compliance within sixty days after the close of the public comment period and will respond to all public comments received.

VI.C. Public Service Company of Colorado (PSCo) BART Alternative Program

VI.C.1. The provisions of this Section VI.C of Regulation Number 3, Part F (with the exception of the SO2 cap of subsection VI.C.4) shall be incorporated into Colorado's Regional Haze State Implementation Plan.

VI.C.2. The sources listed below shall not emit or cause to be emitted nitrogen oxides (NOx), sulfur dioxide (SO2), or particulate in excess of the following limits, after the following compliance dates:

BART Alternative Program Determinations for PSCo Sources			
Emission Unit	**NOx Emission Limit**	**SO2 Emission Limit**	**Particulate 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	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	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	0 Shutdown No later than 12/31/2016
Cherokee Unit 4	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) Natural Gas Operation 12/31/2017	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	0 Shutdown 12/31/2017

Pawnee	0.07 lb/MMBTU (30-day rolling average) by 12/31/2014	0.12 lbs/MMBtu (30-day rolling average) by 12/31/2014	0.03 lbs/MMBtu
Arapahoe Unit 3 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013	0 Shutdown 12/31/2013
Arapahoe Unit 4	600 tpy on (rolling 12 month average) Natural Gas operation12/31/2014	1.28 tpy (rolling 12 month average) Natural Gas operation 12/31/2014	0.03 lbs/MMBtu Natural Gas operation 12/31/2014

* 500 tpy NOx will be reserved from Cherokee Station for netting or offsets

** 300 tpy NOx will be reserved from Arapahoe Station for netting or offsets for additional natural gas generation

VI.C.3. Each source listed in the above table must either shut down or comply with the above limits and averaging times no later than the compliance date set forth in the above table. Each source listed in the above table must maintain any applicable control equipment required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment is properly operated and maintained.

VI.C.4. In addition to the above listed emission limits and compliance dates, between 1/1/2013 and 12/31/2015, Cherokee Units 3 and 4 and Valmont, considered as a whole, shall not emit in excess of 4,200 tons of SO2 per year as determined on a calendar year annual basis. Between 1/1/2016 and 12/31/2017 Cherokee Unit 4 and Valmont considered as a whole, shall not emit in excess of 3,450 tons of SO2 per year as determined on a calendar year annual basis.

VI.D. Craig Unit 1 Additional Compliance Requirements

VI.D.1. Craig Unit 1 will:

VI.D.1.a. Close on or before December 31, 2025; or

VI.D.1.b. Alternatively, cease burning coal no later than August 31, 2021, with the option to convert the unit to natural-gas firing on or before August 31, 2023.

VI.D.1.b.(i) If Craig Unit 1 is converted to natural-gas firing, the Unit will meet a NOx emission limit of no more than 0.07 lb/MMBtu 30-day rolling average applicable after August 31, 2021.

VI.D.2. The owner-operator of Craig Unit 1 will notify the Division in writing on or before February 28, 2021 whether the unit will cease operation or convert to gas.

VI.D.3. Craig Unit 1 will meet a NOx emission limit of 0.28 lb/MMBtu 30-day rolling average going forward from January 1, 2017 (first compliance date January 31, 2017), until closure or converting to natural gas.

VI.D.4. Craig Unit 1 will meet an annual NOx limit of 4,065 tons per year by December 31, 2019 on a calendar year basis beginning in 2020.

VI.E Nucla Compliance Requirements

VI.E.1 Nucla Station will close on or before December 31, 2022.

VI.E.2. Nucla Station will meet an annual NOx limit of 952 tons per year by January 1, 2020 on calendar year basis beginning in 2020.

VII. Monitoring, Recordkeeping, and Reporting for Regional Haze Limits

The provisions of this Section VII of Regulation 3, Part F shall be incorporated into Colorado's Regional Haze State Implementation Plan.

Federal Regulations Adopted by Reference

The following regulations promulgated by the United States Environmental Protection Agency (EPA) were previously adopted by the Colorado Air Quality Control Commission and are thereby already incorporated by reference:

40 CFR Part 60 and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

40 CFR Part 63, Subpart A - National Emission Standards for Hazardous Air Pollutants General Provisions and Subpart LLL - National Emission Standards for Hazardous Air Pollutants From the Portland Cement Manufacturing Industry (As incorporated by reference within Commission Regulation Number 8, Part A, 5 CCR 1001-10).

40 CFR Part 64 (As incorporated by reference within Commission Regulation Number 3, Part C Section XIV., 5 CCR 1001-5)

40 CFR Part 75 including Performance Specifications and Appendices (As incorporated by reference within Commission Regulation Number 6, 5 CCR 1001-8)

VII.A. Definitions

VII.A.1. "BART alternative program unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.C.

VII.A.2. "BART unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.A.

VII.A.3. "Continuous emission monitoring system" or "CEMS" means the equipment required by Regulation Number 3, Part F, Section VII, to sample, analyze, measure, and provide (using an automated data acquisition and handling system (DAHS)), a permanent record of SO2 or NOx emissions, other pollutant emissions, diluents, or stack gas volumetric flow rate.

VII.A.4. "Operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time in a BART unit, BART alternative program unit, or Reasonable Progress unit.

VII.A.5. "Reasonable Progress unit" or "RP unit" means any unit subject to a Regional Haze emission limit contained in the Table in Regulation Number 3, Part F, Section VI.B.

VII.A.6. "Regional Haze emission limit" means any of the emission limits specified in the Tables contained in Regulation Number 3, Part F, Section VI.

VII.B. Monitoring/Compliance Determination: SO2 and NOx Regional Haze Limits

VII.B.1. BART, RP, and BART alternative program units with SO2 and NOx CEMS.

VII.B.1.a. All Boilers, except CENC and Clark boilers.

The owner or operator of a boiler subject to this section shall comply with the Part 75 monitoring and recordkeeping requirements as incorporated by reference into this regulation with the exception of the continuous emission monitoring system (CEMS) data substitution and bias adjustment requirements.

At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3. or VI.C.3., the owner/operator of each BART, RP, or BART alternative program unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR Part 75 not excluded above, to accurately measure from such unit SO2, NOx, diluents, and stack gas volumetric flow rate as such parameters are relevant to the applicable emission limit. The CEMS shall be used to determine compliance with the SO2 and NOx Regional Haze emission limits for each such unit. Such limits are expressed in units of pounds per million Btu. The owner/operator shall calculate emissions in the applicable units.

In determining compliance with the SO2 and NOx Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

VII.B.1.a.(i). Pounds Per Million Btu Regional Haze Limits

For any hour in which fuel is combusted in the BART, RP, or BART alternative program unit, owner/operator shall calculate hourly average SO2 and NOx concentrations in pounds per million Btu at the CEMS in accordance with the requirements of 40 CFR Part 75 except for Part 75 requirements excluded by Section VII. B.1.a. These hourly averages shall then be used to determine compliance in accordance with the particular limit's averaging period, as follows:

VII.B.1.a.(i).(1). Regional Haze limits with a 3-hour averaging period: Emissions shall be calculated on a 3-hour rolling average basis. At the end of each operating hour, the owner/operator shall calculate and record a new 3-hour average emission rate in lb/MMBtu from the arithmetic average of the valid hourly emission rates from the CEMS for the previous three operating hours. (An operating hour is any hour in which fuel is combusted for any time in the unit.)

VII.B.1.a.(i).(2). Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.a.(i).(3). Regional Haze limits with a 90-day averaging period: Before the end of each operating day, the owner/operator shall calculate and record the 90-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 90 operating days.

VII.B.1.a.(i).(4). Regional Haze limits with a 12-month averaging period: Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.a.(i).(5). Regional Haze limits with an annual calendar averaging period: Emissions shall be calculated on a calendar year basis. Within 30 days after the end of each calendar year, the owner/operator shall calculate and record a new emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the preceding year.

VII.B.1.a.(i).(6). Comanche Units 1 and 2 Regional Haze combined annual average limits. The combined annual limitations for NOX and SO2 are on a 365-operating day rolling average. Before the end of each operating day, the owner/operator shall calculate and record an annual rolling average using data from the previous 365 operating days in accordance with the following equation.

Combined emission rate (lb/MMBtu) = [(ER1)(HI1) + (ER2)(HI2)]/(HI1 + HI2)

Where: ER1 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 1.

HI1 = total heat input over the 365 operating day period for Unit 1.

ER2 = average emission rate over the 365 operating day period. This is an average of all valid hours within the 365 operating day period for Unit 2.

HI2 = total heat input over the 365 operating day period for Unit 2.

VII.B.1.b. Portland Cement Kilns and CENC and Clark Boilers: At all times after the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., or VI.B.3., the owner/operator of each BART or RP unit shall maintain, calibrate and operate a CEMS in full compliance with the requirements in 40 CFR Part 60 Section 60.13 and Part 60 Appendices A, B and F to accurately measure SO2, NOX and diluents, if diluent is required. The CEMS shall be used to determine compliance with the SO2 and NOX Regional Haze emission limits for each such unit. For particular units, such limits are expressed in units of pounds per hour, tons per year, pounds per ton clinker or pounds per million Btu. The owner/operator shall calculate emissions in the applicable units. In determining compliance with the SO2 and NOX Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies and malfunctions.

VII.B.1.b.(i). Pounds per Hour and Tons per Year Regional Haze Limits and Pounds per Million Btu Regional Haze Limits.

For any hour in which fuel is combusted in the BART or RP unit, the owner/operator shall calculate hourly NOx and SO2 emissions in the appropriate units (lbs/hr) or (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance in accordance with the particular limits averaging time, as follows:

VII.B.1.b.(i).(1). Pounds per Hour or Pounds per Million Btu Regional Haze Limits on a 30-day rolling average, Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu or lb/hr from all valid hourly emission values from the CEMS for the previous 30 operating days.

VII.B.1.b.i.(2). Pounds per Hour on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the 12-month rolling average emission rate in lb/hr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.i.(3). Tons per year Regional Haze Limits on a 12-month rolling average. Before the end of each month, the owner/operator shall calculate and record the total emissions in tons/yr from all valid hourly emission values from the CEMS for the previous 12 months.

VII.B.1.b.(ii). 30-Day Rolling Average Pounds per Ton Clinker Regional Haze Limits. Hourly clinker production shall be determined in accordance with the requirements in 40 CFR Part 60 Subpart F Section 60.63(b). An operating day includes all valid data obtained in any daily 24-hour period during which the kiln operates and excludes any measurements made during the daily 24-hour period when the kiln was not operating. The 30-operating day rolling emission rate of NOx and SOx shall be calculated and recorded as the total of all hourly emissions data for a cement kiln in the preceding 30 operating days, divided by the total tons of clinker produced in that kiln during the same 30-day operating period in accordance with the equation in 40 CFR Part 60 Subpart F Section 60.64(c).

VII.B.1.b.(iii). CENC Units 4 and 5 NOX Regional Haze limits:

For any hour in which fuel is combusted in CENC Unit 4 or Unit 5, the owner/operator shall calculate hourly NOX emissions in the appropriate units (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance with the Regional Haze limits, as follows:

VII.B.1.b.(iii).(1). Individual unit pound per Million Btu on a 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days, OR

VII.B.1.b.(iii).(2). Combined units 4 and 5 lbs/MMbtu 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record a 30-day rolling average using data from the previous 30 operating days in accordance with the following equation:

Average ER = [(ER4)(HI4)+(ER5)(HI5)] / [(HI4)+(HI5)]

Where:

ER4 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 4.

ER5 = average NOX emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 5.

HI4 = Total heat input over the 30 operating day period for Unit 4.

HI5 = Total heat input over the 30 operating day period for Unit 5.

VII.B.1.b.(iii).(3). The owner or operator shall indicate in the excess emission reports required by Section VII.E of this Part F, which compliance demonstration method has been followed for the reporting period.

VII.B.2. BART and RP Units without NOX and SO2 CEMS.

VII.B.2.a. CENC Unit 3. Compliance with the SO2 limitations shall be determined by sampling and analyzing each shipment of coal for the sulfur and heat content using the appropriate ASTM Methods. In lieu of sampling, vendor receipts may be used provided the sampling and analysis was conducted in accordance with the appropriate ASTM Method. Each sample or vendor receipt must indicate compliance with the SO2 limitation. Compliance with the annual NOx limits shall be monitored by recording fuel consumption and calculating emissions monthly using the appropriate AP-42 emission factor. Monthly emissions shall be calculated by the end of the subsequent month and shall be used in a rolling twelve month total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months data. [*Note: CENC Unit 3 is not subject to annual SO2 limits.]

VII.B.2.b. CEMEX Dryer. Unless performance tests were completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number3, Part F Section VI.A.3, the owner/operator shall conduct a stack test to measure NOX and SO2 emissions in accordance with the appropriate EPA test methods. Frequency of testing thereafter shall be every five years. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition to the stack tests described above, compliance with the annual NOx and SO2 limits shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

VII.C. Monitoring/Compliance Determination: Particulate Regional Haze Limits

VII.C.1. Particulate Regional Haze Limits for all boilers except CENC and Clark boilers

Unless particulate compliance testing was completed within the previous 6 months, within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3., VI.B.3., or VI.C.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5 as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. A test run shall consist of three test runs, with each run at least 120 minutes in duration. Test results shall be converted to the applicable units and compliance will the based on the average of the three test runs.

In addition, to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.C.2. Portland Cement Plant Particulate Regional Haze Limits.

VII.C.2.a. Kilns. Compliance with the particulate matter limitations shall be monitored using a PM CEMS that meets the requirements in 40 CFR Part 63 Subpart LLL. The owner or operator shall calculate emissions in the applicable units. If a PM CEMS is used to monitor compliance with the PM limits, the opacity limits specified in this Part F do not apply.

In the event that the provisions in 40 CFR Part 63 Subpart LLL are revised, stayed or vacated, such that a PM CEMS is not required, compliance with the PM limitations shall be monitored by conducting stack tests in accordance with the requirements of Section VII.C.3. except that the results of the test shall be converted to the appropriate units (lb/ton clinker or lb/ton dry feed) and compliance will be based on the average of three test runs.

In addition, if no PM CEMS is required, as discussed in the above paragraph, the opacity limits specified in this Part F do apply. In order to monitor compliance with the opacity limit, the owner or operator shall install, calibrate, maintain, and continuously operate a COM located at the outlet of the PM control device to continuously monitor opacity. The COM shall be installed, maintained, calibrated, and operated as required by 40 CFR Part 63, Subpart A, and according to PS-1 of 40 CFR Part 60, Appendix B

VII.C.2.b. Dryers. Performance tests shall be conducted in accordance with the requirements in Section VII.C.3. Opacity monitoring shall be conducted in accordance with the requirements in 40 CFR Part 63 Subpart LLL.

VII.C.3. Particulate Regional Haze Limits for the CENC and Clark boilers and the CEMEX dryer. Within 60 days of the compliance deadline specified in Regulation Number 3, Part F, Section VI.A.3. or VI.B.3., the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5, 5B, 5D or 17, as appropriate, as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. Each test shall consist of three test runs, with each run at least 60 minutes in duration.

In addition, to the stack tests described above, compliance with the annual limitations (ton/yr limits) applicable to the Clark boilers and CEMEX dryer shall be monitored by calculating emissions monthly using the emission factors (in lb/hr) determined from the most recent Division-approved stack test and hours of operation for the month. Monthly emissions shall be calculated by the end of the subsequent month and used in a twelve month rolling total to monitor compliance with the annual limitations. Each month a new twelve month total shall be calculated using the previous 12 months' data.

In addition to the stack tests described above, the owner/operator shall monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring plan developed and approved in accordance with 40 CFR Part 64.

VII.D. Recordkeeping

Owner/operator shall maintain the following records for at least five years:

VII.D.1. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable; and any field data sheets from testing.

VII.D.2. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 60, 63, or 75.

VII.D.3. Any other records required by 40 CFR parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75.

VII.E. Reporting requirements

The owner/operator of a BART, RP or BART alternative program unit shall submit semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, Section 60.7(c).

The owner/operator of a BART, RP or BART alternative program unit shall submit reports of any required performance stack tests for particulate matter, to the Division within 60 calendar days after completion of the test.

The owner/operator shall also submit semi-annual reports of any excursions under the approved compliance assurance monitoring plan in accordance with the schedule specified in the source's Title V permit.

PART G STATEMENTS OF BASIS, SPECIFIC STATUTORY AUTHORITY AND PURPOSE

I.A. Adopted June 5, 1980

Rational and Justification for the Repeal and Repromulgation of Regulation Number 3 and Common Provisions Regulation as Related to Regulation Number 3

On December 14, 1978, the Air Quality Control Commission revised Regulation Number 3 (concerning requirements for filing air pollution emission notices, obtaining emission permits, and payment of fees with respect to both) for the primary purpose of bringing Colorado's air pollutant emission permit program into conformity with the requirements of the Federal Clean Air Act Amendments of 1977 to the extent authorized by the then effective State statutory authority: "The Air Pollution Control Act of 1970, "C.R.S. 1973, 25-7-101 et seq. The regulation as revised in 1978 and which became effective January 30, 1972, was submitted to the U.S. Environmental Protection Agency as a revision to the state Implementation Plan ("SIP") pursuant to Subsection 129(c) of the Federal Clean Air Act Amendments of 1977.

Since that submittal, the Colorado General Assembly has repealed and reenacted the State's basic air pollution control statute: Article 7 of Title 25, Colorado Revised Statutes, 1973. The new article, known as the "Colorado Air Quality Control Act" (designated House Bill 1109 in the 1979 legislative session), became effective June 20, 1979, and largely brought the State statute into conformity with the Federal legislation, mandating the Commission to develop a comprehensive air pollution control program meeting the requirements of the Federal Clean Air Act.

Revisions also respond to the requirements set forth in the October 5, 1979 Federal Register notice which conditionally approved portions of the Colorado SIP and set forth certain requirements for securing their unconditional approval. E.G., see Section IV.D.2.a.(iv) of revised Regulation Number 3, which incorporates the requirements of Section l72(b)(II)(A) of the Clean Air Act. 44 Fed. Reg. 57401, 57408 (1979).

The Commission has made an effort to formulate a permit program meeting the requirement of and paralleling of the provisions EPA policies and rules to the extent authorized by House Bill 1109 and to the extent deemed appropriate by the Commission for Colorado's particular circumstances. This has been done in order to meet certain specific requirements expressly set forth in the Federal Clean Air Act, to meet certain specific requirements EPA has determined are required for compliance with the Federal Act, and to avoid subjecting sources of air pollution in Colorado to differing State and Federal requirements. The Commission considered the assurance of reasonable further progress toward attainment of National Ambient Air Quality Standards as the primary underlying criterion in developing permit requirements for sources located in or near nonattainment areas.

Consideration has also been given to the opinion of the United States Court of appeals for the District of Columbia in the case of Alabama Power Company v. Costle F.2d (D.C. Cir., 1979).

APENs

In order to reduce the administrative burden on both the Air Pollution Control Division (“the Division”) and owners and operators of air pollution sources, the filing of revised air pollution emission notices for the purpose of reporting significant changes in emissions will be required only on an annual basis, rather than whenever a significant change in emissions occurs. In making this revision, the Commission relied on the representations of the Division that annual reporting would be sufficient for purposes of keeping the emissions inventory current.

Street Sanding

With the exception of street sanding (and indirect sources), the exemptions provided in the revised regulation from the APEN-filing and emission permit requirements are for minor or insignificant sources of emissions.

Although not finding that particulate emissions resulting from the application and re-entrainment of “sand” applied to snow or ice covered roadways as a traffic safety measure are insignificant, the Commission has exempted sanding from the APEN-filing and permit requirements out of administrative necessity.

Little benefit can be obtained from the filing of APENs in light of the fact that the amount of emissions cannot be predicted with any reasonable accuracy due to varying factors such as weather. APENs would therefore serve little purpose as notices of expected emissions.

It is the judgment of the Commission that protection of persons and property by sanding snow and ice covered roadways is an overriding consideration and that the costs of not taking such safety measures would far outweigh any air quality benefits resulting from requiring permits for sanding. Sanding should not therefore be prohibited -- even without a permit. The only reason for imposing a permit requirement would be to facilitate enforcement of control measures to limit emissions, which the Commission believes may be accomplished without a permit requirement through emission control regulations and provisions in local elements of the State Implementation Plan.

Major Source, Major Modifications, and the "bubble" Concept

The Commission has retained requirements that new "major sources" locating in nonattainment areas and "major modifications" to existing sources in nonattainment areas meet special requirements (Offsets, LAER, etc.) designed to allow for continued development in such areas without interfering with reasonable further progress toward attainment of National Ambient Air Quality Standards. The criteria for determining when a new source or modification to an existing source is "major" however, have been extensively revised.

Prior to the U.S. Court of Appeals Decision in Alabama Power Company v. Costle, EPA had defined "potential to emit" -- a key phrase in the definition of "major emitting facility" -- in terms of uncontrolled emissions. The court however, interpreted the phrase "potential to emit" as used in the definition of "major emitting facility" in Section 169(1) of the Clean Air Act as taking "into account the anticipated functioning of the air pollution control equipment designed into the facility," thereby drastically reducing the number of sources qualifying as major. In response to this decision, on September 5, 1979, EPA proposed amendments to its regulations concerning requirements for SIPs including those pertaining to prevention of significant deterioration of air quality ("PSL)") and new source review in nonattainment areas, as well as EPA's Emission Offset Interpretative Ruling. 44 Fed. Reg. 51924 (1979). The Commission in reviewing Regulation Number 3 and the Common Provisions Regulation has incorporated many of the amendments adopted by EPA in its regulations including classifications of sources as major or minor based on controlled emissions.

The court in Alabama Power Company struck down the ~PA regulation definition of "major modification" which definition required the imposition of the special nonattainment area requirements (Offsets, LAER, etc.) on sources when modifications resulted in an increase in emissions of a criteria pollutants of 100 tons per year or more (for certain~ listed categories of sources; 250 tons or more for sources not listed). The court held that the special nonattainment requirements applied to all modifications of major emitting facilities except those resulting in only "de minimus" increases in emissions. The court stated, however, that it would be permissible to look at the net increase in potential emissions from a major source in determining whether Offsets, LAER, etc., will be required.

In its proposed rules, EPA has adopted the "net increase" or "bubble" approach which generally allows a major source undergoing modification to avoid permit review as a major modification by allowing emission reductions elsewhere at the source to offset any increases resulting from the proposed modification. The Commission has adopted the "bubble" concept and many of EPA's specific regulatory provisions with respect to the concept as applied to modifications.

The court in Alabama Power Company also held that fugitive emissions could be included in determining whether a source is "major" only to the extent, such emissions were expressly determined to be included by rule of the EPA administrator. In response, EPA has proposed a regulatory definition of "Potential to emit" by which fugitive emissions from twenty-seven (27) listed sources would be included in determinations of which new sources and modifications are major. 44 Fed. Reg. 51956, 51958 (1979). In recognition of the fact that such emissions would be included in determinations of whether a source or modification was major if they were emitted through a stack (as opposed to being "fugitive"), recognizing that generally emissions from the twenty-seven (27) listed source categories contribute to hazards to public health and welfare, and to be consistent with the federal scheme, the Commission has also decided to consider fugitive emissions from the twenty-seven source categories in major source/major modification determinations to the extent they are quantifiable. An owner or operator may avoid the inclusion of fugitive emissions of particulate matter by demonstrating that such emissions are of a size and substance, which do not adversely affect public health or welfare.

Banking

C.R.S. 1973, *25-7-304* requires the attainment program to provide that emission reduction offsets exceeding those required for the granting of a permit "may be preserved for sale or use in the future." Section V of Regulation Number 3 establishes an administrative framework and the basic requirements of such a procedure consistent with the "banking" provisions established by EPA in its Emission Offset interpretative Ruling, 44 Fed. Keg. 3274, 3280, 3285 (January 16, 1979) (to be codified as Appendix S to 40 C.R.S. Part 51).

Extended "Debugging" Period.

Pursuant to C.R.S. 1973, 25-7-1 14(4)(j), the Division may grant the owner or operator of a new source up to six months after commencement of operation in which to demonstrate compliance with all terms and conditions of its emission permit. The Commission determined, however, that under certain circumstances it would be appropriate to allow a source employing innovative control technology additional time in which to bring the operation of the source into full compliance. Therefore, pursuant to its authority under C.R.S. 1973, 25-7-109(5), the Commission has provided in paragraph IV. H.6. of Regulation Number 3 for such temporary relief from controls under specified limited circumstances. The provision is intended for very limited application.

PSD

Regulation Number 3 does not address the subject of special permits for major sources locating in attainment areas to insure prevention of significant deterioration of air quality. The Commission decided to wait until EPA's PSD regulations to establish a fully State-operated program. State emission permits are nonetheless still required for sources locating in attainment areas.

Common Provisions Regulation

In connection with the revision of Regulation Number 3, the Commission concurrently made limited, related revisions in its Common Provisions Regulation. Sections I.B. and I.C. of that regulation have been changed to reflect the renumbering of the Sections in the State statute authorizing the Commission to promulgate regulations and to reflect the amended language in the declaration of legislative intent.

Section I.F. of the regulation was amended to add new abbreviations used in revised Regulation Number 3 and Section I.G. (definitions) was amended to delete, revise, and add terms and their definitions to reflect changes in the terminology used in Regulation Number 3.

I.B. Adopted May 13, 1982

Concerning May 13, 1982 Amendment to Section IV.C. (Public Comment) for Small Sources Locating in Nonattainment Areas

The rationale for this proposed revision is based on the underlying purpose of public comment: to obtain public input on proposed sources that the Air Pollution Control Division (APCD) can use in considering whether a permit should be granted.

Under the previous regulation all sources locating in nonattainment areas were subject to the public comment requirement unless the APCD exercised its discretion under Section IV.C.3. (sources of less than 6 month's duration) to exempt them. APCD experience has shown that there are four categories of small sources that frequently locate in nonattainment areas, but which did not stimulate comment from the public. These categories are: (I) service stations; (2) restaurants; (3) land development (houses and commercial); and (4) other small sources (such as concrete batch plants). Basically, all the effort put into preparation of public comment packages for these sources can now be used more efficiently and the associated expense to industry saved.

The limit of 5 Tons Per Year (tpy) of controlled annual emissions is based on calculations that show most of the sources in these four categories emit less than 5 tpy of any one pollutant. Service stations, for example, generally emit I to 2 tpy. In many cases less than I tpy is emitted.

Under the revised regulation, sources less than 5 tpy can still be subject to public comment if the Division determines it appropriate based on criteria set forth in the regulation. The difference is that the APCD would have discretion to decide instead of being required to provide public notice. Controversial sources such as gravel pits, odor sources and landfill operations are subjected to public comment by the APCD regardless of the level of emissions. This practice will continue in effect.

I.C. Adopted March 10, 1983

Prevention of Significant Deterioration Program Regulations in Regulation Number 3

This Statement of oasis and Purpose for the Prevention of Significant Deterioration (PSD) Program Regulations complies with the State Administrative Procedure Act, CR5 1973, 24-4-103(4). The statutory authority for the PSD regulations are in the Air Quality Control Act at CR5 973, 25-7-102, 25-7-105, 25-7-106, 25-7-108, 25-7-109, 25-7-114, 25-7-116, 25-7-201 et seq. The general purpose of these regulations is to prevent the significant deterioration of air quality in those Sections of the state, which has attained the national ambient air quality standards. The parties to this rulemaking include:

> Colorado Association of Commerce and Industry; Rocky Mountain Oil & Gas Association, Inc.; Chevron Shale Oil Company; Union Oil Company of California; Colorado Ute Electric Association, Inc.; The Colorado Mountain Club; COAL; Public Service Company of Colorado; City of Colorado Springs; CF&I Steel; Environmental Defense Fund, Inc.; United States Department of the Interior; and United States Department of Agriculture.

The Air Pollution Control Division acted as staff for and advised the Commission during the proceeding. See CRS 1973, 25-7-lll(2)(g).

The PSD regulations adopted by the Commission are in many respects identical to the U.S. Environmental Protection Agency (EPA) PSD regulations. See 40 CFR 51.24 et seq.; 40 CFR 52.21 et seq. The primary reason for this is that the State Act requires that the S~PSD program be in accordance with the federal Clean Air Act PSD provisions. See CRS 1973, 25-7-203. Thus, federal PSD requirements are generally a minimum for the State PSD Program. For these reasons, to the extent that the federal PSD rules are identical or substantially identical to the state regulations, the Commission incorporates herein the EPA statements of basis and purpose for the federal PSD rules at 43 Fed. Reg. 26380 et seq. (June 19, 1978) and 45 Fed. Reg. 52676 et seq. (August 7, 1980).

The Commission has additional authorities to prevent significant deterioration of air quality. In several important areas the Commission has tailored these regulations to meet the concerns of Colorado citizens. These areas include the requirement for an impact analysis on water to determine acid deposition effects, the authority to make independent determinations on adverse impact to visibility in Class I areas if the federal land manager fails to fulfill his responsibility to do so, the requirement to establish baselines for, and to monitor air quality related values in, Class I areas to determine the effects of emissions on such values, and the application of Class I sulfur dioxide increments to several Class II primitive areas and national monuments.

The proposed PSD regulations included several provisions reflecting the terms of a settlement agreement in the matter of Chemical Manufacturer's Association, et al. V. EPA in which EPA has agreed to propose amendments to its P50 rules. The Commission has rejected the adoption of such provisions for several reasons. They are arguably less stringent than current EPA rules in that they would appear to permit more air pollution. Because they may be less stringent, their adoption appeared likely on the basis of EPA testimony to impede the approval of the state PSD program by EPA at this time. Finally, EPA's schedule for consideration of such provisions is unknown. Subsequent to EPA action on the provisions of the settlement agreement, the Commission will reconsider those provisions.

The PSD regulations will generally not become applicable to major sources or major modifications in Colorado - until EPA has approved them. See CRS 1973, 25-7-210. However, the regulations pertaining to attainment area designations and the enforcement of Class I sulfur dioxide increments in those areas-listed in CRS 1973, 25-7-209 will be applicable upon the effective date of these regulations. These regulations will be effective twenty (20) days from publication in the Colorado Register.

DEFINITION OF “ACTUAL EMISSIONS”

The definition adopted is essentially identical to the EPA definition.

One party proposed that reference should be made to consideration of control efficiency. The Commission did not adopt this proposal because the definition inferentially considers control equipment efficiency and the reference requested would create confusion, when actual test data were available, as to whether a separate “efficiency” factor was to be applied.

Another party, in commenting on the definition of “baseline concentration,” expressed concern that the determination of “actual emissions” could take place, for example, during a low-demand period for a power plant. Such determination would result in an emission rate considerably less than the full-capacity allowable emission rate, resulting in a low baseline concentration. The power plant, operating the next year at full capacity, could consume all or most of the available increment, prohibiting growth in the area. The Commission recognizes that, for certain sources such as power plants (i.e., fossil fuel-fired steam generators), the source must respond to constantly changing demands with significant changes in emissions from year to year. Therefore, for fossil fuel-fired steam generators, “allowable emissions” should generally be considered “representative of normal unit operation” rather than actual emissions in determinations of “actual emissions” for determining baseline concentration and increment consumption, unless it is clearly demonstrated that a lower level of emissions will never be exceeded.

DEFINITION OF “BASELINE AREA” AND “BASELINE DATE”

“Baseline area” is not specifically defined in the State Act but is simply referred to as “an area subject to this article~~ in the definition of baseline concentration. CRS 1973, 25-7-202. The Federal Clean Air Act definition of “baseline concentration,” Section 169(4), is identical to the state's, and EPA has interpreted” an area subject to this article” to mean the attainment and unclassifiable areas designated pursuant to Section 107(d)(l)(D) or (E) of the Federal Clean Air Act. Such an interpretation is also reasonable under the Colorado Air Quality Control Act which states that the Commission shall adopt measures “to prevent significant deterioration of ambient air quality in each region, or portion thereof, of the state identified pursuant to Section 107(d)(1)(D) or (E) of the Federal Act.” The result of EPA's definition is that the entire state is the baseline area for 502, and air quality control regions for particulate matter.

Several parties proposed alternative approaches to the definition of baseline area. These approaches ranged from a modeled 1-$\mu g/m^3$ impact area (based on 7.5 minute quadrangles, the county-township-range-Section system, or a metric grid) to the entire state.

The Commission adopted the EPA definition for the following reasons:

(1) The EPA approach has been in effect for several years and has proven workable. EPA has wel1-developed procedures for performing source impact analyses in large baseline areas, which the state can use. Changing the definition of baseline area would result in use of an approach that has not been proven and that would cause a discontinuity for the regulated industries when the PSD program is delegated to the state.

(2) The use of areas larger than the source impact area means that baseline concentrations will be determined at an earlier date, and increments will be consumed from an earlier date, thus minimizing air quality deterioration. This fulfills the primary purpose of the State Act. See CRS 1973, 25-7-102.

Certain parties were concerned that baseline areas larger than the impact area might unnecessarily inhibit economic growth in the unaffected portion of the baseline area, but should that occur, and there are no specific examples in the record of where that would occur, the Commission could consider subdividing baseline areas to allow for a new baseline date and concentration.

Testimony from Pitkin County and members of the general public indicated concern that with small baseline areas, minor source emission increases would continue to raise the background ambient air concentrations, especially for particulate matter, before a major source would locate in an area to begin the counting of increment consumption. The baseline areas selected by the Commission for particulate matter represent a balance between a recognition that particulate matter emissions are often a more localized problem than are gaseous emissions (hence the use of AQCRs for particulate matter instead of the entire state, as is the approach for S02) and the need to begin counting increment consumption expeditiously (hence, the use of AQCRs for particulate matter rather than the smaller impact area). Only two AQCRs in Colorado have been triggered during the six years PSD has been in effect. Since triggered baseline areas can in the future be subdivided into triggered and untriggered areas, the Commission considers the use of baseline areas the size of AQCRs sufficiently flexible for purposes of reasonable application, economic growth, and prevention of air quality deterioration.

(3) Use of a baseline area equivalent to the 1 ug/m^3 impact area could result in a situation where impacts on a Class I area individually were each less than 1 ug/m^3 , with the result that the Class I area would not be a part of a baseline area. Yet the cumulative impact of these sources could be greater than the 1 ug/m^3 increment for particulate matter 'for Class I areas, so that deterioration of air quality greater than that allowed by the regulation could legally occur.

(4) The use of the entire state as an SO_2 baseline area provides maximum protection for all Class I areas in the state. This is of particular concern to the Commission, since the general flow of air from west to east and the long-range transport of gaseous pollutants can result in effects on nearly all of Colorado's Class I areas by SO_2 sources on the West Slope. The effects and extent of acid deposition, to which SO_2 is a major contributor, was a topic of extensive testimony at the hearings; the definition of the entire state as a baseline area for affords maximum protection of the environment while the problem of acid deposition receives additional study.

DEFINITION OF “BASELINE CONCENTRATION”

Two parties proposed changes to this definition, both suggesting the substitution of “allowable” for “actual” emissions in portions of the definition. The concern regarding power plant actual versus allowable emissions is discussed under “Actual Emissions,” above.

The other concern arises from the possibility of a large difference between actual and allowable emissions in the calculation of increment consumption or in establishing baseline concentrations. This is discussed extensively in the EPA preamble to the August 7, 1980 PSD regulations (Division Exhibit B, pp. 74-76) concerning increment consumption. EPA's rationale is that actual emissions more reasonably represent actual air quality than allowable emissions and that because actual emissions are based on at least two years of operation, future emissions could be reasonably expected to remain at the same level. EPA therefore uses actual emissions to avoid “paper consumption” of increment (or modeled baseline concentrations which would exceed monitored levels) The Commission concurs with the EPA rationale and has adopted the EPA approach of using actual emissions to track increment consumption and determine baseline concentrations.

DEFINITION OF “COMPLETE”

The Environmental Defense Fund (EDF) proposed a list of specific elements of a PSD permit application, for aid in determining whether an application is “complete,” which was generally incorporated in the final rule. The proposed list of items would add some certainty and clarification for the applicant and the Division of the specific items required demonstrating completeness of an application. Regarding items (i) and (iii)-(iv)., opposition to the list by several parties was primarily that it was redundant with other requirements of the rules. York, Nov. 10 Tr. at 18 et seq. and 60 et seq. .Item (ii) was retained because, for many or most applications, such information would be necessary to verify the applicant's modeling.

DEFINITION OF “NET EMISSIONS INCREASE”

Several parties proposed crediting increases or decreases in emissions, which occur up to five years after a modification, becomes operational. The Commission did not adopt this recommendation because EPA specifically prohibits states from crediting decreases, which would occur after the change occurs. 40 CFR 5l.24(b)(3). In addition, it would prove difficult to exact an enforceable agreement for a source to close down or otherwise decrease emissions at some future date.

Several parties proposed in paragraph f(ii) to shift “enforceable” from time of construction to time of operation. This change would not be consistent with the state statutory requirements, which prohibit construction or operation of a non-permitted new source or modification. The suggested change would also needlessly complicate the correlation of permits to enforceable decreases in emissions.

In response to a party comment that 90 days to report a reduction in emissions is too short, the Commission agreed and has allowed such reports to be made within a year of the decrease unless an extension is granted. A longer time would make the reduction difficult to verify.

DEFINITION OF “SECONDARY EMISSIONS”

The final definition incorporates a recent amendment by EPA, 47 Fed. Reg. 27554 (June 25, 1982) and is consistent with CRS 1973, 25-7-202(6.5).

DEFINITION OF “ALLOWABLE EMISSIONS”

In several Sections of EPA's PSD rules, including its definition of “allowable emissions,” EPA grants credit for permit conditions only if they are “federally enforceable. In each of such Sections, the Commission has deleted the qualification of “federally” and has in the Common Provisions Regulation defined “enforceable” so that it is consistent with 'S definition of 'federally enforceable.”

DEFINITION OF “SIGNIFICANT”

Several parties commented that the proposed definition, which defined both “significant” and “significantly” and included a listing of “significant concentrations,” was confusing and unnecessary. The proposed definition also gave the Division the discretion to (1) determine that certain sources were not significant even if the source met the definition, and (2) to determine significance levels for non-listed pollutants. In addition, it limited the definition for sources affecting Class I areas to those sources producing a “significant” impact. There were several Sections in the proposed regulations that used the “significant” definition of ambient concentrations to allow impacts to Class I areas not allowed under EPA rules. EPA and the National Park Service commented that these changes resulted in a less stringent definition. The Commission agreed with these comments. The final definition is essentially identical to EPA's and uses only emission rates to define “significant,” and the use of “significant” to qualify impacts to Class I areas in other Sections of the rules has been deleted.

DEFINITION OF “MODIFICATION”

One party proposed that an existing exception for increases in ~ emissions caused by adding new emission control equipment (e.g., replacing scrubbers with fabric filters) be retained. The Commission acknowledges that this exemption was intended to avoid penalizing a source willing to improve particulate matter collection by converting from scrubbers to baghouses or electrostatic precipitators. Since scrubbers collect gaseous pollutants, but baghouses and precipitators do not, the amount of SO_2 emitted would increase, hence the exemption. Since there are a number of nonattainment areas for particulate matter, but none for SO_2, the Commission will continue to encourage additional control of particulate matter by including this exemption in the definition of “modification.”

It should, however, be noted that this exemption is not included in the definition of “major modification,” so a significant increase in SO2 emissions from a major source will result in P50 applicability. The effect of this is to provide the exemption only for minor sources and minor modifications.

DEFINITION OF “STATIONARY SOURCE”

The proposed definition was revised to include language essentially identical to that of EPA at 40 CFR 51.24(b)(5) and (b)(6). The final rule allows more discretion to define stationary source on a case-by-case basis. The definition clarifies that a source in a nonattainment area may also be “an identifiable piece of process equipment” which makes it consistent with a recent federal case. See Natural Resources Defense Council et al. V. Gorsuch, et al., 685 F.2d 718 (D.C. Cir. 1982).

DEFINITION OF “FUGITIVE DUST”

The State Act exempts “fugitive dust” from regulation under the PSD program, including exemption from determinations of whether a source or modification is major and of increment consumption. C.R.S. 1973, 25-7-202(4), -202(5),-204(l)(b), and -204(2)(c). “Fugitive Dust” is defined as:

> Soil or other airborne particulate matter (excluding particulates produced directly during combustion) resulting from natural forces or from surface use or disturbance, including, but not limited to, all dust from wind erosion of exposed surfaces or storage piles and from agriculture, construction, forestry, unpaved roads, mining, exploration, or similar activities in which earth is either moved, stored, transported, or redistributed; except that fugitive dust shall not include any fraction of such soil or other airborne particulate matter which is of a size or substance to adversely affect public health or welfare.

C.R.S. 1973, 25-7-202(3). Under such definition, fugitive particulates are regulated in the PSD program if they are “of a size or substance to adversely affect public health or welfare.”

The exemption of “fugitive dust” is an issue because EPA counts total suspended particulates (“TSP”) in determining increment consumption, maintenance of primary and secondary NMQS, and source applicability. Therefore, to the extent that the state excludes some sizes of particulate matter in these determinations, its regulations are arguably less stringent than EPA's, although as explained below, because of depositional effects, there is generally an insignificant difference between the counting of TSP and the counting of smaller particulates.

The basis for setting the primary NAAQS is health effects; the basis for setting the secondary NAAQS is welfare effects. These are. also the bases under the State Act for counting fugitive particulates in the PSD program. Because the bases for the State's inclusion of fugitive particulates and for EPA'S promulgation of particulate matter NAAQS are essentially identical, it is appropriate to consider whether the NAAQS should be the standard for determining which particulates are “of a size or substance to adversely affect public health or welfare.” However, EPA's current primary and secondary NAAQS for particulates are based on the “Air Quality Criteria for Particulate Matter” (1969), Div. Ex. R., which has generally been superseded by more recent research and analysis. For that reason, EPA in the CMA v. EPA Settlement Agreement has agreed in the near future to promulgate new primary, and perhaps secondary, NAAQS for particulates which would exclude particulates above a size posing no health or welfare risks.

EPA's staff review, in anticipation of revisions to the particulate matter definition and NAAQS, of the effects of particulate matter on health concludes that the size counted should be less than 10 urn, which includes those particles capable of penetrating the thoracic regions. “Review of the National Ambient Air Quality Standards for Particulate Matter: Assessment of Scientific and Technical Information,” EPA 450/5-82-001 (January 1982).

EPA staff review of welfare impacts indicates that visibility impacts are generally caused by fine particulates of less than 2.5 um. Id. at 122. However, such review recognizes that “the full size range of particles including dustfall can contribute to soiling, become a nuisance and result in increased cost and decreased enjoyment of the environment.” Id. At 140. Further, the EPA “staff recommends consideration of the economic and other effects associated with soiling and nuisance when determining whether a secondary standard for TP or for TSP or other large particle indicator is desirable,” id. at 141, and that “the basis for selecting a particular level for a secondary TP or TSP standard is a matter of judgment.” (emphasis added) Id. at 147. The EPA staff review indicates that EPA will probably propose fine particulate secondary standard but is undecided as to whether to establish a TSP or large particulate secondary standard, and that there is a basis for concluding that welfare impacts are being caused by all sizes of particulates. Additionally, there was public and party testimony on welfare effects from fugitive particulates, some of which can be assumed to be large particles. See Markey, November 10 Tr. at 2 et seq.

One of the apparent concerns of parties and persons opposing the use by the Commission of TSP as a welfare standard is that the increment would be consumed and that no further development could occur. Division Exhibit W, which compares the modeled ambient impacts of TSP using a deposition model with particulates of 10 urn or less using the same model, shows that the larger particles deposit quickly and that the ambient impact is relatively the same at a distance of 1000 meters or greater. The implication of this is that for many sources the modeling of increment consumption would have the same general results whether TSP is counted or whether only particles 10 urn or less are counted (assuming the boundary of the source is 1000 meters or farther from the emissions point). Another implication is that welfare impacts from large particulates can only result within relatively short distances of a source.

Another concern was that the legislative intent was not to count TSP, although there was not clear evidence of legislative intent presented to the Commission. In any event, statutory language leaves the determination to the Commission to decide what particulates are of a size or substance to adversely affect health or welfare.

Given the foregoing considerations and the Commission's general interest in interpreting health and welfare effects of particulates consistent with EPA, but also given the uncertainty surrounding the revision of the particulate NAAQS by EPA, the Commission determines that in applying the definition of “fugitive dust”, the adverse effects on health or welfare of fugitive particulate emissions should be determined individually for each source. Adverse welfare effects of nuisance and soiling will be presumed to occur if the source would have offsite, ambient, particulate impacts unless the permit applicant rebuts such presumption with clear and convincing evidence. The result of this presumption will be that in most cases, large particulates will be counted and there will be no difference between EPA s treatment of particulates and the states. Other health and welfare effects shall generally be evaluated based on EPA's most recent research and analysis, but the permit applicant shall have the burden of proof of demonstrating with clear and convincing evidence, which, if any, sizes or substances of fugitive particulates do not adversely affect, health or welfare. This presumption of health and. welfare effects has been incorporated in the definitions of “major stationary source” and “major modification,” Section XI.A.4 on Exclusions from Increment Consumption, and Section V.D.3.c.(i)(B).

Upon EPA's adoption of revised NAAQS for particulates, the Commission may consider whether to revise this Statement of Basis and Purpose or the definition of “fugitive dust” to reflect such revisions., Should EPA decide not to have a secondary NAAQS incorporating nuisance and soiling (welfare) impacts of large particulates, the Commission will consider whether the welfare effects of large particulates are significant enough to be included, or whether they are relatively insignificant and, thus, should not be counted in the state PSD Program.

DEFINITION OF “MAJOR SOURCE” AND “MAJOR MODIFICATION”

The State Act permits the counting of fugitive emissions in determining whether a source or modification is major “only if the Commission adopts regulations to include fugitive emissions for that source category.” CR5 1973, 25-7-202(4) and (5). The Federal Clean Air Act has a similar requirement at Sec. 302(j). EPA has interpreted the rulemaking requirement to mean simply a consideration in rulemaking of whether fugitive emissions should be counted and a requirement that affected industries be allowed to present policy or factual reasons why fugitive emissions should not be counted. 45 Fed. Reg. 52676 (August 7, 1980). Based on this rationale, EPA's rules currently list 26 categories of sources for which fugitive emissions are counted. A similar interpretation of the State Act is reasonable and has been adopted by the Commission.

One party recommended the addition of uranium mills and coal mines to the list of sources for which fugitive emissions would be counted. However, those sources could not be considered in this proceeding due to inadequate public notice. The Commission intends to consider those sources for listing as soon as practicable.

In the CMA v. EPA Settlement Agreement, the EPA has agreed to remove these 26 listed sources on the basis of industry's argument that the rulemaking requirement means that EPA must identify reasonable methods for measuring and modeling fugitive emissions from a category of sources. Although not agreeing that this is legally required under state or Federal law, the Commission has determined that Division Exhibit F, primarily, makes that demonstration for the ten categories located or expected to locate in Colorado.

It should be noted that measurement methods are not only available, but have been in use for a number of years and have provided test results that are the basis for the fugitive emission factors used by EPA and other control agencies, including the Colorado Air Pollution Control Division.

The following important parallels between stack emission 'factors and fugitive emission factors support the conclusion that fugitive emission factors are relatively as reliable and as reasonably available as stack emission factors:

- Both are based on numerous test data at different locations on different equipment or operations.

- Both are influenced by many variables (e.g., for a stack, flow rate, temperature, process variations; for a fugitive plume, wind speed, moisture content of the material, size distribution of the material).

- Neither is intended to represent actual emissions from a specific source. Actual acceptable test data for a specific or similar source would always be used in lieu of an emission factor.

- Both are intended as air management tools to allow pre-construction assessment of a source impact or as a representative value to average total emissions from a number of similar sources (e.g., all waste incinerators, commercial boilers, or coal storage piles) for such air quality management purposes as determining “reasonable further progress” in nonattainment areas.

Stack and fugitive emission factors are both estimates; such factors are nevertheless widely used by control agencies and applicants alike. However, control agencies generally have no objection to, and would prefer, actual test data in lieu of factors whenever such information is submitted. (See Testimony of McCutchen, October 28, 1982; Egley, November 18, 1982, pp. 72-75 and p. 99; Bertolin, October 29, (am), p.39.)

One party's concern involved whether the emission factors for a facility can be extrapolated to a larger facility, specifically, from a 7000 ton per day oil shale processing facility to a 50,000 ton per day facility. Scale-up is a widely used and accepted approach throughout industry for estimating the feasibility of larger-scale facilities from results at smaller-scale facilities. There are a number of well-known precautions that should always be considered when extrapolating, and a control agency should be at least as cautious in extrapolating emission levels as the applicant is in extrapolating process data. Of course, if different equipment, such as a retort, is to be used at a proposed facility, an emission estimate would be based on mining and handling practices and on different processing equipment emission factors (e.g., refinery emission factors) which are similar to oil shale processing activities where such would be more accurate than extrapolation. Therefore, either through extrapolation or through the application of other more applicable and available emissions factors, relatively accurate emissions levels from all types of oil shale facilities can be calculated.

The same modeling techniques used to model stack emissions can be and are used to model fugitive emissions (Division Appendix F). One modeling parameter, deposition, is more critical in modeling fugitive particulate emissions and should be carefully evaluated. Fugitive particulate emissions usually contain more large particles than do controlled stack emissions. These large particles generally settle out rapidly, so that the impact at a plant boundary is usually much less than would be anticipated by the quantity of emissions at the source. See “Fugitive Dust.” However, acceptable models exist which incorporate deposition and thereby provide a reasonably accurate assessment of fugitive particulate emission impact. Models without deposition can be used for gaseous and fine particulate fugitive emissions. Models have recognized limitations, but they are as accurate for fugitive emissions as for stack emissions.

The following information, which is primarily from Division Exhibit F, concerns the major policy and factual reasons for counting fugitive emissions from each of ten source categories:

Coal Cleaning. A typical plant would process 10,000 tons per year (tpy) of coal and emit approximately 280 tpy of particulate matter, 96% of which would be fugitive emissions. Over 100 tpy of the fugitive emissions are less than 15 microns in diameter and are considered inhalable particulate (IP).

Portland Cement. The typical plant produces 500,000 tpy of cement and emits approximately 370 tpy of particulate matter, 60% of which would be fugitive emissions.

Iron & Steel Mills (Including Coke Ovens). A typical plant would produce several million tons of steel per year and emit approximately 3,600 tpy of particulate matter, 64% of which would be fugitive emissions.

The coke plant would produce over half a million tons of coke per year and emit approximately 700 tpy of particulate matter, 10% of which would be fugitive emissions, and 1,500 tpy of uncontrolled fugitive hydrocarbon emissions.

Petroleum Refineries. A typical plant would process 25,000 barrels of oil per day and emit approximately 1,100 tpy of hydrocarbons, 57% of which would be fugitive emissions.

Lime Plants. A typical plant would produce 300,000 tpy of lime and emit approximately 1,800 tpy of particulate matter, 33% of which would be fugitive emissions.

Fuel Conversion. A typical shale oil plant would produce 50,000 barrels per day of oil and emit 4,800 tpy of particulate matter, 12% (500 tpy) of which would be fugitive emissions, and 8,611 tpy of hydrocarbons, 12% (1,080 tpy) of which would be fugitive emissions.

Sintering Plants. A typical plant would emit approximately 400 tpy of particulate matter, 20% (80 tpy) of which would be fugitive emissions.

Power Plants and Boilers. A typical, but well-controlled, new 500 MW power plant burns 2.1 million tpy of coal and emits approximately 620 tpy of particulate matter, 18% (110 tpy) of which would be fugitive emissions. These fugitive emissions are from coal handling and storage, among the most visible and complaint-related of all fugitive emission sources.

Petroleum Transfer and Storage. A typical plant has a capacity of 476,000 barrels and an annual throughput of 7,123,000 barrels per year and emits 267 tpy of hydrocarbons, 72% of which are fugitive emissions.

In conclusion, the Commission has determined that fugitive emissions from the above sources should be included in determining whether the source or modification is major for the following general reasons:

(a) Fugitive emissions consist of the same pollutants that are emitted through stacks and regulated as stack emissions;

(b) The quantity of fugitive emissions, both in absolute and in relative terms, is significant; and

(c) Although this finding is not legally required, there are methods reasonably available for measuring and modeling fugitive emissions.

PUBLIC COMMENT AND HEARING REQUIREMENTS

The Commission has adopted a regulation designed to offer maximum opportunity for any interested person to learn about, and become involved in, the PSD permit review process. Adopted in the final rule are proposals by one party that (a) the public notice be printed not only in a newspaper of local distribution, but also in one of state-wide distribution to increase the number of potential interested persons reached by the notice, (b) that the public hearing be held at least 60 days after the Federal Land Manager (FLM) has received the notice and permit application, to allow the FLM adequate response time, and (c) that any interested person receive notice of public hearing. In addition, the Commission agrees with the Division proposal to implement and maintain an “interested party” mailing list as described in Division Exhibit M.

The proposed rule contained a requirement that the Division notify the county Commissioners in affected counties when a proposed source would consume 50 percent or more of the remaining PSD increment. Two parties proposed that this requirement be deleted as allowing local land use decision-makers to unduly influence air permit decisions. The intent of this requirement, which has been modified to notify county Commissioners of any PSO permit applications, is not to provide opportunity for counties to comment to the Division on land use; rather, it is to provide information to the counties on proposed sources so that the counties can more adequately assess their priorities and needs. PSD permit approval or denial is to be based solely on the criteria specified in this regulation; land use decisions are, and will remain, the responsibility of local governments.

Regarding the issue of land use decisions, one party commented that Section IV.C.4.e.(iii) of this final rule, which solicits comments from interested parties on alternatives to a proposed PSD source or modification, constitutes the inclusion of land use factors in permit approval determinations. The Commission did not remove this Section because it is required by the State Act, CRS 1973, 25-7-l14(4)(f)(I)(B). Furthermore, the intent of soliciting such alternatives is for the assessment of alternatives with respect to control technology and source impact, not land use.

CONTROL TECHNOLOGY REVIEW

One party proposed that the last sentence in Section IV.D.3.a.(i)(C), which requires the owner or operator of a phased project to demonstrate the adequacy of a previous best available control technology (BACT) determination, be deleted. The Commission did not delete this sentence because (1) an EPA regulation requires such a condition and deletion of this requirement could be considered less stringent, and (2) the requirement is intended to provide for the possibility of a different BACT determination if new technology has developed between the time of permit review and the next phase of a project for which construction has not yet commenced, a time period which can easily exceed five years on large projects.

POST-CONSTRUCTION MONITORING

Five parties proposed that post-construction monitoring requirements be limited to a maximum of one year. The Commission recognizes the concern of lessening the burdens on owners or operators, particularly if the information being gathered is unnecessary. But in many cases, there can be a very real need for monitoring for periods of time greater than a year to obtain reliable data. Accordingly, the final rule requires post-construction ambient monitoring for a period up to one year; additional ambient monitoring can be required only if it is necessary to determine the effect of emissions from the source on air quality. This necessitates an evaluation by the Division regarding the adequacy of the data, and a showing by the Division that additional monitoring is needed, before more than a year of monitoring could be required.

OPERATION OF MONITORING STATIONS

Three parties proposed that the rule be written to allow the latest changes in EPA-approved methods to be used without first having to amend the rule. The Commission agrees with the need to use the most up-to-date approved methods. Accordingly, the final rule specifies that “EPA accepted procedures...as approved by the Division” can be used.

ADDITIONAL IMPACT ANALYSIS

Section IV.D.3.a.(vi) of the final rule requires an owner or operator of a proposed PSD source to provide an analysis of the impairment to water that would occur as a result of emissions associated with the source.

This analysis is not required by the EPA rules. The Inclusion of water in the additional impact analysis reflects a strong concern by the Commission based in the record regarding acid deposition. At this time there is neither the information nor the evidence of damage to justify regulating acid deposition in Colorado. However, the vulnerability of high altitude lakes to acid deposition and the potential increases in acid-forming pollutants such as SO2 and NOx on the Western Slope from sources subject to the PSD program, particularly oil shale processing and large power plants, clearly demonstrate a need for a program to gather data, track and analyze this potential environmental problem. The inclusion of water in the additional impact analysis is intended to gather information on the problem; this analysis is not intended to affect permit approval or denial or control technology review decisions except for determinations of adverse impact to AQRVs in Class I areas. The issues, which have been raised concerning water impact analysis, are discussed in detail below.

a. Legal Authority to Require an Impact Analysis of Acid Deposition

The State Air Quality Control Act requires a PSD permit hearing to consider "air quality impacts of the source... and other appropriate considerations." C.R.S. 1973, 25-7-114(4)(f). Acid deposition can be construed as an indirect but potentially significant air quality impact which should be analyzed, especially in light of one of the stated purposes of the PSD Program "to protect public health and welfare from any actual or potential adverse effect which....may reasonably be anticipated to occur from air pollution or from exposures to pollutants in other media, which pollutants originate as emissions to the ambient air (emphasis added). Section 160(1) of the Clean Air Act. Acid deposition in water is those pollutants in other media originating as emissions to the ambient air.

The Federal Land Manager (FLM) of a Class 1 area is responsible for determining whether a source has an adverse impact on air quality related values which is generally defined as follows:

Any value of an area, which may be affected by a change in air quality. Examples include flora, fauna, soil, water, visibility, culture, and odors. Forest Service Comments, October 7, 1982, p.1.

Acid deposition may adversely affect such values, and thus an analysis of its effects should be required for review by the federal land managers of affected Class I areas.

b. Major Issues

The major issues discussed during the hearings are summarized below:

1. Are Colorado's watersheds sensitive to acid deposition?

John Turk of the USGS is involved in acid deposition research in Colorado and stated that 370 lakes in the Flattops Wilderness area comprising 157 hectares would be sensitive to potentially harmful degrees of acidification if precipitation attains an average pH of 4.0. (Exhibit 3, Nov. 10 Tr. at 153)

Ben Parkhurst maintains that there is talk of Colorado's lakes being sensitive (Oct. 29 Tr. at 146), but states that sensitivity must be considered together with acid inputs. Thus, if acid input to the water system is not sufficiently large the sensitivity question is not important.

Dr. William Lewis stated that Colorado's lakes are sensitive to acid deposition as demonstrated by the measured loss in buffering capacity he found in his studies. (Nov. 18 Tr. at 136-138)

In conclusion it can be inferred that some Colorado lakes are poorly buffered and if sufficient levels of acidity are introduced into the lakes, these poorly buffered "sensitive" lakes could develop acidification problems.

2. Has acidification occurred in any Colorado lakes?

John Turk of the USGS states that there has not been any large degree of acidification taking place in the lakes or streams he has studied in the Flattops. (Nov. 10 Tr. at 172)

Ben Parkhurst also states that there is no evidence to show that any acidification has taken place in Colorado Lakes. (Oct. 29 Tr. at 144 and 150-152)

Dr. William Lewis states that he has noted pH changes in lakes he has studied (Nov. 18 Tr. at 140), but he does not consider that to be the major point in regard to the acidification question. Lewis considers the loss of buffering capacity to be the best indicator of acidification effects on lakes and he has found statistically valid evidence to show that this has occurred. (Nov. 18 Tr. At 13 6-138)

In summary, there is some evidence that pH has dropped slightly in some of the lakes Lewis has studied, however, it does not appear that acidification (drop in pH) has occurred to any large degree in Colorado, however, in the prediction of future impacts, buffering capacity should be examined and this has dropped in the lakes examined by Lewis.

3. Is there a potential for acidification in the future?

Paul Ferraro has done some research on estimating potential acid deposition impacts on Colorado and has determined that under different energy development scenarios, there is a potential for acidification in sensitive lakes. (Nov. 10 Tr. at 158-159)

Parkhurst states that he would not expect acidification to be a problem in the future, unless the acid deposition reaches levels similar to those found in the Northeast. (Oct. 29 Tr. at 154-156) Parkhurst states that Ferraro's study is conservative and a pH drop to 5.8 would not affect fish.

Oppenheimer (EDF Exhibit 32 p. 6) states that if a 1-$\mu g/m^3$ increase in SO_2 (annual average) occurs, acid deposition levels could result which would be damaging to sensitive lakes.

In summary, it can be inferred that there is a potential for energy development activities to cause increased levels of acids to be deposited in the watershed, and effects on pH may occur depending on the buffering capacity of the water. The degree of the effect will depend on the amount of acid, thus the amount of emissions.

4. Are there adequate methods of modeling for acid deposition effects on watersheds?

Paul Ferraro has utilized what he refers to as a "first cut" approach in estimating impacts due to acid deposition. The approach utilizes methods employed by John Turk for determining sensitivity of waters and methods for estimating deposition rates developed by Systems Applications, Inc. (Nov. 10 Tr. at 154-176)

Oppenheimer (EDF Exhibit 32 p. 12-13) states that acid deposition modeling could be conducted using presently available plume models (approved by EPA), which incorporate a plume depletion function to account for deposition. Results from this model could then be compared to deposition standards.

In summary, there appear to be only screening techniques available at this time for estimating the impacts of acid deposition.

5. What level of acidification is dangerous to aquatic ecosystems?

Parkhurst stated that fish could survive in pH's as low as 4.1. (Oct. 29 Tr. 143)

Lewis states that he feels that trout would be adversely impacted if pH dropped significantly below six as an average. He would not expect trout populations to be able to reproduce and grow at a pH below six. (Nov. 18 Tr. at 152,153)

Parkhurst also states that a permanent pH decrease from 6.0 to 5.0 is not a natural variation and that many species would probably be eliminated and species numbers and diversities reduced. (Nov. 10 Tr. at 110)

Parkhurst also testified that there is not any evidence to show that trout are capable of both reproducing and maturing in an environment, which is consistently of a pH of 4.5 or less. (Nov. 10 Tr. at 114)

In conclusion, the record does not clearly identify the point at which damage to fish will occur. However, testimony indicates that below a pH of 4.5, and maybe below 6, fish populations would not be able to reproduce and mature.

Summary

Few definitive conclusions could be drawn from the evidence and testimony. The main point of agreement was that at the present time there has not been any adverse acidification identified in any of Colorado's watersheds. The buffering capacity of lakes appears to be the important factor to consider in determining sensitivity of lakes. Testimony was given that buffering capacity has diminished in certain mountain lakes; however, the cause of this loss has not been identified. No agreement was reached on what level of pH could be tolerated by aquatic ecosystems without causing adverse impact. It could be agreed by all parties that more research must be conducted on acid deposition so that its effects may be better understood and predicted by appropriate models.

Although more information is needed, studies in the Northeastern United States, Canada, and Europe show that acid deposition can be a serious problem (Oct. 29 Tr. at 144-145 and EDF Exhibit 32 p.3). Colorado contains many lakes, which are sensitive, exhibiting low buffering capacities. If energy development occurs on the Western Slope emissions of acid precursors will grow substantially, which will result in increased acid deposition levels. The nature of energy industry in Colorado may result in rapid growth in a short period of time, which will occur before all information on acid deposition is understood. If a large industry develops and new information shows that ambient air standards and increments do not protect the state from acidification problems, a valuable resource may be damaged. For these reasons, the Commission intends to remain vigilant in monitoring this problem, and as analytical capabilities are developed or a problem develops, to re-address this issue for possible regulatory and/or legislative solutions. A subcommittee should be formed, if resources permit, to develop specific guidelines for acid deposition analyses based on recent modeling innovations. In the interim, proposed PSD sources emitting acid or acid precursors will be required to analyze the impact of these emissions on water, utilizing the most up-to-date techniques available.

AREA CLASSIFICATIONS

Several parties objected to the application of Class I sulfur dioxide increments to those areas of Colorado listed in Section VIII.B. which are otherwise Class II areas. The sulfur dioxide Class I increments are required to be enforced in these areas by CRS 1973, 25-7-209. However, pursuant to CRS 1973, Section 25-7-105(8) (Supp. 1982), this Section VIII.S. may not be made a part of the State Implementation Plan (SIP) until these areas are redesignated as Class I under the procedures of Section IX. Until they are redesignated, they may only be enforced under state law and regulations. However, unlike Class I areas, the increment in these areas may be protected now. See CR5 1973, 25-7-210.

The Commission has also determined that the variances from increment consumption allowed by Sections XIV.C., XIV.D., XIV.E., and XIV.F. for Class I areas should also apply to the areas listed in Section VIII.B. It is a reasonable interpretation of CRS 1973, 25-7-209 that if the Class I (sulfur dioxide) increments are to apply to such areas, the variances from the increments should also apply. There is nothing in the State Act to indicate that the areas listed in CRS 1973, 25-7-209, are to be given better air quality protection than Class I areas, which would be the result if the variances did not apply.

REDESIGNATIQN

Several parties objected to what were considered burdensome requirements for redesignating areas to Class I. The adopted rule incorporates only the minimal requirements for redesignation from state and federal law. See CR5 1973, 25-7-208; Sec. 164 of the Federal Clean Air Act; 40 CFR 5l7~(g). However, the Commission did lessen the burden imposed by the proposed rule on those persons requesting a redesignation by allowing such requests to be made without providing all of the information necessary for a redesignation. Who would provide such information is not specified so that it could be any combination of federal, state and private entities.

TECHNICAL MODELING & MONITORING REQUIREMENTS

Several parties proposed the inclusion of future EPA amendments or guidelines in this Section of the regulation, which specifies the air quality model, monitoring and stack height requirements to be used. In response, the Commission adopted the use of “EPA approved” terminology instead of references to specific documents.

Two parties proposed language making EPA or the state responsible for any needed meteorological data. The Commission did not adopt this proposal because it is the applicant's responsibility to demonstrate that it will not cause exceedance of an NAAQS or increment, and meteorological data are nearly always needed to make such determinations. If the Division has such data, it has an obligation to make that data available to the applicant.

INNOVATIVE CONTROL TECHNOLOGY

Several parties proposed that the phrase “greater than or” be deleted from Section XIII.B.2. which specifies that the innovative system achieve emission reductions “greater than or equivalent to” BACT. The EPA regulation uses the phrase “equivalent to” and the parties considered the proposed state rule more stringent. The Commission does not consider the phrase “greater than or equivalent to” (emphasis added) to be more stringent, but instead to be a clarification that an acceptable innovation can result in either equivalent or lesser emissions from the source, but not a higher level of emissions. The preamble to the EPA RSD regulation (Div. Exhibit B, p. 84) clearly specifies that the “...final emission limitation must at least represent the BACT level that would have been initially defined.”

FEDERAL CLASS I AREAS

1. (Section XIV.A.) The State's Independent Determination of Adverse Impact to Visibility

   Section XIV.A. allows the Division or the Board (if applicable) to determine independently if there are an adverse impact to visibility in Class I areas if the federal land manager (FLM) fails to make such determination or such determination is in error. This authority is intended to allow the state to fulfill the FLM's responsibility for protection of visibility if for whatever reason, including political, the FLt4 fails to do so. The Commission recognizes that scenic vistas are an important resource of the State of Colorado. (Colorado Mountain Club Exhibit #1) A subcommittee may be formed to further develop visibility protection for the State of Colorado.

Several parties suggested problems with the state's independent authority' to make such visibility determinations. These consisted of (1) measuring or predicting visibility impairment, (2) quantifying man-induced , as opposed to naturally-occurring, visibility impairment, (3) the subjectiveness of visibility impairment, (4) the lack of correlation of current particulate standards to visibility impairment, and (5) the lack of guidance in the regulation regarding determinations of significant and adverse visibility impacts.

The Commission's response to these concerns is as follows:

(1) Although it is true that there are not federal reference methods for measuring visibility at this time, there are reliable means to accurately measure and predict visibility impairment. Scientific instruments such as the telephotometer, nephelometer, and the fine particulate monitor are recognized as being capable of obtaining objective information on visibility-related parameters. Photographs are also useful in visibility assessment.

Visibility theory involving scattering and absorption of light is well documented and has been incorporated into the models described in the Workbook for Estimating Visibility Impairment (EPA-450/4-8-031). The preface to the Workbook for Estimating Visibility Impairment states: “EPA believes these techniques are at a point where the results should now be employed to assist decision-makers in their assessments.” “These techniques” include the Plu-Vu Model. Div. Ex. J at iii. Thus, these models are appropriate for use at this time.

(2) It is possible to determine if a source of visibility impairment is natural or anthropogenic through various chemical/physical analysis techniques. Improvements in air sampling and analytical techniques have made available, for the first time, detailed information on the chemical and physical nature of the ambient aerosol and of source - emissions. Using these chemical “fingerprints,” particle morphology and the natural variability of airshed sources, recent developments in receptor models have provided new techniques of assigning source contributions.

(3) Perception of visibility impairment is subjective and involves individual variability; however, norms do exist around which an assessment can be made. As noted above, EPA supports the use of its Workbook for Estimating Visibility Impairment as a guide to decision-makers.

(4) Particulate standards do not address visibility-related effects. It is also true that the major anthropogenic visibility impairing pollutant is fine particulate matter. Since the Class I increment for particulate is in terms of total mass concentration, rather than fine particulates, visibility impairment could occur without the increment being violated. Furthermore, the particulate increment is a maximum allowable ground level concentration; consequently it will not protect visibility impaired by plumes at elevations above ground level. These facts form the basis for the Clean Air Act requirement that visibility should be assessed and regulated in a separate analysis. Div. Ex. S.

(5) The primary guidance for determinations of adverse impact to visibility would be the Workbook for Estimating Visibility Impairment, which has very specific guidelines.

2. (Section XIV.B.) Pre-Application and Operational Monitoring of Air Quality Related Values (AQRVs)

Section XIV.B. of the regulation allows the Division to require a source, which will have or is likely to have an impact on any Class 1 area to conduct monitoring to establish the baseline status of and impacts on AQRVs in such Class 1 areas. EPA has not imposed this requirement on applicants, although under EPA rules and the Commission rule, Section IV.D.3.(a)(vi), an Additional Impact Analysis is required which would include an analysis of impacts on AQRVs based on available data, for example, through literature searches. The data gathered from such monitoring are important and necessary in aiding the federal land manager of a Class 1 area in determining whether or not a source will cause an adverse impact on AQRVs and the state in deciding on concurrence with such determination. The data also aid the public information function of the Additional Impacts Analysis. The authority to require submission of such Information includes, but is not limited to, CRS 1973, 25-7-206(2), 25-7-106(5) and (6), and 25-7-114(4).

A. National Park Service and Forest Service Testimony and Positions

The National Park Service ("NPS") and the Forest Service ("FS") supported the rule as a supplement to their current monitoring activities on the basis that the data is necessary to determining adverse impacts on AQRV5, including visibility. See Mitchell, Nov. 18 Tr. at 122 et seq., 161 et seq.; Haddow, 0ct. 28 (p.m.) Tr. At 22 et seq., Nov. 10 Tr. at 68 et. Seq.; Region 2-USDA Forest Service Comments on Proposed PSD Rule; Comments on the May 19, 1982 Proposed Colorado PSD Regulation by National Park Service Air Quality Division.

The NPS stated its willingness to provide a list of sensitive receptors of AQRVs to applicants for monitoring Mitchell, Nov. 18 Tr. at 162.

The Forest Service recognized severe technical difficulties and high costs of monitoring some pollutants and visibility in wilderness areas. Haddow, Oct. 28 (p.m.) Tr. at 22 ~. However, lichen monitoring could be done without great difficulty and special use permits are available for some complex monitoring. Haddow, Nov. 10 (p.m.) Tr. at 112., The FS intends to identify sensitive indicators of AQRVs for each Class 1 area, e.g. 2 or 3 species of lichen and 2 or 3 scenic views, and proposes that the state require the monitoring of such indicators Id. at 82-83.

B. Environmental Defense Fund's (EDF) and Friends of the Earth's (FOE Position

EDF's and FOE's general contentions in support of the proposed monitoring requirements were:

1. the technology for monitoring of AQRV's exist;

2. the Forest Service has identified AQRV's for wilderness areas;

3. although some monitoring is being done, most areas are not being monitored and will not be without the participation of industry;

4. decisions on adverse impacts to AQRV5 cannot be made rationally without reliable scientific evidence; and

5. the state is required to have a visibility monitoring program by EPA rules, 40 CFR 51.305.

"EDF and FOE Final Recommendations; Summaries of the Record and Legal and Policy Analyses," Section IV.

C. Trade Association Parties' Position

The Trade Association Parties' general contentions in opposition to the monitoring requirements were:

1. The Clean Air Act places the responsibility on the federal land manager to determine adverse impacts on AQRVs and, thus, the responsibility to obtain the data necessary to make such determination;

2. There is insufficient information available at this time to develop an AQRV monitoring program in that sensitive receptors for each Class 1 area have not been identified, there is no monitoring reference method available and no validated models to project impacts of particular emissions levels;

3. In some Class 1 areas monitoring is either physically impossible or inordinately expensive; and

4. The Division's discretion in specifying sensitive receptors is too vague and broad.

Trade Association Parties' Closing Argument at 31-34.

D. Commission Analysis and Decision

The above-cited testimony and evidence and other portions of the record support the conclusion that monitoring of AQRVs or sensitive receptors of AQRV5 would be helpful, and in many cases necessary, to determine whether adverse impacts on AQRVs would occur. It is also evident that baseline data are not available and may never be developed by federal land managers for some AQRVs and sensitive receptors and for some Class 1 areas. Thus, the primary issue is where to place the responsibility for obtaining background data on AQRVs - the federal land manager, the state and/or the applicant.

As the Forest Service suggested, it is traditional permitting practice to require a permit applicant to obtain the data upon which the agency decides. Haddow, Nov. 10.(p.m.) Tr. at 89. This practice is consistent with the economic philosophy that companies should internalize their environmental costs. Furthermore, the Clean Air Act does not change such practice; it places the “affirmative responsibility” on federal land managers to protect AQRVs and to consider whether there will be an adverse impact on AQRVs but does not expressly state whose responsibility it is to provide necessary data upon which to exercise their responsibility.

The Commission has determined that there is available research and test methods, for obtaining background data and impact data on many AQRVs that will be critical in making adverse impact determinations, even though there are not generally adopted reference methods or modeling techniques. For example, to perform a reasonably accurate visibility impairment analysis, background data is needed. Div. Ex. J. Although there are no generally accepted reference methods for estimating visibility impacts, methods for estimating visibility Impairment have been developed and are relatively sophisticated. See Div. Ex. J.; Geier, Oct. 28 (a.m.) Tr. at 62-71. The rule recognizes this potential limitation on monitoring AQRVs by only allowing monitoring if “monitoring methods are reasonably available and research and development of monitoring methods are unnecessary.”

In response to the objection that the Division's discretion in selecting AQRVs for monitoring is too vague and broad, the rule provides:

1. A definition of AQRVs (in the Common Provisions Regulation);

2. That the Division will consult with the federal land manager in the selection of AQRVs; and

3. That the AQRVs selected must be important to the affected Class I area and there must be cause to believe that monitoring of the AQRVs will provide a basis for evaluating effects to the AQRVs.

In response to the objection that the monitoring of AQRVs may not be economically reasonable, the rule provides that:

1. no duplication of monitoring may be required;

2. not more than three AQRVs may be required to be monitored;

3. monitoring methods must be reasonably available;

4. monitoring may only be required if the source is a major contributor to the expected effects on the AQRV; and

5. it is economically reasonable as compared to other monitoring and analysis expenses required of a PSD permit applicant.

SULFUR DIOXIDE AMBIENT AIR STANDARDS FOR THE STATE OF COLORADO

The proposed rule would have revised the Colorado ambient air quality standard for sulfur dioxide to be consistent with the federal standard. Because the Colorado standard is not enforceable in the permitting process, see CRS 1973, 25-7-114(4)(g), the Commission ordered on November 10, 1982 That revisions of the state ambient air quality standard for SO2 be removed as a subject of this rulemaking.

The Commission agreed to reconsider the state standard if and when it becomes enforceable.

PUBLIC ACCESS TO CONFIDENTIAL INFORMATION

One party raised the issue of whether Section VII of Regulation NO. 3 improperly restricts access to confidential information, which would be available under the Federal Clean Air Act. Section VII may not be considered for amendment in this rulemaking due to lack of public notice.

I.D. Adopted March 10, 1983

Revisions to Regulation Number 3 (Excluding PSD Program Revisions)

This Rationale complies with the requirement of the Administrative Procedures Act, C.R.S. 1973, 24-4-103(4), to prepare a Statement of Basis and Purpose for adopted regulations. The statutory authority for these amendments are at C.R.S. 1973, 25-7-102, 25-7-105, 25-7-106, 25-7-109, and 25-7-114. These revisions to Regulation Number 3, adopted February 10, 1982, are intended to clarify and further define certain portions of the regulation adopted June 5, 1980. The 1980 revisions were extensive changes designed to reflect the new provisions of the 1979 Colorado Air Quality Control act (HB 1109); these changes reflect policy changes and clarifications to the existing rule. The basis and purpose of each revision is discussed below.

I. MINOR SIGNIFICANCE DETERMINATIONS FOR PERMIT AND APEN EXEMPTIONS

Section II.C.1.j. of Regulation Number 3 allows the Division to exempt sources from Air Pollutant Emission Notice (APEN) filing and permit requirements if the criteria in this Section are met. Since mid-1980, the Division has granted approximately 25 exemptions under Section II.C.1.j.. Of the approximately 700 permits issued by the Division annually, 55 percent are to sources with uncontrolled emissions of less than 5 tons per year (tpy); 35 percent of the total permits are to sources with uncontrolled emissions below 1 tpy. Thus, except for the specific source categories exempted by the Commission under Section II.C.1. of Regulation Number 3, nearly every air pollution source, no matter how minimal its emissions, has had to file an APEN and obtain a permit. The record supports a finding that most sources of less than one ton per year emissions and some of less than five tons per year emissions will have a negligible impact on air quality and should be exempted from the APEN and/or permit requirement.

On that basis and for the following more specific reasons and purposes the adopted revisions to Section II regarding APEN filing exemptions and to Section III regarding permit exemptions are intended to:

(a) require APEN filing and permits for any source of hazardous, toxic or odorous air pollutants, however small the source. The Commission considers the gathering of information on, and the regulation of, such pollutants to be of high priority.

(b) exempt sources of all other pollutants from both APEN filing and permit requirements when uncontrolled emissions from the source would be less than one tpy. Such sources, according to a Division study, account for less than 1 percent of total uncontrolled emissions and would be anticipated to have 24-hour impacts, at a maximum, of less than 2 micrograms per cubic meter (uglm3) assuming 24 hours per day operation, a negligible impact given the localized area of the Impact.

(c) require sources of other than hazardous, toxic or odorous pollutants whose uncontrolled emissions are less than five tpy but greater than or equal to one tpy to file an APEN. These sources would be exempt train permit requirements (with one exception) unless the Division demonstrated using specific guidelines that the source was significant. The Division would have to notify the source that a permit was required; otherwise, the source would be exempt from permit requirements. The APEN should provide all needed information to preclude unnecessary delay in making such determinations.

Emissions from these 1 to 5 tpy sources, according to a Division study, account for no more than two percent of total emissions, yet comprise 20 percent of the total sources obtaining permits. Such sources could, however, produce 24-hour ambient air impacts as high as 10 ug/m ^{3} , which could be significant in certain cases, especially if such source would cause a violation of a NAAQS or increment or by itself or in combination with similar sources cause a health or welfare problem or interfere with reasonable further progress towards attainment.

Volatile Organic Compound (VOC) sources are treated differently. The record demonstrates that 45 percent of the total of all uncontrolled stationary source VOC emissions are emitted by sources ranging from 1 to 5 tpy in size. Most of these sources locate in urban areas such as Denver, which is nonattainment for ozone. Since VOC emissions are an ozone precursor, such sources should be subject to permitting requirements to ensure compliance with applicable VOC emission limitations.

Therefore, VOC sources equal to or exceeding 1 tpy (uncontrolled) locating in nonattainment areas must both file an APEN and obtain a permit. VOC sources ranging from 1 tpy to 5 tpy locating in attainment areas where there is less concern for ozone will be treated like other sources and will be at least required to file an APEN.

(d) require sources of other pollutants whose uncontrolled emissions equal or exceed five tpy to file APENs and obtain permits unless specifically exempted from such requirements. These sources constitute approximately 98 percent of total uncontrolled emissions, and the Commission feels that such sources should be required to submit APENs and obtain permits unless specifically exempted as a class or as an individual source.

II. "SIGNIFICANT CHANGE" IN EMISSIONS REQUIRING THE FILING OF A REVISED APEN

The purpose of this revision to Sections II.B. and II.C. is to clarify and revise the requirements for reporting changes in emissions (either increases or decreases) to the Division.

The record shows that an acceptable emissions inventory, usually referred to as the EIS (for Emissions Inventory Subsystem), is essential for effective air quality management and that the revised APENs provide an effective system for obtaining EIS data. Revised APENs reporting significant changes in emissions are required by statute, C.R.S. 1973, 25-7-114(1), and the $40 fee for a revised APEN defrays the cost of processing the information (see "Fiscal Impact"). The levels set for reporting emissions changes are significant and will allow the effective tracking of air quality changes and use for air quality management.

It is obvious, however, that there has been confusion concerning these requirements in the past. The following statements should clarify the confusion:

A. Revised APENs reporting significant changes in emissions are to reflect actual emissions for the preceding year, not projected or maximum emissions. Actual emissions are the emissions actually emitted by a source into the atmosphere on an annual basis, determined as accurately as is feasible using production or processing or combustion rates, and emission factors, or test results, or other accepted methods for estimating emission rates. These actual emission rates are the "actual emissions used in the PSD definition of "actual emissions", except that for PSD, an "actual emission" rate can be ignored if it is not representative of "normal" operation. The APEN forms should clearly distinguish an APEN filed with a permit application (which estimates maximum anticipated production or emission levels) and a revised APEN (which reports actual emissions when a significant change in emissions has occurred). Changes in emission rates reported on a revised APEN shall not be used to modify allowable emissions rates or permit conditions for the source unless the revised APEN is filed specifically for the purpose of modifying an existing permit or obtaining a new permit, in which case the APEN must (1) be accompanied by an application, written request, or letter of explanation from the applicant and (2) reflect maximum anticipated production or emission level changes resulting from the requested action, not "actual" emissions from the existing source.

B. Each affected source should discuss with the Division the most efficient format in which significant changes can be reported and the degree to which similar emission sources can be combined for reporting purposes. It is the intent of the Commission that the Division carry out this flexible approach to the maximum extent possible in order to reduce the burden on regulated sources.

The Commission has made these revisions economically reasonable by easing the burden of reporting by allowing the use of any mutually convenient reporting format in lieu of a "standard" form and by allowing individual, but similar, emission point sources to be grouped. It should be stressed that this grouping of emission point sources for purposes of reporting significant changes to the Division does not constitute, nor does it set any precedent for, any netting or bubbling or other emission trading approach; emission trading can be conducted only through specific regulations pertaining to this activity. These APEN groupings also do not relieve the source of any obligation to meet any emission control limitations for specific point sources within the group.

In general, the reporting requirements for significant changes have been given greater latitude than existed before, partly in response to concerns that, at certain reporting levels, the accuracy requested exceeds the accuracy of the available data, and in response to EPA requirements for reporting EIS changes which are in the range of 5 tpy for small sources or 5 percent for 100 tpy or larger sources. The adopted "significant change" definition reflects a deliberate selection based on the public hearing testimony and the exhibits and testimony submitted by the Division and interested parties during these deliberations. For odorous, hazardous or toxic pollutants, any emissions change must be reported (again, on an annual basis). With changes of only 0.0004 tpy (for beryllium), for example, considered "significant" by EPA, close scrutiny of all hazardous, toxic and odorous pollutants is needed.

III. REVISED APEN FEES

An issue raised is whether the Commission has statutory authority to require a $40.00 filing fee with a revised APEN. The statutory authority for a fee states, "Any person required by the Commission to file an air pollutant emission notice shall pay a nonrefundable fee of forty dollars...." C.R.S. 1973, 25-7-114(5)(a). The statutory authority for requiring the filing of APENs and revised APENs refers to: "air pollutant emission notice" and "revised emission notice", C.R.S. 1973, 25-7-114, the latter reference being to "revised (air pollutant) emission notice". Section 25-7-114(5)(a) does not limit the $40.00 fee to initial APENs filed for a source but refers simply to "air pollutant emission notice" which may be interpreted to include both initial and revised APENs. Testimony by the Division estimated the administrative costs of processing a revised APEN at over $40.00. For these reasons, the Commission finds that it has authority and should charge a $40.00 filing fee for revised APENs.

IV. NON-PERMITTED SOURCE APPLICABILITY

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 a permit requirement.

V. STATIONARY INTERNAL COMBUSTION ENGINE EXEMPTION

The purpose of this revision is to decrease the extent of the exemption for stationary internal combustion engines. Prior to this revision, stationary internal combustion engines less than 1000 HP in attainment areas and less than 250 HP in nonattainment areas were exempt from permit requirements. The record shows that these sources not only constitute large individual sources (a 1000 HP engine can emit 96 tpy of NOx), but also can be situated close to each other (one compressor station in Colorado consists of 15 925 HP stationary internal combustion engines which can emit a total of 1340 tpy NOx). Small stationary internal combustion engines in terms of emissions (less than 5 tpy) or size (less than 50 HP) are excluded from permit requirements. In addition, the Commission has retained the exclusion from permit requirements for emergency power generators and added exclusion for stationary internal combustion engines powering portable oil drilling rigs.

The exclusion for stationary internal combustion engines on portable oil drilling rigs is based on testimony and on information developed by the Division which indicates that these sources move frequently (average 10 days per well site), generally are located at remote sites, and emit only 1.3 tons N02 per well drilled. The Division indicated that the total estimated NOx emissions from portable oil drilling rigs in Colorado could be as high as 2200 tpy and that this could increase the total NO emissions inventory in specific active drilling areas by as much as 50 percent. To determine if an air quality problem exists for these sources, testimony from the Colorado Petroleum Association (CPA) indicates a willingness to provide the information needed by the Division to assess emissions by modifying existing data-gathering reports.

One party requested a delayed effective date for this revision so that compressor stations planned for construction during the summer of 1983 would not be held up by an unanticipated requirement that permits be obtained. Such a request is reasonable, and the delayed effective date of October 1; 1983, has been adopted.

VI. PUBLIC COMMENT FOR DEMOLITION AND NONATTAINMENT AREA PERMITS

Since the record shows that sources for which public comment has been received are in every case either large (greater than 25 tpy) or controversial (e.g., odorous emissions), the public comment requirement for sources in nonattainment areas is being raised from 5 tpy to 25 tpy, which makes it the same as for sources locating in attainment areas. Demolition projects have been exempted from public comment requirements because they often need to be completed, by contract agreement, in a short period of time, and the need for public comment has on occasion been an unnecessary time delay. Very few public responses have been received for small demolition projects. The Division retains the authority to require public comment for demolition projects if considered warranted for reasons of asbestos emissions or other significant concerns.

VII. CONSTRUCTION SCHEDULE DEADLINES

Under previous rules, owners and operators applying for new permits have not been held to any time limits for commencing construction or operation once the permit to operate has been obtained. Sources must be evaluated (C.R.S. 1973, 25-7-114(4)(b)) to determine whether operation of the source will comply with all applicable regulations, an evaluation that can be made with an acceptable degree of certainty provided that the source actually does construct and operate within a reasonable period of time following receipt of the permit. However, a source which delays construction for a number of years may finally initiate operation at a time when ambient air concentrations or other factors used in evaluating compliance have changed; in addition, delaying construction and operation results in the reserving of emissions that could have been used by other applicants.

This provision implements an 18-month construction deadline, imposed by the Division, to all sources, major and minor, statewide. Owners and operators will be prevented from applying for a permit without intending to construct in the near future, a form of “reserving” emissions or increments which makes compliance analysis difficult and could inhibit real economic growth in the state. Under these provisions, the Division will grant necessary extensions to permits that are issued, so a source with good reason for delaying a project would not be penalized by loss of a permit.

VIII. NON-REACTIVE VOLATILE ORGANIC COMPOUNDS (NRVOCs)

The EPA maintains a list of NRVOCs, which are considered either totally non-reactive or insignificantly reactive in the formation of ozone. NRVOCs can therefore be used to replace reactive VOCs as offsets.

A list of additions to this list appeared in the July 22, 1980 Federal Register. The revision to Regulation Number 3 updates the list of NRVOC5, which are non-hazardous, to conform to EPA's revised list of NRVOC. In addition to this, the revision extends the concept of NRVOC Statewide (instead of nonattainment areas only), and clarifies that NRVOCs will be reviewed separately during initial approval analysis of a new source. Previously, NRVOCs pertained to nonattainment areas only and were used only based on emission-offset credit. The revision clarifies that NRVOCs can be substituted for VOCs for banking and other emission reduction credits.

IX. CLEAN PORTION OF NON-ATTAINMENT AREA

No revisions to Sections IV.D.2.c. or IV.D.3.b. were made because the State Act provides for the exemption of Section IV.D.2.c. at C.R.S. 1973, 25-7-303.

I.E. Adopted March 19, 1987

Revisions to Regulation Number 3 Section II.C.1.

The specific statutory authority under which the Commission shall hold and conduct this hearing is prescribed by 24-4-103, 25-7-105, -106, -110, and the hearing will be conducted in accord with provisions of 24-4-103 and 25-7-110, C.R.S. 1982 and the Commission's Procedural Rules.

The revision to Regulation Number 3 Section II. C. 1. is an addition to the list of sources, which are exempt from filing Air Pollution Emission notices. Addition of Part l. (small L) to this regulation exempts petroleum industry flares, approved by the Oil and Gas Conservation Commission, from having to file an Air Pollution Emission Notice (APEN) if emissions of any pollutant do not exceed five (5) tons per year. This exemption only applies to flares, which do not combust gas containing hydrogen sulfide (H2S) except in trace amounts, since H2S is classified as a hazardous air pollutant. Previously APENS were required for these flares when emissions exceeded 1 ton per year.

The Air Quality Control Commission adopts this change for the following reasons:

1) Records of the amount of gas flared will be kept by the Oil and Gas Commission and made available to the Division;

2) The flaring is a temporary activity in most cases;

3) Statewide emissions from flares are relatively low, with nitrogen oxides (NO_X) being the main pollutant emitted (emissions of NO_x from flares is approximately 200 tons per year statewide, while total stationary source NO_x emissions are over 160,000 tons per year in Colorado);

4) Ambient impacts from flares are low;

5) No hazardous pollutants will be emitted;

6) Larger flares will still have to be permitted by the Division.

I.F. Adopted November 19, 1987

Addition of Section XV to Air Quality Control Commission Regulation Number 3 Regulation Requiring an Air Contaminant Emission Notice, Emission Permit Fees

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirement of the Administrative Procedures Act, C.R.S. 1973, Section 24-4-103 (4) for adopted or modified regulations.

This revision to Regulation Number 3, adopted November 19, 1987, is intended to bring the Colorado regulations into conformance with current U.S. EPA regulations. U.S. EPA's regulations were revised in response to a court order which required each state to develop a program to assess and remedy visibility impairment in Class I areas from new and existing sources, as established in Section 169A of the Clean Air Act.

Section XV. is added to Regulation Number 3 as part of the State's plan to meet the national goal of preventing future, and remedying existing, visibility impairment in Class I areas. Section XV. Together with this Statement of Basis, Specific Statutory Authority and Purpose and the monitoring and long-term strategies represents Colorado's State Implementation Plan (SIP).

This Regulation addresses a type of visibility impairment, which can be traced to a single source or small group of sources known as reasonably attributable impairment. The U.S. EPA deferred action on the regulation of regional haze and urban plumes due to scientific and technical limitations in visibility monitoring techniques and modeling methods.

The FLMs were consulted and their suggestions considered in developing the plan. In addition, the Commission provided public notice 60 days prior to the public hearing stating that interested parties would be given the opportunity to provide testimony concerning the Regulation and its requirements at the hearing. Wyoming, Utah and New Mexico were also sent notice of the hearing.

Section XV.D. allows the FLMs to certify visibility impairment to the Division Director at any time. At such time of certification the Division must assess the impairment, identify the contributing source(s), and conduct a Best Available Retrofit Technology (BART) analysis for any contributing sources located in Colorado. The FLMs have not certified reasonably attributable impairment as of this adoption date. Section D. also requires BART and is incorporated for future use, if necessary.

Any source subject to the BART requirements of this Section may apply to the U.S. EPA Administrator for an exemption. The application to the U.S. EPA must include a written concurrence from the Division and Commission; therefore, the source must first apply to the Division, as set forth in Section D.2.c. An exemption granted by the Division and approved by the Commission will constitute the written concurrence required by U.S. EPA.

The New Source Review requirement of Section XV.E. is included for purpose of reinforcing Sections IV.D.2.a. (vi) and IV.D.3.a. (vi).

In addition to existing and new source review, the Division must develop a visibility monitoring strategy to collect information on visibility conditions and must develop a long-term (10-15 year) strategy to assure progress towards the national goal. The monitoring plan and the long-term strategy are set forth in the SIP submitted to the U.S. EPA. Section XV.F. provides procedures for reviewing and revising the long-term strategy.

State Implementation Plan for Class I Visibility Protection State of Colorado

The purpose of this plan is to assure reasonable progress towards meeting the national goal of preventing future, and remedying existing, visibility impairment in Class I areas.

The plan includes provisions for existing and new source review (attached as Regulation Number 3, Section XV.), a monitoring strategy, a long-term strategy, and consultation with FLMs.

Monitoring Strategy

The State of Colorado's Class I Visibility monitoring strategy is based on meeting four goals:

1. Provide information for new source visibility impact analysis;

2. Determine existing conditions, in Class I areas and the source(s) of any certified impairment;

3. Determine actual effects from the operation of new sources or modifications to major sources on nearby Class I areas; and

4. Establish visibility trends in Class I areas in order to evaluate progress toward meeting the national goals of visibility protection.

The goals will be achieved through a combination of objectives concerning monitoring, gathering and evaluating existing visibility data, and mechanisms for the use of visibility data in decision-making.

Potential new major stationary sources or major modifications to existing stationary sources subject to the Air Quality Control Commission (AQCC) Regulation Number 3, Section IV.3, are required to perform an analysis of visibility impacts on potentially affected Class I areas. The analysis must be conducted utilizing existing visibility data, if any. The Division must consider and evaluate available data from potentially affected Class I areas or other areas that may be representative of background conditions in the Class I area(s) of interest. If data is adequate, the permittee will be notified of the background or base level of visibility against which impacts will be assessed (Regulation Number 3, Section IV.3.(a)(iii)(D)). If visibility data is not adequate, Regulation Number 3, Section XIV. allows the Division to require any source, which will have or is likely to have an impact on any Class I area to conduct monitoring to establish baseline status of visibility. The monitoring information will be used in the new source review analysis and will add to the background and trend data bank of that Class I area. No monitoring shall be required if it is currently being conducted by any federal, state, or local agency (AQCC Regulation Number 3, Section XIV.B.1).

FLMs may at any time identify to the Division Class I areas where emissions from a specific source or small group of sources may be causing or contributing to visibility impairment in the Class I area. The Division will determine if emissions from any local sources 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, which may have been done for other air quality programs.

The Division may be unable to make a decision regarding “reasonable attribution” of visibility impairment from an existing source or sources using available data. The Division will make available to the affected FLML and the U.S. EPA a discussion of what data was considered and what measures the Division is taking, if any, to resolve the situation. The Division may consider modeling the impact of nearby suspected sources with existing visibility models. Funding and other factors may limit the Division's ability to unilaterally initiate studies designed to establish “reasonable attribution”. Therefore, the Division may join with the FLMs, the suspected source(s), the U.S. EPA , and others in implementing special monitoring and analysis programs to address the specific problem.

The Division will sponsor or share in the operation of visibility stations with FLMs as the need arises and resources allow. Fiscal, logistical, and other considerations may constrain the Division in conducting visibility monitoring in Class I areas.

The Division will request from each FLM responsible for Class I areas in Colorado copies of any and all past or existing programs designed to monitor or evaluate visibility. All future visibility data gathered by each FLM will also be requested, including any analysis and interpretation.

The Division will assemble and evaluate the visibility data supplied by the FLM in addition to any other data collected by the Division or any other appropriate source (such as a proposed major stationary source) on an annual basis.

Long-Term Strategy (LTS)

The Commission shall review the strategy set forth below and prepare a public report as required in Section XV.F. The FLMs shall be consulted throughout all phases of the LTS development and revisions.

A Commission subcommittee will be established to address the following components of the LTS:

1. Statewide visibility standards

2. Smoke management

3. Vistas

4. PM10 and PM2.5 emissions

5. Any other components the subcommittee deems applicable.

The Division is pursuing the adoption of statewide visibility standards. The subcommittee will determine how and if standards should be set and how the standards will apply to various areas of the state. Although the end result may apply to regional haze, Class I areas will benefit from statewide standards.

The Division presently has smoke management agreements with the FLMs. The affected agencies are required to obtain an open burning permit from the Division. Virtually all controlled burns are for wildlife habitat and range management; little slash/timber management burning occurs.

The Division believes existing smoke management techniques do not adversely affect visibility in Class I areas. The subcommittee will address this issue to determine how smoke management should be integrated into the LTS. If necessary, the existing agreements may be revised during the LTS review process. The Division will continue to coordinate with the FLMs to insure that best smoke management techniques are employed.

The FLMs declined to identify integral vistas (important views of landmarks or panoramas that extend outside of the boundaries of the Class I areas and considered critical to the enjoyment of the areas). The Commission is therefore not required to address vistas but may do so under their own authority. The subcommittee shall determine if integral vistas and/or other scenic vistas should be identified, and if so, the criteria to be used for such identification. Any vistas shall be identified using the specific criteria developed by the subcommittee.

The Division is in process of studying PM10 emissions and their role in the formation of Denver's brown cloud. Conceivably, such studies could lead to information and strategies related to visibility impairment. The subcommittee will address the integration of this component into the LTS.

The FLMs and Division have not identified reasonably attributable impairment at this time, therefore the Commission will not address source retirement and replacement, construction activities, and enforceability of emission limitations. Should the FLMs or Division identify impairment from a specific source or small groups of sources, the Commission will address these issues during the LTS review process.

Each time the LTS is reviewed, the following six factors (at minimum) must be addressed.

1. Emission reductions due to ongoing air pollution control programs.

2. Additional emission limitations and schedules for compliance.

3. Measures to mitigate the impacts of construction activities.

4. Source retirement and replacement schedules.

5. Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for these purpose, and

6. Enforcement of emission limitations and control measures.

Consultation with Federal Land Managers (FLMs)

The Division as part of the implementation of this Regulation will send within 30 days of its adoption written notification to the FLMs stating that the Division Director is the official to whom any recommendations may be sent regarding Colorado's SIP for Class I visibility protection, including but not limited to:

1. Integral vistas to be listed by the state;

2. Identification of impairment of visibility in any Class I area(s), and

3. Identification of elements for inclusion in the monitoring strategy.

The Division will provide the opportunity for consultation with the FLMs, in person and at least 60 days prior to any public hearing on any element of the SIP. The Division is interested in the FLMs opinion regarding:

1. Assessment of impairment of visibility in any Class I area, and

2. Recommendation on the development of the long-term strategy.

The FLMs may contact the Division Director at any time regarding the implementation of the SIP for Class I visibility protection.

I.G. Adopted August 8, 1988

Revisions to Regulation Number 3 and the Common Provisions Definitions

Revisions are made to Regulation Number 3 and definitions in the Common Provisions. Prevention of Significant Deterioration (PSD) and New Source Review (nonattainment) requirements are revised to conform to the Federal regulations. Provisions for the regulation of the National Ambient Air Quality Standard (NAAQS) for particulate matter (PM-10) are added. Section V, concerning certification of Emission reduction, is revised to conform to Federal requirements. Other minor changes are made to clarify existing policies. Requirements for Revised Air Pollution Emission Notices (APENS), Air Quality Related Value (AQRV) monitoring, solid waste fuel, and temporary sources are revised.

Dual Definition of Source

Federal regulations require the use of the dual definition of source for nonattainment areas. (See discussion, in the August 7, 1980 Federal Register, 45 FR52680 and 52693). The concept is intended to provide for more air pollution control in nonattainment areas, such that more rapid progress can be made toward attaining the standards.

When determining if a source locating in an attainment area is major, emission increases and decreases at the entire facility are considered. When determining if a source located in a nonattainment area is major, two cases are examined. First, if the single piece of equipment or modification itself represents a major source or significant increase, nonattainment review applies. Second, if the piece of equipment itself is not major, examine the entire facility as for attainment area sources. If a significant increase occurs, nonattainment review applies.

The definition of “Stationary Source” in the Common Provisions indicates the Commission intended to use the dual definition (see also the Statement of Basis and Purpose, March 10, 1983). The definition of “Net Emission Increase”, Part K, however, incorrectly stated that only the single piece of equipment is examined. This was less stringent than Federal law and allowed facilities to install a series of de minimus units whose aggregate emissions could be significant, without undergoing nonattainment review. Part K is corrected to allow the Division to use the dual definition.

When the dual definition is used, nonattainment review applies to reconstructed sources. Section IV.D.2.a clarifies this.

Section IV.D.2.a also clarifies that nonattainment review applies only to nonattainment pollutants emitted in major amounts. This differs from PSD requirements, which apply to attainment pollutants emitted in significant amounts if the source is major for any pollutant (attainment or nonattainment). (See discussion, 45FR52676.)

Fugitive Emissions

The Colorado Air Quality Control act includes fugitive emissions when calculating a source's potential to emit only if the Commission adopts regulations to include fugitive emissions for that source category. (See Statement of Basis and Purpose, March 10, 1983). Federal law requires that fugitive emissions are included for all “listed” sources (those listed in the definition of major source). The Commission is adopting the requirement to include fugitive emissions for all listed sources.

Portions of the Colorado Act not Allowed in Federal Act

Portions of Regulation Number 3 are not allowed in the Federal Regulations, but are contained in the Colorado Act and therefore cannot be removed from regulation Number 3 until removed from the Colorado Act. The items are discussed below. The Division will not honor these items unless an applicant insists, in which case a permit from the EPA will be required to meet Federal law.

Best Available Control Technology (BACT):

The Colorado Act's definition of BACT states that revisions to New Source Performance Standards (NSPS, Regulation 6) or National Emission Standards for Hazardous Air Pollutants (NESHAPS, Regulation 8) made after April 10, 1983 (the effective date of the definition) can't be used to determine BACT. The Federal Act requires that BACT can't exceed the NSPS or NESHAP in effect at the time of application. The Division will make BACT determinations taking into consideration the most current NSPS and NESHAP regulations.

Clean area in nonattainment area: The Colorado Act and Section IV.d.2.B.ii allows exemption from nonattainment requirements if the source proves they are located in a clean portion of a nonattainment area. This is not allowed in the Federal Act.

Shale oil exemption: The Colorado Act and Section I.B.2.C.viii excludes from the definition of major modification a fuel switch to shale oil or coal/oil mixtures. This is not allowed in the Federal Act.

Fugitive Dust Exemption: The Colorado Act and Regulation Number 3 does not include fugitive dust that does not adversely affect public health or welfare when calculating a source's potential to emit. The

March 10, 1983 Statement of Basis, Authority, and Purpose discusses the Commission's previous position. - The discussion indicates that when the EPA promulgates new standards for particulate matter the fugitive dust issue will be resolved. The EPA has promulgated a new NAAQS for PM-10, which replaces the TSP NAAOS. The PSD increments, however, are still based on TSP. PM-l0 fugitive emissions can thus be used to determine potential to emit, but some question remains as to whether or not TSP fugitive emissions should be used. The EPA is developing PM-10 increment standards. In the interim, if a source does not want to include fugitive dust (TSP or PM-10) for a State permit, an EPA permit may have to be obtained.

Permit Review Time Frame: The Colorado act contains specific time frames for processing permits (60 days, etc.). Section IV.F of Regulation Number 3 states that a permit is automatically issued if the Division fails to meet the time constraints. This is not acceptable for major source review. PSD and major nonattainment applications are often complex. The Federal Act allows one year to complete the review process (including public notice, hearings, etc). The Division will automatically ask for a time extension for major source applications. If an extension is not granted and/or the time frame is not met, an EPA permit will be required.

Other Minor Revisions

These definitions are revised as follows to conform to the Federal Act: “construction” now includes demolition and modification; “enforceable” now includes Regulations Number 6 and 8; “Lowest Achievable Emission Rate” does not allow BACT to be exceeded.

References to the “Board” are deleted and replaced with “Commission” throughout the Regulation. The (Hearings) Board no longer exists.

Class I areas in neighboring states are recognized in Section VIII.

Section VIII.K is added to allow redesignation of an area to class III if a permit can't be obtained unless the area is redesignated and sufficient public notice is given. The Federal Act requires this.

Section XIII.B exempts Innovative Control Technology from BACT only, not all of the PSD requirements. This conforms to the Federal Act.

Public notice procedures (Section IV.C) for major sources are expanded and clarified to conform to the Federal Act.

The word “new' is removed from Section IV.D.2.a.iv to clarify that alternate sitting studies apply to new and modified sources.

Exemption c under the definition of modification is removed. This exemption allowed sources choosing to improve control of particulate matter to increase SO2 emissions without the need for>additional S02 control. (See Statement of Basis, Authority and Purpose, March 10, 1983). This exemption is no longer allowed, since it is inconsistent with the Federal Act.

The language pertaining to interim PSD authority is deleted. The State received full authority on September 2, 1986.

Annual fee requirements are added to Section VI. This provision was added to Section 25-7-114(5)(a) of the Colorado Act on July 1, 1987.

Household use of paints and solvents is exempt from APEN and permit requirements. The Division classifies these materials as toxic air pollutants which would require permits if emitted in any amount. The Division does not have available resources to regulate this activity.

The six-month, 25 acre APEN and permit exemption clarifies that all mining operations must obtain a permit (unless exempt elsewhere).

Temporary sources operating less than one month may receive initial and final permits at the same time. The Division will thus avoid issuing final permits for sources that no longer exist. The Division has discretion to issue the permits separately if the operator or owner of the source or the source type has a history of compliance problems.

PM-10 NAAQS

This new standard replaces the Total Suspended Particulate (TSP) standard for Federal purposes only. The State is adopting the PM-10 requirements and is also retaining the TSP standard at least until the EPA approves our PM-10 State Implementation Plan. This will ensure that Reasonable Further Progress will be maintained in the interim.

The PM-10 standard is implemented under Section 110 of the Federal clean Air Act. The other criteria pollutants are regulated under Section 107, which includes provisions for designated nonattainment areas, emission offsets, and sanctions for areas where the standard is exceeded. Section 110 does not utilize nonattainment areas; it requires that the standard be met in all areas. The State regulations applied specifically to designated attainment and nonattainment areas. Since there are no PM-10 designated areas, reference to pollutants regulated under Section 110 is added in several places to ensure regulation of PM-10.

PM-10 sources that impact an area where the standard is exceeded are “major” if they emit 100 tons per year or more of PM-10. Such a source is then subject to PSD requirements (Section I.4.a). Such sources must also offset their impact to the degree which it exceeds the standard (as opposed to sources of other criteria pollutants, which must offset total emissions). Offsets will be required as part of the PSD source impact analysis, as necessary.

PM-l0 fugitive emissions are included when calculating potential to emit. (See discussion under Portions of the Colorado Act not allowed in Federal Act in this Statement of Basis, Authority and Purpose).

PSD increments are still regulated in the TSP form, therefore significant emissions and impact levels exist for both PM-10 and TSP. PSD will apply to TSP until the EPA promulgates PM-10 increments.

New definitions are added to the Common Provisions to differentiate between particulate matter, PM-10 and TSP.

The EPA has left regulation of minor sources to the state. Section IV.D.3.E is added to require minor sources locating in areas where the PM-10 standard is being exceeded to apply BACT.

The Commission had the option to add PM-10 monitoring “phase in” provisions. Methods and equipment are reasonably available, therefore, phase in is not necessary.

Corrections to typographical errors are made for significant ambient levels of beryllium, lead, and hydrogen sulfide. (Section IV.D.3.b.iii)

Revised Air Pollution Emission Notices (APENS)

Section II.B requires Revised APENS when a significant change in emissions occurs. The definition of net emission increase requires that a Revised APEN be filed to receive credit for decreases. Historically, the Division has not received all of the APENS required. The April 1 deadline and calendar year requirement are added for clarification. The removal of a piece of equipment represents a significant change and the requirement for submittal of an APEN to cancel a permit is added for clarification. These clarifications will help the Division update the Emission Inventory System; proper credit will be received for emission decreases; and sources will avoid being charged an annual fee for equipment, which no longer exists.

The Regulation now requires all portable sources to submit revised APENS prior to relocating, regardless of the length of time at the new site. This helps the Division track sources in the event complaints are received.

Air Quality Related Value (AQRV) Monitoring

Section XIV.B.4.c limited the cost of AORV monitoring to 1/4 of the cost of the Additional Impact Analysis, including preconstruction monitoring. The Federal Land Managers testified that such a limit is not sufficient to provide even minimal AQRV monitoring. The limit is removed and the Division will determine economic feasibility on a case-by-case basis.

Section XIV.B.1. is revised to require joint monitoring among all major sources affecting an AQRV in the same Class I area. This will provide for ongoing, high quality data.

Waste Fuel Exemptions

Sections I.B.2.C.iii and IV.D.1.c.i (F) exempted switches to fuel derived from municipal solid waste from new source review. Due to the public's increased concern for toxic/hazardous emissions, many sources now undergo scrutiny for such emissions. All sources should be treated equally when proposing to burn municipal solid waste and should be required to apply the best control for reducing toxic/hazardous emissions. The exemptions for solid waste fuel are deleted.

Emission Reduction Credits

Revisions made to this portion of the Regulation are based on the Emission Trading Policy Statement; General Principles for Creation, Banking and Use of Emission Reduction Credits as published in 51FR43814. That Policy set out general principles that EPA will use to evaluate emission trades under the Clean Air Act. The goal of that Policy is to create more flexibility for the states and industry to help meet the goals of the Clean Air Act more quickly and inexpensively. The purpose of Colorado adopting the salient points of that Policy is to create a generic regulation, which is acceptable to EPA, and thereby eliminate the need for a SIP revision for every banking or emission trading action. Other than clarifications and procedural changes the key changes to this portion of the Regulation include:

a. A greater than 20% discount will be taken in areas without approved SIPs. The discount will be based on the level of reduction in emissions needed in that area to achieve attainment status.

b. Added provisions for trading of PM-10, lead and NOx

c. Added new criteria for modeling to determine ambient equivalence of trades.

d. Shutdowns and curtailments in production emission reductions may be used for on-site replacement of equipment only.

e. Specify no credit allowed for reduction in emissions from mobile sources unless those sources were subject to ambient impact and new source review.

f. Credit for switching to a cleaner fuel is given only if a permit is conditioned to require control equipment to achieve the same reduction if the source switches back to the dirtier fuel.

I.H. Adopted September 15, 1998

"A Regulation Requiring Air Contaminant Emission Notices, Emission permits and Fees"

With the passage of HB 1372, 1st session of the 56TH GA, two stationary source fees were established for FY 1987-88. An annual compliance-monitoring fee of $60.00 per source was to be charged .to each permitted source. An hourly rate of $96.00 was to be applied to all permit processing time. After 1987-88 these fees were to be set by the Commission. These fees were to cover the "direct and indirect costs of such permit] processing. In establishing such fees, the Commission shall provide a higher per hour charge for permits which require five hours or more than for permits which require less than five hours to process; except that for the fiscal year 1987-88, the fee shall be ninety six dollars per hour for all permits. In addition to such fee for processing, the Commission shall establish and as necessary revise non-refundable annual fees for each emissions source covered by a stationary source permit sufficient to cover the direct and indirect costs of administration and periodic inspections; except that for the fiscal year 1987-88, the fee shall be sixty dollars per year for each emissions source."

The Division has performed a thorough analysis of the direct and indirect costs of the permit and compliance monitoring programs and has proposed fees to the Commission designed to meet statutory requirements.

Statutory Authority

The statutory authority for this regulation is Section 25-7-114.

Section VI - Fees

A. General

Paragraph 1 of this Subsection requires that all persons required to obtain an emission permit or file an air pollution emission notice pay fees sufficient to recover the direct and indirect costs of processing and issuing permits in accordance with the fee schedule shown in the Regulation. With this regulatory change, the following language was struck to be consistent with the statutory language: '...to include the reasonable costs of such processing or administration, and of enforcement of the permit provisions. Such costs shall include the cost of predictive model utilization when the use of such models is deemed necessary by the Division for proper evaluation of the permit application." Paragraph 2 is unchanged.

Sub-Sections B and C are unchanged

D. Annual Fees

Sub-Section D is changed by noting that the annual fees to be charged are in accordance with the schedule shown in the Regulation.

Fee Schedule

The fee schedule shows what the fees are for the hourly processing charge, the annual charge, and the APEN.

I.I. Adopted August 20, 1992

Revisions Concerning the Long-Term Strategy to Protect Visibility in Class I Areas (Section XV.F)

Authority

Colorado Air Quality Control Act

The Colorado Air Quality Control Commission's (Commission) authority to revise Regulation Number 3.XV.F, concerning the Long-Term Strategy Review of Colorado's State Implementation Plan for Class I Visibility Protection, is in the Colorado Air Quality Control Act. Relevant Sections are 25-7-102 Legislative declaration and 25-7-105(1)(a)(I) Duties of Commission.

Federal Clean Air Act

Additional authority for the Commission to make the regulatory revisions can be traced to the 1977 Amendments to the Federal Clean Air Act. Section 169(A) requires the federal Environmental Protection Agency to promulgate regulations that in turn require states to amend their State Implementation Plans (SIPs) to provide for Class I visibility protection - including a long-term strategy for making reasonable progress toward the national visibility goal. On December 2, 1980, EPA released final regulations to states detailing the specific requirements - including the development and periodic revision of a long-term strategy as specified by federal law.

Statement of Basis and Purpose of Changes to Regulation Number 3 Section XV.F.

Section XV.F.1.c.

Commission Regulation Number 3 required a Long-Term Strategy (LTS) review/revision report from the Colorado Air Pollution Control Division (Division) to the Commission every three years following the effective date of the regulation (November 1987). The August 1992 LTS report from the Division is late in arriving to the Commission. The purpose of the regulatory change is to clarify when subsequent LTS review and revision report cycles will occur. Without a regulatory change, the next LTS review would be due September 1993 - approximately a year from adoption of the August 1992 report.

In order to maintain the intent that a report is to arrive to the Commission, and ultimately EPA, at least every three years and to allow the Division to get back on schedule with a report to the Commission in approximately three years, Section XV.F.I.c. was altered.

Old language:

> (c) The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available on September First of every third year following the effective date of this regulation. This report shall include an assessment of:

New language (changes underlined):

> (c) The Division shall prepare a report for the Commission on any progress made toward the national visibility goal since the last long-term strategy revisions. The report will be made available by September First at least every third year following the submittal of the previous report. This report shall include an assessment of:

Section XV.F.I.c.vii

EPA regulations (CFR Part 40 Section 51.306) require that the LTS be reviewed in seven areas. There was a discrepancy between EPA requirements and State regulations regarding the seventh item to be assessed. The purpose of the regulatory change is to bring Commission Regulation Number 3 into conformance with EPA requirements.

Old language:

(vii) The progress achieved in developing the components of the strategy.

New language (changes underlined):

(vii) The need for BART to remedy existing impairment in an integral vista declared since plan approval. I.D. Adopted November 19, 1992

I.J. Adopted November 19, 1992

Revisions to Regulation Number 3, Common Provisions and Regulation Number 7

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The EPA has identified portions of the State's Prevention of Significant Deterioration and New Source Review (PSD and NSR) rules, which do not conform to the Federal rules. The State rules must be at least as stringent as the Federal rules in order for the EPA to approve the State Implementation Plans. In addition, the State must revise the rules to include the addition of new requirements that were set forth in the 1990 Federal Clean Air Act. The EPA has also identified additional non-reactive volatile organic compounds, and a significant level for municipal waste combustor emissions. All of these revisions must be made for EPA approval.

The 1992 State Legislature revised the Colorado Clean Air Act to include new definitions and fee requirements. In addition, the revisions allow the Commission to make necessary revisions to the State's PSD and NSR rules, as described above.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. Section 25-7-103 sets forth definitions for use in implementing the new Colorado Act. Section 25-7-105 (1)(A)(I) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(1)(c), 203, 204, 205, 206, 210 and 301 provide authority to adopt a PSD and NSR program in conformance with the Federal and Colorado Acts. Section 25-7-105.1 sets forth the Commission's authority regarding Federal enforceability. Section 25-7-106 (1)(c) provides authority for adopting regulations, which are applicable to entire state, or only within specific areas or zones, or only to a particular pollutant. Section 25-7-114.5 sets forth time frames for the Division to review permit applications, and procedures for owners and operators to demonstrate compliance with construction permits. Section 25-7-114.7 sets forth fee requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 through 25-7-109 and 25-7-114, C.R.S., as amended.

Purpose

New Source Review Rules

Regulation Number 3 contains the permit requirements for major sources (Prevention of Significant Deterioration, PSD and New Source Review, NSR). The Common Provisions Regulation contains definitions that are used in the permit requirements of Regulation Number 3. The PSD and NSR requirements and definitions must be equivalent to the Federal requirements. The EPA has identified the portions of Regulation Number 3 and the Common Provisions, which do not conform to the Federal rules. On October 17, 1991, the Commission adopted revisions to Regulation Number 3 and the Common Provisions, to address some of the EPA's concerns. Additional concerns remained, however, because some of them could not be addressed until the Colorado Clean Air Act was revised. On May 27, 1992, the Governor signed Senate Bill 105, which revised the Colorado Clean Air Act to allow the Commission to proceed with the remaining necessary revisions to Regulation Number 3 and the Common Provisions. The new Colorado Act is effective as of July 1, 1992.

The 1990 Federal Clean Air Act revisions set forth additional revisions, which must be made to all State PSD and NSR rules.

The Commission has adopted the necessary revisions, which address the remaining EPA concerns regarding the State's PSD and NSR rules. These revisions are required to eliminate discrepancies between the State and Federal rules, and for approval of our State Implementation Plan. The required revisions are as follows.

Regulation Number 3

1. The regulation previously allowed sources of fugitive emissions to be exempt from the NSR and PSD requirements. The Federal Act does not allow the exemptions. Several Sections throughout the regulation needed to be revised or eliminated:

   Section I.E. - Eliminate the reference to the definitions of major stationary source and major modification from the definition of fugitive dust;

   Section I.B.3.e. and f - Eliminate the references to fugitive dust from the definition of major source;

   Section IV.D.3.b.(i)(B) - Eliminate the fugitive dust exemption from the PSD rules;

   Section XI - Eliminate the fugitive dust exemption from increment consumption requirements.

2. Section I.B.2, Section (vii) of the regulation allowed sources, which switched from oil or gas to a coal-derived fuel (shale oil) to be exempt from the PSD and NSR requirements. This is not allowed under the Federal Act, therefore (vii) is removed from the definition of major modification.

3. The new Federal Act requires major sources in nonattainment areas obtain to offsets from sources that are also located in the same nonattainment area, unless a source outside of the area contributes to nonattainment in the area in which the major source is located. Section IV.D.2.a(iii) is revised to add this new requirement.

4. The Federal Act does not allow major sources located in a “clean portion” of a nonattainment area to be exempt from the NSR requirements. Section IV.D.2.c.(ii) is revised to eliminate the clean portion of a nonattainment area exemption.

5. Section IV.D.3.e. required minor sources which contribute to the exceedance of an ambient air standard in a non-designated area (not designated attainment or nonattainment) to apply best available control technology. This requirement was previously adopted to comply with the EPA's interim policy for the PM-10 ambient air quality standards. The provision applied until the EPA was able to formally designate areas as attainment or nonattainment for PM-10. Now that the EPA has designated areas, the PSD and NSR (nonattainment) rules apply and Section IV.D.3.e. has been removed.

6. The regulation previously stated that certain permit conditions had to be removed from the permit upon issuance of final approval. The conditions on a final permit were limited to the list of items required to obtain a permit. The Federal Act requires that permits must contain all conditions necessary to ensure compliance with all applicable requirements, and any conditions necessary to make limits on production rates, hours of operation, the potential to emit, etc. federally enforceable. The language that limits the enforceability of permit conditions after Final Approval is removed from Section IV.E.

7. The Federal Act does not allow automatic approval of permits if the State fails to meet processing deadlines. The language that provides for automatic approval of permits if processing deadlines are not met is removed from Section IV.F. Likewise, confidentiality determinations do not affect the time constraints in the regulation. Section VII is revised to reflect this.

8. The new Federal Act does not allow reductions of pollutants required to meet any Act requirements to be credited for use as offsets. Language is added to Section V.E.9 of the State's Emission Reduction Credit rules to clarify this requirement.

9. The new Federal Act no longer limits the boundaries of Class I areas to those that existed in 1977. Section VIII is revised to eliminate this restriction.

10. The Federal rules state that if innovative technology is used by a PSD source, they are only exempt from the BACT requirements, not all of the PSD requirements, and that the consent of governors of other affected states must be obtained. Section XIII previously exempted such source from all PSD requirements. The Section is revised to clarify this allowance.

Common Provisions Definitions:

1. The EPA has added visible emission standards to applicable emission limitations under the definition of Best Available Control Technology. The State's definition is likewise revised.

2. Under the new Federal Act, Asbestos, Beryllium, Mercury, and Vinyl Chloride are now regulated under new hazardous pollutant requirements (Maximum Achievable Control Technology). These compounds are no longer subject to Prevention of Significant Deterioration (PSD) requirements (which would require Best Available Control). The definition of significant, which determines when a source is subject to PSD, is revised to omit these pollutants.

The Federal rules do not allow an exemption from PSD and NSR rules for right of ways, pipelines, etc. The definition of stationary source is revised to delete this exemption.

Non-Reactive VOCs:

On March 18, 1991, the EPA added five halocarbon compounds and four classes of perfluorocarbons to the list of organic compounds, which are negligibly reactive, and thus exempt from regulation as Volatile Organic Compounds under Regulation Number 3, the Common Provisions, and Regulation Number 7. In addition, the EPA revised the definition of Volatile Organic Compound.

The Non-reactive Volatile Organic Compound (VOC) list, as amended by the EPA, is incorporated into Regulation Number 3, Section IV.D.4, the Common Provisions (definition of Net Emission Increase, paragraph h.), and Regulation Number 7, Section II.B. The State is not allowed to take credit for controlling these compounds in our SIP. In other words, sources cannot use reductions of emissions of these compounds to offset VOC emissions, and we are not allowed to include emissions of these compounds in our SIP inventory. The EPA has determined that these compounds do not react in the atmosphere to produce ground level ozone.

The EPA also revised the definition of "Volatile Organic Compound" to make slight clarifications. The definition in the Common Provisions and in Regulation Number 7, Section II.A.1. is likewise revised.

Municipal Waste Combustor Emissions Significant Level:

On February 11, 1991, the EPA promulgated New Source Performance Standards for Municipal Waste Combustors. In addition, the EPA promulgated "significant emission levels" for municipal waste combustor emissions. These significant levels are used to determine if PSD requirements apply to major sources.

The Commission revised the definition of "Significant" in the Common Provisions Regulation, to add the emission level for municipal waste combustor emissions. This addition is required in order to conform to the Federal PSD and NSR rules.

Senate Bill 92-105 Revisions

Senate Bill 105 revised the Colorado Clean Air Act. The new Colorado Act contains some new and revised provisions which are relatively simple and straightforward, and which could therefore be easily adopted into Regulation Number 3 and the Common Provisions at this time. These particular revisions were adopted to facilitate transition from the old Act to the new Act, and to eliminate confusion that could occur due to differences between the new Act and the existing regulations. The proposed revisions are as follows.

Regulation Number 3

1. Sections IV.B.3, 4 and 5 - The new Act gives the Division 60 days (instead of the previous 20 days) to determine if an application is complete. In addition, the Division has 12 months to complete the application process for PSD construction permit applications (previously limited to 135 days).

2. Section IV.C.1.c - Change the reference date for the definition of hazardous pollutant. A new definition has been adopted in the new Act. The definition includes the list of 189 chemicals from the Federal Act, and an additional list contained in the Colorado Act.

3. Section IV.H - Change the procedures for granting of final approval construction permits. Previously, the Division had only 30 days once a source commenced operation to inspect the source to determine that all permit conditions were being met. The source now has 180 days to demonstrate compliance. Also previously, the Division could allow a source additional time to come into compliance before Final Approval was issued. Now the Division must grant Final Approval or revoke the permit.

4. Section VI - The new Act sets forth new fee schedules for permits, annual fees, and APENS. The permit fees have changed from a schedule based on the type of facility to $50 per hour for all applications. The Division cannot exceed 30 hours in processing time unless the applicant is first notified that 30 hours will be exceeded. The annual fees are no longer based on the number of sources at, or the size and complexity of a facility. Instead annual fees are based on actual emissions. The APEN fee has changed from $60 to $75 for fiscal year 92.

Common Provisions

1. Section I.C - Incorporates the new Legislative Declaration of the new Act. The new declaration adds to the existing declaration that an accurate emission inventory is necessary for implementation of the air quality requirements.

2. Incorporates the new Acts definition of Air Pollutant. The definition is the same as previous except that precursors are now also considered" air pollutants." Precursors can be emissions such as nitrogen and sulfur oxides, which can contribute to particulate matter emissions.

3. Revise definition of Emission Control Regulation. The new definition is the same, except such regulations can now include work practices and design, equipment, and operational standards. In addition, such regulations that apply to hazardous pollutants must be consistent with the new Act requirements concerning hazardous pollutants.

4. Revise definition of Federal Act to reference 1990. (Previously referenced 1977.)

5. Revise the definition of Federally Enforceable to indicate that the Division has authority to issue permits to synthetic minor sources.

6. Revise definition of Hazardous Air Pollutant. The new definition includes the pollutants listed under the Federal and Colorado Acts.

7. Refers to Adverse Environmental Effect, therefore this definition is added.

8. Add definition of Ozone Depleting Compound. The fee schedule requires the Division to charge fees for emissions of such compounds, therefore the definition is added. I.E.

I.K. Adopted June 22, 1993

Revisions to Regulation Number 3 Regarding Construction Permits

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The Colorado Clean Air Act requires stationary sources to report their emissions, obtain construction permits, and be subject to public notice before construction occurs. The Commission has authority to exempt sources from these requirements, if the sources do not have a significant adverse impact on air quality. Regulation Number 3 has been in effect for approximately twenty years, and contains exemption lists for APEN and permit requirements. Based on twenty years of experience, the Commission believes it is appropriate at this time to revise the exemption lists to include additional sources, which do not adversely affect air quality in Colorado. In addition, it is appropriate to revise the public notice requirements to address the sources for which is public comment is most likely to be received.

The 1992 State Legislature revised the Colorado Clean Air Act to include new provisions concerning non-criteria pollutants. The Commission needs to address these provisions and revise the APEN reporting, permitting, and public notice requirements regarding these pollutants.

A technical revision must be made to the definition of "significant," contained in the Common Provisions, to address major sources in nonattainment areas, as required under the Federal Act.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. The Legislative Declaration, Section 25-7-102, recognizes that an accurate emission inventory is needed in order to adequately manage air resources in Colorado. Section 25-7-105 (1)(A)(1) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(l)(c), 203, 204, 205, 206, 210 and 301 provide authority to adopt a PSD and NSR program in conformance with the Federal and Colorado Acts. Section 25-7-105(12) provides authority to adopt regulations to implement the emission notice and construction permit programs. Section 25- 7-106 (1)(c) provides authority for adopting regulations, which are applicable to the entire state, or only within specific areas or zones, or only to a particular pollutant. Section 25-7-109.3 provides authority for regulating non-criteria pollutants. Section 25-7-111 provides authority for the Division to administer regulations adopted by the Commission. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirement. Section 25-7-114.2 provides authority for requiring construction permits, and for allowing exemptions from the requirement. Section 25-7-114.5 provides authority for requiring public notice of construction permits. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to -109 and 25-7-114, C.R.S., as amended.

Purpose

Definition of "Significant"

The Common Provisions Regulation contains definitions that are used in the Prevention of Significant Deterioration (PSD) and New Source Review (nonattainment, NSR) permit programs of Regulation Number 3. The PSD and NSR requirements and definitions must be equivalent to the Federal requirements. The definition of significant lists emission levels at which modifications at major sources become subject to the PSD and NSR requirements. Currently, the language in the definition indicates that the emission levels only trigger PSD requirements. The definition is changed to indicate that the levels also apply to the NSR nonattainment rules.

APEN Requirements - General

This language is revised to clarify what emission estimates must be included in an APEN (actual emissions for annual fee purposes, and requested amount for permit limits). In addition, language is added to clarify that a source need not perform a stack test for the sole purpose of providing an APEN emission estimate. Other acceptable estimation methods are usually available for APEN purposes. In some instances, it is possible that an emission factor may supply a more accurate estimate than mass balance calculations, and vice versa. In such cases, a source may choose to use either mass balance, or emission calculations. If the Division believes that estimates can be better made using the method of these two that the source does not choose, the Division may question that source regarding the choice. The emission estimate included in an APEN is not required to be an exact calculation of emissions, but rather the source's best estimate, to the extent practical, of emissions. As stated in the Legislative Declaration of the Colorado Air Quality Control Act, the APEN information is to be used to achieve the most accurate and complete inventory possible, and to provide for the most accurate enforcement program achievable based upon that inventory.

The Colorado Clean Air Act states that APENs are valid for five years, unless a significant change in emissions occurs. This provision is added to the regulation.

Language is added to clarify that each unit is considered to be a "source" for APEN purposes, unless similar sources can be grouped together.

Emission calculations for purposes of determining if a de minimis emission level is triggered will be based on actual uncontrolled emissions. Sources will not be allowed to take credit for control devices in the de minimis calculation because the Commission has no method of determining if the control equipment will be used, or used continuously and properly.

The Commission believes there may be cases where the source demonstrates that it is not feasible to estimate the control efficiency of a device for non-criteria pollutants. In such instances, the Commission gives the Division discretion to allow the de minimis level to be triggered based on actual, instead of uncontrolled actual, emissions. New language is added regarding non-criteria pollutant APEN requirements.

Revised APEN Requirements

The Colorado Act requires revised APENs to be submitted whenever a "significant change" in emissions occurs. The significant levels for criteria pollutants remain unchanged from the previous regulation, except that a significant level has been added for lead emissions. For non-criteria pollutants, the significant change level is set at 50% or five (5) tons per year, whichever is less.

Sources should note that APENs must be submitted if the source begins to emit a pollutant which was previously not included on an APEN. Also, the Commission may add pollutants to the list of non-criteria reportable pollutants. When chemicals are added, the Commission will determine the schedule for submitting new or revised APENs to report the new pollutant emissions.

NOTE: Significant change criteria are used to report changes in emissions for inventory purposes only. If a planned change in emissions requires a new permit, or modification of an existing permit (violates an emission limit, triggers PSD or NSR), then an APEN must be filed and the permit must be revised before the change at the facility occurs.

Revised APENs for emission updates must be submitted by April 30 of the following year. The EPA requires states to update the emission inventory by July 1 of each year, to include the previous year's emissions (Code of Federal Regulations, 40 CFR 51.321). The Commission believes the April 30 date should give sources enough time to compile their inventory, and will also give the Division enough time to update the system by July 1. Sources should plan ahead and have as much of their inventory completed as possible before the end of the year. In this way, the source would then only need to add December, or at worst information for the last couple of months of the year, to the data in order to meet the April 30 deadline.

Revised APENs are required when a change in the type of control equipment being used is made. This allows the Commission to ensure that the new control equipment will meet the applicable requirements, and to verify that actual emissions have decreased or increased due to the use of the new equipment. Oftentimes, stack tests are required to ensure that control equipment meets applicable requirements. A change in the control equipment can affect this compliance determination. Revised APENs will not be required for routine maintenance, repair and replacements. These routine activities should not affect the effectiveness of the equipment.

Permit applications must include an APEN on which the owner or operator indicates what production or emission level the source wishes to be permitted at. Any desire to increase the permitted emission level requires the submittal of a revised APEN, so that the Division can evaluate the change against the regulations before modifying the permit.

Portable Facilities

Revised APENs are no longer required when a portable source changes location. The Commission does not believe it is reasonable to charge the APEN filing fee each time a source moves. Portable sources will still be required to notify the Division at least ten (10) days before relocating. This allows the Division to be aware of a source's location if any concerns regarding the source are raised by the public.

Emergency and Backup Generators

Electric utilities may use emergency or backup generators to ensure that blackouts do not occur in the electrical grid. These units are usually operated instead of, or for short periods in addition to, main utility boilers. Facilities that include the main boilers are usually major sources, and therefore have a major source construction permit, or will in the future have a major source-operating permit. Once the facility is covered under one of these permits, the Commission sees no need for the owner or operator to submit annual updates regarding the emissions from the emergency units.

Other emergency units are not located at the main unit facility, but are located individually in the field. These units will most likely obtain a synthetic minor permit to avoid major source permit requirements, since operation is usually intermittent. Once such sources obtain a synthetic minor permit, the Commission again will not require the source to submit annual emission updates.

APEN Requirements - Non-Criteria Pollutants

There are 363 non-criteria reportable pollutants. The Commission divided the pollutants in two major groups: those that are required to be reported in 1993, and those that have to be reported in 1994 and subsequent years. There are also two groups of chemicals (Radionuclides and Polycyclic Organic Matter) whose reporting requirements were postponed until such time as the Commission determines that they can be accurately quantified and reported.

APEN Requirements - De Minimis Levels

All de minimis levels are based on uncontrolled actual emissions (except where the control efficiency cannot be estimated), as discussed above under General APEN Requirements.

APENs are required of sources in attainment areas when the emissions of any criteria pollutant from a source exceed two tons per year (except for lead).

Sources in nonattainment areas must file when emissions of any criteria pollutant exceed one ton per year. Note that the pollutant being emitted above the de minimis level does not have to be a nonattainment pollutant. Any pollutant triggers the one-ton per year level, regardless of the pollutant's attainment designation.

Because the area is a growth area, and inversions occur in the area, a Grand Junction group requested that APENs be filed when emissions of any criteria pollutant exceed one ton per year. The Commission determined that hearings should be held in the Grand Junction area, and that Grand Junction should pursue their own rules. Language that would have treated Pueblo likewise is not included, due to requests from industries in Pueblo, and the Pueblo County Health Department.

The de minimis level for lead in all areas is 100 pounds per year.

For non-criteria pollutants, the Commission assigned each pollutant to one of three “bins” based on information concerning the health effects of the pollutant. The Commission also developed a series of three scenarios for an emission point based on the release height of the pollutant and the distance from the release point to the property boundary. The resulting three by three grid as well as instructions on how to apply it can be found in Appendix A. Note that future actions by EPA may effect the de minimis reporting levels for certain chemicals that appear on the EPA list of 189 toxic chemicals.

APEN Requirements - Exemption List

Numerous new source categories have been added to the APEN exemption list. Each category was examined for its impact on air quality in Colorado before being added to the list. Each category that was added is believed to have a negligible impact on air quality.

The source category exemptions override the de minimis levels. Sources that fit into the category are exempt, even if emissions exceed the de minimis levels.

Each category will not be addressed individually in this statement, however the following categories deserve specific comment.

Fires and equipment used for cooking of food for human consumption: Not all cooking equipment has been exempted in this category. The Commission has concerns regarding equipment in which grease from the food being cooked comes into contact with the flame of the equipment, thus leading to potential opacity and particulate matter problems. This is especially of concern in PM-10 nonattainment areas. This exemption applies only to noncommercial cooking and to food service establishments, such as restaurants and cafeterias. The exemption does not apply to manufacturing facilities.

Fuel burning equipment: The design rate cutoff for fuel burning equipment has been raised from 750,000 BTU/hour to 5 MMBTU/hour. The fuel use is still restricted to gas, and does not include oil or coal, since the latter two fuels may result in significant sulfur dioxide emissions. Fuel burning equipment which uses gaseous fuel and which is used solely for building heat is exempt if the design rate is below 10 MMBTU/hour. The Commission has determined that the emissions from the exempted unit, based on EPA AP-42 emission factors, are negligible.

Chemical storage areas where chemicals are stored in closed containers...: This exemption only applies to the storage of chemicals at qualifying facilities. The exemption does not include facilities where chemicals are loaded into or out of, or transferred between, storage containers. Bulk storage tanks would not qualify for this exemption, since often the material is loaded and unloaded, and such tanks have vents from which emissions occur due to breathing losses. See Sections II.D.1.n., ee., uu., ddd. and fff. for storage tank exemptions.

The Commission will require APENs only for pollutants that are defined as “criteria” pollutants or “reportable non-criteria” pollutants (HAPs, CFCs, SARA 313). Any other pollutants such as carbon dioxide, methane, nitrogen, oxygen, do not require APEN submittals.

Aerosol Can Usage: There may be instances where a source may exclusively use large amounts of aerosol cans, or may use large amounts in addition to other processes. The Commission expects that these instances will be rare. If the Division, a local agency, or others discover such a source, and if the source emits amounts of pollutants, which are believed not to be negligible, such concern can be brought before the Commission as a request to require such source to file APENs and/or obtain a permit. (See discussion under “Adding and Deleting Exemptions,” below)

Odorous emission sources: This exemption only applies to odor emissions, and not to any other emissions of criteria or non-criteria pollutants, which may be associated with the odor. This exemption does not absolve any source from the requirements of Regulation Number 2 (regarding odor limits). If a source emits any pollutant that is above an APEN de minimis level, the source must file an APEN, regardless of odor.

Portable 5 mm btu/hour engines: One party requested that these sources be exempt from APEN and permit requirements. The Commission has determined that sufficient evidence is not available to indicate that emissions from these sources have a negligible impact on air quality in Colorado, therefore they are not exempt until such evidence is forthcoming.

Laboratory equipment and pilot plants: The subcommittee for these rule revisions held extensive discussions regarding exemptions for laboratory equipment and pilot plant activities. More work is needed to define these activities, determine if the emissions are negligible, and if such activities should be exempt from APENS, permits, or both. The Commission recommends that subcommittee discussion of this issue continue, and that it be addressed when Regulation Number 3 is revised to include the Title V operating permit rules (currently scheduled to occur in July of 1993).

Adding and Deleting Exemptions

The Commission has delegated authority to the Division for adding source categories and activities to the APEN and permit exemption lists. If any person believes that a source category or activity should be removed from the exemption lists, because it is discovered that emissions have an impact on air quality or health that is not negligible, such person may at any time go before the Commission to request that such source category or activity be required to file APENs and/or obtain permits.

Oil and Gas Exploration Activities

Oil and gas exploration activities are activities for which it is difficult for the owner or operator to estimate what emission equipment will be required, and therefore what emissions will occur, until the exploration activities are already underway, and near completion. For this reason, the Commission has extended a temporary exemption from APEN and permit requirements for such activities. Before commencing exploration activities, the source must notify the Division. In this way, the Division is aware of the activities and will be able to address any concerns that are raised by the public. Once an owner or operator has determined that an oil or gas well will be produced, and has filed well completion information, the owner or operator must file an APEN and a permit application within 30 days of that completion filing. The permit application must indicate what regulations are applicable to the source, and how compliance will occur, until the construction permit is issued. This helps the source and the Division to ensure that air pollution regulations are being met. If the well will not be produced, the source must notify the Division so that the Division does not expend resources following up on unproduced wells.

APEN Reporting Deferrals for Source Categories

Due to ongoing studies aimed at quantifying their emissions of non-criteria pollutants, the Commission has deferred APEN reporting requirements for five source categories until six (6) months after the studies have been completed or December 31, 1994, whichever is earlier. The categories are industrial boilers, municipal wastewater treatment plants, publicly owned water treatment plants, municipal power generators of less than ten (10) megawatts, which operate for 250 hours or less per year, and natural gas glycol dehydration units. The EPA is conducting studies regarding the first four categories. The oil and gas industry is conducting studies to quantify emissions from dehydration units. This study is currently underway and is expected to be completed in the near future.

In addition, sources which are not undergoing study, but which believe sufficient information is not available for estimating their non-criteria pollutant emissions, may petition the Division for deferral of those emissions until sufficient information is available.

HAP Permit Requirements

Of the 363 non-criteria pollutants/compounds, 330 are defined as hazardous air pollutants (HAPs). Sources emitting HAPs are required to obtain permits if they are subject to Colorado MACT or GACT or the Federal Title III or Title V provisions.

Synthetic Minor HAP Sources

Some parties to the hearing requested that sources which emit HAPs be allowed to avoid future Maximum Achievable Control Technology (MACT) and operating permit requirements by obtaining "synthetic minor" permits. These permits would contain federally enforceable limits, which would keep emissions below the levels, which trigger the MACT and operating permit requirements. The Colorado Act appears to restrict synthetic minor permits to criteria pollutants only. The subcommittee recommended that this issue be deferred to the HAP subcommittee, which will meet in the near future to address Colorado MACT and other HAP issues. Synthetic minor permits for HAP sources are therefore not addressed in this revision.

Permit Transfer of Ownership

The party to which a permit is issued, whose name is included on the permit, is legally responsible for ensuring that all conditions and terms in the permit are met. The permit must contain the correct legal name, reflecting the correct responsible party, in case an enforcement action needs to be taken. In some cases, the legal name of a company may change, while no modifications are made to the equipment. In such cases, the source need only file a single APEN indicating the change. In all cases, the Division must have on file an application and APEN form with the correct name of the responsible party, and including the signature of the person legally responsible for the information.

Permit Requirements - De Minimis Levels

Permit de minimis levels for criteria pollutants have been increased. Levels differ based on the attainment status of the area. As for the APEN de minimis levels, the nonattainment area levels are triggered by any pollutant, not just the nonattainment pollutants.

Language, which would have set permit levels for the Grand Junction area lower than the levels for attainment areas, was not adopted. See discussion above under APEN de minimis levels.

Emissions are compared against the de minimis levels by adding emissions from all sources at the facility that are required to file and APEN. In some cases, a source may initially be below the de minimis levels, but as new units are added to the facility, the de minimis level is eventually exceeded. At such time that addition of new units causes the permit de minimis level to be exceeded, the source must file a permit application for all units at the facility.

Permit de minimis levels for sources of HAPs will be set at the time that the MACT or GACT for that source category is determined.

Permit Requirements - Exemption List

A few new source categories have been added to the permit exemption list. As for APENs, the source category exemptions override the de minimis levels.

Domestic wastewater treatment works: This exemption applies only to treatment facilities which handle wastewater strictly from domestic homes, or wastewater that is similar in nature. It does not include facilities that treat wastewater from municipalities or other sources. The facility may be publicly or privately owned. Wastewater other than domestic wastewater, including municipal wastewater, may contain contaminants from industry and other sources which would result in emissions which are much more significant than the emissions from domestic wastewater.

Fuel burning equipment: Fuel burning equipment with a design rate less than 10 MMBTU/hour, using natural gas as a fuel, are exempt from permit requirements because this is the rate at which the New Source Performance Standard for small boilers is applicable (Regulation Number 6).

Surface Mining Activities: 70,000 tons per year is the production rate at which the Mine Land Reclamation Bureau exempts mining operations from MLRB permit requirements. Oftentimes, these small operations are only temporary, in order to provide material for highway construction projects. The source has often ceased operation before an Air Pollution Control inspector can visit the source to determine compliance. Crushers, screens and other processing equipment are not exempt because these activities may be subject to specific air quality emission limit regulations.

Applicable Requirements Override APEN and Permit Exemptions

To ensure that sources comply with all applicable air quality regulations, an APEN or permit exemption may not be used if taking the exemption would allow a source to avoid any air quality regulation requirements. This provision applies to the source category exemptions and to the de minimis level exemptions. For example, a source may not claim that it is exempt from permit requirements because it has numerous sources, which are below a de minimis level, if the potential emissions from those sources would exceed the PSD major source limit of 100 or 250 tons per year. In such a case, the source would be required to apply for a PSD permit, or must obtain a permit to limit its potential to emit. In order to limit potential to emit, the permit must contain federally enforceable conditions, which limit the physical or operational capacity of the source so that emissions are below the 100 or 250 ton per year level.

Sources, which are subject only to the opacity or general fuel burning and manufacturing requirements of Regulation Number 1, may take any applicable exemption. Likewise, sources, which are subject to the general RACT requirements (but not the specific RACT requirements) of Regulation Number 7, and sources, which are subject to the current Regulation Number 8 provisions, may take any applicable exemptions (i.e., they are exempt if their emissions are below de minimis levels). RACT for sources that would qualify for the APEN exemptions is usually “no control.”

Similarly, sources which are subject only to Regulation Number 1 opacity, general fuel burning, and general manufacturing requirements are exempt from permit requirements. Sources which are subject to Regulation 7, but which must adopt only work practice standards, are exempt from permit requirements if their emissions fall below the de minimis level (two tons per year of VOC). Sources, which are subject to State-only requirements of Regulation Number 8, are exempt from permit requirements.

Regulation Number 1, 7 and 8 sources, which take APEN or permit exemptions must still meet the regulation requirements, even though an APEN or permit is not required. The provisions that would apply to these sources are straightforward and can therefore be easily enforced by the Commission through the regulation, without requiring a permit.

Public Notice Requirements

The criteria pollutant emission level at which a source in an attainment area must go to public notice has been increased from 25 to 50 tons per year (except for lead). In nonattainment areas, the level remains at 25 tons per year. Lead sources are required to go to public notice when the emissions exceed 200 pounds per year. The Commission has determined that raising these levels will not impact the number of public comments the Division receives. Any source requiring a permit for HAPs is required to go to public notice.

Note that Section I IV.C.3 provides that the Division may require any source to be subject to public comment, if it is determined that such source warrants public comment. The EPA requires that all sources subject to PSD or NSR go to public comment. In addition, in order to make limits on potential to emit federally enforceable, permits containing such limits must go to public notice. At this time, the Commission will use this Section to ensure the EPA requirements are met. Language will be added to clarify these requirements when the next revision to Regulation Number 3 occurs (currently scheduled to occur in July of 1993).

I.L. Adopted July 15, 1993

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The 1990 Amendments to the Federal Clean Air Act requires states to implement an operating permit program. This program is applicable to certain sources, and requires the sources to obtain detailed permits, which are to be renewed every five years.

Failure of a state to implement an operating permit program will result in EPA sanctions, such as loss of highway funds and increased offset requirements for sources wishing to locate in Colorado nonattainment areas. In addition, the EPA may implement the operating permit program if a state fails to implement a program.

The existing construction permit program will continue to exist, however changes have been made to the program so that the two permit programs (construction and operating) compliment each other.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Quality Control Act, 1992 as amended. Section 25-7-105(1)(A)(I) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(12) provide authority to implement the operating permit provisions of Title V of the Federal Act. Section 25-7-105.1 sets forth federal enforceability provisions. Section 25-7-106(6) provides authority for monitoring, recordkeeping and reporting requirements, Section 25-7- 109.3 provides authority for regulating hazardous air pollutants (HAPs). Section 25-7-111 provides authority for the Division to administer regulations adopted by the Commission. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirement. Sections 25-7-114.2 through 114.5 set forth construction and operating permit requirements, and application and public participation requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to -109 and 25- 7-114, C.R.S., as amended.

Purpose

NOTE: Subcommittee documents, which discuss the issues and decisions regarding this regulation in detail, and provide fact sheets for various provisions, are available at the Division and Commission offices.

I. Operating Permit Program:

A. Who is subject to the Operating Permit Program?

1. Definition of Air Pollutant

Sources with potential to emit* 100 tons per year of any air pollutant must obtain an operating permit (these sources are referred to as 'major sources"). For purposes of the operating permit program, air pollutant means any pollutant for which an ambient air quality standard has been set (and their precursors), any pollutant which is regulated under the New Source Performance Standard regulations (NSPS, Regulation Number 6), any Class I or Class II ozone depleting compound, and any hazardous air pollutant (all HAPs listed in either the Federal or Colorado Acts).

The Commission has determined that it is not appropriate to use the Colorado Act definition of air pollutant for operating permit purposes. The Act defines air pollutant as being any substance emitted to the ambient air, except for water vapor. Since many substances occur naturally in ambient air, and others will never be subject to any air regulations, operating permits are not needed for emissions of such pollutants.

Major sources of any air pollutant as defined for operating permit purposes must obtain an operating permit, even if no specific standard has been set for the particular air pollutant (see further discussion under "regulated pollutant," below).

2. Major HAP Sources

Sources, which have potential to emit 10 tons per year or more of a single HAP or 25 tons per year or more of a combination of HAPs, are considered" major sources," and must obtain an operating permit, even if no standard for the HAP has yet been set.

Major sources of Colorado HAPs must obtain an operating permit. Permit conditions related to Colorado HAPs will be treated as state only conditions (see further discussion below).

*See definition of potential to emit, Part A of this regulation. Potential emissions are calculated assuming the source operates continuously, at full design rate, using no pollution control equipment. See additional information and details in subcommittee papers (Group D, Synthetic Minors Issue Paper and Fact Sheet).

3. Fugitive Emissions

Fugitive emissions must be included when determining if a source is major for HAPS. Fugitive emissions must be included when using the 100-ton per year threshold (to determine if the source is major) if the source is listed, or if the source and pollutant is subject to any NSPS or Title III regulation.

Fugitive emissions must be included as required for the Prevention of Significant Deterioration (PSD) and nonattainment new source review (NSR) programs.

The Commission has not included language, which exempts fugitive dust sources from the major source definitions at this time. Further investigation is occurring regarding HAP emissions from such sources, and discussions with EPA will continue to determine how to treat such sources. Once these activities are completed, the Commission will consider this issue.

4. Applicability Determinations

Sources are ultimately responsible for determining if they are subject to operating permit requirements. The Small Business Assistance Program is available to assist small businesses in understanding the requirements, in determining applicability, and in complying with the requirements. No "applicability determinations" are available for other sources. The Division must recover the cost of implementing the operating permit program. Time spent reviewing informal requests for applicability determinations would not be recovered. Sources who believe they are subject to the operating permit program should file an application. During the sixty-day completeness determination, if the Division discovers that the source is not subject to the operating permit requirements, the source will be notified. In addition, if the source has obtained a construction permit, it will most likely have been determined then if an operating permit is required. Also, preapplication meetings with the Division are available to sources. All time spent by the Division in reviewing applications will be charged to the source.

5. Synthetic Minor Sources

Existing sources are subject to the operating permit requirements. Some existing sources may want to obtain federally enforceable limits on their production rates or hours of operation, or emission limits in order to avoid the operating permit requirements (known as synthetic minor sources because such limits are needed to make them minor). Construction permits can be obtained to keep emissions below the major source thresholds. Some existing sources do not have construction permits. Others may have construction permits, which do not currently limit emissions below the major source thresholds. Sources may avoid the operating permit requirements by obtaining an emission-limiting construction permit before they are required to apply for operating permits. Sources must obtain a synthetic minor construction permit before the November 1994 due date, or before one year after EPA program approval, whichever applies (see discussion below). If a synthetic minor permit is not obtained before the applicable date, an operating permit application must be submitted.

The Division will review all existing construction permits over a period of time as resources allow, to determine if the existing permits are federally enforceable. In the interim, the Division will assume that all previously issued construction permits are federally enforceable.

New sources may likewise obtain synthetic minor construction permits before they construct in order to avoid the operating permit requirements. All synthetic minor permits must go to public notice in order to be federally enforceable (see discussion below).

"Once in always in" does not apply to the operating permit program (however it does apply to the PSD program). If a major source has an operating permit and reduces its emissions below major source levels, the source may apply for a synthetic minor permit in order to cease being subject to operating permit requirements.

6. Minor Source Exemption

The EPA allows states to give minor sources subject to existing New Source Performance Standards (NSPS) a five-year deferral from the operating permit requirements. Within five years of the approval of any State program, the EPA will determine if the deferral should be extended further, or if some or all minor sources should be permanently exempt from operating permit requirements. If the EPA first approves any State program in November of 1994, this means that minor sources may be exempt until November of 1999. The EPA will decide if minor sources subject to new MACT or GACT (Maximum or Generally Available Control Technology) standards and NSPS should be exempt on a case-by-case basis as the new rules are promulgated.

The Commission has exempted existing minor NSPS sources from the operating permit program at this time. New NSPS and MACT standards will be adopted by the Commission as EPA promulgates them, and at such time, the Commission shall determine operating permit applicability.

7. Voluntary Operating Permits

Any source which is not required to obtain an operating permit (minor sources) can request an operating permit, if desired. An operating permit allows minor sources to obtain the operational flexibility and permit shield provisions allowed in the operating permit program (note, however, that most of the operational flexibility provisions are available under the construction permit program, see discussion under construction permit program Section). The operating permit will replace the source's construction permit. A construction permit is a SIP requirement, and conditions in the construction permit are federally enforceable (except for state only conditions). All conditions in the operating permit must therefore be federally enforceable. Operating permits, which are issued to sources voluntarily applying, will be subject to all of the operating permit procedural requirements (public notice, EPA review, etc.).

B. When is operating permit applications due?

1. Existing Sources

The federal act allows states to phase in processing of existing source applications over a three-year period. One third of the applications must be acted upon within each year after EPA approves the state's program. The program will be submitted to the EPA by November 15, 1993. The EPA has one year to approve the program, therefore the Division must begin processing applications beginning November 15, 1994.

The Commission has directed the Division to divide the existing sources into thirds. One third of the existing sources must submit their operating permit applications by November 15, 1994. The Division will use the new APEN information to identify the first third, and will notify the first third by November 15, 1993. The first third will consist of the least complex sources. The least complex sources should find it easier to prepare their operating permit applications, and the Division should find it easier to process these applications first. The Division will be able to identify any problems with the review procedures, etc. during the first year.

NOTE: The Division cannot issue an operating permit until the EPA has approved the program and is thus ready to begin receiving permits for review. The Division will therefore "hold" applications processed during the first year until the EPA is ready to accept them for review. Once EPA has reviewed and approved the permits, the permits can be issued.

The remaining existing source applications will be due one year after the EPA approves the state's program. The Division will provide notice of the EPA approval date and sources are responsible for submitting their applications on time.

The Division must determine if each application is complete within 60 days of receipt. This may not be possible during the three-year phase in, as many applications will be received at once. The Division will make its best effort to make the completeness determination for all permits within 60 days. If the Division fails to do this, the application shield applies, and the Division cannot enforce against the source for failure to have a complete application on file. The Federal rule provides, however, that the Division has the authority to ask for additional information at any time during the process, and to set a reasonable date by which the information must be submitted. If the source fails to submit the additional information by the due date, the application shield no longer applies. The Commission is confident that under these provisions sources and the Division can effectively work together to ensure that applications are processed in a timely fashion.

2. New Sources and Relationship to the Construction Permit Program

New sources that wish to locate in Colorado must obtain a construction permit, or a combined construction/operating permit before commencing construction. The source may choose to obtain a construction permit or a combined permit.

Sources that choose to obtain a construction permit must apply for a construction permit according to the provisions of Part B of this regulation. Once a construction permit is obtained, the source can commence construction and begin operating. Within 180 days of commencing operation the source must undergo a "final approval" inspection to demonstrate that all permit conditions are being met. Within 12 months of commencing operation, the source must apply for its operating permit. Once a complete operating permit application is submitted, the source can continue to operate under its construction permit until it receives its operating permit.

Sources that choose to obtain a combined construction/operating permit must apply for such permit before commencing construction. The application for a combined permit must contain all of the required information for an operating permit. The Division will issue the permit, which will essentially be an operating permit. The source can then commence construction and operation. Within 180 days of commencing operation, the source must demonstrate compliance with all permit conditions (this 180 day requirement will be a permit condition, and the appropriate hourly processing fee will be charged for the associated inspection). The source continues to operate under its operating permit and no further action is required until permit renewal.

The procedures for obtaining construction permits are not as intense as those required to obtain an operating permit. More extensive public and EPA participation is required in the operating permit process. In addition, more information and requirements must be incorporated into an operating permit than into a construction permit. Nevertheless, it may be advantageous for sources to combine the processing of these two types of permits in order to avoid duplication of effort.

The advantage of a combined permit is that an additional application step is avoided. Sources should note, however, that an operating permit application requires more specific information regarding compliance monitoring, recordkeeping, etc., than a construction permit application. Sources that choose to obtain an operating permit before construction must be able to supply all of the required information for a complete operating permit application.

Sources that choose to obtain an operating permit before construction will be subject to the operating permit timeframes for processing instead of the shorter construction permit timeframes. Construction permit applications can take up to 90, 135, or 365 days, depending on type and size of source. Operating permit applications can take up to 540 days. Construction permits require public notice and opportunity for comment only for sources emitting more than 25 or 50 tons/year of any criteria pollutant, and requires opportunity for public hearing for Prevention of Significant Deterioration (PSD) sources only. The operating permit program requires public notice and opportunity for hearing for all sources. If the programs are not combined, a source may have to undergo public notice twice, once under each process. PSD sources may have to undergo public hearings twice. The EPA only reviews certain applications and draft permits under the construction permit program, and usually does so during the public comment period. The EPA is allowed 45 days to review draft operating permits near the end of the process, and then the Division has 90 days to revise the permit, if necessary.

Sources should consider carefully their confidence in their ability to operate as expected or planned after construction before choosing to obtain a combined permit.

3. Application Shield

Once a source has submitted a complete operating permit application the source is protected from enforcement action for operating without an operating permit, and can continue to operate until the operating permit is issued.

Sources that submit an application for a combined permit may not construct the source until they receive their combined permit.

C. What must be addressed in operating permit applications and permits?

1. Configuration and Grouping of Sources

Total emissions at an entire site (including fugitive emissions at listed and HAP sources) must be considered to determine if a source is subject to the operating permit requirements. Once a source is subject, however, the owner or operator may choose how many operating permits to obtain for the source. A single permit may be issued for the entire source, or individual permits may be issued for individual units, buildings, processes, etc. For example, research and development activities may be permitted separately from the rest of a facility, in order to take full advantage of the operational flexibility provisions for constantly changing research and development activities. In addition, portions of a source could be covered under general permits. See discussions below under operational flexibility and general permits.

The configuration for operating permits may, but is not required to, conform to the way in which a source chooses to file APENS. For example, a source may file separate APENs for all of the units at its facility, but a single operating permit can be obtained. Similarly, a source may file grouped APENs for similar units at its facility, and the operating permit could contain a general statement that the types of units exist at the facility, and could then state what the applicable requirement and associated monitoring, recordkeeping and reporting requirements are for that group of sources. The permit does not have to list the requirements separately, and the monitoring, recordkeeping and reporting requirements can be tailored to meet the needs of the source and the Division for that group of sources. SPECIFIC EXAMPLE: Numerous degreasers are located throughout a facility, which is located in the ozone nonattainment area (metro-Denver). A grouped APEN is filed for all of the degreasers. Since Regulation Number 7 applies to the degreasers, they must be addressed in the operating permit. The operating permit choices are: 1) obtain an operating permit for the degreasers only, separate from the rest of the facility; 2) obtain a single permit for the whole facility, and include a general statement/applicable requirement condition as described above for the degreasers; 3) obtain more than one operating permit for the facility, placing the degreasers in whatever permit(s) the owner or operator chooses. The Commission believes substantial flexibility is available for issuing operating permits that the source can most efficiently deal with, while still meeting the Clean Air Act requirements.

2. “Regulated Pollutants”

Once subject to operating permit requirements, a major source must include all applicable requirements and emission units in their application and must address each “regulated pollutant” associated with the source (except for insignificant activities, see below).

The definition of regulated pollutant is to be used strictly for determining what must be addressed in an operating permit once a source is required to obtain the permit. The definition of regulated pollutant has nothing to do with the definition of major source. (See discussion above, regarding the definition of air pollutant).

Pollutants to be addressed in the application include each pollutant for which an ambient standard has been set (and precursors to such standards, such as volatile organic compounds), ozone depleting chemicals (CFCs), any pollutant subject to a standard under regulation Number 6, and any pollutant subject to a standard under the HAPs requirements (including Colorado HAPs).

"Regulated HAPs"

Note that a HAP must be subject to a standard before the applicant is required to address it in the permit application. Once the EPA adopts a MACT standard for a particular HAP, all sources, even those not subject to the particular MACT standard, and even those not in the source category, must address that HAP in applications. In cases where the Commission or Division determines MACT on a case-by-case basis because the EPA has not, the HAP becomes regulated only for the particular source subject to the case-by-case standard. Once the EPA promulgates the list of 112(r) (accidental release) pollutants, those pollutants will be considered to be "regulated" for all sources.

Fees

The definition of regulated pollutant contained in Part A of this regulation is not used for fee purposes. The Colorado Act specifically sets forth which pollutants are to be assessed fees, and the fee pollutants are set forth in Section VI of Part A. A pollutant does not need to be subject to a standard before the Commission can assess fees.

3. Insignificant Activities

Once subject to operating permit requirements, a major source must include all applicable requirements and emission units in their application and must address each "regulated pollutant" associated with the source except for activities, which the Commission has determined are "insignificant." This regulation sets forth to what extent each activity or piece of equipment at a facility needs to be fully described and included in an operating permit.

The Commission has tailored the insignificant list after the Air Pollution Emission Notice (APEN) and construction permit exemptions, to promote consistency and reduce confusion. The lists are repeated in Part C of the regulation, for convenience. The activities and sources listed in the APEN and construction permit exemption Sections are considered to be insignificant activities, with two exceptions. The lower APEN emission de minimis levels are used instead of the higher construction permit de minimis levels for insignificant activity purposes. Since the permit de minimis levels apply to the facility, the Commission does not believe it is appropriate to use the permit levels. The APEN 5 MMBTU per hour boiler design rate is controlling, rather than the higher 10 MMBTU per hour permit boiler exemption. All boilers with design rates greater than 5 MMBTU per hour must be addressed in the application and operating permit.

Exemptions based on emissions, size or production rate must still be listed in the permit. Enough information must be submitted in the application just to identify the equipment as qualifying for an exemption. An asterisk appears next to each activity listed in Part C, which must be listed in the application.

Applications do not have to list activities that are exempted based on category.

Applications cannot omit information needed to determine the applicability of, or to impose any applicable requirements on a source. In addition, the exemptions cannot interfere with fee determinations. Since the mechanism used to assess fees is the APEN and not operating permits, this should not pose a problem for purposes of insignificant activities.

The Commission has added APEN exemptions for research and development and laboratory activities. The exemptions apply to small research and development facilities, and to lab activities that the Commission has determined have a negligible impact on air quality in Colorado. Owners and operators of research and development facilities that are subject to APEN reporting are expected to report emissions from samples received from clients for evaluation, but only to the extent, the information is available. The Commission believes that facilities that accept material for evaluation should have some responsibility and knowledge regarding what is being accepted.

Research and development facilities may continually change the types of projects under investigation, therefore the control efficiency of equipment may not always be known. The Commission has determined that research and development facilities may base APEN reporting thresholds on actual instead of uncontrolled actual emissions. In addition, since owners and operators of such facilities do not always know in advance what projects will be undertaken, the Commission has allowed such sources to report emissions after the fact, in annual APEN updates to the inventory.

Research and development activities are prime candidates for the types of operational flexibility allowed in this regulation (see discussion below). The Commission encourages research and development activities to use the operational flexibility provisions.

Some of the activities were described in the Statement of Basis and Purpose for the Commission's May 1993 Regulation Number 3 hearing. Parties to this hearing have asked for clarification regarding some of the provisions.

The emission levels for triggering APEN reporting requirements are based on uncontrolled actual emissions. The Commission recognizes that in some cases, “uncontrolled” emissions are not easily defined. For example, the uncontrolled emissions from a degreaser may be subject to interpretation. The emissions from this type of operation depend on how often it is used and how fast objects are cleaned in the unit. Uncontrolled emissions could possibly mean that a person is standing at the degreaser using the machine continually, and as rapidly as is humanly possible. The Commission recognizes that calculation of emissions for this and similar operations involves some judgment, and will take into consideration reasonable assumptions used in determining uncontrolled emissions.

The exemption for land development (less than 25 acres in size and 6 months in duration) applies to all land clearing activities, such as preparation of land for housing development, or preparation of land for oil and gas activities to occur.

As stated above, insignificant activity exemptions cannot be used if it, would result in an applicable requirements being avoided. The EPA requires all applicable requirements to be addressed in operating permits. Similarly, APEN and construction permit exemptions cannot be taken if an applicable requirement would be avoided. The Commission has given certain sources an exemption from the applicable requirement provisions, for APEN and construction permit purposes. For example, a source that is subject to Regulation Number 7, but not to a specific source category requirement of regulation Number 7 (i.e. the source is subject only to a case by case RACT determination), may take the APEN exemption based on the 1 ton per year de minimis level. The Commission has determined that RACT for such small sources is usually no control. For construction permits, a source may take an exemption if it is subject solely to a work practice standard of Regulation Number 7. For example, degreasers used in the ozone nonattainment area (metro-Denver) are subject to a specific Section of Regulation Number 7, which requires covers and proper operation. Degreasers in the nonattainment area are subject to a specific Section of the regulation, therefore they must file APENs, however since the Section only requires work practice standards, no permit is required if the emissions are below the permit de minimis levels. It should be noted that since an applicable requirement exists, the degreaser and associated work practices must be addressed in the operating permit. Degreasers in the rest of the State are exempt from APEN and permit requirements if they are below the de minimis levels. Note that the EPA is required to set Maximum Achievable Control Technology (MACT) limits for degreasers in 1994. When the Commission adopts the MACT standards for degreasers, all degreasers subject to the MACT standard will be required to file APENs and obtain permits.

4. Inapplicability Determinations

Operating permits must list all applicable requirements and must state how continuous compliance with the requirements will be demonstrated. The source is provided with protection from enforcement as long as each permit condition and compliance requirement is met (known as the permit shield). The source may wish to obtain enforcement protection for regulations, which do not apply. In such cases, the application must identify which regulations do not apply to the source. These regulations will then be identified in the permit, and the permit shield will apply.

This protects the source in the event that a mistake is made and the regulation really does apply to the source. The source is protected from enforcement action until the permit can be reopened and the correct requirements inserted.

5. Application Form and Checklist

Operating permit applications must contain a lot of complex information, including identification of all applicable (and inapplicable, if the permit shield is to apply) requirements. This can be a daunting task for the applicant. The Commission has directed the Division to develop checklists for use by the applicant. One checklist will identify all data that must be included in an application. Another checklist will identify all air regulations. The applicant can use the latter checklist to identify which regulations apply to their source, and which don't.

The State must submit an application form to the EPA along with the operating permit regulations. The Commission has directed the Division to develop an application form, taking into account suggestions and comments from the public.

6. SIP Equivalency

The Commission has determined that it is appropriate to allow sources to set forth procedures in their permit that will show that a SIP limit is being met through methods that are equivalent to, but do not exactly follow, procedures set forth in the SIP.

For example, suppose a source is required to meet a volatile organic (VOC) compound limit by using a coating that does not contain more than a certain amount of VOC. The source could propose to meet the limit by some other means than using such a coating. Their application would set forth quantifiable, replicable, accountable procedures that would show that they could still meet the limit even though they would not be using the required coatings. Such procedure could consist of using control equipment, or using a combination of complying and non-complying coatings for which the average emissions would meet the VOC limit. Monitoring, recordkeeping and reporting procedures would be set forth in the permit. The procedures must be sufficient to show continuous compliance with the underlying applicable requirement.

This procedure allows sources to show compliance through alternative methods without having to go through the Commission and the EPA for a case-by-case SIP revision. The EPA would review the process during its 45-day review period. The public would have opportunity for comment and hearing.

NOTE: This procedure overrides the requirement in Regulation Number 7, which states that all such alternatives will undergo a case-by-case SIP revision.

7. 112(r) (Accidental Release) Requirements

Operating permits must address any requirements established under Title III (hazardous air pollutants) of the Federal Act, except that the accidental release plans required under Section 112(r) do not have to be incorporated into the permit. The permit must merely state that the source is required to submit a plan to the appropriate entity. The Commission can take enforcement action against a source for failure to submit a plan. Enforcement action cannot be taken for failure of the source to meet any of the requirements contained in the plan.

8. Compliance Monitoring

Operating permits must contain monitoring sufficient to demonstrate compliance with the applicable requirements. Methods and procedures may be set forth in the applicable requirements. If methods and procedures in the applicable requirement are insufficient to demonstrate compliance, the operating permit must “fill the gap” by specifying appropriate methods. Compliance methods may be as simple as recordkeeping, or may require continuous monitoring equipment. The source must state in their application how they will demonstrate compliance. The Division reviews this proposal and agrees with it or recommends something else. The Common Provisions provides the Division with the authority to require monitors. The Division has used, and will continue to use, best engineering judgment to determine when monitors are necessary and feasible. The Commission has determined that in some instances it may be appropriate to require continuous emission monitors, even in cases where the applicable requirement does not specify monitors, and that sufficient opportunity for discussion and appeal are available to the source, therefore monitors can be required even if the applicable requirement does not specifically require monitors.

The EPA is in process of developing and promulgating their enhanced monitoring rules. These rules may speak specifically to continuous monitoring. The Commission will take into account this new rule and determine if the operating permit monitoring requirements should be revisited once the EPA rule is promulgated.

By January 1994, the EPA will publish a list of existing rules, which do not contain sufficient monitoring, or recordkeeping methods, and will develop criteria that could be used to determine what is sufficient. After the rules are identified, the EPA will proceed to revise the rules to make them sufficient. The need for "gap filling" will then decrease.

9. Compliance Certifications

Each operating permit application must be accompanied by a "compliance certification" indicating that all information presented is true and accurate. The certification must be signed by a "responsible official," usually a CEO, of the company. Likewise, compliance certifications must be submitted every six months, indicating the compliance status of the source. Such certifications must also be signed by the responsible official. The burden is on the source owner or operator to ensure that all permit conditions are addressed in the certification, and all information is complete and correct.

The Commission's definition of "responsible official" allows delegation of responsible official authority to plant managers under certain conditions, including prior approval from the Division.

10. Recordkeeping and Reports

The operating permit must contain all recordkeeping necessary to ensure compliance with the applicable requirements. The Federal Act requires such data to be maintained for five years. The Commission has determined that sources need not keep a full five years of data on site for inspection review. Instead, sources are required to make immediately available to the Commission or Division data for the past year, along with the compliance certifications for the past five years. The actual data for the remaining four years must be provided to the Commission or Division within 48 hours of request.

Monitoring data must be reported at least every six months.

The Commission will allow sources flexibility in determining what records are appropriate, and in determining the schedule for reporting, in order to allow coordination with other reporting requirements (such as Community Right To Know, etc.). Such flexibility is allowed provided the requirements of the Clean Air Act are met.

Malfunctions and emergencies - The Commission has adopted the Federal provisions for emergency and malfunction protection, except that sources are required to provide oral notice within two hours of the next working day, and written notice with one month after the emergency occurs. Past experience indicates that sources will most likely not be able to meet the EPA's recommended two-day written notice.

The Commission does not include continuous monitor malfunctions in the emergency provisions. The emergency provisions serve to provide an absolute defense if an applicable requirement is violated. Since the Commission cannot tell if a source is in or out of compliance with an applicable requirement when monitors malfunction, it is not appropriate to include monitor malfunctions in the emergency provisions. Monitor malfunctions which would violate provisions which set specific operating conditions and specifications for the monitor, however, could be granted the emergency protection for those specific performance conditions, if such malfunctions were due to unforeseen circumstances and reported as set forth in the emergency provisions. The Commission has determined that extra protection for monitor malfunctions is not warranted, as procedures and specifications for monitors include performance requirements which take into account the inherent operational fluctuations and abilities of the monitors.

Sources must report any exceedances of standards, which are not due to malfunctions or emergencies “promptly.” The Commission has determined that including such deviations in the six-month monitoring report is sufficient. This will not impair the Division or Commission's authority to assess penalties regarding the deviation.

Public Availability of Reports: Copies of all reports and compliance certifications will be made available at the local health departments. As always, such information is available at the Division offices.

11. State-Only Conditions

Certain Commission regulations are not part of the State Implementation Plan, and therefore are not federally enforceable. The Commission has given sources the option of including state only conditions in operating permits, or of maintaining such conditions in a separate construction permit. This option is available for all state-only conditions except those pertaining to major Colorado HAP sources. Major Colorado HAP sources are required by statute to obtain an operating permit. “State-only” conditions will be listed separately from federal conditions in operating permit. (Sources that are major for federal HAPs must obtain an operating permit, and provisions pertaining to the federal HAPs are federal, not state conditions.)

Since the operating permit is meant to be used as an all-encompassing document for sources and the Division, the source may want to refer to only one document to determine what needs to be done to remain in compliance. If the conditions are included in an operating permit, the source may choose whether or not to have the permit shield, operational flexibility, and other operating permit allowances and requirements apply to the conditions.

State-only conditions do not have to undergo the same procedural requirements as other operating permit conditions. Affected state and EPA review is not required.

Currently, the following regulations are state-only requirements: odor Regulation Number 2, municipal waste combustor Regulation Number 6, Part B. Future Colorado MACT/GACT standards will be state-only requirements.

12. Confidentiality

Applicants are allowed to classify certain information as being confidential in terms of product or processes. In no case may emission information be kept confidential, and in no case may compliance certifications be kept confidential.

Records and reports may be kept confidential, however, instances where this will be allowed will most likely be rare, since emissions data or information related to emissions data may not be kept confidential.

The current confidentiality provisions and procedures remain in effect, however the Commission has directed the Division to examine the provisions and procedures and to recommend improvements.

D. How Long Does It Take To Obtain the Permit?

1. Completeness Review

The Division has sixty days from receipt of an application to determine if all information necessary to process the application is included. If the application is incomplete, the Division must notify the source and request the additional information. Additional information must be submitted by the applicant within a reasonable amount of time. Once a complete application is received, the Division must act on the application within 18 months. The Division must analyze the application, prepare the permit, and ensure that all of the procedural steps as set out below are met. Once all requirements are met, the Division will send the source its fee letter, and will not issue the permit until all applicable processing fees are paid. The fee letter must be sent within 18 months of receipt of a complete application.

2. Public Notice and Hearing

Once the Division analyzes the application and prepares a draft permit, the permit and application must undergo a thirty-day public notice. If a hearing is requested during the public notice, thirty-day notice of the hearing must be provided, and the hearing must occur within sixty days of the notice.

The Commission has provided an opportunity for sources to respond to any public comments received. This source response in no way affects the Division's time constraints for issuing the permit, nor does it affect the permit, which the Division ultimately issues.

3. Affected State Review

During the public notice, a copy of the draft permit will also be sent to any affected, nearby states, for their review.

4. EPA Review

Once public notice and hearing are completed, the Division will make any necessary revisions to the draft permit, and will submit a proposed permit to the EPA for their review. The EPA has 45 days to review the permit. The Division then has up to 90 days to make any necessary revisions to the permit to address EPA concerns, before the permit can be issued.

5. Copies of Application

The applicant must provide a sufficient number of copies of the application for submittal to the EPA, affected states and public notice, including copies for County Commissioners.

E. Renewals

1. Renewal Application Content

Operating permits must be renewed every five years. Renewal applications must undergo all of the review procedures (public notice, EPA review) as the initial operating permit.

Applicants may incorporate by reference any previous application material or permits for portions of the operation which will not change from the initial application. The renewal application may only address operations which will change and which will require new permit terms or conditions. Copies of all material incorporated by reference must be included with the renewal application. All material must be provided for public comment, affected state review, and EPA review.

2. Renewal Application Due Date

The federal rule states that permitting authorities should be able to process "90%" of renewal applications within six months. The federal rule does not mandate that states process renewals within six months. The rule gives states flexibility to require applications for renewals, and specifically states that other times may be approved, which are necessary to issue the permit before it lapses. The application can be due as soon as 18 months before expiration, and as late as six months. Renewed permits must be issued before the old permit expires.

As described above, the public comment, hearing notice, hearing, EPA review, and revision periods required in the Federal rule take up 220 days, or approximately seven and a half months. The time allotted for these activities is fixed in the Acts and rules (except for the time allowed for States to revise draft permits, based on EPA review). The amount of time for actual review of the application itself varies depending upon the type of application. A breakdown of the allotted times follows:

Public Notice:	30 days
Hearing:	60 days
EPA Review:	45 days
Division Response:	90 days
TOTAL	220 days

Two hundred and twenty (220) days is the minimum required. No time is allotted for revising the permit between each step as necessary, nor for transmitting the permit from one step to the next. The 220 days is required for public notice and EPA review only, it does not include any time for the Division to actually review the application and draft a permit.

Sources are allowed to seek judicial review if a permit is not issued in time. This could potentially result in wasted Division and court resources dealing with an impossible situation. In addition, the EPA may determine that the program is not adequate if the Division continually fails to issue renewed permits before expiration. Finally, if permits are not issued in time, the EPA can revoke and reissue permits, or can terminate the permits, in which case the source's right to operate ceases.

Given that the notice and review procedures alone take 220 days, and the allowed flexibility, and the requirement that renewed permits be issued before expiration, the Commission has determined that it is not reasonable to allow renewal applications to be submitted as late as six months before expiration. Nine months may be adequate if hearings are not requested for such renewals, however, no one can predict how many applications will or will not require public hearing. It would not make sense to accept applications only six or nine months before expiration, knowing that if a hearing is requested, the new permit will not be issued before expiration. The twelve months will give the Division sufficient time to review the application, and in addition, will give the source some time to ensure that they have submitted a complete application before the permit expires. Sources are allowed to update their applications up to the time a draft permit is issued for public notice. This will allow sources a chance to address any last minute market considerations or changes in their application.

The Division will send written notice of the need to apply for a permit renewal to permittees six months prior to the date a renewal application is due. This notice is to aid permittees, and the failure of the Division to provide notice to any individual permittee is not contended to be used as a defense for the failure to apply for a permit renewal.

As sources and the Division gain experience with the new operating permit program, the Commission and the Division will determine if the timeframe for renewals can be shortened. The first renewals will not be due until the year 2000.

F. Reopenings

Operating permits must be “reopened” during the term of the permit if new regulations become applicable to the source, if a mistake is found in the permit, or if additional measures need to be incorporated to ensure compliance with applicable requirements. A permit is reopened to address only the new requirement or correction, not to address the entire permit. The Division must give the source 30 days notice before reopening the permit. Reopenings must undergo all of the same procedures and requirements as the original permit (notice, EPA review, etc.). The Commission will allow sources the option to reopen an entire permit instead of just the necessary portion. This would require, however, that a source be able to submit a complete application for renewal within 30 days of notice, so that the Division can meet the 18-month deadline.

G. Modifications

States must adopt expeditious procedures for processing changes that require a modification to a permit.

1. Administrative Modifications

   Administrative modifications are *minor changes to the permit, such as change in owner, more stringent monitoring requirements, or correction of typographical errors. The change at the source can be made upon submittal, and the Division must revise the permit within 60 days. No public notice or EPA review is required. The original expiration date does not change when administrative modifications are made.

2. Minor Modifications

   The existing construction permit program requires sources to obtain construction permits before they construct or modify. Revisions to construction permits are required before any changes at the source are made. In contrast, the Federal rule allows changes to be made without revisions to the operating permit, provided no SIP requirements are violated. Sources are allowed to make "minor modifications" upon notice to the Division. The source must supply a draft permit, which is submitted for affected state and EPA review. The permit is revised within 90 days. No public notice is required at the time the modification is made. The Commission was faced with a dilemma. Since the construction permit program is a SIP requirement, sources would not be allowed to make minor modifications without first obtaining a construction permit. This in effect would negate the operational flexibility envisioned in the Federal Act.

   Only certain modifications at the source may qualify as "minor modifications" for operating permit purposes. The change cannot be a "Title 1" modification. Title I contains requirements applicable to new sources. Title I revisions include the following changes:

   1. Modification that triggers Prevention of Significant Deterioration and New Source Review (significant net emission increase)

      The significant levels (defined in Part A of this regulation) are based on the potential to emit of a source or modification. Since no construction permit is in place to limit the potential to emit of a minor modification, all minor modifications will be triggered based on potential emissions, not actual emissions.

   2. Modification which triggers New Source Performance Standards (NSPS) (Any change that increases the amount of any air pollutant) - This definition only applies to specific NSPS sources, unless it is referenced in an applicable requirement

   3. Modification that triggers Section 112 (hazardous pollutants). EPA will be adopting "de minimis" levels that will trigger a modification.

   Minor modifications cannot involve any significant change or relaxation in monitoring, recordkeeping, or reporting requirements. Minor modifications also cannot violate any permit condition, which the source has voluntarily obtained in order to limit potential emissions for avoidance of requirements (such as PSD requirements).

The EPA expressed their concern regarding the construction permit SIP requirements and minor modifications. The Commission has determined that it is appropriate to submit a SIP revision for the construction permit program, in order to allow sources the flexibility allowed under minor modifications. The Commission will allow minor modifications under the operating permit procedure, and changes before obtaining a permit, however all substantial requirements needed for a construction permit must be met. These requirements include ambient modeling to assess the modification's impact on air quality in Colorado, as required in the SIP. As under the current construction permit program, minor modification procedures cannot be used to circumvent PSD or NSR requirements by making individual changes, which together would otherwise trigger PSD or NSR. The enforcement protection of the permit shield does not apply to these modifications. Sources should be confident that all applicable requirements would be met before submitting a change as a minor modification. If the source errs in its determination, the Division, the Commission, and the EPA can take enforcement action against the source and the source's right to operate under the modification is terminated (the source must revert back to the permit as it existed before the modification was requested).

Upon permit renewal, the minor modification undergoes public notice along with the rest of the permit, and the permit shield can be extended to the minor modification provisions.

3. Significant Modifications

Significant modifications are changes at the source which are not administrative modifications, and which do not qualify as minor modifications. Such changes trigger PSD or NSPS, etc., or involve significant changes in or relaxation of monitoring, recordkeeping and reporting requirements. A revised permit must be obtained before the source is allowed to commence construction for the change.

A source may choose to obtain a revision to its operating permit, or it may choose to obtain a construction permit before making the change. Significant modifications to operating permits must undergo all of the public notice and EPA review requirements, therefore a source should plan on submitting its application well in advance of making the change. If a construction permit is obtained first, the source should apply at least three to four and a half months in advance (except for PSD sources, which should plan 12 months in advance). Once the construction permit is obtained, the source may commence construction. The conditions of the construction permit do not need to be incorporated into the operating permit until renewal, unless more than three years remains in the term of the operating permit, in which case the operating permit must be reopened, and the significant modification provisions incorporated.

H. Operational Flexibility

The Federal rule requires a State's program to include operational flexibility provisions, which allow a source to make certain changes without having to obtain a modification to their operating permit. The changes are simply incorporated into the operating permit when it is renewed. The types of operational flexibility are described briefly below. Subcommittee papers and fact sheets, which explain the provisions in more detail, and give specific examples, are available at the Division and Commission offices. The Commission has directed the Division to devise simplified explanations of all of the provisions.

"502(b)(10)" Changes (named after a Section of the Federal Act): A source is allowed to make a change, which would violate an express permit term, provided no applicable requirements are violated. The source can make the change after a seven-day advance notice to the Division. The permit shield does not apply. The Commission will allow sources to revert back to the original permit term, provided seven-day notice is given to the Division. The permit shield can then apply again to the provision, which is contained in the permit.

Permit Caps: A source may ask for an upper limit in total facility emissions. Changes may occur within the facility, as long as the upper limit is not exceeded, and all applicable requirements are met. The permit shield applies to these changes. Seven-day notice is required before the change is made. This type of operational flexibility may be suitable for research and development facilities.

Alternative Scenarios: The source can identify various operational scenarios in its application, along with the applicable requirements and compliance demonstrations. The source can then switch from one scenario to another without notification to the Division. The permit shield applies to these changes.

Emission Trading Based on the Permit: The applicant can request that the trading provisions (for netting out) provided for in Part A of this regulation be incorporated into their operating permit. As long as all of the provisions are met, the source can use the provisions to make changes without notification to the Division.

Off Permit Changes: These changes can be made at the source with seven-day notice to the Division. The changes involve activities that are not addressed in the operating permit. The same qualifications as those for minor modifications apply to these changes (cannot be Title I modifications, significant monitoring changes, etc.) Note that the same SIP concerns apply to these changes that are discussed above under minor modifications. A construction permit would be required before these changes could be made. The Commission has decided to submit a SIP revision to allow these changes.

Emission trading based on the SIP: This is the only federally allowed operational flexibility provision that the Commission did not adopt. This provision would allow sources to use the emission trading provisions of Part A without specifically stating the procedures in the permit. The Commission does not currently have an approved SIP that would allow this, therefore the EPA would not approve this procedure at this time. The EPA is expected to develop guidelines for approvable SIPs within two years. The Commission will consider this provision once it is apparent what the EPA would approve.

I. General Permits

General permits are standard permits that apply to specific source categories. The sources in the category have similar applicable requirements and similar monitoring, recordkeeping and reporting requirements. The general permit will include criteria by which a source may qualify for the permit. Sources that are out of compliance may not qualify for a general permit, since a separate individual compliance plan would be required. The general permit undergoes one-time public notice and hearing and EPA review when it is initially developed. Qualifying sources can use standard, simplified applications and obtain the general permit without having to go through the entire application process (public notice and hearing) individually. A list of all sources that have been issued a general permit shall be maintained by the Division and made available upon request.

The general permit (as originally developed) undergoes five-year renewal, including public notice and EPA review.

General permits will also be developed for the construction permit program, and will usually be identical to the general operating permit for that source category. Existing sources that have not obtained a general construction permit through the construction permit program (probably because a general permit did not exist at the time a construction permit was obtained) may operate under the general operating permit within 60 days of submitting a complete application for the permit, which corresponds with the amount of time allowed for a completeness determination. The application shield becomes effective upon submission of a complete application. The Division will issue the general permit to the source upon completion of the analysis. The permit shield becomes effective upon issuance of the operating permit.

Sources which receive a general construction permit through the construction permit program may operate under the general permit as an operating permit 60 days after a complete operating permit application is submitted, provided the required compliance demonstration has been performed in the required time (180 days). Such source must apply for the operating permit within 12 months of commencing operation. Once such application is received and determined to be complete, the Division will issue a certification, which states that the construction permit now becomes the operating permit.

General permits will ideally be useful for minor sources that will be subject to operating permits at a later date. Minor sources are more likely to be subject to similar applicable requirements. The Commission has directed the Division to devote resources as they become available to identification of sources that would be suitable for general permits and to the development of general permits. Candidates for general operating permits include sources that become subject to new MACT/GACT standards (i.e. dry cleaners), or existing and new NSPS sources (i.e. asphalt plants).

The Commission will allow major sources to have general permits as part of their overall operating permit. As general permits are developed, major sources may use them. The source would just reference in their initial or renewal application that they have a general permit. General permits, however, cannot be issued to major sources if the issuance of the general permit would cause a violation of any of the applicable requirements in any other operating permits they have, or if issuance of a general permit would trigger a Title I or Title III modification. The Commission will allow general permits to be used for an entire major source only in those instances where the use of general permits is appropriate (homogenous, straight-forward sources).

J. Title III (Hazardous Air Pollutant Requirements)

The provisions of Title III must be implemented through the operating permit program. As discussed above, all major sources of HAPs must obtain an operating permit. As the Commission adopts MACT standards, the permit must be reopened to include the new requirements.

As the EPA promulgates new MACT standards, they will decide if minor sources as well as major sources affected by the standard must obtain operating permits.

Once the EPA approves the State's operating permit program, the Division and Commission must begin making case by case MACT determinations for new major sources and modifications, if the EPA has not yet set a MACT standard for that category. The EPA will be setting emission levels at which modifications are triggered.

Once the EPA approves the State's operating permit program, if the EPA fails to meet its mandated deadline for setting a particular MACT standard, the State must determine MACT for that source category within 18 months. Permits will be reopened to incorporate the State MACT standard. Once the EPA determines MACT for the category, permits may need to be reopened again, and sources may need to retrofit their units, depending upon the difference between the State and EPA MACT determinations.

K. Title IV (Acid Rain Provisions)

The Commission is required, and fully intends, to adopt the acid precipitation rules and requirements as promulgated by the EPA, and to implement the requirements through the Title V permits, as also required under the Federal Act.

Title IV sources (power plants) are required to submit the Title IV portion of their operating permits by January 1, 1996. The permits must be issued by December 31, 1997. The EPA is planning on having all of the requirements and forms finalized so that Title IV sources can apply for Title IV requirements at the same time they apply for their initial operating permit. This could help avoid re-opening of the permit. To facilitate this, the Commission has determined that Title IV sources should be included in the last group of existing sources required to apply for operating permits (due one year after EPA approves the program, see discussion above).

The Commission also intends to adopt provisions related to the WEPCO rule promulgated by the EPA, which deals with Clean Coal Technology Projects and other modifications at utilities. The rule is currently slated for the spring of 1994 in the Commission's regulatory agenda. In the interim, the Commission and Division will continue the existing policy of treating such projects as allowed by the EPA. Also, the Commission wishes to encourage Clean Coal Technology Projects, which are used to develop and identify better methods of controlling and preventing air pollution. The Commission has directed the Division to consider research and development factors, and the importance of developing new technologies, if enforcement action may be necessary due to violations related to such projects.

II. Construction Permit Program

A. Synthetic Minors

As discussed above, construction permits are the vehicles through which sources can obtain federally enforceable limits on their emissions in order to avoid the operating permit requirements. In some cases, sources may also choose to obtain limits to avoid PSD or NSR requirements. Such synthetic minor permits must undergo public notice in order to be federally enforceable.

B. SIP Equivalency

The Commission has determined that it is appropriate to allow construction permit sources to use the SIP equivalency procedure that is provided for operating permits in the Federal Act. Current regulations, such as Regulation Number 7, require a case-by-case SIP revision for equivalent procedures, which involves public notice, a mandatory Commission hearing, and EPA approval. The new SIP equivalency provisions override Regulation Number 7 provisions. All SIP equivalency proposals require public notice, opportunity for hearing (but not mandated if not requested), and EPA review. The Commission will require such construction permits to follow the PSD track, which requires public notice and an opportunity for public hearing. The EPA will review the proposal during the public comment period.

C. Minor Modifications and Operational Flexibility

The Commission has extended most of the operational flexibility provisions directly to the construction permit program, since no modification to a permit is required. These provisions include Administrative Modifications, Alternative Scenarios, Emission Trading Based on the Permit, and Permit Caps.

The remaining operational flexibility provisions, and the minor modification provisions are not available through the construction permit program, however sources may obtain these additional allowances by voluntarily applying for an operating permit.

D. General Permits

The Commission has determined that the general permit process will be allowed only for the operating permit program. The general application and permit forms, however, should be used for construction permits as they are developed. The Colorado Act requires new sources to obtain a construction permit before commencing construction, therefore the source must have their construction permit in hand before constructing. In addition, Regulation Number 3 requires certain sources to undergo public notice before construction. The Commission believes that notice should continue to be provided to the public where appropriate, before a source constructs near them.

As discussed above under general operating permits, the Division will identify candidates for general construction permits as resources are available. The same sources identified in the discussion above are candidates for general construction permits. In addition, general permits may be suitable for sources wishing to obtain synthetic minor status, such as emergency and backup generators.

III. Emission Fees

Though it was not noticed for this hearing, some parties indicated they had concerns regarding the Division's policies for charging annual emission fees. A request was made to include the Division's policy in the regulation. The Commission believes the Division should be given the flexibility to determine the most efficient and reasonable procedures and policies for assessing fees, therefore the policy will not be included in the regulation. The Division will prepare a written policy for public distribution on the methods it will use to calculate and collect emission fees.

IV. Where Can a Source Go For Assistance In Understanding the New Requirements?

A. Small Business Assistance Program

Even though existing minor sources (small businesses) are exempt from the operating permit program, small businesses will need help understanding the construction permit program requirements. In addition small businesses need to understand the operational flexibility requirements, and need to understand if it would be advantageous for them to apply for an operating permit. The EPA may decide that some minor sources should be required to apply for operating permits as new MACT and NSPS standards are promulgated.

Last September, the Commission approved a plan for developing a Small Business Assistance Program. The program is under development and is expected to be implemented and fully operational by November of 1994. In the interim, Division staff is available to answer any questions, which a small business may have regarding air quality regulations and requirements.

Some information has already been developed regarding APEN requirements and simplified calculation procedures.

B. Pre-application Meetings

This regulation provides opportunity for any source to request a preapplication meeting with the Division, to discuss what requirements may be applicable to a source.

C. Division Staff

Division staff will remain available to all sources and the public, to answer questions regarding the operating permit and construction permit programs.

I.M. Adopted March 17, 1994

Revisions to Regulation Number 3 Part A, Section II.E.

Pursuant to Section 112(n) of the federal Clean Air Act, the US Environmental Protection Agency (EPA) is required to conduct an extensive study to create a reliable estimate of the existence or quantity of hazardous air pollutants (HAPS) emissions from certain sources such as utility and non-utility industrial boilers. Another study under Section 112(n) relates to emissions from publicly owned treatment works (POTWs). Section 112(n) recognizes that technological limitations exist on the ability to reliably estimate these emissions. The required studies are complex and costly, and EPA has indicated that the utility and non-utility boiler study will not be concluded until the end of 1995. The original time frame contemplated by Congress anticipated that the study would be completed by November 15, 1993. Unlike the mandatory boiler study, the Clean Air Act merely authorized EPA to study POTW emissions and EPA has decided not to continue with the study. Thus, the emissions information that was originally expected will not be developed in time to facilitate APEN reporting by December 1994. Since the emissions from facilities that treat municipal-type wastewater are virtually identical to those from POTWs, the lack of POTW emissions data also affects this category of sources as well.

During rulemaking in 1993, a deferral for HAP reporting from boilers and other listed sources was granted until six months from the date federal studies are complete or until December 31, 1994. This deferral appears in Part A, Section II.E.

This was based in large part on the recognition that it would be unreasonable and infeasible to expect these sources to attempt to duplicate the EPA studies and to provide meaningful data earlier than EPA. The postponement was not intended to forgo reporting obligations (it applied to emissions points and processes only, not to entire facilities), but rather, to recognize technical limitations and to await (not duplicate) the results of the EPA studies. The Statement of Basis, Specific Statutory Authority and Purpose for the 1993 rulemaking session explained, “Due to ongoing studies aimed at quantifying their emissions of non-criteria pollutants, the Commission has deferred APEN reporting requirements for five source categories until six (6) months after the studies have been completed or December 31, 1994, whichever is earlier.”

It is now apparent that neither the EPA boiler study nor the POTW study will be timely completed for effective implementation of ' II.E. The clear intent of the regulation is to postpone report of HAP emissions by sources such as utility and non-utility industrial boilers, POTWs and municipal-type wastewater treatment works, pending the results of the ongoing EPA studies. The rationale for this intention is that it is technologically infeasible for these sources to comply with this reporting requirement without the results and utilization of the EPA studies. The original intent and rationale for a postponement continue to pertain at this time and provide the basis for this rulemaking.

Additionally, highly costly tests would be required if reporting is required prior to the results of the EPA studies. There is a serious question about the accuracy of any reporting prior to the conclusions of the EPA studies. Moreover, if sources attempt to formulate tests, inconsistencies with testing procedures, resulting data and interpretation thereof would result, thereby further complicating issues for impacted sources and administration by the state. It is believed that using the EPA studies results will allow avoidance of such costs and result in more accurate APENS, which, in turn, will facilitate easier administration by the state.

During the Commission's prior deliberations on this matter, the Commission expressed intent to revisit this December 31, 1994 deadline if the EPA studies would not be timely completed. Impacted sources must be placed on notice as early as possible concerning any deadline because lead-time to conduct studies and extensive planning would be necessary. This rulemaking postpones to December 31, 1995, or six (6) months after the EPA studies are complete, whichever are earlier, for utility and non-utility industrial boilers, and POTWs and municipal-type wastewater treatment plants. This decision furthers the Commission's original intent concerning the underlying reporting. This issue may be revisited in the future if the information expected to be derived from the EPA studies continue to be delayed.

The specific authority for this regulation is contained in the Colorado Air Pollution Prevention and Control Act, 1992 as amended. The Legislative Declaration, ' 25-7-102, recognizes that an accurate emission inventory is needed to adequately manage air resources in Colorado. Section 25-7-109.3 provides authority for regulating HAPs. Section 25-7-114.1 provides authority for requiring APENS, and for allowing exemptions from the requirements. Section 25-7-109(4) requires the Commission to promulgate regulations pertaining to HAPs.

I.N. Adopted May 19, 1994

Findings Regarding the Basis for the Emergency Rule Revisions to Regulation Number 3, Concerning the Operating Permit Program

The Air Quality Control Commission held this emergency rulemaking hearing on May 19, 1994, after such notice of rulemaking as practical, to postpone the November 15, 1994 deadline for submission of operating permit applications by those existing major stationary sources previously notified by the Division to submit applications by that deadline. The revisions to Regulation Number 3 would phase-in the required submission of operating permit applications by these sources over a three-month period beginning January 1, 1995. The Commission finds that the immediate adoption of this emergency regulation is imperatively necessary for the preservation of the public welfare and to ensure compliance with the federal law, and that compliance wit normal notice requirements for rulemaking would be contrary to the public interest.

This emergency regulation is necessary for three reasons. First, the Environmental Protection Agency (EPA) has issued a formal letter to the State of Colorado advising the State that its Title V operating permit program submission, contained in the Commission's Regulation Number 3, must be revised in order to obtain federal approval of the State operating permit program in accordance with the mandates of the federal Clean Air Act. The earliest date by which the Commission is able, pursuant to law, to promulgate such revisions and make them effective is September 30, 1994. Sources that are subject to the operating permit application deadline of November 15, 1994 will not have sufficient time to complete their applications and submit them by that time after the promulgation of the revisions.

Secondly, and more importantly, it was not until the 1994 Colorado legislative session that the legislature appropriated money for the necessary FTE's at the Division to process operating permit applications and to implement the program. The money will not be available for the Division's use until July 1994, and given the shortcomings of the State personnel system, the new Division employees will not, in all likelihood, begin their employment until on or around November 1, 1994. If the Commission did not act on an emergency basis to postpone the application deadline of November 15, 1994, persons subject to the application deadline will be required to apply to the Division prior to its ability to fully train the new employees or to provide sources any services necessary under the mandates of the federal Clean Air Act. This imposes an unnecessary burden on sources, as well as the Division.

Finally, the federal Clean Air Act requires that the State have sufficient money to cover the direct and indirect costs of implementing the Title V program. These costs include those necessary for the Division to review permit applications and issue permits within certain established timeframes, as well as to perform inspections and other compliance monitoring actions. The EPA has indicated to the State, in a letter dated April 8, 1994, that if the State does not have sufficient money to cover these costs, the EPA cannot grant any type of approval, including interim program approval. In this event, EPA must take over the Title V program in Colorado, and has threatened to impose sanctions on the State. Therefore, the Commission must act on an emergency basis to postpone the operating permit application deadline in order to give sources sufficient advance notice of the changed deadline and in order to ensure that the Division will be able to review and process those applications within the timeframes set forth in the federal Clean Air act.

In light of the evidence presented at the emergency hearing on the difficulty and cost to sources of completing operating permit applications, given the short timeframe between the Commission's ability to revise and make effective changes to Regulation Number 3 required by the EPA and the current deadline; on the difficulty and cost of evaluating operating permit applications filed with the Division and of the Division's inability to perform services required by the current Regulation Number 3 and deadline of November 15, 1994; and on the EPA's letter evidencing its concern that the Division will not be sufficiently financed to perform those federally-mandated services, the Commission finds that an emergency exists which warrants the passage of this emergency regulation. The Commission does not believe that this emergency regulation represents any risk to public health.

I.O. Adopted August 18, 1994

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority, and Purpose comply with the requirements of the Administrative Procedures Act, Section 24-4-103(4), C.R.S. (1994) for adopted or modified regulations.

Basis

The 1990 Amendments to the Federal Clean Air Act require states to implement an operating permit program. Failure of a state to implement the operating permit program will result in EPA sanctions.

On July 15, 1993, the Air Quality Control Commission adopted revisions to Regulation Number 3 necessary to implement the State's operating permit program. The Commission also adopted revisions to Regulation Number 3 that were necessary to integrate the operating permit program with the existing construction permit program, and that were necessary to extend certain provisions of the operating permit program to minor sources not otherwise subject to the program.

On November 5, 1993, the Governor submitted Colorado's operating permit program to the Region VIII, Environmental Protection Agency (EPA) for its approval. The EPA reviewed Colorado's submittal and on April 8, 1994 responded to the State's submittal, noting certain deficiencies in the program. These deficiencies must be corrected and the revisions submitted to the EPA no later than October 1, 1994. The Commission promulgated these revisions to Regulation Number 3 in response to EPA's comments. EPA also noted certain legislative changes that are required in order for the State of Colorado to obtain full approval of its operating permit program. Therefore, at this time, the Commission contemplates that the State will receive interim approval of the operating permit program; within 18 months after receiving the interim approval from EPA, the State must submit legislation that will satisfy all of the federal requirements.

The EPA in its April 8 letter required the Commission to revise in certain respects the Statement of Basis, Specific Statutory Authority, and Purpose for Revisions to Regulation Number 3 that was dated July 15, 1993 and which was submitted to the EPA on November 5, 1993. The required revisions are reflected in this Statement of Basis, dated August 18, 1994.

Specific Authority

The specific authority for this regulation and its revisions is contained in the Colorado Air Quality Control Act, 25-7-101, et seq. (1989 & 1994 Supp.). Section 25-7- 105(l)(A)(1) requires the Commission to adopt into the State Implementation Plan all requirements of the federal act. Sections 25-7-105(12) provide authority to implement the operating permit provisions of Title V of the federal act. Section 25-7-105.1 sets forth the federal enforceability provisions. Section 25-7-106(6) provides authority for monitoring, recordkeeping and reporting requirements. Section 25-7-114.1 provides authority for APEN requirements and for allowing exemptions from the requirements. Section 25-7-114.2 through 114.5 set forth construction and operating permit requirements, and application and public participation requirements. Commission action in promulgating these revisions is taken pursuant to Sections 25-7-105 to 109 and 25-7-114.

Statement of Basis and Purposes of Changes to Regulation

1. In Part A, I.B.9.e., the definition of “applicable requirement” concerning enhanced monitoring was changed to comply with the federal definition, incorporating all monitoring and enhanced monitoring requirements established pursuant to Sections 504(b) and 114(a)(3) of the federal act.

2. In Part A, I.B.22., the definition of “federally enforceable” was amended to mirror the definition found in Section 25-7-105.1 of the Colorado Air Pollution Prevention and Control Act.

3. In Part A, I.B.35.D.e., the Commission exempted any modifications that are not “major modifications” from the definition of Title I modifications, for sources with operating permits that utilize the minor permit modification procedures set forth in Part C, Section X.A. This is because EPA cannot allow the minor permit modification procedures to be used for Title I modifications; therefore, for the minor permit modification procedures to have any use at all, this change was necessary. All modifications must still comply with the requirements of 40 CFR Part 51.165, as reflected in Regulation Number 3, Part B, IV.D.1.a.-h. In effect, this change merely allows an operating permit source to modify without going through the procedural requirements of obtaining a construction permit, but still requires the source to meet all substantive requirements.

4. Part C, X.A.5., XII.A.1 and XII.B. were revised to reflect the change described in paragraph Number 3 above.

5. Part A, I.B.62, a definition of “state-only condition” was added. This term is used throughout Regulation Number 3.

6. In Part A, Section II.D.1.aaa. (APEN exemptions), and in Part C, Section II.E.3.aaa. (insignificant activities for operating permits), the Commission exempted storage of lubricating oils from notice and permit requirements. Because new source performance standards apply to storage tanks of capacity > 40,000 gallons, the Commission revised these provisions to ensure that the exemptions would not allow a source to avoid new source performance standards.

7. In Part A, II.D.5., the Commission established an administrative procedure whereby the Division could process and grant requests for exemptions from permit and APEN requirements. However, this amounted to a SIP revision without allowing EPA the opportunity to review and approve the revisions. Therefore, the Commission amended this procedure to require that the Commission adopt the exemptions pursuant to rulemaking, on an annual basis, and submit the revisions to EPA prior to a source being able to take the exemptions.

8. Part A, IV.B. contains operational flexibility provisions concerning “trading based on the permit.” The federal rule allows a source to take advantage of any EPA-approved emissions trading program, without the need for a SIP revision. At this time, Colorado does not have an EPA-approved generic emissions trading program. To obtain EPA approval of the State's operating permit program, the Commission amended this provision to clarify that the trading based on the permit may be utilized only if the SIP contains an EPA approved trading program.

9. At Part B, III.A.6., the Commission clarified that the provisions of IV.D.1.a.-h. must be met in order for the source to utilize the minor permit modification procedures. Previously, the Commission had merely cross-referenced Section IV.D.1., which contained time periods for review that conflicted with the minor permit modification procedures.

10. At Part B, IV.D.1.i. and in Part C, V.C.1.c., the Commission had provided authority for a source to use an alternative emissions limitation that is as stringent as an applicable requirement so long as the permit contained provisions to ensure that the limitation is quantifiable, accountable, enforceable and based on replicable procedures. The preamble to the operating permit rule, 40 CFR Part 70 makes clear that it is the SIP, not the permit that must contain these replicable procedures. Therefore, in Part C, the Commission amended V.C.1.c. to clarify that the alternative emissions limitation may be taken only if it is allowed by the SIP; then in Part B, IV.D.1.i., the Commission removed the alternative emissions limitation language because the SIP must itself contain the replicable procedures. EPA is expected to have guidance in the near future on alternative emissions limitation.

11. In Part C, III.B.7., the Commission clarified that a source applying for a combined construction/operating permit must first obtain the permit prior to commencing construction.

12. In Part C, III.C.12., the Commission clarified that ambient air quality standard considerations in issuing permits apply only to temporary sources (pursuant to the federal law), and to new and modified sources applying for a combined construction/operating permit (pursuant to state and federal law). Although this was always the case, the provision previously could have been read to allow consideration of these standards in issuing operating permits.

13. In Part C, V.B.3. & 5., the Commission allowed minor sources to voluntarily opt into the operating permit program in order to gain the operational flexibility of operating permits. These minor sources, however, could avoid the public participation, EPA and affected state review provisions. The EPA was concerned that synthetic minor sources would be able to opt into the program, and in so doing would lose their federally enforceable limitation (imposed by the construction permit which would be lost), without going through the required public participation and EPA and affected state review. The Commission revised these provisions to clarify that synthetic minors opting into the program must go through all the necessary reviews. In addition, major sources of Colorado-only HAPs need not go through the public review process attendant to operating permits. The EPA was concerned that the provision could be read to allow federal HAP major sources to avoid public participation and review. The Commission clarified these provisions to ensure that such was not the case.

14. In Part C.III.B., the Commission revised the schedule for submission of operating permit applications by the remaining two-thirds of sources in order to reflect the anticipated interim approval date of the operating permit program of January 1, 1995. This revision would also allow the Division to notify some sources of the need to submit an application before January 1, 1996, but on or after November 15, 1995, upon twelve months' notice.

Changes to the Statement of Basis and Purpose dated July 15, 1993

I.C.2. “Regulated HAPS”

Revise this paragraph to read:

Note that a HAP must be subject to a standard before the applicant is required to address it in the permit application. Once the EPA adopts a MACT standard for a particular HAP, all sources, even those not subject to the particular MACT standard, and even those not in the source category, must address that HAP in applications. In cases where the Commission or Division determines MACT on a case-by-case basis because the EPA has not timely promulgated a MACT standard for a source category or subcategory of sources, the MACT becomes applicable to all sources within that source category, pursuant to 112(g) of the federal act. In cases where the Commission or Division determines MACT on a case-by-case basis for an existing source that modifies prior to promulgation of an applicable MACT standard, the HAP becomes regulated only for a particular source subject to the case-by-case standard, pursuant to 112(g) of the federal act. Once the EPA promulgates the list of 112(r) (accidental release) pollutants, those pollutants will be considered to be “regulated” for all sources.

I.G.2. Minor Modifications

Revise the second paragraph under this heading to read:

Only certain modifications at the source may qualify as “minor modifications” for operating permit purposes. The change cannot constitute a “major modification” as that term is defined in Part A, Section II.B.35.B. The change cannot otherwise be a “Title I” modification. Other Title I requirements are applicable to new sources. These Title revisions include the following changes: (same).

I.H. Operational Flexibility

Emission Trading Based on the Permit: Revise this paragraph to read: The federal rule allows a source to change its operations, using the emissions trading provisions of an EPA-approved SIP to net out and avoid the need to revise its permit. At this time, the emissions trading provisions of Part A, Section V, have not been approved by EPA as generic trading provisions. Therefore, until the Colorado SIP contains a generic emissions trading policy approved by EPA, each emissions trade request will require a case-by-case SIP revision. EPA is intending to provide guidance for an emissions trading program in the near future.

I.P. Adopted March 16, 1995

Revisions to Regulation Number 3 Construction Permit Program

Background

At the request of the U.S. Environmental Protection Agency, Region 8, the Air Quality Control Commission adopted amendments to Regulation Number 3, Parts A and B, in order to clarify how the provisions relate to each and the federal regulations. These changes were necessary in order to gain federal approval of the State Implementation Plan.

Specific Statutory Authority

The Specific authority for this regulation is found in the Colorado Air Quality Control Act. Section 25-7-105(1) provides that the Commission shall promulgate such rules and regulations as are consistent with the legislative declaration and necessary for the proper implementation and administration of the Colorado Pollution Prevention and Control Act, including a comprehensive state implementation plan which shall meet all requirements of the federal act and shall be revised whenever necessary or appropriate. Section 25-7-109 provides that the Commission shall adopt, promulgate and from time to time modify or repeal emission control regulations that require the use of effective practical air pollution controls. Section 24-4-103 provides the rule making procedure followed during the promulgation of this rule. Section 25-7-110 provides the specific Commission procedures followed during the setting of standards and regulations. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions.

Purpose

Most of the amendments to Regulation Number 3, Parts A and B are of a general housekeeping nature. However, three provisions require greater explanation:

The Division originally proposed adding a definition of “construction” consistent with the federal definition for New Source Review and Prevention of Significant Deterioration. To eliminate the potential for confusion and conflict with the state statutory definition, the Division has removed that provision from the amendments. There is a definition for construction, which applies to Regulation Number 3, Parts A and B, in the General Provisions Regulations; that definition matches the state statutory definition.

The changes to the definition of “Net Emissions Increase” in Part A, Section I.B.37 needs some explanation. In order for an increase or decrease to be creditable, the Division could not have relied on the increase or decrease in issuing a permit under Regulation Number 3. Also, the source has two choices for proving the extent of the emissions increase or decrease: (1) the source submits or has on file an APEN indicating the baseline emissions rate and then submits a revised APEN within one year after making the increase or decrease (the difference between the two APENs is the amount of creditable increase or decrease) or (2) the source provides credible, demonstrable evidence to the Division of actual emission rates both before and after making the increase or decrease (the source can make the before and after demonstration any time during the contemporaneous period).

The general constructions permit provisions of Part B, Section IV.J. were amended to provide greater detail of how the Division would actually implement the provisions. The Division retains the discretion to determine whether it will issue a general construction permit, although a source or group of sources can request that the Division do so. These provisions are meant only for minor sources, including sources wishing to obtain federally enforceable limits on their potential to emit, making them synthetic minors. The contents of a general construction permit will vary depending on the type of source involved. The Division will state in the general construction permit that goes out for public notice all the criteria a source must meet in order to qualify for coverage under the permit, the method of application (including specific application forms if different from a standard construction permit), the deadline for application, and other requirements as necessary and specified in the permit (i.e. monitoring, reporting, and recordkeeping requirements). After receiving an application to be covered by a general construction permit, the Division will determine whether the source fits within the intended coverage of the general construction permit, meets all applicable requirements, and satisfies all the criteria as laid out in the general construction permit. If the Division grants a source the right to construct and operate under a general construction permit, there are still some situations under which the Division may require the source to obtain an individual construction permit (i.e., the source makes changes that bring it out of compliance with the general construction permit or circumstances change such that the source is no longer appropriately controlled under the general construction permit).

Overall, the amendments to Regulation Number 3, Parts A and B are meant to integrate with the existing rules and meet the federal requirements for the State Implementation Plan.

I.Q. Adopted May 18, 1995

Revisions to Regulation Numbers 8 and 3 Synthetic Minor Permit Program

This Statement of Basis, Specific Statutory Authority, and Purpose comply with the requirements of the Administrative Procedures Act, Section 24-4-103(4), C.R.S. (1994) for adopted or modified regulations.

Background

At the request of the Division, the regulated community and the state legislature (HB94-1264), the Air Quality Control Commission adopted rules that would allow the Division to issue permits to limit a source's potential to emit hazardous air pollutants (HAP). Such a mechanism is necessary and important because it enables the Division to issue a permit to a source of HAP in order to limit the source's potential to emit below emission thresholds requested by the applicant, thus allowing the source to avoid a variety of requirements such as Title V operating permit requirements, Title III maximum achievable control technology (MACT) requirements promulgated by the U.S. Environmental Protection Agency (EPA), or Colorado MACT requirements.

Specific Statutory Authority

The specific authority for these revisions is contained in the Colorado Air Quality Control Act, 25-7-101, et seq. (1989 & 1994 Supp.). Section 25-7-109.3(2) provides the specific authority for the Commission to adopt provisions allowing the Division to create synthetic minor sources of hazardous air pollutants. Section 25-7-109 provides that the Commission shall adopt emission control regulations requiring the use of effective practical air pollution controls. Section 25-7-109.3(2) provides that in order to minimize additional regulatory and compliance costs to the state's economy, any program created by the Commission shall contain a provision, which exempts those sources or categories of sources, which it determines to be of minor significance from the requirements of the program. Section 24-4-103 provides the rule making procedure followed during the promulgation of this rule. Section 25-7-110 provides the specific Commission procedures followed during the setting of standards and regulations. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions.

Purpose

The rulemaking includes the permanent addition of Regulation Number 8, Part E, Section IV and amendments to Regulation Number 3, Part B. Following is a description of the purpose of each Section within Regulation Number 8, Part E, Section IV:

Section A of the rule clarifies that Regulation Number 8, Part E, Section IV applies to sources that choose to voluntarily limit their potential to emit HAP. This Section clarifies that although the Division shall issue permits to qualified applicants, the Division will not include in the permit any indication of the source's exemption status for other requirements (i.e. Title V or Title III of the federal Act) unless the source asks the Division to include all relevant emissions units and pollutants in the permit review. Under this regulation, the applicant chooses which emission units to cover in the particular permit: that can be all HAP emission points, some or one HAP emission points, all criteria pollutant emission points, and/or some or one criteria pollutant emission points. Unless there is a need for a state-only or federally enforceable permit condition, the Division will not impose any additional applicable requirements on criteria pollutants or HAPs for the emission unit or a number of emission units. If the permit applicant wants a thorough review of the facility and a determination by the Division that the facility qualifies as a synthetic minor from Title V and/or Title III, or other specific provisions of the state or federal Act, then the applicant can choose to have a comprehensive Division review in the permit. Sources choose in the permit application the threshold level below which they want to limit the potential to emit hazardous or criteria pollutants. Sources may want to bring their emissions below Title V major source thresholds or may want to limit their emissions below affected source thresholds under specific MACT standards or enhanced monitoring thresholds when those rules are eventually enacted. When a source applies for a permit under Regulation Number 8, the Division uses the procedural provisions of Regulation Number 3 to issue the permit. Finally, this Section clarifies that receiving a permit under this regulation will not relieve a source from possible future EPA requirements that apply to minor or area sources of HAP or state conditions; however, such sources may request a permit to further limit the potential to emit HAP below the trigger threshold.

Section B describes the elements of a permit issued under this regulation. The permit needs to include practically enforceable permit conditions. The Division makes the final determination on what those conditions are on a case-by-case basis for each permit. The monitoring, recordkeeping, and reporting requirements will depend on the specific source, for instance, practical enforceability may require calculating mass balances, installing a continuous emission monitor, keeping track of consumption rates for various materials, etc. However, the permit conditions to limit a source's potential to emit shall be only as stringent as necessary to limit the source's potential to emit the pollutant of concern. For instance, the Division cannot require a source to add control equipment to reduce emissions significantly if the source can adequately reduce emissions without that control equipment. The applicant may consolidate reporting or monitoring requirements from this regulation and Regulation Number 3 for the emissions unit. Finally, if requested by the applicant, the permit may include alternative operating scenarios, approved by the Division. Such alternative operating scenarios shall include specific monitoring, recordkeeping, and reporting methods as needed. However, Section IV.B.4 for alternative operating scenarios is not intended to include modifications that trigger new source review unless such sources go through all the specific requirements of the construction permit program for modifications under new source review.

Section C tells the source what information to turn in to the Division, increasing the efficiency of communications between the source and the Division and streamlining the application process. The application forms will reflect the intent for the Division to be flexible in its approach to permitting these sources. Although the Division would prefer a consistent approach (i.e., all applications filled out fully), the Division recognizes that often these sources will have unique circumstances that cannot be adequately addressed in a standard application form. The Division further intends that the application forms be flexible enough so that sources can choose to have the Division calculate emissions and determine the permit conditions for them.

Section D, the public participation requirements, is a requirement of EPA. This Section makes mandatory what was previously discretionary for the Division.

Section E clarifies that the Division can combine the requirements from this Regulation with those for limiting the potential to emit criteria pollutants under Regulation Number 3 into a single permit so that it is easier for both the Division and the source to keep track of the overall permit requirements. Also, this Section IV of Regulation Number 8 is not intended to restrict the ability of a source to apply for and the Division to issue a construction permit under Regulation Number 3 with limits on the potential to emit criteria or hazardous air pollutants.

Section F explains to the source that if a physical or operational change triggers another requirement, the permit issued under this Section will not relieve the source of the obligation to comply with that requirement.

Section G informs the source that is must comply with the permit conditions at all times, i.e. on an ongoing basis.

Section H serves as an interim mechanism for gaining federal enforceability of the permit and is based on EPA guidance on potential to emit; this Section does not apply once EPA has approved these rules for limiting the potential to emit HAP. In order for a permit to be federally enforceable, EPA must receive a certification of compliance from the source indicating the source will comply with the permit terms. The source should send a copy of the initial permit approval with the certification of compliance to EPA and a copy of the certification to the Division (to keep in the permit file). The responsible official, defined in Regulation Number 3, needs to sign the certification.

The revisions to Regulation Number 3 are necessary to implement the provisions of Regulation Number 8, Part E, Section IV through the construction permit program. Note, that the operating permit program already has the necessary provisions to integrate Regulation Number 8, Part E, Section IV. The amendment to Section III.A.4 is not intended to extend any new rights to the applicant in the event the applicant declines permit conditions set by the Division, this amendment just makes explicit that the permit is strictly voluntary and that a dissatisfied applicant has normal rights of appeal associated with construction permits issued under Regulation Number 3. The addition of Section III.A.7 is to clarify that if a source wants to request a limit on the potential to emit in a standard construction permit, the source may do so. This Section also gives the Division the authority to limit the potential to emit HAP in a construction permit. The amendments to Section IV.C implement the public participation requirements of Regulation Number 8, Part E, Section IV. The requirement that the Division submit a copy of the public notice to EPA for sources applying for a permit to limit the potential to emit criteria pollutants or federal HAP is meant to include criteria pollutants (already required under an agreement between the Division and EPA) and federal HAP listed in Appendix A of Regulation Number 8 (these are the HAP listed by EPA under Section 112(b) of the federal Act). Permits for sources limiting the potential to emit Colorado HAP do not need to be sent to EPA for comment.

Overall, these rules are intended to meld with the existing permit provisions within Regulation Number 3 while providing the added authority for the Division to issue permits to limit the potential to emit hazardous air pollutants and the opportunity for Colorado sources to get out of more rigorous permit requirements.

I.R. Adopted May 18, 1995

Revisions to Regulation Number 3 Part A, Section II.E.2 (As requested by Metro Wastewater Reclamation District)

This Statement of Basis, Specific Statutory Authority and Purpose for revisions to Regulation Number 3 complies with the requirements of the Administrative Procedures Act, C.R.S. ' 24-4-103(4) for adopted or modified regulations.

Basis

The 1990 Clean Air Act Amendments required states to inventory air emissions. C.R.S. ' 25-7-114.1 contains the requirements for this inventory. The Amendments also authorized EPA to conduct emissions studies for certain source categories, included publicly owned treatment works (POTWs). No adequate, reliable, and economically reasonable emissions estimations methods are currently widely available for these emissions.

Based on the expectation that publication of these studies would result in the creation and dissemination of practical emission estimation techniques, revisions to Regulation Number 3 were promulgated in March of 1994 which postponed reporting of non-criteria reportable pollutants for these sources until July 31, 1995, or until six months after the completion of the national studies, whichever occurred first. The postponement also applied to facilities, which treat municipal-type wastewater, since such facilities' emissions are virtually identical to those from POTWs.

EPA has eliminated funding for the federal POTW study. However, the Association of Metropolitan Sewerage Agencies (AMSA) has been assisting EPA in preparing its guidance document, and AMSA has also been preparing its own guidance. These documents are expected to be useful in estimating POTW air emissions. A final draft of AMSA's report is expected to be issued in the summer of 1995. EPA is also expected to issue its finding of presumptive MACT for POTWs for purposes of the Clean Air Act " 112(j) and (g) at about this time.

Authority

The specific authority for this regulatory amendment is contained in C.R.S. ' 25-7-106(1), which authorizes the Air Quality Control Commission to promulgate such regulations as are necessary or desirable to carry out an effective air quality control program, and ' 25-7-114.1, which authorizes the Commission to promulgate the APEN inventory program.

Purpose

In order to give POTWs and facilities that treat municipal-type wastewater sufficient time to prepare reliable APENs, the Commission has extended the postponement of reporting for non-criteria reportable pollutants for these sources until December 31, 1995. The Commission finds that extending the APEN reporting deadline is in the public interest because the information to be published by EPA and AMSA will not become available to these sources in time to allow for sufficiently reliable APEN reporting.

I.S. Adopted August 17, 1995

Revisions to Regulation Number 3 to Change TSP to PM-10 for PSD Increments and Housekeeping

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

On June 3, 1993 the U. S. EPA promulgated changes to the Prevention of Significant Deterioration (PSD) rules replacing the Total Suspended Particulate (TSP) increment with particles with an aerodynamic diameter of less than or equal to a nominal 10 micrometers (PM-10) increments. TSP continues to have a significance level for new sources but no longer influences the PSD increments.

Additionally the Division has identified several mistakes in the publishing of Regulation Number 3.

Specific Authority

The specific authority for this regulation is contained in the Colorado Air Pollution Prevention And Control Act, 1992 as amended. Section 25-7-105 (1) (a) (I) requires the Commission to promulgate a comprehensive state implementation plan that meets all requirements of the federal Clean Air Act. Section 25-7-105(1) (c) requires the Commission to promulgate a prevention of significant deterioration program.

Purpose

The Regulation Number 3 PSD rules implement the Federal PSD rules in Colorado. Under the PSD program areas that are in compliance with the National Ambient Air Quality Standards (NAAQS) are required to adopt a permit program for the preconstruction review of new stationary sources and modifications of existing stationary sources to prevent significant deterioration of existing air quality levels. The implementation of the new PM-10 increments will utilize the existing baseline dates and baseline areas for PM. The PM increments measured, and PM-10 already consumed since the original baseline dates established for TSP will continue to be accounted for, but all future calculations of the amount of increments consumed will be based on PM-10 emissions.

The Division is also proposing some minor housekeeping while revising this regulation. There were several Sections where the language published in the Colorado Register was either repeated or the changed paragraph and the original paragraph were both printed. There was also an outside request that submitted an outdated version of the regulation that was inadvertently published.

I.T. Adopted December 21, 1995

Part A, Sections I.B.37 & 67; Part B, Section IV.D.4

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulations 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado Regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify Regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

Of the EPA list of non-photochemically VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all These revisions to Regulations Number 3, 7, and the Common Provisions are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists Colorado Air Quality Control Commission Regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly reactive VOC industries will be able to take advantage of and benefit from this possible shift in product contents.

I.U. Adopted February 15, 1996

Revision to Part A, Section II.E.1 APEN Deferral for Utility and Non-Utility Boilers

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, CRS 1793, Section 24-4-103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3, Part A, Section II.E.1., were designed to postpone reporting of non criteria reportable pollutants by sources such as utility and non-utility industrial boilers and small municipal generators pending the results of ongoing studies being conducted by EPA pursuant to Section 112(n) of the federal Clean Air Act. EPA was directed by Congress to complete those studies within three years after enactment of the federal act, i.e., by November 15, 1993; however, EPA has yet to do so.

During the Commission's last deliberations on this subject, it was stated that if EPA could not meet its deadline, then the Commission would revisit this deadline. Both the Commission and the regulated community were hopeful that EPA would be able to finish its work by the fall of 1995 so sufficient time was available for utilities to meet the December 31, 1995 deadline.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. There currently are no federal reporting requirements concerning emissions of non-criteria reportable pollutants (NCRPs) or hazardous air pollutants (HAPs) from boilers. The current state regulations exceed federal regulatory requirements with respect to APEN reporting of emissions.

Purpose

A short postponement of the original deadline serves a significant dual purpose and both the state and the regulated community benefit from a deferral in this instance. The postponement avoids forcing an uneconomic and non-beneficial compliance requirement at this time on the regulated community. Since there are no compliance obligations respecting HAP emissions from boilers, either in effect or proposed, EPA and Division interpretations provide that an applicant for a Title V operating permit need only list - not estimate quantities of emission of - an application for an operating permit. This revision is administrative in nature, and is not intended to affect air emissions.

I.V. Adopted March 21, 1996

Revisions to Parts A, B & C for Insignificant Activities (Parties: Air Pollution Control Division, Colorado Association of Commerce & Industry and the Colorado Utilities Coalition for Clean Air Division - Part A, Section I.B.9.a; Section II.D.1.kk, 4.a, b.(iii) & (vi); Part C, II.E.3.kk

Basis

The Division reviews the addition of any requested insignificant activities to Regulation Number 3 once each year. The additions requested included small remote reservoir degreasers and torch cutting activities. Both of these items were reviewed by EPA Region VIII prior to the hearing date and given verbal approval.

The degreaser exemption provides that degreasers not using any chemicals covered by a Maximum achievable Control Technology (MACT) standard and meeting the definition of small remote reservoir are not required to submit an APEN to the Division. The torch cutting exemption clarifies the status of torch cutting as an exempt activity.

Authority

The specific authority for this regulatory amendment is contained in §25-7-114.1(2), C.R.S., which requires the Commission to exempt those sources or categories of sources, which it determines to be of minor significance from the requirement than an air pollutant emission notice is filed. Section 25-7-114.6(1), C.R.S., requires that the Commission designate those classes of minor or insignificant sources of air pollution which are exempt from the requirement for an emission notice or the payment of an emission notice filing fee because of their negligible impact upon air quality.

Purpose

This rule change provides some clarification and additions to the APEN exemption list for those sources that the Division believes to be of minor significance.

Colorado Association of Commerce and Industry - Part A, Section II.D.1.ttt; Part C, Section II.E.3.nnn.

Basis

The Division reviews the addition of any requested insignificant activities to Regulation Number 3 once each year. The Colorado Association of Commerce and Industry (CACI) requested the addition of emergency power generators with limitations based on the size or hours of operation. The revisions rely on EPA guidance regarding emergency power generators.

Authority

The specific authority for this regulatory amendment is contained in C.R.S §25-7-114.1(2), which requires the Commission to exempt those sources or categories of sources, which it determines to be of minor significance from the requirement that an air pollutant emission notice be filed. C.R.S. §25-7-114.6(1) requires that the Commission designate those classes of minor or insignificant sources of air pollution that are exempt from the requirement for an emission notice or the payment of an emission notice filing fee because of their negligible impact on air quality.

Purpose

This rule change provides an addition to the APEN exemption list and clarification of the insignificant activities list for emergency power generators that are of minor significance base on size and/or hours of operation.

Colorado Utilities Coalition for Clean Air - Part A, Section II.D.1.aaa.(i), (ii); sss.(1).iv to vii; uuu; vvv; www; xxx; yyy; zzz; aaaa.(i), (ii); Part C, II.E.3.aaa.(i), (ii), xxx.(1).iv to vii; yyy; zzz; aaaa; bbbb; cccc; dddd; eeee

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 24-4-103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3., Part A and Part C both contain lists of activities and sources considered to be “insignificant” or exempt from reporting requirements. On December 29, 1995, the Commission proposed revisions to its existing Regulation Number 3, Parts A and C. Alternative proposals were submitted by members of the public, and after consultation, were endorsed by the Division.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. Further, the rulemaking authority of the Commission is found in Sections 25-7-105 to 109 CRS, as amended. The regulations of the Commission currently contain lists of activities and sources exempt from APEN and reporting requirements. On July 10, 1995, the U.S. EPA issued a White Paper designed to streamline and simplify the development of Part 70, Title V permit applications. The White Paper explains that Part 70 provides permitting authorities considerable flexibility in defining certain activities or sources as “insignificant” upon proper showing of such. The White Paper itself contains substantial lists of activities or sources that are insignificant for reporting purposes.

Purpose

The addition of the following sources or activities to existing APEN exemption and reporting requirements serves a significant dual purpose and both the state and regulated community benefit from the alternate proposals. The revision of existing regulation avoids forcing an uneconomic and non-beneficial compliance requirement on the regulated community. Several of the following activities or sources are on federal lists as “insignificant,” as well as those of neighboring states. These revisions are administrative in nature, and are not intended to affect air emissions.

Non-road Internal Combustion Engines:

Machinery utilized by the construction and service industries such as various types of pumps, light plants, compressors, and generators are powered by various sizes of internal combustion engines. Most are relatively small. Some emergency equipment such as fire pumps are powered by larger engines, but are operated infrequently. The exemptions listed above identify those within this category that have insignificant emissions. This exemption is consistent with other exemptions in the regulation (see, for example, Subsections k. and l.). As a practical matter, APENS have not been required from most of these machines in the past. The sizes of most of these engines are comparable to the thousands of light and heavy trucks (gasoline and diesel powered), which travel the roads in this state without any reporting requirements.

The EPA proposal of May 17, 1990 (58 Fed. Reg. 28809) and the EPA study it references contains useful findings. It exempts all spark-ignition (gasoline, propane and natural gas powered) engines. On page 28816 of the Federal Register notice, EPA finds that it did not propose manufacturing standards for spark-ignition engines because little to no emission benefit would be achieved for testing, record keeping and reporting requirements on these engines. Cost burdens industry would have to bear would not be reasonable. It also found that test procedures have not been demonstrated to be capable of accurately predicting the levels of hydrocarbons, carbon monoxide and particulate matter emissions generated by these engines in actual use. In addition, the economics and failure problems associated with gasoline-powered engines dictate that relatively small sizes of gasoline engines are used for the light commercial equipment described above. As a result, all spark-ignition engines should be exempt from APEN reporting and classified as an insignificant activity.

The EPA study found that it could also exempt engines located on a trailer or truck bed. These engines are relatively small (dictated by trailer size and carrying capacity limitations) and power light commercial equipment, such as welders, compressors and generators, see page 28815 of the Federal Register notice.

Larger machines are typically powered by diesel engines of varying sizes. A review of emission factor data from AP-42 supports a Division of diesel-powered engines into three categories for APEN exemption purposes. Using emission factors from AP-42, expected emissions from a 175 horsepower diesel engine operating 24 hours per day, 7 days per week, 52 weeks per year at a load factor of 0.5 would present a "worst case" estimate under the 8760 hours per year "potential to emit" methodology. The following emissions are calculated:

-0.5 ton per year of carbon monoxide
-0.2 ton per year of hydrocarbons
-0.2 ton per year of particular matter
-2.5 ton per year of nitrogen oxides
-0.2 ton per year of sulfur oxides

A 300 horsepower engine could operate up to 3 hours per day, or 1095 hours per year, and have the same emissions as the 176 horsepower engines. Similarly, an engine up to 750 horsepower could operate 1 hour per day, or 365 hours per year and have the same emissions as the 175 horsepower engine class.

This approach is consistent with the approach taken by the EPA in its Guidance Document for "Calculating Potential To Emit for Emergency Generators," issued September 6, 1995. There, the EPA agreed that the use of 8,760 hours per year for calculating the potential to emit for emergency generators did not control. Instead, EPA recommended that the potential to emit be based upon an estimate of the maximum amount of hours the generators could operate based on a case-by-case basis where justified by the source owner or permitting authority. Surface water storage impoundment of non-potable water and storm water evaporation ponds: Chemical analysis and observation of these sources has consistently demonstrated that they are a negligible emission source of any regulated air pollutant.

Non-potable water pipeline vents:

Proper flow through of non-potable water maintains these sources as insignificant. Proper flow keeps the water in line from becoming septic and therefore a negligible source of any regulated air pollutant.

1. Steam vents and safety release valves:

   Safety release valve vents enable immediate reduction of pressure in steam lines. Emissions out of the safety valves consist only of pure water vapor.

2. Deaerator/vacuum pump exhausts:

   These are negligible sources of emission of any regulated air pollutant.

3. Seal and lubricating oil systems for steam turbine electric generators:

   Atmospheric vents exist in coal-fired utility turbine lube oil systems enable removal of water vapor from lube oil return lines from the turbine and generator bearings. This enables atmospheric pressure operation of lube oil storage tanks. These are not storage systems, but actual service operations. Calculations reveal that these activities would emit less than one ton of VOC's a year, per facility.

4. Venting of natural gas lines for safety purposes:

   To enable the safe delivery of fuel gas to the utility boilers, and provide the ability to safely purge natural gas from fuel lines within a generation building, vent lines exist to allow the intermittent discharge of natural gas to safe areas away from personnel and ignition sources.

   The intermittent discharge of natural gas would occur during start-up and shutdown of the natural gas supply to generating unit burners to purge air or natural gas from the piping system within the generation building. These activities are not expected to emit more than one ton of VOC's or more than 110 pounds of hexane a year.

   Sulfuric acid storage tanks not to exceed 10,500 gallons capacity and sodium hydroxide tanks:

   Sulfuric acid and sodium hydroxide, used to control pH, are stored in tank systems vented to the atmosphere. These vents will exhaust vapor from a tank system through vapor extraction and contraction because of changes in temperature and barometric pressure. These losses, which are referred to as breathing losses, occur without any significant change in liquid level in the tank, and are negligible.

   Waste lubricating oil storage tanks not larger than 40,000 gallons and lubricating oil-conditioning systems:

   Low volatility waste turbine and motor lube oil generated by utility plant machinery and mobile heavy equipment is stored in tanks. These tanks are equipped with atmospheric vents on the tops of the tanks. Emissions through these vents are expected to occur during the filling and emptying of the tanks. These emissions contain trace amounts of VOC's, with no other reportable emissions expected. Based on the low annual throughput of these tanks, emissions are insignificant, assuming that the tanks are emptied approximately five times per year or less.

Colorado Utilities Coalition for Clean Air - Part A, Section II.E.1

This Statement of Basis, Specific Statutory Authority and Purpose complies 24-4- with the requirements of the Administrative Procedure Act, C.R.S. 1973, Section 103(4) for adopted or modified regulations.

Basis

The current provisions of Regulation Number 3, Part A, Section II.E.1, were designed to postpone reporting of non-criteria reportable pollutants by sources such as utility and non-utility industrial boilers and small municipal generators pending the results of ongoing studies being conducted by EPA pursuant to Section 112(n) of the federal Clean Air Act. EPA was directed by Congress to complete those studies within three years after enactment of the federal act, i.e., by November 15, 1993; however, EPA has yet to do so.

Both the Commission and the regulated community were hopeful that EPA would be able to finish its work by the fall of 1995 so sufficient time was available for utilities to meet the original December 31, 1995 deadline. The EPA did not meet that deadline, and the Commission granted a deferral until June 30, 1996. The EPA study is now the subject of further delay due to one of the individual constituent hazardous air pollutant studies and the extensive federal government furloughs in both late 1995 and early 1996 that substantially contributed to further delay the study's progress.

Specific Authority

Section 25-7-114.1 provides authority to the Commission to identify APEN reporting requirements. There currently are no federal reporting requirements concerning emissions of non-criteria reportable pollutants (NCRPs) or hazardous air pollutants (HAPs) from boilers. The current state regulations exceed federal regulatory requirements with respect to APEN reporting of emissions.

Purpose

A short postponement of the amended deadline serves a significant dual purpose and both the state and the regulated community benefit from a deferral in this instance. The postponement avoids forcing an uneconomic and non-beneficial compliance requirement at this time on the regulated community. Since there are no compliance obligations respecting HAP emissions from boilers, either in effect or proposed, EPA and Division interpretations provide that an applicant for a Title V operating permit need only list - not estimate quantities of emissions of - HAPs reasonable believed to be contained in the boiler emissions in an application for an operating permit. This revision is administrative in nature, and is not intended to affect air emissions.

I.W. Adopted March 21, 1996

Revisions to Part B, Section III.D.1.f, Section IV.C.1.e, Section IV.C.1.f, and Section IV.C.

The changes to Regulation Number 3 were adopted in order to make it clear that the redesignation of the Denver metropolitan area as an attainment maintenance area for ozone does not change the requirement for gasoline stations in the Denver metropolitan area are to obtain a construction permit.

Section III.D.1.f appears to imply that, upon such redesignation, gasoline stations in the Denver area would not be required to obtain a permit because that area would become an attainment area. However, Section III.D.5 goes on to provide that such exemptions do not apply because gasoline stations are subject to the RACT requirements of Regulation Number 7, Section VI.B.3.b. The purpose of the revisions is simply to make it clear from the text of Regulation Number 3, Part B, Section III.D.1.f alone that gasoline stations in the Denver area are still required to obtain a construction permit. The revisions to Sections IV.C.1 and IV.C.4 were necessary to ensure that permits for de minimis exemptions from, and alternative means of compliance with, the requirements of Regulation Number7 are subject to review and comment by the public and by EPA. Such comment and review is necessary because the Sections I.A. and II.D of Regulation Number 7 provide the agency with the authority to revise the requirements that apply to a source without revising the SIP. The SIP requirements were developed and adopted following review and comment by EPA and the public. It follows that any change in those requirements with respect to any source or category of sources should also be subject to such public comment and review. The specific statutory authority to amend this regulation pertaining to exemptions from permit requirements is set out at § 25-7-114.2. Further statutory authority can be found in the Commission's authority to redesignate the area because such redesignation must include an approvable maintenance plan. The specific statutory authority to promulgate the rules necessary for redesignation is set out in § § 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301.

This revision to Regulation Number 3 is not intended to reduce air pollution and will have no regulatory effect on any person, facility or activity.

For clarification, the Commission adopted these regulation revisions as follows:

Regulation Revision	Ozone SIP and Maintenance Plan
Part B, Section III.D.1.f	Exists in Appendix C of the Ozone Maintenance Plan to be come a part of that document approved March 21, 1996
Part B, Section IV.C.1.e and f; Section IV.C.4	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA Separately and concurrently as a revision to the SIP (and Maintenance Plan).

I.X. Adopted June 20, 1996

Revisions to Part A, Section V.C.1.f (Fees Correction)

Basis

This revision corrects an erroneous regulation change requested by the Division in response to an EPA letter of September 19, 1994, which provided comments on the revisions to Regulation Number 3 for the operating permit program. The comment made by EPA was for clarification, not a requirement that the State should not charge for fugitive emissions. The change requested by the Division in 1995 included the term fugitive emissions in the paragraph of exclusions from the definition of regulated pollutant. Because of this change, the Division's authority under the statute to charge annual fees for fugitive emissions became confused which affected the Division's ability to cover its operating costs through fees. The regulation text also no longer conformed to Section 25-7-114.7, as revised in the 1996 legislative session.

Authority

Section 25-7-114.6.(3), C.R.S., requires that the revenues from fees collected by the Division approximate the annual appropriations to the Division to carry out its duties with respect to stationary sources. Section 25-7-114.7, C.R.S., requires imposition of an annual emission fee on stationary sources, and defines what is a regulated pollutant for purposes of these fees.

Purpose

These changes address an erroneous March 1995 revision made with respect to the charging of fees for fugitive emissions. The revision specifically exempted fugitive emissions and would significantly reduce the Division's ability to collect fees sufficient to cover duties with respect to stationary sources. In 1992 the General Assembly prohibited imposition of annual fees for fugitive dust or fugitive emissions as those terms were defined at the time in "Commission rule I.B.1 of regulation number 3, 5 CCR 1001-5." That rule defined only fugitive dust and the March 1995 regulatory revision inadvertently addressed fees on fugitive emissions as well. This rule conforms the regulation to statute, and eliminates any ambiguity between the two. Moreover, during the 1996 legislative session, the legislature in HB1271 amended Section 25-7-114.7(1) to clarify the authority of the Commission to assess fees for fugitive emissions. The Commission intends that all forms of "fugitive dust," regardless of whether the dust is of a size or substance to adversely affect public health or welfare, is excluded from the definition of "regulated pollutant", for purposes of annual fees.

The Commission determines that these revisions are administrative in nature and are not intended to reduce air pollution.

I.Y. Adopted June 20, 1996

Revisions to Part A, Section I.B.9, 59, Section V.C.12; Part B, Section III.D.2; Part C, Section II.A.1.b, Section VI.A, E, H.3 and Section XII.A.1;Appendices B, C and D for Hydrogen Sulfide

Background

The Division requests that the Commission adopt changes to Parts A and C and the Appendices within Regulation Number 3 to better reflect current EPA implementation of the Title V operating permit program. These changes include: (1) noting that a source major only for Total Suspended Particulate (TSP) is not required to obtain an Operating Permit in Part C; (2) deleting the Hazardous Air Pollutant reference beside the pollutant Hydrogen Sulfide (H2S) in Appendices B, C, and D of Regulation Number 3 to reflect the federal delisting of this pollutant, and; (3) expanding the definition of "applicable requirement" in Part A to clarify that EPA-issued PSD permits are applicable requirements of the Operating Permit Program. A discussion of each of these changes follows.

The current notation under Regulation Number 3, Part C Section II.A, General Considerations, lists all major sources as being required to obtain Operating Permits. The EPA has issued a written guidance document indicating that the definition of regulated air pollutant for purposes of Title V applies only to emissions of PM-10, and not TSP. The current requirements reflected in Part C, Section II.A.1.b does not reflect the federal program requirements.

Currently, H2S is reflected as a Hazardous Air Pollutant in Appendices B, C, and D. The EPA stated that the inclusion of H2S on the federal list was a typographical error and removed the pollutant from the federal list. As a result of the reference to H2S as a hazardous air pollutant in the Appendices, sources emitting H2S have been charged annual fees for HAPs and sources major for H2S emissions could be required to get an Operating Permit.

The current definition of applicable requirement in Part A, Section I.B.9.a does not provide authority for EPA-issued PSD permits to be incorporated into Operating Permits. The definition of "applicable requirement" in Part 70 of the federal program includes permits issued by EPA. The State needs this regulatory change to make the rules consistent with the federal law. Currently, regulated entities subject to these requirements can obtain a permit from EPA or can voluntarily have the requirement placed in their Title V permits, but this situation does not support the intent behind the Title V program.

Specific Authority

The specific authority for changes to this regulation is found in the Colorado Pollution Prevention and Control Act. Section 25-7-105(12) provides authority to promulgate regulations, which are necessary to implement the minimum elements of Title V. Section 25-7-103(1.5) allows the Commission to define air pollutant consistent with the federal act. Section 25-7-114.4(1)(l) and Section 25-7-114.4(3)(a) provide authority for promulgating regulations for the effective administration of construction and operating permits, and complying with all applicable requirements for operating permits. Section 25-7-114.5 provides authority for evaluating permit applications to determine whether operation and emissions comply with all applicable emission control regulations. Relevant federal law includes 42 U.S.C. Section 7661a(b)(5)(A), and 40 C.F.R. Sections 70.1(b), 70.3, and 70.6(a)(1) regarding applicable requirements. Commission action in making changes to Regulation Number 3 is taken pursuant to the above statutory provisions.

Purpose

The amendments adopted by the Commission add language in Regulation Number 3, Part C, Section II.A.1.b indicating that a source that is major only for TSP is not required to receive an Operating Permit. This amendment ensures conformity with the federal law.

The amendments delete the reference to Hazardous Air Pollutant noted next to hydrogen sulfide in Appendices B, C, and D. This ensures consistency with the Federal delisting and eliminates the potential confusion for sources that will be major only based on emissions of hydrogen sulfide as a Hazardous Air Pollutant to obtain an Operating Permit. The amendments expand the definition of applicable requirement in Part A to include those permits issued by EPA under Part C and Part D of the federal act. This ensures conformity with the federal law.

The amendments correct a few typographical errors that existed in Regulation Number 3, Parts A, B, and C.

Finally, the amendment to Part C, Section II.A.1.b, regarding TSP, is administrative in nature and is intended to reflect current EPA policy; it is not intended to reduce air pollution. The amendment to Part A, Section I.B.9.a, regarding the definition of applicable requirement, is administrative in nature and reflects the requirements of Part 70. This action regarding the definition of applicable requirement maximizes air quality benefits in the most cost effective manner by enabling sources to incorporate federally issued PSD permit into their Operating Permit. Thereby, these sources will only be reporting to one enforcement authority. These revisions applicable to Part C are not to be submitted as part of the State Implementation Plan.

I.Z. Adopted October 24, 1996

Revisions to Generic Part A, Section V, (with Regulation Number 5, Emissions Trading and Banking

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110, 25-7-110.5 and 25-7-110.8, C.R.S.

Basis

The Division has worked with the emissions trading and banking subcommittee to develop Regulation Number 5 and revisions to Regulation Number 3 for the purpose of implementing an EPA-approvable emissions trading program.

The subcommittee has developed a trading rule combining elements from the existing EPA guidance and the prior Commission rule. The subcommittee spent a great deal of time discussing the issues around the possible uses for credits, how credits could be certified, and how they should be traded and tracked.

Emission reduction credits are intended to be granted only for reductions beyond compliance levels that are actual, quantifiable, surplus and enforceable. This rule is not intended to impose additional control limitations on sources. The rule does impose requirements to ensure that these basic criteria are met in order to guarantee that the source flexibility afforded by this program does not occur at the expense of air quality.

This rule is a revision to the SIP done only under the Commission's general authority. Thus, the trading and banking rule will not be state enforceable until after legislative review. Section 25-7-133(2), C.R.S. Additionally, because EPA must approve this change into the SIP, the Commission finds it appropriate to delay the effective date of these revisions until EPA approval as a SIP revision. This will provide the sources that might wish to participate the assurance that the rule is approved and that the credits are useable prior to the implementation of the program. The existing trading provisions in Regulation Number 3 will remain in effect until the new trading rules are approved by EPA. These constraints on the effective date of these revisions are reflected in the rule text approved by the Commission. In addition, in order to avoid confusion about what portions of the regulations are effective until EPA approval of the SIP change, the parts of Regulation Number 3 that will be repealed are printed in italics.

State implementation plans are to include, among other things, enforceable emissions limitations and other control measures, means or techniques to meet the requirements of the Clean Air Act. These are to include economic incentives such as fees, marketable permits, and auctions of emissions rights. 42 U.S.C. 7410(a)(2)(A). These regulation revisions are being submitted as a SIP revision pursuant to the foregoing Clean Air Act requirements.

The following issues were identified by the subcommittee and noticed by the Commission for further consideration. The Commission discussed and resolved these issues in the course of this rulemaking proceeding and makes the following findings regarding these issues.

Issue: Once used, does a permanent emission reduction credit (ERC) ever expire? Some believe that an ERC once used, even if from a permanent reduction, should expire after some period (e.g., 20 years).

Conclusion: The Commission, based on the experience in the previous trading rules, decided that the permanent credits should not expire after they are put into use.

5. Issue: Should a decrease in electrical demand be usable to generate emission reduction credits?

Conclusion: Because of the existence and operation of the national electrical grid system, the Commission believes that it would be far too difficult to verify that there had been a decrease in demand (a decrease in actual emissions) and not a variation in the grid structure, and therefore at this time finds it is inappropriate to allow a decrease in demand to generate ERCs.

6. Issue: As the proposed rule is written, inter-pollutant trading is allowed on a case-by-case basis subject to Division approval. The subcommittee and the Division recognized that a universal or standard protocol for approving such trades would be desirable, but that no officially approved protocols for any inter-pollutant trades exist.

Conclusion: The Commission agrees that there is currently insufficient scientific information available to support inter-pollutant trades in most cases. In order to ensure that the Division staff is not placed in the position of having to develop information and protocol to support an inter-pollutant trade proposal, the Commission finds that the burden of proving the acceptability of an inter-pollutant trade shall be placed on the source.

Because of concerns expressed by the EPA that the protocol for inter-pollutant trades has not yet been developed, the language of VI.B. was amended to allow proponents of such trades the opportunity to

make their case to the Division and EPA for approval. This amendment attempts to address the EPA concern.

7. Issue: The proposed rule states that temporary credits must be credited and traded within the same "season" for seasonal pollutants. Should temporary credits be allowed to be traded from a season of lower concern to a season of higher concern?

Conclusion: The Commission finds that the use of temporary credits should be restricted to the same season in which they were generated, or a season of lower concern. This will help mitigate any significant increases in seasons that may cause a violation of the NAAQS.

Issue: At this time no internal provisions exist for program development and implementation. How should the cost of the program implementation and development be addressed?

Conclusion: The Commission acknowledges that the Division will monitor the activity in the trading program and, if needed, legislative fee authority will be sought. Fees for permit changes required by this rule will be charged pursuant to Regulation Number 3. Nevertheless, the Commission acknowledges that resources are not currently available and funding may be needed for this program.

8. Issue: Should the rule contain procedures or criteria specific to trading Hazardous Air Pollutants (HAPs)? The subcommittee and the Division agreed not to address this issue of HAPs in the proposed rule.

Conclusion: The Commission is concerned that use of ERCs for criteria pollutants that contain or consist of HAPs could unduly increase the risks to communities and the environment in the vicinity of the credit-using source. Assessing relative risk is difficult, time-consuming and highly fact-specific to a particular source and trade. In order to address this concern, the Commission adopted Section VI.G.8 that requires that the HAPs reduced to generate the ERC must be of equal or greater toxicity than the HAPs contained in the emissions for which the ERC will be used in lieu of satisfying an applicable requirement. Section VI.G.8 does not operate as an emissions control regulation on any HAPs, but is simply a limitation on participation in the trading program.

9. Issue: How is the base emission rate set? In order to show the level of actual emissions at a source before reductions for which credits are claimed, a period representative of normal operating conditions must be used.

Conclusion: The Commission adopts provisions that require using the last twelve months' actual emission rate unless the last twelve months are not representative. The source may propose to the Division to use any consecutive twelve months in the last ten years as more representative of normal unit operations. This allows most sources to use a period, which the Commission believes is likely to be representative of normal operating conditions. Where the source can show that the period is not representative, the rule allows source flexibility in determining their pre-reduction actual emissions.

10. Issue: Should the Commission give authority to the Division to allow discounts from the ten percent contribution of emission reductions for air quality benefits for generators that participate in a voluntary pollution prevention program or other voluntary "beyond-compliance" programs? Should a generator be allowed to contribute only five percent of its their emissions reductions for air quality benefits as an incentive for participation in pollution prevention programs?

Conclusion: The Commission agreed to provide such flexibility to the Division for generators that have voluntarily adopted comprehensive and facility-wide environmental programs such as a Pollution Prevention Program or other similar voluntary "beyond-compliance" programs.

11. Issue: Should ERCs be used to satisfy Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) requirements where a source triggers PSD or nonattainment New Source Review and must install BACT or LAER control technologies? Recent reports in the national press have indicated that EPA is giving serious consideration to allowing ERC use for BACT as it attempts to move away from command-and-control approaches to more contemporary market approaches.

Conclusion: The Commission believes that ERCs may appropriately be used in lieu of the emissions reductions which would otherwise be achieved by application of the BACT technology requirements in situations where such technology requirements are not cost-effective or exacerbate other pollutant emissions, and the use of an ERC would achieve the same purposes more efficiently. In such instances, it will be incumbent on the source to demonstrate that such a situation exists. In any case, however, the other PSD provisions and required analyses would apply to the source. PSD requirements are performed on future allowable emission rates. Because of concerns about the use of ERCs for BACT requirements, although the Commission has allowed ERCs to be used to meet BACT requirements in limited instances, it believes that this provision should only be applied prospectively for new BACT requirements and not to allow a source to remove BACT where it has already been installed. The Commission concludes that use of ERCs in lieu of emissions reductions from LAER is not appropriate because of the potential impacts on nonattainment areas.

12. Issue: How will the local effect of “hot spot” pollutant trades be analyzed to prevent a local criteria pollutant exceedance due to emission credit transactions? Should the rule require modeling of criteria, pollutants to assure there are no exceedances of the National Ambient Air Quality Standards? Conclusion: The Commission adopts the language in Section VI.G.7 of Regulation Number 5 requiring modeling for all trades in order to ensure that trades do not cause or contribute to a NAAQS exceedance, an increment exceedance, or any violation of a required SIP provision. As that Section reflects, the source may request that the Division waive the modeling requirement if the source can document to the Division's satisfaction that the trade has a negligible impact.

13. Issue: How and who modifies the conformity budget for intersector trading? With mobile to stationary source trades, does the emission budget increase after the life of the credit has expired, and how is this accomplished?

Conclusion: The Commission has provided for ERCs to be available to satisfy conformity requirements in accordance with the federal rules. The Transportation Conformity requirements (40 CFR Parts 51 and 93) presently allow for trades among emissions budgets where either a SIP revision or a SIP establishes mechanisms for such trades. 40 CFR §93.124(c). The Colorado emissions trading rule is intended to be a SIP revision establishing such a “mechanism” to allow for such trades.

The Commission recognizes that, if mobile source emissions rise above the mobile source emissions budget in the state implementation plan, a plan revision may be necessary as otherwise required by state and federal law.

14. Issue: What becomes of the “buffer” between a credit-generating source's potential to emit and its actual emissions before the reduction for which the credit is claimed? Does the generator get to keep a portion, all, or none of it?

Conclusion: The Commission finds that methods exist to allow a source to retain the operating flexibility from a pre-reduction “buffer.” When a source wants such flexibility, it may claim credits for less than the entire reduction in emissions accomplished; the difference constitutes a new “buffer.” A source may use temporary credits to meet short-term operating needs.

These methods retain flexibility for the source without relying on "paper reductions." The Commission concludes that it is imperative that reductions for which credits are granted must be actual reductions. Allowing a source to retain a buffer from within the credits granted, as proposed by the Colorado Association of Commerce and Industry, would result in credits for "reductions" which did not actually occur. This result is unacceptable, particularly because sources determine their own permitted emissions levels when they file their Air Pollution Emission Notices.

For example, a source with a ninety-five ton per year permitted level that actually emits fifty tons reduces its emissions to forty tons. The source should take a new permit with a level between forty and fifty tons (e.g., forty-five tons) so that the source has a five-ton buffer. The source may then fluctuate its emissions between forty and forty-five tons without violating the permit, and generate temporary credits for any emissions reductions below forty-five tons.

In order to ensure that reductions are actual, an ERC-generating source will not be able to increase its permitted emissions in the absence of a process or control modification. The source cannot, for example, simply file an APEN with higher emissions estimates and thereby increase its permitted emissions. The effect would be to allow emissions for which credits were already granted, resulting in "paper reductions." This consequence is unacceptable.

15. Issue: Should a closer relationship be established between emission trades and the various pollutant-specific SIP elements? With regard to the spatial distribution of emissions, the rule as proposed did not acknowledge any sub-regional emission budgets, dispersion modeling requirements, or other spatial considerations contained in attainment and maintenance demonstrations for specific SIP elements.

Conclusion: The original proposed regulation did not have a modeling requirement for ERC use. The Division subsequently proposed that modeling be required prior to an ERC use unless the source requests that such modeling be waived and the source can show that the ERC use would have a "negligible" impact. The Colorado Association of Commerce and Industry expressed a concern that the Division would require costly or unnecessary modeling in most cases. This concern stems from the lack of definition of what is "negligible" in the judgment of the Division. The Commission believes that modeling should only be required where the location or circumstances of the ERC use would reasonably be expected to cause or contribute to a NAAQS violation, an increment exceedance, or violation of a SIP provision such as near a "hot spot" in a nonattainment area or where ambient conditions are within 5% of any applicable standard. The Commission, based on the explanation offered by the Division, believes that the modeling required by the rule as adopted will adequately address this issue.

16. Issue: Should the emission trading rule clarify whether trades can take place among different air sheds/Air Quality Control Regions.

Conclusion: The Commission adopts two levels of limitations on the geographic scope of trading. First, trades are limited to sources within the same nonattainment area or from a source in a nonattainment area to one in an attainment area. Second, all trades must be between sources within the same PM-10 PSD areas. These limitations are intended to avoid excessive impacts on local communities and Class I areas from long-distance trades.

In addition to the issues discussed above, the Commission also considered concerns about granting ERCs for emission reductions that occurred in the past. This rule allows a source to use credits generated under the old rule and to seek credit certification for reductions, which occurred prior to adoption of this rule. However, the Commission wants to emphasize that past emission reductions, which have been used to demonstrate attainment or reasonable further progress for SIP purposes are not eligible to qualify as ERCs.

The Commission recognizes that use of ERCs in lieu of compliance with an emission limitation may raise public concerns in the vicinity of the credit-using source. For this reason, the rule anticipates that notice to the Division will be required prior to use of ERCs. Permanent ERC use must be accomplished through a permit change. Temporary ERC use may occur only after an APEN is filed with the Division. Each of these documents is available to the public. Notices of ERC use will be published on the ERC Trading Network by the Division. The provisions of Regulation Number 3 requiring and allowing public notice and comment of proposed permits and modifications will also apply to permit actions to approve use of ERCs. The Commission believes that use of the Division's discretion to seek public comment needs to be supplemented in order to provide sufficient information to the public regarding proposed uses of ERCs. Accordingly, the Commission has included a requirement that the Division notify local governments in the affected area when the trade will result in the use of ERCs, which would exceed the threshold for, or otherwise trigger, public notice and comment pursuant to Section IV.C.1 of Part B, Regulation Number 3. The Commission anticipates that local governments will be able to use this notice to schedule informational meetings for citizens, which Commission members and appropriate Division staff will be able to attend. The Commission also emphasizes that the Division should exercise appropriate discretion to provide public notice and comment for trades that involve HAPs, which would be implemented by notifying the local government pursuant to the process described above.

The Commission elected to preclude trading of elemental lead because of that pollutant's particular characteristics and modified the definition of criteria pollutant for the purposes of this regulation.

The Commission included Section IV.A.1.d. in this regulation to ensure that ERCs are granted only for real overall reductions in emissions. This provision ensures that reductions will be creditable only if the emissions are not replaced in the airshed by another generator in a business of like kind. In order to assure that this program does not grant credit for “paper” reductions, the rule prohibits generating ERCs where this business shift will replace emissions within the same airshed. This determination will be made on a case-by-case, fact-specific basis.

Specific Statutory Authority

These regulation revisions are adopted under the general authority of the Commission found in Section 25-7-105(1), C.R.S. and are consistent with 42 U.S.C. 7410(a)(2)(A).

Purpose

This rule was proposed in order to provide the maximum flexibility for sources in meeting the state and federal requirements outlined under the possible uses for credits. The Commission makes the following findings in regards to the adoption of this regulation:

1. The Commission has considered, and has based its decision, on the reasonably available, validated, reviewed and sound scientific methodologies and information made available by interested parties.

2. Where these revisions are not administrative in nature, the record supports the conclusion that the provisions adopted will result in a demonstrable reduction in air pollution. This reduction is accomplished through the retirement of 10% of the achieved reduction in emissions.

3. The revisions selected maximize the air quality benefits of the emissions standards that apply. The revisions selected are the most cost-effective based on the documents submitted by the parties under Section 25-7-110.5, and provide the regulated community with flexibility in meeting emissions limitations. Although the requirement for increased emissions modeling may impose additional costs, the Commission believes this requirement is necessary to ensure that no violations of air standards will occur as a result of using ERCs.

I.AA. Adopted November 21, 1996

Revisions to Appendices B, C

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulations 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Number 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3 Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify Regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(l)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Number 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

I.BB. Adopted November 18, 1999

Revisions to Part C Incorporation by Reference of New and Revised Federal Regulations Concerning Compliance Assurance Monitoring (40 C.F.R. Parts 64, 70, and 71) into Colorado Air Quality Control Commission Regulation Number 3, Part C, Addition of Section XIV.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Pursuant to Section 114 of the 1990 Clean Air Act Amendments ("CAAA"), the U.S. Environmental Protection Agency ("EPA") promulgated new regulations in 40 C.F.R. Part 64 and revised regulations to 40 C.F.R. Parts 70 and 71 to implement compliance assurance monitoring ("CAM") for pollutant specific emission units at major stationary sources of air pollution that are required to obtain Title V operating permits. The requirements imposed by the CAM rule are separate from the requirements of EPA's "periodic monitoring" rule found at 40 C.F.R. Section 70.6(a)(3)(i). The periodic monitoring rule requires that each operating permit contain any emissions monitoring or test methods already required by an applicable requirement including any "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit . . . such monitoring shall assure use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement." See 40 C.F.R. Section 70.6(a)(3)(i)(B) (emphasis added).

Subject to certain exemptions, the new CAM regulations require owners or operators of such sources to conduct monitoring that satisfies particular criteria established in the rule to provide a reasonable assurance of compliance with applicable requirements of the Act. Monitoring requirements contained in the rules focus on emissions units that rely on pollution control equipment to achieve compliance with applicable standards. The CAM regulations also provide procedures for coordinating these new requirements with the Operating Permits Program regulations.

The CAM regulation generally will not require implementation of its requirements for most units subject to CAM until the first round of Title V permit renewals, which will generally be five years after initial Title V permit issuance.

The following table reflects the schedule by which CAM plans must be submitted by owners and operators of affected emissions units:

Pollutant Specific Emission Unit (PSEU) Size	CAM Plan Due as part of the Operating Permit INITIAL Application	CAM Plan Due as part of the Operating Permit REVISION Application	CAM Plan Due as part of the Operating Permit RENEWAL Application
"Large" PSEU (see 40 C.F.R. Section 64.5(a))	If Title V permit application is not complete by 4/20/98 OR if PSEU part of a greenfield permit application after 4/20/98	If a significant permit revision[1] at an existing Title V source	If Title V permit application was complete before 4/20/98
"Other" PSEU (see 40 C.F.R. Section 64.5(b))	Never	Never	Always

1. "significant permit revision" is defined as "significant permit modification" in Colorado Air Quality Control Commission Regulation Number 3, Part A, Section I.B.36.h. This definition is subject to change when the federal Part 70 revisions are promulgated and adopted by the Colorado Air Quality Control Commission.

In the event of a significant proposed operating permit modification that may trigger the earlier application of the CAM rule, the rule's provisions only become applicable with respect to those pollutant specific emission units for which the proposed operating permit revision is applicable. See 40 C.F.R. Section 64.5(a)(2).

Basis

Regulations to implement these CAAA mandates were originally proposed in 1993 as the "enhanced monitoring" program. The enhanced monitoring proposal focused on monitoring air emissions as a means of ensuring source compliance with CAAA emission limitations and operating permit conditions. The EPA received approximately 2,000 comment letters to the enhanced monitoring proposal. In response to these comments and through a series of stakeholder meetings, the agency decided to redesign the Part 64 program. In 1995, the EPA promulgated a revised draft Part 64 rule, which is now known as the CAM rule. The final CAM rule was promulgated on October 22, 1997.

The Commission heard testimony from members of the public who were concerned that the implementation of the rule would have the effect of making existing applicable requirements more stringent. It is the Commission's understanding however that this is not the purpose nor should be the result of implementation of the CAM rule. In adopting the CAM rule by reference, the Commission does not intend that existing applicable requirements become more stringent.

Authority

Section 25-7-105(12), C.R.S. (1997) provides authority to promulgate regulations that are necessary to implement the minimum elements of Title V of the Clean Air Act. Section 25-7-106(6), C.R.S. (1997) provides the Commission with the authority to require testing, monitoring and record keeping. Commission action in promulgating these regulations is taken pursuant to the above statutory provisions. The Commission is not adopting the CAM rule in this incorporation by reference as part of the Colorado State Implementation Plan. For that reason, the provisions of Section 25-7-105.1 C.R.S. (1999) regarding federal enforceability do not apply.

Purpose

Adoption by reference of the Federal CAM regulations contained in 40 C.F.R. Part 64, and the revisions to 40 C.F.R. Parts 70 and 71 make the regulations enforceable under Colorado law. Adoption of the regulations will not impose upon sources additional requirements beyond the minimum required by Federal law, and may benefit the regulated community by providing sources with up-to-date information.

I.CC. Adopted November 15, 2001

Revisions to Regulation Number 3, Part B: Concerning Construction Permits, Including Regulations for the Prevention of Significant Deterioration

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S., and implements Sections 25-7-105(17) and 25-7-212, C.R.S.

Basis

The rule revisions adopted implement the provisions of House Bill 99-1351. Regulation Number 3 contains permitting, monitoring, reporting, visibility protection, and fee requirements.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105(17), C.R.S., provides the authority for the Commission to hold hearings to approve emission inventories related to state and federal lands. That subsection also directs the Air Pollution Control Division to prepare inventories for all state land management agencies with jurisdiction over state lands. Section 25-7-212, C.R.S., requires federal land managers to develop a plan for evaluating visibility in mandatory class I federal areas and to provide to the state an emission inventory for pollutants that affect any mandatory federal class I area within Colorado. This Section also directs the Commission to use the inventories to develop control strategies for reducing emissions within the state of Colorado as a primary component of the visibility long-term strategies.

The Commission's action is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

In general, HB 99-1351 was intended to provide mechanisms for the state to develop information important to its efforts to protect and enhance visibility, particularly in mandatory federal class I areas. This bill specifies the types of information that must be reported, collected and approved for use in the state implementation plan.

Federal agencies own and administer approximately 36 % of the land in Colorado. Accordingly, the federal government has jurisdiction over many sources of emissions within the state. The inventory information developed under this regulation will provide additional information needed regarding these emissions, as well as those from similar state lands.

The rule requires that all federal and state lands have emission inventories approved by the Commission by December 31, 2002 and at least every five years thereafter. The emission inventories must include emissions in both Colorado and other states that may affect visibility in mandatory federal Class I areas in Colorado.

House Bill 99-1351 requires the first submittal of inventory information by the federal land management agencies by December 31, 2001. The Commission anticipates that the affected federal land managers may rely upon regional inventory information to satisfy in part the requirements of this rule. The regional inventory development process is in its early stages. In addition, this hearing has been continued once and accordingly this rule may not become effective before the statutory deadline for the initial federal public lands emission inventory submittal. The Commission recognizes that this created uncertainty for the federal land managers. Nevertheless, the General Assembly established the deadline for submittal of the federal public lands inventory in 1999 and the federal agencies have known about this requirement for more than two years.

The Commission anticipates that submittal of the regional emission inventory will provide enough information to reasonably meet the December 31, 2001 deadline. In order to ensure that inventories reflect the best information available, however, the Commission allowed the federal agencies an additional six months to provide supplemental information to fully meet the requirements of this rule. Any such additional information must be submitted to the Commission by July 1, 2002. The Commission is to hold a public hearing on the inventories and approve them by December 31, 2002. This schedule will still allow sufficient time for the Commission to consider and approve, if appropriate, the inventory information submitted.

The Commission believes that the emissions subject to the reporting requirements of this rule are in the order of hundreds of tons per day of criteria pollutants and that this level of emissions justifies application to federal and state land managers of reporting requirements similar to those that apply to owners and operators of other large emissions sources.

The Commission has the authority to exempt from the inventory requirements any sources or categories of sources that it determines to be of minor significance. This rule does not contain such an exemption because little is known about several of the source categories (e.g., biogenic sources). The Commission may consider at a later time whether such an exemption is appropriate based on additional information that may be gathered.

The Commission elected for the purposes of this regulation to define federal land management agencies as those agencies that own and manage at least 50,000 acres of land in Colorado. The Commission intended to exempt agencies with relatively small amounts of land (e.g., Department of Commerce, Bureau of Reclamation) from having to prepare inventories. In the Commission's view, the benefit of developing information relative to emissions from lands managed by smaller agencies did not justify the administrative burden and costs of preparing such emission inventories.

The Division is required by the bill's provisions to provide an inventory of emissions from activities of all state of Colorado land management agencies on state of Colorado lands that may affect visibility in Colorado's Class I areas. The inventory is to be delivered to the Commission by July 31, 2002 and at least every five years thereafter.

There are several requirements in the statute that have not been included in the regulation as they are largely policy directives to the Commission and Division from the General Assembly

The rule revisions adopted address the procedural mechanisms for accomplishing the mandatory requirements of House Bill 99-1351. The Commission concludes that these rule revisions are adopted to implement prescriptive state statutory requirements, where the Commission is allowed no significant policy-making options, for the purposes of § 25-7-110.5, C.R.S. The Commission also concludes that it has no discretion under state law to adopt alternative rules that differ significantly from these revisions, for the purposes of § 25-7-110.8(1), C.R.S. Accordingly, the Commission did not include in the record some of the portions of the rulemaking prerequisites addressed in § 25-7-110.5, C.R.S. and did not make specific determinations regarding the factors listed in § 25-7-110.8(1), C.R.S.

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

I.DD. Adopted July 18, 2002

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose comply with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. The regulation is organized into four parts: Part A contains general provisions and the Air Pollution Emission Notice (APEN) program; Part B deals with major and minor source Construction Permits; Part C sets forth the Operating Permit program; and, Part D provides the statements of basis, specific statutory authority and purpose for revisions to the regulation. Changes have been made to each of these parts to clarify ambiguous language, eliminate duplicative or unnecessary provisions and to make the requirements more understandable and easier to read. Additionally, some substantive changes have been made to address inconsistencies between the regulation and state and federal law, to improve the permit program from an air quality protection perspective and to eliminate unnecessary burdens on the regulated community. Appendices B and C to the regulation were deleted because they were duplicative of Appendix D. The majority of the revisions were proposed by the Air Pollution Control Division based on internal review and extensive discussions with interested parties. The Division's initial proposals were addressed at length during a subcommittee process involving the Commission, the Division, stakeholders and other interested parties. During this process, participants commented on the initial proposal and offered additional suggestions. The proposal presented to the Commission is a collaborative effort of the Division and interested stakeholders.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in various Sections of the Colorado Air Pollution Prevention and Control Act ("Act"). Section, 25-7-105(1), C.R.S., gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of the Act, including regulations to assure attainment and maintenance of national ambient air quality standards, emission control regulations and a prevention of significant deterioration program. Section, 25-7-105(12), C.R.S., provides specific authority to establish, emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114, through 25-7-114.7 of the Act, and these Sections in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Section 25-7-106, C.R.S., in Section 25-7-119, C.R.S., and in Section 25-7-132, C.R.S.

Purpose

A review of the previous Regulation Number 3 revealed numerous stylistic, grammatical and formatting problems, language ambiguities and obsolete or duplicative provisions. These revisions are intended to update, clarify and streamline this regulation. Additionally, changes have been made to address developments in state and federal law, to eliminate inconsistencies between the regulation and state and federal law, and to improve the programs set forth in the regulation from an air quality perspective while eliminating or minimizing undue and unnecessary burdens on the regulated community.

I. Part A Revisions

Part A of Regulation Number 3 contains a definitional Section and provisions that set forth the Air Pollution Emission Notice program and other general provisions relevant to the notice and permit programs.

A. Definition Changes

Numerous changes to the definition Section were made. Primarily, these changes were designed to fix ambiguous language, to make the definitions more readable or to delete obsolete or duplicative definitions. For example, the definition of applicable requirement was modified to clarify that it included construction permit requirements that may have been modified during the operating permit process. This definition was always intended to include such modifications, but the old language failed to clearly explain that intent. Similarly, a change to the definition of major modification was necessary to clarify that the term included both physical changes and changes in the method of operation. The prior version omitted language resulting in an ambiguity regarding this intended meaning. Changes were made to the definition of net emissions increase to clarify that in calculating an increase or decrease of emissions, sources are not committed to use the emission numbers contained in an APEN. For example, when credible demonstrable evidence indicates a different amount of actual emissions exists, this information can be used to demonstrate a net emissions decrease. The definition of significant was also changed to clarify that the Prevention of Significant Deterioration (PSD) and New Source Review (NSR)-nonattainment area (NAA) programs do not apply to certain hazardous air pollutants. Specifically, the state PSD and NSR/NAA programs exempt those hazardous air pollutants that are exempt from the federal PSD and NSR/NAA programs pursuant to Section 112(b)(6) of the Federal Act.

In addition to the clarifications, formatting and readability changes made to the definition Section, a number of definitions were added or modified to reflect developments in federal law. For example, the Commission revised the definitions of actual emissions and major modification to include special provisions governing physical or operational changes at electric utility steam generating units. These changes were necessitated by changes in the federal regulations arising out of the decision in the Wisconsin Electric Power Company ("WEPCO") case. The changes are applicable only to coal-fired electric utility steam generating units. Colorado law has required that NSR provisions be interpreted consistent with federal requirements since 1994 when the Colorado General Assembly enacted HB94-1264, Section 25-7-109, C.R.S. The WEPCO definitions have been added, consistent with EPA's regulations, in order to clarify the meaning and scope of the changes to the definitions of actual emissions and major modification. Units need not have obtained a formal applicability determination from the Division before proceeding with the physical or operational change, although doing so is at the risk of the source. Actual emissions levels may be determined from the information found in periodic APENs which sources file pursuant to Regulation Number 3, Part A., or from other credible information, such as data from continuous monitoring systems. The filings by sources in the past, such as APENs, have enabled the Division to track sources' emission increases and decreases in a manner consistent with the provisions in the WEPCO rule, therefore, the Commission believes this formal adoption should not impose a greater burden on sources in Colorado than they have historically experienced. The Commission notes that, consistent with the legislature's intent, the WEPCO provisions have been implemented by the Division in recent years. One example is the flexibility provided a change qualifying as a pollution control project.

The definition of major modification was further changed to restrict what constituted a temporary activity. Under both the old and new regulations, temporary activities are not considered to be part of a major stationary source. The old definition could be read, however, to exclude activities that constituted temporary sources under the PSD program. Such sources are subject to certain limited PSD requirements, and could be classified as an exempt temporary activity resulting in an exemption from those limited requirements. The new version clarifies that only temporary construction or exploration activities are exempt, thus preserving the applicability of the PSD temporary source requirements.

Under the definitions for major modification and major source, while emissions from temporary construction are not included in determining whether there is a major modification or source, emissions from ongoing construction are included. Several parties requested clarification as to what constitutes ongoing construction. Such a determination must be made on a case-by-case basis, but generally, construction lasting more than two years will be considered ongoing.

At the suggestion of the regulated community, the definition of commenced construction was supplemented to identify the entire range of pre-construction activities that may be undertaken without obtaining a construction permit.

Provisions governing regulation of non-road engines have undergone a complete overhaul. In addition, the definition of non-road engines was moved from the APEN exemption provisions in Part A, Section II.D.1.sss., to the definition Section of Part A. The prior regulation (Section II.D.1.sss.) exempted certain non-road engines from APEN and permitting requirements, provided these exemptions did not apply where the engines would otherwise trigger PSD, NSR-NAA review or other applicable requirements. Since the promulgation of that regulation, Congress amended the federal Clean Air Act. These amendments, as interpreted by the D.C. Circuit Court of Appeals, precluded the states from enacting emission control regulations for non-road engines except under very restricted circumstances. The Court of Appeals held, however, that states could enact use restrictions such as restrictions on the hours of operation or amount of fuel usage. To address this situation, the regulated community requested that non-road engines be specifically identified as non-stationary sources, thus exempting them from most, if not all, of the requirements of Regulation Number 3. While agreeing that non-road engines should not be treated as stationary sources, the Division expressed a concern that a large aggregation of these engines might result in a violation of ambient air quality standards. To reconcile these conflicting concerns the regulatory revisions create a new state-only non-road engine program for certain non-road engines.

The Commission's authority to establish a non-road engine program and to regulate the operation of non-road engines is set forth in 27-7-106(1) C.R.S., and through the legislative declaration in 25-7-102 C.R.S. Non-road engines subject to the program must submit an APEN and pay appropriate APEN fees. If specified emission levels are tripped in the APEN, the program further requires that the source obtain a temporary permit and pay applicable permit fees. The permit will include such use restrictions as are necessary to prevent an exceedance of ambient air quality standards. Non-road engines that are mobile or self-propelled equipment such as bulldozers, haul trucks, water trucks, loaders, shovels, backhoes, road graders, cranes or similar mobile equipment are not subject to the state-only permit program and are not required to obtain an APEN.

Whether an engine qualifies as a non-road engine as opposed to a stationary source will depend on the facts of a particular case. To qualify as a non-road engine under Regulation Number 3, Part A, Section I.B.40.a.iii., the engine must be portable. What constitutes portable will be determined on a case-by-case basis. Additionally, such portable engines lose their status as non-road engines if they remain at a location for more than twelve consecutive months. The regulation narrowly defines location such that use of a portable engine at multiple sites at a given source does not constitute use at a single location. This provision, however, is not intended to allow a source to circumvent the regulation by moving a given engine for the purpose of avoiding expiration of the twelve-month period.

For sources that have voluntarily obtained permits for a non-road engine(s) as defined in Regulation Number 3, Part A, Section I.B.40., prior to the effective date of this rule revision, a source may continue to operate under the existing permit. A modification or re-opening of the existing permit will effectively subject a source to the requirements set forth in the non-road engine state-only permit program (Part A, Sections I.B.40.c. and I.B.40.d.)

During the public hearing on this rulemaking, the Commission raised concerns regarding the flexibility and responsiveness of the new state-only non-road engine permit program in emergency or other unforeseen situations. In these situations, it is an operator's obligation to file an APEN and obtain a state-only non-road engine permit under Sections I.B.40.c., and I.B.40.d., prior to the exceedance of any trigger level (i.e., hours of operation and/or emission limitation). This clarification is intended to increase program flexibility by ensuring that operators, including local and state government, will not be penalized when responding to emergencies and business planning conditions when such conditions subsequently trigger APEN and permit application requirements under the program.

To enhance and foster program responsiveness, the Commission expects that the Division shall act to complete state-only non-road engine permit applications as expeditiously as possible. In addition, under the authority set forth in Section 25-7-114.5(5), C.R.S., the Commission has determined that state-only non-road engine permit applications shall not be designated as permit actions subject to public notice requirements.

B. Changes to APEN Program

The Division proposed to add record keeping requirements to a number of APEN exemptions. The Commission did not adopt the specific record keeping language in Part A of the regulation. The intent of the Commission, however, is that sources should have records or other information sufficient to verify that an exemption from APEN requirements can be taken in accordance with the regulatory requirements.

The Commission revised Section II.D.4.a.(vi), deleting the solvent return opening size requirement for small remote reservoir cold solvent degreasers contained in Section II.D.4.a.(vi)(A). The Commission also revised the emissions limit in Section II.D.4.a.(vi)(C) from 350 pounds of volatile organic compounds per year to one ton of emissions per year. These changes were requested by industry based on the argument that the existing provision was specifically designed for one particular source and is not useful for the broader industry. While sources are no longer required to meet the solvent return opening provision in order to claim the exemption, they are subject to the requirements contained in Regulation Number 7, Section X.B.

Measurement of the throughput threshold for the fuel storage and dispensing equipment APEN Exemption in Section II.D.1.ccc., was changed from a 30-day average to an annual average. In addition, language was added to clarify that sources in the Denver ozone attainment-maintenance area must still utilize Stage 1 vapor recovery on all tanks with a capacity greater than 550 gallons, as required by Regulation Number 7. While ordinarily sources subject to other applicable requirements would be precluded from taking the exemption under the APEN and constructions permit exemption catchall provisions, in this particular instance, it is the Commission's intent that sources may take this exemption providing that the Regulation Number 7 vapor recovery requirements are met.

An APEN exemption for wet screening operations was added at Section I.D.1.cccc. Certain wet screening operations are subject to New Source Performance Standard (“NSPS”) Subpart OOO. This federal requirement requires that such facilities comply with a zero visible emissions standard. Ordinarily, a source that is subject to a New Source Performance standard precludes the source from taking an APEN exemption pursuant to the catchall provision in Section II.D.4. It is the Commission's intent that in this particular case, application of NSPS Subpart OOO shall not prevent a wet screening operation from taking the exemption.

A substantive change was made to the applicable de minimis levels for APEN exemptions in attainment and nonattainment areas. Under the prior regulation, if an area was nonattainment for any pollutant the lower nonattainment de minimis levels applied for all pollutants. This has been revised so that the lower levels will only apply to the pollutants for which the area is not in attainment.

The exemption for agricultural operations was changed to provide greater clarity and to be consistent with the requirements of the State Act. Conforming changes were also made to the agricultural exemption set forth in Part C.

Because Regulation Number 3 and the Common Provisions Regulation under went contemporaneous review, the primary focus with respect to duplicative provisions was to eliminate duplications between the two regulations. Duplicative provisions that were only applicable to Regulation Number 3 were deleted from the Common Provisions Regulation. Provisions applicable to multiple regulations remain in the Common Provisions and were deleted from Regulation Number 3. Certain non-Regulation Number 3 duplications were also addressed. A full review of all the Commission's regulations was not undertaken at this time. It is expected that there are additional duplications that should be addressed as other regulations are opened for revision.

C. Fee Schedule Revisions

The language governing the fee schedule for APENs and permit processing was simplified to provide that fees will be charged in accordance with the procedures and amounts set forth in the Act. This change alleviates the requirement of revising the regulation every time the statutory fee schedules change.

D. Confidentiality Provisions

The rules governing confidentiality of documents submitted in connection with APENs and permit applications were changed to be consistent with the Act, and to clarify ambiguities in the prior regulation. In addition, more specific provisions were added regarding the process involved in asserting confidentiality and determining whether documents are in fact confidential. Under the prior regulation, the evaluation of confidentiality claims was very ambiguous making it difficult for the Division to determine whether a document was confidential, and providing sources no guidance as to the steps they should take to ensure confidential treatment of documents. The new provisions clearly set forth the rules for claiming confidentiality and for evaluating such claims. This should benefit the Division and the regulated community by providing a clear understanding of confidentiality protections.

Pursuant to the State Act, information submitted as part of an air pollutant emission notice, Permit Application or Operating Permit reports is confidential only if it relates to secret processes or methods of manufacture or production. This limitation is reflected in the revised regulation. In contrast, Section 25-7-111(4), C.R.S. provides that information obtained by the Division in connection with an enforcement action may be entitled to confidential treatment if it constitutes a trade secret. The current regulatory revision is not intended to alter or affect the protections offered under Section 25-7-111(4), C.R.S.

In cases where the Division determines that certain information is not subject to confidential treatment the revisions shorten the notification period from fifteen to three days. This change was made based on the statutory mandate in the Colorado Open Records Act requiring release of public records within three days after a request for such records. The notification period is intended to allow the source the opportunity to obtain judicial relief from the Division's determination under the State Administrative Procedures Act prior to release of the information. While it is recognized that the three-day notification period may make it difficult for a source to institute a timely action, the requirements of CORA preclude a longer period. It is expected that the Division will take the steps necessary to provide actual notice to the source as soon as a determination is made, so that the source will have adequate time to protect its rights.

II. Part B Revisions

The majority of revisions to Part B involve stylistic changes intended to improve the readability of the regulation. A small number of substantive revisions were made as described below.

The provisions in Section IV.H., were changed to clarify the requirements for obtaining a final approval construction permit. The previous regulation required the source to demonstrate compliance with the initial approval construction permit. The Division was then required to conduct an inspection to determine compliance. Because an inspection during the initial approval period is not required by law, the new regulation makes the inspection discretionary. This provides necessary protections in those instances where an inspection may be needed. The provision was further modified to give the Division discretion as to whether to issue a final approval permit when there is a pending operating permit application. Requiring the issuance of a final approval permit was often an unnecessary step in situations where an operating permit would be issued shortly thereafter. To avoid confusion among sources when the Division elects not to issue a final approval construction permit, a notice will be provided to the source in writing. Similar flexibility was added to Section III.D.6., in cases where a previously permit exempt source loses its exemption based on addition of new emission points.

The prior regulation required submission of an operation, maintenance, and record keeping plan with the construction permit application. This provision ignored the reality that such plans are difficult to provide until after the source has been constructed. The new regulation provides that these plans must be submitted prior to obtaining final approval.

Significant changes were made to the post construction monitoring requirements for the PSD program. The changes were made to be consistent with the federal PSD regulations. The revisions provide flexibility to either require or waive post-construction monitoring.

The revisions expand the provisions governing appeals of construction permits. The prior regulation provided that a source could appeal the Division's decision to the Commission, but failed to identify the process for such an appeal. The revision provides that the appeal must be made within thirty days after the issuance of the permit, denial or revocation, and will be held in accordance with the general rules for adjudicatory hearings. A similar provision was also added in Part C at Section V.E.

Section V.B. has been changed to reflect that the Black Canyon of the Gunnison has been reclassified as a National Park. The boundaries of this area remain the same, and there is no change in the classification of this area as Class I or Class II.

Revisions have been made throughout the regulation to address changes in areas from the nonattainment classification to the attainment/maintenance classification. A search of the regulation was conducted to identify those provisions that depended on the area being classified as nonattainment. When a requirement remains in place after the reclassification of an area, the word nonattainment was changed to attainment/maintenance. Otherwise, no change was made. A substantive change was made to the applicable de minimis levels for permit exemptions in attainment and nonattainment areas. Under the prior regulation, if an area was nonattainment for any pollutant the lower nonattainment de minimis levels applied for all pollutants. This has been revised so that the lower levels will only apply to the pollutants for which the area is not in attainment to be consistent with a similar revision in Part A.

III. Part C Revisions

As with Parts A and B, the majority of revisions to Part C include changes to improve readability and to clarify ambiguous provisions. Revisions were made to Section II.E., to fix poorly worded language. The new provision more clearly explains when an insignificant activity exemption can be taken. In addition, changes in II.E., and to other Sections regarding exemptions included in Part C were made to conform to exemptions in Part A and B.

Provisions regarding the phase-in of the operating permit program were deleted since these provisions are now obsolete.

Section III.B.2., sets forth certain timing requirements with respect to submitting operating permit applications. The prior regulation was unclear as to the new legal requirements for sources subject to the operating permit requirement after start-up by operation of law. The revised provision clarifies that sources shall submit an application within twelve months of the effective date of the new requirements or at such other time specified in those requirements. The revisions also clarify that when a source subject to an operating permit is modified, an application to revise the permit must be submitted within twelve months of the modification.

In the past, significant confusion has arisen when a source seeks an operating permit prior to obtaining a final approval construction permit under Part B. Revisions to Sections V.A., and IV.B.3., clarify the rules governing these situations. These revisions also conform to the changes made in Part B, Section IV.H. The flexibility given to the Division to issue an operating permit absent a final approval construction permit under Section V.A., is intended to apply regardless of whether the source has commenced operation of the emission unit(s) at issue.

IV. Appendices

Prior to this rulemaking, Regulation Number 3 included four appendices: Appendix A, Method for Determining De Minimis Levels for Non-Criteria Reportable Pollutants; Appendix B, 1993 Non-Criteria Reportable Pollutants; Appendix C, 1994 and Subsequent Years Non-Criteria Reportable Pollutants; and Appendix D, Non-Criteria Reportable Pollutants. This rulemaking deletes the original Appendix B and Appendix C because they are duplicative of Appendix D. Appendix D has been revised to Appendix B in order to maintain continuity in the regulation.

I.EE. Adopted October 17, 2002

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose comply with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. Pursuant to its statutory authority, the Commission may exempt certain stationary sources from permitting and APEN requirements where emissions from such sources are deemed to be insignificant. The Commission is revising the exemptions for condensate and crude oil tanks and condensate and crude oil loading equipment to ensure that the exemptions apply only where the emissions are truly insignificant. Additionally, the Commission is revising the provisions designed to ensure that in exempting certain sources from APEN and permit requirements, the regulation does not allow sources to avoid other state and federal requirements. This revision clarifies when application of other requirements prohibit sources from claiming exemptions.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in various Sections of the Colorado Air Pollution Prevention and Control Act ("Act"). Section, 25-7-105(1), C.R.S., gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of the Act, including regulations to assure attainment and maintenance of national ambient air quality standards, emission control regulations and a prevention of significant deterioration program. Section, 25-7-105(12), C.R.S., provides specific authority to establish, emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114.1, and 25-7-114.2 of the Act, including the authority to exempt certain sources from APEN and Permitting requirements. These Sections in turn, provide additional statutory authority for the current revisions.

Purpose

I. Condensate Tanks and Truck Loading Equipment

Revisions to the crude oil and condensate storage tank exemption in Part A, Section II.D.1.ddd.and crude oil and condensate truck loading equipment exemption in Part A, Section II.D.1.ee., were proposed to address the issue of flashing emissions in condensate tanks. The exemptions, and a corresponding exemption in Part C, Section II.E.3.ee. and ddd., did not take flash emissions into account when the Commission initially adopted the exemption. The large quantity of volatile organic emissions that can be released during a flash event led to changes in the exemptions. Additionally, separate exemptions have been established for crude oil tanks and equipment and condensate tanks and equipment in recognition of the fact that flashing emissions from crude oil and condensate are significantly different.

The Commission recognizes that in changing these exemptions a number of tanks and equipment that were previously exempt from APEN reporting, and therefore exempt from construction permitting requirements, will now be required to file APENs. The Commission does not believe, however, that these existing sources will now be required to obtain state construction permits, since such a requirement is triggered by construction or modification of a source, and not by a change in a previously applicable exemption. If, however, the tanks or equipment is modified after December 30, 2002, a construction permit will be required for the modification unless the tanks or equipment qualifies under the revised APEN exemption or constructions permit exemption. During the revision process there was some discussion about what might constitute a modification that would trigger construction permit requirements. Based on the information provided to date, the Division and Commission do not currently believe that reworking of an existing well would constitute a modification under the regulations. Additionally, sources subject to PSD, NSR-NAA and Title V permitting requirements are required to have such permits regardless of their exemption status. The Commission notes to permit applicants that this change becomes effective on the effective date of this regulation.

In connection with these revisions, the Commission has also looked at the timing requirements set forth in Part A, Section II.D.1.lll., for submitting APENs and obtaining construction permits for tanks at crude oil and natural gas exploration and production sites. The Commission enacted this provision in 1993 to allow sources sufficient time to determine production levels before being required to submit APENs or construction permit applications. To affect this, Section II.D.1.lll. provided that APENs for oil and gas exploration and production operations were not required until 30 days after filing the well completion or recompletion report with the appropriate state or federal agency. Additionally, Part B, Section III.D.8. provided that applications for construction permits for such operations were due at the same time as the APEN filing. Based on discussions during the regulation revision process the Commission discovered that the well completion report must be filed before production levels can be determined and that the provision should have referenced the report of first production. Therefore, the Commission has revised Section II.D.1.lll. to clarify and effectuate the intent of the 1993 revisions.

The Commission also recognizes the definition of condensate that appears in the Common Provisions Regulation does not include reference to an API gravity and therefore could be read to include crude oil. It is the Commission's intent that for the purposes of these exemptions, as well as APEN reporting, condensate should only include hydrocarbon liquids that fit within the Common Provisions definition and that have an API gravity of 40 degrees or above. The Commission anticipates revising the Common Provisions definition to more clearly reflect this intent the next time the Common Provisions regulation is opened for revision.

II. APEN Catchall

Changes to the APEN catchall in Part A, Section II.D.4. and the construction permit catchalls in Part B, Section III.D.5., were significantly reworked to add clarity. The prior versions were somewhat unclear as to both the effect of APEN and permitting exemptions on other applicable requirements and when otherwise exempt sources would be required to file APENs. While the revisions minimally change the substantive requirements of the two catchall provisions the new language is intended to more clearly express these requirements. The new language clarifies that sources that are exempt from APEN and/or construction-permitting requirements are not, by virtue of that exemption, exempt from any other applicable requirements. Thus, for example, a source that is exempt from APEN or permitting requirements, must still comply with the Regulation Number 1 20% opacity standard. Likewise, an APEN exempt emission point at a major source is excused from paying APEN fees but may still need to be listed as an insignificant activity under the requirements of the Title V program. Additionally, where the emissions from a particular emission point would cause a source to avoid PSD, NSR-NAA or Title V information regarding that emission point cannot be omitted from any permit application, notwithstanding the fact that the emission point standing alone might be exempt from APEN or Construction Permit requirements.

The Commission also requires that if the potential to emit, taking into account full design rate and continuous operation, triggers PSD or NSR requirements, the source must submit an Air Pollutant Emission Notice and apply for the appropriate permit, or must apply for a permit to limit the physical or operational capacity of the source such that the source is not considered to be a major source as defined in Section I.B.59 of Part A of this regulation. This language previously appeared in the catchalls, but was relocated to this statement of basis.

Finally, the revised catchall provisions subject certain emission points and sources to APEN and Construction Permit requirements notwithstanding the fact that such points and sources would otherwise be exempt. Sources specifically identified in the applicability Section of any subpart of Part A of Regulation Number 6 (New Source Performance Standards), or Regulation Number 8 (Hazardous Air Pollutants), Parts A, C, D, and E. This provision allows the Division to keep track of these points and sources, and ensure that the requirements of these programs are being properly followed. It must be noted, however, that wet screening operations subject to the exemption set forth at Part A, Section II.D.1.cccc may claim exemptions notwithstanding the fact that such sources are subject to New Source Performance Standard OOO.

I.FF. Adopted April 16, 2004

Revisions to Colorado Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emissions Notice Requirements

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's (“Commission”) permitting and air pollutant emission notice programs for stationary sources. The rule revisions adopted reorganize and clarify the permitting, monitoring, reporting and fee requirements of Regulation Number 3. In addition, new provisions were added to conform the state program to the federal rules.

The existing regulation was composed of four parts. Part A contained general provisions and the Air Pollution Emission Notice [APEN] program; Part B addressed major and minor source construction permits; Part C set forth the Operating Permit Program; and Part D included the statements of basis, specific statutory authority and purpose for historical revisions to the regulation.

The Commission reorganized the rule in order to make it easier for sources to find and comply with applicable requirements. Part A now contains general provisions applicable to reporting and permitting, including the Air Pollution Emission Notice requirements; Part B addresses construction permits; Part C includes the operating permit program; and Part D deals with the Nonattainment New Source Review and Prevention of Significant Deterioration [“New Source Review” or “NSR”] programs for major stationary sources. Minor sources will only be subject to Parts A and B; major sources (as defined for the Operating Permit program) are governed by Parts A, B and C. Major stationary sources must comply with Parts A, B, C and D. In particular, this reorganization separated the major stationary source NSR provisions from the construction permit requirements applicable to all sources. This will make it easier for minor sources to comply with the regulation. The Commission also made changes to each part in order to clarify ambiguous language, eliminate duplicative or unnecessary provisions, increase the level of certainty for the regulated community and make the regulation more understandable. Part E is now reserved for Environmental Management Systems and Part G contains the historical and current Statements of Basis, Specific Statutory Authority and Purpose for Commission rulemaking actions.

In addition, the changes incorporate modifications to the nonattainment new source review and prevention of significant deterioration programs. Changes to these programs were necessary to comply with federal rule revisions that must be incorporated into the Colorado State Implementation Plan ("SIP"). The Commission tailored the federal requirements to Colorado's air quality program to ensure efficient and flexible operation and administration of the program while eliminating or minimizing undue and unnecessary burdens on the regulated community.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105(17), C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national ambient air quality standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S, provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

General Revisions to Regulation Number 3

The Commission's reorganization of this rule separates the provisions applicable to all sources (Part A), the construction permit program (Part B) and the operating permit program (Part C). The NSR provisions for major stationary sources are now contained in Part D. In the past, these various components of the rule were intermingled to an extent that caused confusion and unnecessary work for both sources and for the Air Pollution Control Division ("Division"). By separating the major components of Regulation Number 3, the Commission intends to make the provisions more readily usable, particularly for minor sources.

As part of the reorganization, the Commission relocated some definitions. If a definition relates only to one part, it can be found at the beginning of that part. Definitions that are used in more than one part are placed in Part A. This approach will allow minor sources to identify applicable provisions without having to address the differences between construction permit, operating permit and major NSR requirements.

The Commission in this rulemaking did not amend Section V. of Part A of the existing rule. That Section addresses emissions trading and changes to it are beyond the scope of this proceeding. Likewise, the Commission specifically concluded that this rulemaking should not extend to changes to the construction-permitting program for minor sources unrelated to the federal NSR revisions; this restriction appeared in the notice of rulemaking. The Commission understands that discussions between the Division and stakeholders prompted by this proceeding may lead to policy and implementation changes.

The Commission established the effective date for the NSR revisions as the date of EPA approval of the changes as part of the Colorado SIP. An earlier effective date would have created differences between federal and state rules that could expose the regulated community to inconsistent requirements. For the remainder of the rule, the Commission concluded that the effective date need not await EPA action. Those provisions will become effective following publication in the Colorado Register.

Finally, an issue arose regarding the use of the term “attainment/maintenance” areas. Although this terminology is used in Colorado's State Implementation Plan, its relationship to these rule changes is unclear. The Commission decided to address this question at a later time.

Finally, the Commission concluded that the revisions to Regulation Number 3 do not change the procedural, administrative nature of the regulation and are not specifically intended to reduce air pollution. Accordingly, the Commission did not make the determinations addressed in Section 25-7-110.8, C.R.S., although this Statement of Basis and Purpose includes discussion to inform interested parties of the Commission's intent.

Part A Changes

Changes to Part A largely clarify or correct existing provisions. Where EPA changed specific language used in this part, the Commission adopted identical phrasing absent an identified reason for a distinction.

The term “annual actual emissions” in Section I.B.9. replaces “actual emissions” throughout Part A in references to Air Pollutant Emissions Notices (“APENs”) so that a source's reported emissions are those actually emitted during a single calendar year. This will distinguish reported emissions from the two-year average of “actual emissions” used for major NSR purposes.

Section II.D.1.g. has been modified to refer to a “major source” rather than a “major stationary source,” a term that is specific to the major NSR program. This conforms to Section 25-7-109, C.R.S.

The Commission changed Section VI.C.3 to permit sources sixty days from issuance of an invoice to pay annual emissions fees. This approach will allow sources additional time to process fee payments. In addition, the Division is required to forward any bills more than thirty days overdue to the collections office for the state. This extended payment period will reduce the number of instances in which delays in payment result in a fee bill being sent to collections.

The Commission adopted a change to the definition of “stationary source” reflected in Section Part A, Section I.B.41 to conform it to federal and state law.

Changes to Parts B and C

The Commission made only conforming changes in Parts B and C after moving the provisions applying to major NSR to Part D.

Part D Changes

Nonattainment New Source Review and Prevention of Significant Deterioration Provisions

On December 31, 2002, the Environmental Protection Agency (“EPA”) promulgated a final rule addressing the major NSR programs mandated by Parts C and D of Title I of the federal Clean Air Act. The Agency changed the requirements applicable to Colorado's SIP. The Commission adopted these revisions in order to comport Colorado's air quality program to the EPA rules. The revised regulation references to “NSR requirements” include both the nonattainment new source review and prevention of significant deterioration programs.

EPA's major NSR changes modified the method for determining whether a proposed facility modification results in a significant emissions increase, thus triggering major NSR evaluation and technology requirements. In addition, EPA added new applicability options, Plant-wide Applicability Limitations and Clean Units, and an exclusion from major modification provisions for Pollution Control Projects.

On October 27, 2003, EPA adopted further revisions to the major NSR program. In that rule, EPA provided a category of equipment replacement activities that would not be subject to the major NSR requirements under the routine maintenance, repair and replacement ("RMRR") exclusion. That rule has been challenged in U.S. Court of Appeals in Washington, D.C. The Court issued a stay, because of which the rule was not yet effective at the time of the hearing in this proceeding. The Commission elected to address RMRR issues in the future and not consider RMRR rule changes at this time.

In general, the Commission changed Part D of Regulation Number 3 to mirror the EPA major NSR rules. There are instances in which the Commission's rule differs from the federal provisions. These cases are specifically identified in this Statement of Basis and Purpose, as required by Section 25-7-110.5, C.R.S.

General

The Commission required Division review and/or approval of certain actions in instances in which the federal rule was either silent or contained no similar specific requirement. The EPA rule preamble anticipates that state minor source permit programs will continue and the Commission agreed. Colorado's Air Pollution Prevention and Control Act ("the State Act") specifically requires permits for construction and modification of air pollution sources. The Commission has historically used permits as the basic administrative structure for its stationary source programs. Exceptions to permit requirements exist in the rule for sources or activities with small emissions that have a minimal impact on air quality. In Section I.B.5., the Commission imposed a requirement that owners or operators using the actual-to-projected-actual applicability test for a project that requires a minor source permit or modification [pursuant to Part A, Section I.B.26., Part C, Section I.A.4. or Part C, Section X., or any minor source permit under any provisions of Part B], to submit an otherwise-required permit application and include documentation adequate to substantiate calculations made for the test. The federal rule requires that the owner or operator retain, but not report to the permitting authority, this information. However, the information listed in this Section would necessarily be generated by the owner or operator to satisfy the federal requirements and need only be submitted with an otherwise-necessary construction permit application. Accordingly, the Commission concluded that this requirement does not exceed federal requirements for the purposes of the Colorado Air Pollution Prevention and Control Act.

The Commission also concluded that the emissions calculated for the actual-to-projected actual test did not need to be the subject of a permit limitation. Accordingly, the information submitted will only be placed in an appendix to the major stationary source's Title V and/or in a construction permit note. This provision will assist the Division in evaluating the results of the applicability test before the relevant project is begun. Both the Division and the owner or operator will benefit from early identification of any disagreements about the applicability test.

The Commission noted discrepancies in the use in the federal rule of the terms "regulated NSR pollutant" and "regulated air pollutant." The latter includes Hazardous Air Pollutants by definition. In order to conform all of the Sections using these terms, the Commission used "regulated NSR pollutant" throughout Part D.

The federal rule allows a reviewing authority to establish a "reasonable period" for determining what constitutes a "contemporaneous" net emissions increase. Part A, Section I.B.37.b. of the old rule specified a period of five years. The Commission retained that five-year period in the revisions adopted. This period remains reasonable, just as it was under the prior version, serves to increase certainty and should assure that any net emission increase calculations are more accurate.

For calculation of Baseline Actual Emissions levels in Part D, Section II.A.4., the Commission concluded that emissions during periods of startup, shutdown and malfunction must be quantified based on the rate of operation during that period. For example, during a control equipment malfunction the calculation must assume that no controls were used to reduce emissions during that period unless the source can demonstrate the actual level of control provided during the malfunction. The Commission will allow a source to use estimation methods based on best engineering judgment, subject to approval by the Division; however, sources utilizing Continuous Emissions Monitors should be able to quantify these emissions with relative ease. In any event, the Baseline Actual Emissions calculations must be approved by the Division for use in the applicability test.

In calculating Baseline Actual Emissions, Part D, Section II.A.3., the emissions from malfunctions/upsets that exceed any enforceable limitations effective at the time of the event must be excluded. Allowing inclusion of these emissions in the calculation could reward a source for failing to limit, as much as possible, emissions during these events. Existing rules relating to these periods and “upsets” are not otherwise changed by the revisions.

The federal rule requires that emissions from “demand growth” be excluded from the Projected Actual Emissions calculation. Demand growth is any increased utilization that could have been accommodated by the source prior to any change. In no case, however, may demand growth emissions exceed an enforceable limitation existing prior to the change or modification.

The Commission elected not to elaborate on or further define some issues in the rule, instead relying on policy and practice that will be developed as necessary by the Division and/or EPA. These include what “could” increase emissions and what constitutes “regular operations” in Section VI.B.5.c. as well as the approach for evaluating “design capacity” in Section II.A.38.a. In another provision, Section VI.B.5., the Commission intends that the Division will implement the wording “reasonable possibility” consistent with, though not necessarily identical to, EPA's rule preamble and the Notice of Reconsideration issued by EPA regarding this issue. Likewise, when an owner or operator uses emission factors to monitor PAL pollutant emissions [Section V.A.7.c.(iii)], it and the Division will adjust, as appropriate, those factors to account for uncertainties or limitations inherent in the factor. The federal preamble may be consulted for guidance on such issues, including the option for the Division to exempt a source from having to validate the factors.

Sections II.A.4.a. and VI.B.5.c. include the concept of a period that is “more representative of normal source operations” in the definition of Baseline Actual Emissions. The Commission decided that such determinations will continue to be resolved on a case-by-case basis by the Division.

Plant-wide Applicability Limitations (“PAL”)

For the purpose of setting a PAL, a unit planned but not yet constructed as of the date of PAL determination has Baseline Actual Emissions of 0 tons per year, as it does not have actual emissions as of that date. These units do not differ in practice from those later planned but not yet constructed under the PAL. Both types of units must meet the emissions limitations and other conditions assessed in the PAL. Emissions units constructed at the time the PAL is set, but that have not yet operated for more than two years are new units. The Division, after consultation with EPA, recommended that the Commission not allow PALs for major stationary sources that have not been in operation for at least two years. The Commission agreed. These sources would not have “actual emissions” for this purpose because they would not yet have operated during a representative period. Allowing PALs for these sources would effectively create an “allowable PAL.” EPA clearly indicated in the December 31, 2002 preamble that it did not intend to create provisions for allowable PALs in that promulgation. The phrasing here comports with EPA's intent.

Process and control equipment changes under PALs require application and approval of a permit under existing provisions of Colorado law. PALs, since they establish a new emissions limitation for an entire facility, will necessitate a revision to the Operating Permit held by the owner or operator. The Division will act on any such permit application during the period otherwise provided in Part C. Once a source has obtained a PAL, the PAL emission limits and conditions must remain in place for the entire ten-year effective period of the PAL. Allowing a source to obtain and renounce a PAL at a shorter interval would create confusion and potentially allow manipulation of the PAL option to avoid major NSR.

The Commission adopted language differing in minor respects from the federal rule in Sections XVII.B.2. and XVII.I.2. The federal language used to construct Section XVII.B.2. was incomplete and unclear in that it did not specify that baseline actual emissions calculations must be provided for each emissions unit as parts of a PAL permit application. The phrase added creates no additional burden for sources that would have to evaluate emissions from these units in any event. In Section XVII.I.2., the Commission added the phrase “including any additional information requested by the Division.” Although the Division's authority to request information in order to confirm an owner or operator's calculations is well accepted, this addition places the PAL applicant on notice that a request may be made.

The Commission also departed from the federal wording in Section XVII.N.1. that addressed the semi-annual report to be provided by PAL sources. The Commission concluded that requiring submittal with the report of all data relied upon imposed an unnecessary and undue burden on sources. Instead, the rule allows the Division to request these data if it finds it necessary to implement its administration of the PAL permit.

Clean Units

The CU provisions of this regulation address only the emissions from a specific unit. If a unit is designated as a Clean Unit, the source does not need to go through the major source NSR program if it makes certain types of changes in the future. This allows greater flexibility to a source. The source must accept the changes to its Title V permit that are required by the rule. Additionally, an owner or operator must apply for and obtain either a Construction Permit or Operating Permit for future changes at the CU that meet the definition of modification for Part B or C purposes even though it need not evaluate the project for major source NSR applicability. The Division will act on a permit application during the period otherwise provided in Part B or C of this regulation.

Section XV.A.3. requires an owner or operator to submit a request for designation as a Clean Unit (“CU”), although this requirement does not affect automatic qualification as a CU. This provision ensures that the Division may conduct an initial, cursory review to confirm the qualification. Absent this provision, sources mistakenly using the CU option might operate for years in the belief that the designation protects operation of the unit. One principal concern for the Commission in adopting any regulation is to provide a high level of certainty for sources to avoid delayed compliance issues. By allowing the Division to review the information the source used to qualify as a CU, the Commission is providing that certainty for sources. In addition, this provision simplifies field and other inspections by assuring that the Division has an accurate record of the operations and equipment at the source.

Pollution Control Projects

The Commission believes that the Pollution Control Project ("PCP") exclusion will only be used for projects that result in a significant emissions increase in a "collateral" pollutant. If the project does not cause increases in any regulated pollutant, it would not need an exclusion from major modification requirements. Therefore, Section XVI.A. requires that a source intending to use the PCP exclusion must submit an APEN and a permit application, whether the PCP is listed or unlisted, as a significant emissions increase is likely to occur. Under the federal rule, unlisted PCPs are required to obtain permits or permit modifications. The Commission omitted the provision in the federal rule requiring a written notice for listed projects to streamline duplicative requirements in the federal PCP provisions and Parts B and C of the regulation. However, recognizing the nature of PCPs, the Commission has retained the list of the information that must be submitted to the Division. This list differs in some respects from the information required in the permit provisions of Regulation Number 3.

The Commission also adopted a provision requiring owners or operators of PCPs to retain records for a minimum of five years, consistent with the Operating Permit recordkeeping timeframe. The federal rule does not specify a retention period. This Commission action was appropriate to assure that sources and the Division have a common understanding about the retention period. Finally, in order to comply with the federal rule, the Commission included a public notice and comment opportunity for PCPs.

I.GG. Adopted December 16, 2004

Revisions to Regulation Number 3

The primary purpose of this rule revision is to clarify the applicability of various permitting and APEN provisions to sources within areas designated as attainment/maintenance. Such clarification merely makes express the rule that applied by interpretation. In most cases, the revision makes the requirements applicable to attainment areas applicable to attainment/maintenance areas. One notable exception is the requirement for construction permits for gasoline stations within the Denver 1-hour ozone attainment/maintenance area, which requirement is specified in the SIP. 40 CFR 52.320(c)(94). This rule revision also includes other minor revisions, including reporting requirements for condensate storage tanks subject to Regulation Number 3, Section XII., and corrections for accuracy. This rule revision makes no significant, substantive changes to the regulation. Nothing in this rule change exceeds the requirements of federal law. This rule change is administrative in nature, is not intended to cause reductions in air pollution, and therefore is exempt from the requirement for findings pursuant to Section 25-7-110.8, C.R.S.

I.HH. Adopted July 21, 2005

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

Regulation Number 3 sets forth the Air Quality Control Commission's permitting and air pollutant emission notice programs for stationary sources. The Commission amended Regulation Number 3, Part A, Section V. to make it consistent with the repeal of the Emissions Trading Rule in Regulation Number 5 in December 2004. It was originally anticipated that Regulation Number 5 would replace Part A, Section V. in Regulation Number 3 as the Commission's trading program, essentially identical to EPA's. The text of Part A, Section V. was italicized to represent provisions that would remain effective until EPA approved the program in Regulation Number 5. EPA decided not to finalize its trading program; therefore, it would never approve Regulation Number 5 as a SIP component. The Commission deleted Section V.A.3., Part A that contained the outmoded effective date. The Commission also replaced the italicized text with normal font in all of Part A, Section V. to conform the text to these circumstances. In addition, one hazardous air pollutant (2-butoxyethanol) was deleted to conform the State's list (in appendix b) to the Federal list of hazardous air pollutants.

The Common Provisions Regulation sets forth requirements and definitions that pertain or may pertain to all of the other Commission regulations. EPA added four compounds to its list of compounds (known as non reactive volatile organic compounds) to be excluded from the definition of volatile organic compound on the basis that these compounds make a negligible contribution to tropospheric ozone formation. The Commission adopted a conforming change to the definition of non-reactive volatile organic compounds in the Common Provisions Regulation, Section I.G.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act give the Commission authority to promulgate regulations necessary for the proper implementation of the act. Section 25-7-105(12), C.R.S, provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission took into consideration the appropriate items enumerated in Section 25-7-109(1)(b), C.R.S.

The purpose of removing the italicized text from Regulation Number3, Part A, Section V. was to prevent any ambiguity about the applicability of those provisions. Changing the font of the text does not have any regulatory impact since the provisions were already in effect and will remain in effect. Section V.A.3. was deleted because it was an outmoded provision that was only necessary if Section V. was to be replaced by Regulation Number 5. The Commission's repeal of Regulation Number 5 made that provision unnecessary. Removing the italics from Section V. also will eliminate confusion with the italicized text in Part D of Regulation Number 3.

The purpose of the deletion of one hazardous air pollutant in appendix b of Regulation Number 3 and the addition of four non-reactive volatile organic compounds to the list in Section I.G. of the Common Provisions Regulation is to conform the Commission's rules to Federal regulations. The Federal rule changes were published on November 29, 2004. If the Commission did not make these revisions, the State rules would be more restrictive than the Federal rules because these revisions serve to exempt the compounds from emission standards, monitoring, reporting and record keeping requirements.

I.II. Adopted December 15, 2005

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national Ambient Air Quality Standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

On December 31, 2002, the Environmental Protection Agency (“EPA”) promulgated a final rule revising the Major New Source Review [“NSR”] programs mandated by Parts C and D of Title I of the Federal Clean Air Act. EPA changed the several Federal provisions that were reflected in Colorado's SIP and in 2004 the Commission made revisions to match the new Federal Rule.

In the 2002 Rule, EPA provided several new applicability options for stationary sources. Among those options is treatment of some sources as clean units. To qualify, the source operators must employ state-of-the-art pollution control technology as a result of a major NSR determination within the last ten years, or demonstrate that control technology being employed is comparable to the best available control technology or lowest achievable emission rate. A source that qualifies as a clean unit would not have to go through a traditional NSR applicability determination if it makes certain types of changes in the future. The Commission’s 2004 Rule adopted the clean unit exemption virtually without change.

The 2002 Rule also expanded the exemption from major modifications for pollution control projects (PCPS), originally provided only to electric utility steam generating units in the 1992 WEPCO Rule. Under the 2002 Rule, collateral emissions increases resulting from a PCP at an existing unit would not be included in calculations to determine if a project involving that unit would trigger NSR.

As part of the 2002 rule, EPA allowed sources to calculate their actual and projected actual emissions to determine whether a modification will trigger NSR. If a source concludes that there is no “reasonable possibility” that emissions from a project will trigger NSR, the source is not required to keep records substantiating that calculation. However, the data and records would necessarily be generated by the owner or operator to calculate its emissions.

The Commission did not follow the Federal Rule in this regard. In Section I.B.5., the Commission imposed a requirement that owners or operators using the actual-to-projected-actual applicability test for a project that requires a minor source permit or modification [pursuant to Part A, Section I.B.26.; Part C, Section I.A.3.; or Part C, Section X.; or any minor source permit under any provisions of Part B], submit an otherwise-required permit application and include documentation adequate to substantiate calculations made for the test.

On June 24, 2005, the United States Court of Appeals for the District of Columbia Circuit issued its decision and opinion in the case of State of New York v. U. S. Environmental Protection Agency,----F.3D---- 2005 WL 1489698, 35 Envtl. L. Rep. 20,135, D.C.Cir., June 24, 2005. The court concluded that, regarding the clean unit exemption from NSR, the plain language of the Clean Air Act indicated that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions. As a result, the court vacated the clean units portions of the Federal Rule. The court also concluded that EPA lacks the authority to create pollution control project exemptions from NSR and vacated the PCP portions of both the 1992 Wepco Rule and the 2002 rule. By vacating those portions of the Federal NSR rule, the court terminated those exemptions to new source review.

In view of the court's decision, the Commission concluded that there was no basis to retain the clean unit and pollution control project provisions in Regulation no. 3. The federal rule no longer allows operators to use those provisions to determine applicability of NSR to the source and Colorado law and the Colorado State Implementation Plan should be conformed to federal law in this instance.

The D.C. Circuit court also addressed the recordkeeping and reporting requirements of the federal rule. The 2002 rule excused a source from maintaining records of the information and calculations used in the actual-to-projected actual applicability test if the source determined that there was no "reasonable possibility" that the modification would trigger NSR. These are the same records necessary to substantiate calculations made for the applicability test. The court concluded that lack of evidence, in the form of data and records, could inhibit enforceability of the NSR program in this context. The court remanded this part of the rule.

By remanding this portion of the 2002 rule, the court allowed EPA to further consider its position and return to the court at some time in the future for more proceedings in support of the rule. In this case, EPA has the opportunity to explain how it can ensure NSR compliance without the relevant data. There is no deadline, or requirement, for EPA to take further action.

The Commission, in its 2004 rulemaking, elected to require that sources retain records that, among other things, are essential to substantiate sources' calculations using the actual-to-projected-actual applicability test. The Commission also chose to require that a source submit its data and calculations along with a permit application that would otherwise be required for the physical or operational change. The Division reviews the data and calculations only to confirm a source's conclusions whether it triggers NSR. The information submitted is then included in a non-enforceable appendix to a source's Title V Permit or as a permit note in the source's construction permit

The recordkeeping requirement adopted by the Commission has benefits to both sources and the Division, one of which is to avoid later uncertainty whether a project triggered NSR. Accordingly, the Commission elected not to modify this part of Regulation Number 3.

The recordkeeping requirement adopted by the Commission has benefits to both sources and the Division, one of which is to avoid later uncertainty whether a project triggered NSR. Accordingly, the Commission elected not to modify Part D, Section I.B.5. and to modify Part D, Sections V.A.7.c. and VI.B.5. in a manner, that maintains consistency with Section I.B.5.

I.JJ. Adopted March 16, 2006

Revisions to Regulation Number 3, Part F, Best Available Retrofit Technology

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in C.R.S., Sections 25-7-105 (general authorities and duties of the Commission for air quality control); 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-106 (additional authorities of the Commission for air quality control); 25-7-106(1) (authority to exercise flexibility in developing effective air quality control program); 25-7-106(2) (authority to hold public hearings); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); 25-5-114.5 (authority to require permit applications and make determinations, and to provide for public participation), and 25-7- 1002 (authority to maintain a program that complies with the requirements of the Federal act for prevention and remediation of significant deterioration of visibility in class I Federal areas).

Basis and Purpose

On July 1, 1999, the U.S. Environmental Protection Agency promulgated final regulations that require each state to submit a State Implementation Plan (SIP) to address regional haze. Those regulations require the State to establish a mechanism to identify sources that must analyze installation of Best Available Retrofit Technology (BART) and to require those analyses and implementation of resulting determinations.

The process begins with defining air pollution facilities that are “BART-eligible.” Among the BART-eligible sources, some sources are “subject to BART.” Sources that are subject to BART must complete an analysis and submit a proposal for determination by the State of the Best Available Retrofit Technology applicable to that source. This regulation establishes the mechanisms for this process. In many instances, the regulation matches the Federal BART rule, including provision for a BART-Alternative approach that would yield “better than BART” results.

The Commission elected to assume that all BART-eligible sources are subject to BART, but require the Division to perform modeling to determine whether BART eligible sources will cause or contribute to visibility impairment in any class I area. BART-eligible sources that do not cause or contribute to visibility impairment in any class I area would not be subject to BART. Individual sources would also have the opportunity to demonstrate that they are not eligible or not subject to BART. This approach will provide information necessary to develop the regional haze SIP on the schedule required by Federal law and allows for challenges to decisions on whether individual sources must complete BART analyses and to BART determinations by the State.

Sources subject to BART must evaluate all technologies through a five step case-by-case BART analysis. The five steps require sources to: 1) Identify All Available Retrofit Control Technologies; 2) Eliminate Technically Infeasible Options; 3) Evaluate Control Effectiveness of Remaining Control Technologies, 4) Evaluate Impacts and Document the Results and 5) Evaluate Visibility Impacts. The Commission intends that sources conducting a case-by-case analysis will follow EPA’s Appendix Y to 40 CFR, Part 51 – Guidelines for BART Determinations under the Regional Haze Rule. Sources must evaluate the visibility impacts of each technology option using CALPUFF and/or Division-approved modeling protocols.

This rule requires a source subject to BART to file an application for a construction permit as the mechanism for submitting its BART analysis and proposal, and for seeking a Division determination of BART for the source. The Commission concluded that using the existing permitting mechanism was the most expedient way to present the analysis for Division determination. The Commission further determined that applications for BART determinations should be subject to the public comment process applicable to construction permit applications for new or modified major sources.

When identifying the available retrofit control technologies, sources must include appropriate BACT, LAER, NSPS, Pollution Prevention (P2) and other controls used by similar sources. This can include new control technologies that are in the development stages of licensing and commercial demonstration or commercial sales. Where EPA has already conducted extensive analyses for a source category (e.g., EGUs) in relation to the Federal BART Rule and determined that certain control technology would not be required under the pertinent BART analyses, the Commission intends that a Colorado source subject to BART may adequately demonstrate that the same technology excluded under the EPA analyses would not be appropriate for the Colorado source by showing sufficient similarity between the source evaluated by EPA and the Colorado source.

Sources that identify specific options as technically infeasible must show to the Division's satisfaction that the technology is not commercially available or that specific physical or chemical characteristics of the unit(s) or emission(s) involved will not allow the technology to operate effectively.

The control effectiveness of any technology must be evaluated based on the highest removal efficiency available for the technology. Sources may also look at lower efficiencies in addition, but must include consideration of the best removal efficiency. If a source has existing controls in place, improvements to the existing controls or running the existing controls at a higher efficiency must be included in the analysis.

The Commission realizes that emission controls often have secondary impacts. Sources must evaluate the costs of compliance including the average cost effectiveness and the incremental cost effectiveness of each technology that is feasible for the source. Energy impacts including the direct energy consumption for each technology and any locally scarce fuels must be evaluated. Many control options have secondary impacts on other media. Sources must evaluate any increases in hazardous waste, wastewater, or other waste products, including increased usage of scarce resources such as water. In cases where a facility has a limited remaining operating life, the source can place a federally enforceable shutdown date in its operating permit.

The Commission intends that the Division use EPA's presumptive limits as guidelines when evaluating the BART analyses, with the understanding that there is a strong presumption that power plants capable of generating 750 megawatts or greater will meet these limits or do better, while the coal-fired electric generating units at smaller plants need to consider the presumptive limits as part of the BART analysis. Further, if a source submits an analysis demonstrating that it will meet the presumptive limits, then the source will be presumed to have met the BART-analysis requirements, absent an adequate showing to the contrary. If a source proposes a BART limit that exceeds EPA's presumptive limits, the Division would determine whether the BART analysis sufficiently supports the higher limit or whether other controls or increased control efficiencies are feasible. The Commission intends that the Division would establish a BART limit higher than the presumptive limit if supported by the BART analysis.

The Federal rules require the State to submit a SIP that identifies BART-eligible sources in the State, and requires the State to either adopt BART controls or adopt a BART Alternative. In some respects, the approach in the proposed State rule to applying the requirements of the Federal Act is not specifically mandated by the Federal rule, but left to the discretion of the State. The Federal Act does not specify the administrative decision-making process that will be used to make the relevant BART determinations. The State rule establishes such a procedure, relying on existing permitting procedures to the extent possible and appropriate. The procedure established by the State rule affords sources an opportunity for a hearing on the relevant BART decisions. This process is consistent with permitting practices and otherwise not more stringent than Federal requirements.

NOx emissions from coal-fired power plants vary considerably depending on the design of the boiler, the type of combustion controls and the type of coal used. Each of these factors has an impact on the BART analysis. In setting presumptive BART limits for NOx, EPA took into account available types of combustion control equipment, the differences between boiler types, and ranks of coal (bituminous, sub-bituminous and lignite), thereby indicating these factors should be a part of BART analyses—not solely for large power plants subject to the presumptive levels for NOx, but for all coal-fired power plants. These NOx-related characteristics should be taken into account in setting BART limits. The BART guidelines allow states to take these characteristics into account and it is the intent of the Commission that the Division should evaluate this issue as part of BART analyses. Consistent with the Federal BART Guidelines, BART determinations should take into account possible local economic disruption and unemployment that might result from adverse impacts on coal sales related to BART determinations.

In consideration of the unusual number of significant and complex permit determinations under the BART rule that will be become open to public comment about the same time, the Commission intends that the Division consider reasonable flexibility in applying procedures and time periods for public comment. The Commission also intends that all agreements and BART alternatives be noticed together with the construction permit for public comment purposes.

The Air Quality Control Commission expects that the Division will provide the information required by 40 CFR 51.308.(d)(1) and (2) for the July 20,2006 regular monthly meeting of the Commission.

I.KK. Adopted August 17, 2006

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Basis

In accordance with the 1990 Amendments to the Federal Clean Air Act, the U.S. Environmental Protection Agency (EPA) has approved incorporation of the provisions for the New Source Review and Prevention of Significant Deterioration programs (collectively referred to as “NSR”) into Colorado’s state implementation plan (SIP). In June 2005, the Governor submitted revisions to Colorado’s NSR program to EPA Region VIII for review and approval. During review of the submittal, Region VIII identified minor issues with provisions in Regulation Number 3 that the Commission is correcting to ensure continuing federal approval of Colorado’s NSR program. The Commission is also adopting language to treat nitrogen oxides as an ozone precursor, consistent with EPA’s promulgation of corresponding language on November 29, 2005.

Section 112 of the Clean Air Act requires EPA to maintain a list of hazardous air pollutants (HAPs) subject to regulation under that Section. EPA occasionally revises the list by adding or removing pollutants based on updated scientific evidence of health impacts. EPA removed methyl ethyl ketone (MEK) from the list on December 19, 2005. Therefore, the Commission is removing MEK from the list of HAPs in Regulation Number 3, Part A, Appendix B.

On November 29, 2004, EPA revised the federal definition of volatile organic compounds (VOCs) to specifically treat tertiary butyl (t-butyl) acetate as a VOC only for certain purposes, including reporting and photochemical dispersion modeling. The Commission is making corresponding changes to the definition of VOCs in the Common Provisions Regulation, and is adding t-butyl acetate as a non-criteria reportable pollutant in Regulation Number 3, Part A, Appendix B. Sources of t-butyl acetate will be required to report the pollutant separately from their VOC emissions on an Air Pollutant Emission Notice, and should not count their t-butyl acetate emissions when evaluating compliance with applicable VOC emission limitations. The Division should combine VOC emissions and reported t-butyl acetate emissions when conducting dispersion modeling for sources of t-butyl acetate.

The Commission is also correcting several regulatory reference errors in Parts A, C, and D.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of national Ambient Air Quality Standards and a prevention of significant deterioration program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Some of the statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and these Sections, in turn, provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

Purpose

The Commission is revising Regulation Number 3 to address issues identified by the U.S. Environmental Protection Agency (EPA) during review of Colorado's state implementation plan (SIP) in 2005, to incorporate federal changes to the New Source Review program, to revise the definition of volatile organic compounds and the list of hazardous air pollutants consistent with federal actions, and to make miscellaneous technical corrections. These changes will help to ensure continued approval by EPA of Colorado's New Source Review program and will provide consistent treatment by EPA and the Division of hazardous air pollutants and volatile organic compounds. These changes will also correct regulatory cross-references within Regulation Number 3, which will make the regulation easier to understand. Further, these revisions include any typographical errors within the regulation.

I.LL. Adopted December 15, 2006

Revisions to Regulation Number 3, Part A, Section VI.D.1.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2007. The revised fees are within the statutory limit set by Section 25-7-114.7, C.R.S. The increase is necessary to address decreasing fee revenues used to fund existing programs, as well as to provide additional funding for requested additional permitting and inspection personnel. The proposed increase was addressed at length during a subcommittee process involving the Commission, the Division, stakeholders and other interested parties. The revision is a collaborative effort of the Division and interested stakeholders.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to cover anticipated revenue shortfalls and fund requested additional FTE that will be used to address the Division's permitting backlog and the increased workload arising from the rapid growth of oil and gas sources in Colorado.

I.MM. Adopted October 18, 2007

Revisions to Regulation Number 3, Part A, Section VI.D.1.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2007. The revised fees are at the statutory limit set by Section 25-7-114.7, C.R.S. The increase is necessary to address decreasing fee revenues used to fund existing programs. These revisions are concurrent with other recent fee adjustments to ensure appropriate funding for the program.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to cover anticipated revenue shortfalls and fund requested additional FTE that will be used to address the Division's permitting backlog and the increased workload arising from the rapid growth of oil and gas sources in Colorado.

I.NN. Adopted December 21, 2007

Revisions to Regulation Number 3, Part E, Best Available Retrofit Technology

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002 (authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in class I federal areas).

Basis and Purpose

This regulatory change places the Division's BART determinations and associated requirements in a new section of Regulation Number 3, Part E - Section VI.

EPA has raised concerns regarding the practical enforceability of the Colorado's BART determinations. The emission limits and averaging times for each of Colorado's BART sources will be included in each Title V permit, and included in the proposed SIP. The Title V permits and the SIP are each federally enforceable when approved by EPA. Nonetheless, EPA believes that more is needed to ensure the practical enforceability of these BART limits.

To address EPA's concerns the BART emission limits and related provisions concerning the installation, operation and maintenance of BART controls have also been added to Regulation Number3, and new Section VI will become part of Colorado's SIP.

The foregoing approach is largely similar to the approach taken on the state's PM-10 SIP in 2001, where the state agreed to include certain emission limits in Regulation Number 1.

I.OO. Adopted February 21, 2008

Revisions to Regulation Number 3

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis and Purpose

The Colorado Air Quality Control Commission ("Commission") intends to revise the provisions of Regulation Number 3, Part A and B to include PM2.5 as a Colorado regulated pollutant, to address inadvertent removals of rule revisions previously adopted by the Commission, and finally to correct typographical, grammatical and formatting errors found throughout Regulation Number 3.

Regarding PM2.5 emissions, the EPA promulgated a revised national ambient air quality standard ("NAAQS") for PM2.5 emissions on October 17, 2006. The effective date for the new standard was December 18, 2006. The Commission intends to apply the Regulation Number 3 requirements to PM2.5 emissions.

Additionally, the Commission intends to reinstate several previously adopted revisions and to correct several typographical errors in Regulation Number 3.

Note that the Commission intends to defer any decision to exclude ethanol production facilities from the major stationary source definition of "chemical process plant" as proposed in the Federal Register on May 1, 2007 [see *72FR24060*] until all relevant pending matters at the federal level are resolved.

PM2.5 Emissions

The Commission intends to apply the Regulation Number 3, Part A and B requirements to PM2.5 emissions by 1) including PM2.5 emissions under the "air pollutant" and "criteria pollutant" definitions found in Part A, Sections I.B.6 and I.B.16, and 2) setting permitting thresholds as the same level as PM10 emissions (revise Part B, Sections II.D.2 and II.D.3). Note that the EPA has not yet promulgated the PM2.5 New Source Review ("NSR") Implementation Rule, which will specify how PM2.5 emissions should be treated for Prevention of Significant Deterioration ("PSD") and major source NSR sources. Upon promulgation, the Commission intends to incorporate those changes into Regulation Number 3, Part D as well.

Inadvertent Removals of Rule Revisions

Several previously adopted rule revisions were discovered as having been inadvertently removed from Regulation Number 3. The Commission intends to reinstate these previously adopted revisions.

Specifically, the Commission intends to:

Re-identify volatile organic compounds ("VOCs") as being subject to the Reasonably Available Control Technology ("RACT") requirements. During the December 16, 2004 Regulation Number 3 rulemaking, VOCs were inadvertently removed from the RACT requirements. Since the minor source RACT requirement for VOC emissions were part of the State Implementation Plan, EPA considers removal of VOCs from minor source RACT requirements as backsliding. Therefore this revision should be reinserted into Regulation Number 3, Part B, Section III.D.2.

Re-insert the inadvertent removal of the following text previously adopted by the Commission on December 16, 2004:

Reference to "attainment/maintenance" areas in Part B, Sections II.D.1.c.(iii)(B), III.B.5.d., and III.C.1.a., and

Remove exemption reference to Denver Metropolitan PM10 attainment/maintenance area and change reference to "Denver Metropolitan PM10 and ozone attainment/maintenance area" to "Denver 1-hour ozone attainment/maintenance area" in Part B, Section II.D.1.f.

Typographical, Grammatical and Formatting Errors

The Commission intends to correct several specific typographical errors in Regulation Number 3.

Specifically, the Commission intends to:

Revise "citric acid plants" to "nitric acid plants" in Part A, Section I.B.23.b.(ix), and

Revise incorrect citation in Part B, Section I.A.

In addition, the Commission intends to correct grammatical and formatting errors in Regulation Number 3.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Section 25-7-105, C.R.S., gives the Commission authority to promulgate regulations necessary for the proper implementation of the Act, including rules to assure attainment and maintenance of the NAAQS and a PSD program. Section 25-7-105(12), C.R.S. provides specific authority to establish emission notice, construction permit and operating permit programs. Key statutory parameters for these programs are set forth in Sections 25-7-114 through 25-7-114.7 of the Act and provide statutory authority for the current revisions. Additional authority for these revisions is set forth in Sections 25-7-106, 25-7-119 and 25-7-132, C.R.S.

The Commission's adoption of this rule is taken pursuant to procedures and requirements set forth in Sections 25-7-105, 25-7-110 and 25-7-110.5, C.R.S.

I.PP. Adopted May 14, 2008

Revisions to Regulation Number 3, Part F

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, § § 25-7-110 and 25-7-110.5, C.R.S ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002 (authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in Class I federal areas).

Basis and Purpose

The original language in Section IV.B established that the Division could not require post combustion NOx controls for any BART source. The Division has reviewed the data available on post combustion NOx controls in the EPA BART regulation and requested that the Commission narrowly modify the exclusion of post combustion NOx control. The EPA BART regulation investigated post combustion NOx control for Electric Utility Generators (EGUs) and generally determined that post combustion NOx control was only necessary in limited cases. The Commission believes that this analysis should be extended to boilers, as they are similar types of equipment. The Commission does not believe that the analysis done by EPA in the BART rule can be extended to cement production because of the dissimilar nature of the overall process of operation between boilers and cement kilns. The Commission narrowly modifies the provisions regarding the analysis of post combustion NOx controls as it relates to non-EGUs and non-boilers. The Commission believes this narrow amendment to Regulation Number 3 is appropriate and supported by the evidence in the hearing record.

I.QQ. Adopted September 18, 2008

Revisions to Regulation Number 3, Part A

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, § 24-4-103(4), C.R.S., for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions to Part A, Section VI.D.1. in order to increase the annual emission fees charged to air pollution sources in Colorado commencing in 2008. The revised fees are at the statutory limit set by Section 25-7-114.7, C.R.S. The proposal increases the fees to the levels enacted by the General Assembly, and signed by the Governor, in SB08-055, reflected in Section 25-7-114.7, C.R.S. as amended.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-114.7 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allows the Commission to set annual emission fees for regulated and hazardous air pollutants.

Purpose

The revisions to Part A, Section VI.D.1. were adopted to provide necessary revenue for existing and anticipated revenue shortfalls, and fund additional legislatively-authorized FTE and legislatively-directed air quality monitoring.

I.RR. Adopted December 12, 2008

Revisions to Regulation Number 3, Part A, B and C

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the 8-Hour Ozone Nonattainment Area expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-Hour Ozone NAAQS of 0.08 parts per million (ppm) for ground level ozone. This area is now known as the Denver Metro Area/North Front Range Nonattainment (DMA/NFR) Nonattainment Area. The DMA/NRF Nonattainment Area includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a State Implementation Plan (SIP) to the EPA no later than by June 30, 2009. This plan must propose measures designed to reduce ground level ozone precursor pollutants. The plan must provide for reductions in these precursor pollutants sufficient to ensure that ozone is reduced to below the 8-Hour Ozone NAAQS no later than 2010. If Colorado fails to submit a sufficient SIP by the aforementioned deadline, the Clean Air Act mandates that the U.S.E.P.A. prepare and implement a Federal Implementation Plan in Colorado.

Pursuant to C.R.S. § 25-7-105(1)(a)(I), the Commission must adopt such measures as are necessary to ensure compliance with the NAAQS. The Commission has adopted these rules to carry out this mandate. Specifically, the Commission has adopted revisions to Regulation Number 3, Parts A, B and C to address ozone formation in the DMA/NFR Nonattainment Area. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment of the current 8-Hour Ozone NAAQS set at 0.08 ppm. Also, these revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin – within 0.001 ppm on a standard of 0.08 ppm. Photochemical dispersion modeling analysis is the primary tool used to assess present and future qir qulaity trends, and is requried for EPA to approve the state attainment demonstration in the SIP. Dispersion modeling results have an inherent level of uncertainty, as recognized in EPA guidance, and it is appropriate for a state to use other tools at its disposal, including further control measures, to address and mitigate any uncertainties that can be present in dispersion modeling. It is appropriate for the state to use such tools to increase the confidence in and otherwise ensure that the predicted modeling results are accurate and borne-out in future air qulaity monitoring demonstrating attainent with the 8-Hour Ozone NAAQS.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of the evidence" analysis and other supplemental analysis in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010, although by a narrow margin. To encrease the certainty of the model results and the weight of evidence demonstration, the Commission concludes that these additional control measures are necessary to carry out its mandate to adopt a SIP that contains those elements that are necessary to assure attainment of the 8-Hour Ozone NAAQS.

In order to maintain consistancy between state regulations and federally enforceable regulations contained in the SIP, specifically changes to the exemptions, the Commission intends these revisions be adopted into the SIP.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S.§ 25-7-101, et seq., specifically, C.R.S. §25-7-105(1)(a) (authorizing a comprehensive state implementation plan which will assure attainment and maintenance of the NAAQS), 105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs) and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 3 are part of an overall ozone reduction strategy to be incorporated into Colorado's SIP for ozone. The Commission intends that this overall ozone reduction strategy accomplishes five objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the ozone nonattainment area, B) revise the control requirements for condensate tanks by transitioning from a system-wide to an emissions threshold control strategy in the ozone nonattainment area, C) expand VOC RACT requirements such that all ozone nonattainment areas are subject to Regulation 7's RACT requirements, D) clarify how the RACT requirements in Regulations 3 and 7 interact in the ozone nonattainment area, E) improve the Division's inventory of specific source category emissions state-wide; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

The Commission is adopting revisions to Part A to eliminate exemptions for certain facilities from air pollution emission notice requirements. These facilities include:

- Petroleum industry flares less than 5 tons per year (tpy) emissions,
- Specified crude oil truck loading equipment,
- Oil/gas production wastewater
- Crude oil storage tanks,
- Surface water storage impoundment, and
- Condensate tanks with production 730 BBL/year or less.

The Commission is also adopting revisions to Part B to exempt the following facilities from construction permit requirements:

- Petroleum industry flares less than 5 tons per year (tpy) emissions,
- Specified crude oil truck loading equipment,
- Oil/gas production wastewater, except for commercial wastewater processing facilities, and
- Specified crude oil storage tanks.

The Commission is adopting revisions to Part C to clarify that the chemical storage tank exemption and surface water storage impoundment exemptions do not apply to specified production wastewater.

In support of objectives A and E above, the Commission adopts these revisions to Regulation Number 3, Parts A, B and C to revise APEN reporting exemptions for specific source categories (Regulation Number 3, Part A, Section II.D., Part B, Section II.D., and Part C, Section II.E.).

Improve Emissions Inventory

The Commission is changing several categorical APEN reporting and/or permitting exemptions in Regulation Number 3, Parts A, B and C in order to improve the Division's emissions inventory and for the sake of equity. These changes fall in three categories: 1) specific APEN and permitting exemptions were removed altogether; 2) specific APEN exemptions were removed and permit exemptions were kept in place; and 3) specific APEN and permit exemptions were clarified, but kept in place.

Remove APEN and Permitting Exemptions

The Commission has eliminated the APEN exemption for condensate tanks because the exemption was based on an emission level used in attainment areas. The Division will now be able to develop a complete inventory of condensate tanks and their emissions.

Condensate tanks are now subject to the same APEN requirements as other source categories in the 8-Hour Ozone Nonattainment Area. Additionally, the condensate tank exemption is based on a standardized emission factor, 13.7 pounds of VOC emissions per barrel of production, which may not be representative of each natural gas field. Even though the exemption was removed sources may still make use of the generic APEN exemption, upon determining that actual annual uncontrolled emissions fall below the applicable de minimis levels identified in Regulation Number 3, Part A. If based on this generic exemption, a source is determined to be APEN exempt, the source is also permit exempt.

Remove APEN Exemptions, Keep Permit Exemptions

The Commission has removed specific source category APEN exemptions for petroleum industry flares, crude oil truck loading, oil production wastewater and crude oil storage tanks to improve the inventory of actual uncontrolled emissions. Sources may still use the generic APEN exemption, upon determining that actual annual uncontrolled emissions fall below the applicable de minimis levels. The Commission is maintaining current permitting exemptions until such time that the APEN data justify the need for permitting activities.

Revise APEN and/or Permitting Exemptions

Similarly, based on the Division's experience, actual emissions from several source categories specific to oil and gas-related operations may be higher than previously believed. Thus the APEN and permitting exemptions for surface water impoundments (Regulation Number 3, Part A, Section II.D.1.uuu. and Part C, Section II.E.3.yyy.) were revised to exclude from the exemption, oil and gas production wastewater (similar to Regulation Number 3, Part A, Section II.D.1.uu.). Also, the APEN and permitting exemptions for chemical storage tanks (Regulation Number 3, Part C, Section II.E.3.n.) were revised to exclude oil and gas production wastewater or commercial facilities' operations (similar to Regulation Number 3, Part A, Section II.D.1.uuu. and Part C, Section II.E.3.yyy.).

Finally, the APEN and permitting exemptions for fuel storage dispensing (Regulation Number 3, Part A, Section II.D.1.cccc. and Part C, Section II.E.3.cccc.) were revised to expand the applicability of the current exemption from specifically the 1-Hour Ozone Nonattainment or Attainment/Maintenance Area to any ozone nonattainment area for the sake of equity.

I.SS. Adopted December 19, 2008

Revisions to Regulation Number 3, Part F

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Specific Statutory Authority

The Commission promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 25-7-1002(authority to maintain a program that complies with the requirements of the federal act for prevention and remediation of significant deterioration of visibility in Class I federal areas.

Basis and Purpose

This regulatory change updates the Division's BART determinations by adding determinations for Colorado Springs Utilities Drake Units 5, 6, and 7 and CEMEX Portland cement facility regarding limits and averaging times for sulfur dioxide, nitrogen oxides and particulates.

The proposed change provides state and federally enforceable limitations for the BART sources. States must ensure 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" . 40 CFR 51.308(e)(v). This is required for SIP approval.

I.TT. Adopted October 21, 2010

Revisions to Parts A, B, C and D to Address Greenhouse Gases or GHGs

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4) and (12.5), C.R.S. for new and revised regulations.

Basis

Regulation Number 3 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act ("Act") including provisions of the State Implementation Plan addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b), Prevention of Significant Deterioration requirements addressed in C.R.S. Section 25-7-105(1)(c), regulations as may be necessary and proper for the orderly and effective administration of construction permits and renewable operating permits addressed in C.R.S. Section 25-7-114.4(1), as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were proposed by the Air Pollution Control Division based on EPA's GHG Tailoring Rule. On June 3, 2010, EPA promulgated the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule." See 75 Fed. Reg. 31514 (June 3, 2010). EPA's Greenhouse Gas (GHG) Tailoring Rule was designed to tailor the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V Permitting Programs of the Clean Air Act (CAA).

Specific Statutory Authority

The Act, under C.R.S. Section 25-7-105(1)(a) authorizes the Air Quality Control Commission (Commission) to adopt rules necessary to implement the Act, and to adopt and revise comprehensive State Implementation Plans (SIP) to assure attainment and maintenance of national ambient air quality standards. C.R.S. Section 25-7-109 authorizes the Commission to adopt rules that are consistent with state policy regarding air pollution and with federal recommendations and requirements. C.R.S. Section 25-7-109(2) authorizes the Commission to regulate oxides of carbon, oxides of nitrogen and other chemicals, which encompasses the pollutant GHG. Additionally, Colorado is authorized to regulate GHGs under PSD and Title V in C.R.S. Sections 25-7-103(1.5), 25-7-114(3), 25-7-114.3, and 25-7-201. Additional authority for these revisions is set forth in C.R.S. Sections 25-7-106 and 25-7-109, and 25-7-114.

In order to maintain consistency between state regulations and federally enforceable regulations contained in Colorado SIP, the Commission intends these revisions be adopted into the SIP.

Purpose

The Commission has adopted revisions throughout Regulation Number 3 to address GHG regulation in Colorado. These revisions were made to incorporate EPA's GHG Tailoring Rule into Colorado's Title V and PSD Permitting Programs, and to extend synthetic minor permitting to Colorado's stationary sources seeking federally enforceable limits to avoid major source or major stationary source applicability thresholds specific to GHGs.

EPA's GHG Tailoring Rule establishes a phased approach for applying the CAA's PSD and Title V Permitting Programs to the sum of six GHGs.[1] The GHG Tailoring Rule has several different components including permitting thresholds and timing, commitments to the next steps, implementation options, and information requests.

1 The GHG air pollutant consists of the aggregate sum of six GHG gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). These species of each GHG class are treated in aggregate, based on the total carbon dioxide equivalent (CO_2e).

On April 2, 2007, the U.S. Supreme Court held that GHGs are included in the definition of "air pollutant" under CAA Section 302(g). Massachusetts v. EPA, 549 U.S. 497 (2007). As part of this decision, the Court mandated EPA to determine under CAA Section 202(a) whether GHG emissions from new motor vehicles endanger public health or welfare, or if too much scientific uncertainty remains to make such a determination. [2]

2 CAA Section 202(a) requires EPA to "prescribe (and from time to time revise) … standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles … which … cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare."

On December 7, 2009, EPA issued the Endangerment Finding and the Cause or Contribute Finding, both addressing GHGs under CAA Section 202(a). See 74 Fed. Reg. 66496 (Dec. 15, 2009). EPA's Endangerment Finding found that GHGs endanger the public health and welfare of current and future generations. The Cause or Contribute Finding found that the combination of the six well-mixed GHGs from new motor vehicles contributes to the GHG pollution which threatens public health and welfare. EPA's findings were a prerequisite to establishing GHG standards for light-duty vehicles, but they did not in themselves impose any requirements on GHG stationary sources.

On May 7, 2010, EPA published the Light-Duty Vehicle Rule (LDVR) jointly with the National Highway Traffic Safety Administration to reduce GHG emissions and improve fuel economy of new passenger cars, light-duty trucks, and medium-duty passenger vehicles. See 75 Fed. Reg. 25324 (May 7, 2010). The new GHG emissions standards under the LDVR first apply to model year 2012 vehicles and become increasingly more stringent through model year 2016.

EPA addressed the implications of GHGs as a newly regulated pollutant under the LDVR through the Johnson Memo ("EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program"). See 75 Fed. Reg. 17004 (March 29, 2010). EPA concluded that a previously unregulated pollutant is subject to regulation once it is subject to actual control of emissions under the CAA or EPA regulation, and that control requirement takes effect. Accordingly, EPA concluded that once the LDVR takes effect on January 2, 2011 (the earliest date that a model year 2012 vehicle could be put on the market), GHGs will become regulated pollutants under the PSD and Title V permitting programs. Absent the Tailoring Rule, GHGs would then be subject to regulation at the existing PSD and Title V thresholds of 100 / 250 tons per year (tpy).

The foregoing federal actions now require appropriate changes to Colorado's regulations. Colorado law already provides the Commission authority and an obligation to regulate GHGs under the state's PSD and Title V permitting programs. Colorado's definition of "air pollutant" mirrors EPA's definition under the CAA. See C.R.S. Section 25-7-103(1.5) and CAA Section 302(g).[3] Following the U.S. Supreme Court's holding in Massachusetts v. EPA, GHGs are included in the definition of air pollutant under CAA Section 302(g). Colorado's PSD program applies PSD permitting requirements to new major stationary sources and major modifications. C.R.S. Section 25-7-210. Similarly, Colorado defines a Title V "major source" as "any stationary source […] that directly emits, or has the potential to emit, one hundred tons per year or more of any air pollutant." C.R.S. Section 25-7-114(3)(b). Furthermore, a Title V permit is required for any major source. C.R.S. Section 25-7-114.3(1)(b). The Division's proposed changes to Regulation Number 3 align these key definitions to Colorado's statute (which in turn map to the CAA) and add a definition of "subject to regulation," as defined in the Tailoring Rule.

3. The CAA defines "air pollutant" as "… any air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive […] substance or matter which is emitted into or otherwise enters the ambient air." CAA Section 302(g). Colorado's statute defines "air pollutant" as "… means any fume, smoke, particulate matter, vapor, or gas or any combination thereof which is emitted into or otherwise enters the atmosphere, including, but not limited to, any physical, chemical, biological, radioactive […] substance or matter …" C.R.S. Section 25-7-103(1.5).

The Commission's mandate includes promulgation of regulations to reduce air pollution, including the promulgation of a comprehensive state implementation plan which "shall meet all requirements of the federal act and shall be revised whenever necessary or appropriate." C.R.S. Section 25-7-105; see also C.R.S. Section 25-7-102 (legislative declaration). Furthermore, Colorado's statutes provide that "In the formulation of each emission control regulation, the commission shall take into consideration […] the state policy regarding air pollution, as set forth in section 25-7-102 [and] Federal recommendations and requirements." C.R.S. Section 25-7-109(1)(b).

In addition to Colorado's statutory authority, federal PSD and Title V provisions under the CAA also place requirements on states to maintain PSD and Title V Permitting Programs in compliance with federal requirements. The chain of events described above renders GHGs to be considered a regulated pollutant subject to the federal PSD and Title V permitting requirements. Under PSD, EPA mandates that "each applicable implementation plan shall contain emission limitations and such other measures as may be necessary, as determined under regulations promulgated under this part, to prevent significant deterioration of air quality …" CAA Section 161. Under Title V, the CAA provides that "Whenever the Administrator makes a determination that a permitting authority is not adequately administering and enforcing a program, or portion thereof, in accordance with the requirements of this title, the Administrator shall provide notice to the State and may, prior to the expiration of the 18-month period referred to in paragraph (2), in the Administrator's discretion, apply any of the sanctions specified in section 179(b)." CAA Section 502(i)(1).

In order to avoid both the possibility of sanctions for failure to comply with EPA's permitting programs, as well as the unsustainable workload of regulating GHGs at the existing permitting thresholds of 100 / 250 tpy, the Division proposes regulatory revisions to comport with EPA's GHG Tailoring Rule.

Permitting Thresholds and Timing

Regarding permitting thresholds and timing, EPA's GHG Tailoring Rule identifies three steps – Steps 1, 2 and 3 – to phase in GHG permitting requirements over time. This rulemaking addresses **only** Steps 1 and 2, as discussed in EPA's GHG Tailoring Rule. While EPA's GHG Tailoring Rule generally discusses a Step 3,[4] it provides few details on any associated timing and thresholds; instead EPA's GHG Tailoring Rule establishes an enforceable commitment to complete another rulemaking no later than by July 1, 2012 for Step 3 and beyond. The Commission intends to expressly address these future actions expeditiously as they arise.

4 EPA proposes to promulgate a separate rule specific to Step 3 by July 1, 2012. It is anticipated that this Step 3 will span from July 1, 2013 through April 30, 2016. EPA offers limited regulatory details, but states that no stationary sources having potential to emit GHG emissions of less than 50,000 tons per year CO2e would trigger PSD or Title V Permitting Programs under the Tailoring Rule due to GHG emissions alone. No other details are provided.

This rulemaking establishes key definitions and the authority to regulate GHGs as well as addresses Steps 1 and 2 as identified in EPA's GHG Tailoring Rule. Step 1 spans from January 2, 2011 through June 30, 2011, and applies PSD and Title V permitting requirements to GHG emissions at "anyway sources," or stationary sources that are already subject to these permitting requirements for non-GHG pollutants. During Step 1, no source shall be required to obtain a Title V operating permit or PSD permit solely due to GHG emissions. Step 2 spans from July 1, 2011 through June 30, 2013. In Step 2, in addition to the requirements of Step 1, PSD and Title V permitting requirements apply to stationary sources which may be major[5] for GHG emissions and no other regulated pollutant.

5 Major source or major stationary source.

EPA's GHG Tailoring Rule sets a 100,000 tpy carbon dioxide equivalent (CO2e) applicability threshold for stationary sources that are major for GHG and no other non-GHG NSR regulated pollutant for PSD, and re-affirms that a significant emissions increase and a significant net emissions increase must occur in order to trigger PSD review. PSD and Title V permitting applicability thresholds and significance levels have traditionally been determined on a mass-basis. However, the Tailoring Rule sets a PSD significance level for GHG at 75,000 tpy on a CO2e basis. There are distinct units of measure used in identifying GHG applicability thresholds and significance levels. Some are mass-based and some are CO2e-based. The distinction between the two focuses on whether or not the global warming potential (GWP) is applied to each individual GHG species before summing the total of GHG classes for comparison to the appropriate value.

The Commission recognizes that the EPA is currently developing GHG permitting guidance. At its earliest convenience prior to January 2, 2011, the Division is instructed to provide permitting guidance to sources to minimize uncertainty.

Permitting and Application Requirements

The Commission recognizes the difficulties in developing a GHG inventory in short order, and directs the Division to request permit applicants which are required to provide a GHG inventory to submit one by a reasonable deadline set by the Division.

See the citations below for further information.

Complete Application

In Regulation Number 3, Part C, Section III.C.3.a., the Commission requires that all information related to the "emissions of pollutants sufficient to verify which requirements are applicable to the source" (which includes GHG) must be included in a complete application. Similarly, 40 C.F.R. 70.5(c)(3)(i) requires that Title V applications must include emissions of all regulated air pollutants.

Further, in Regulation Number 3, Part C, Section IV.B.4, the Commission requires that a source update its permit application to address any requirements that become applicable after the date the source has submitted its application, prior to issuance of the draft permit for public comment.

Application Shield

In Regulation Number 3, Part C, Section II.B., the Commission grants a defense to an enforcement action to sources which submit a timely and complete application under Part C until a final determination on the permit has been made. Per Regulation Number 3, Part C, Section IV.D., after an application is deemed complete, the Division may request additional information in writing and set a reasonable deadline for response. However, the application shield defense is not available if the source "fails to submit by the deadline specified in writing by the Division any additional information identified as necessary to process the application, or to otherwise supplement its application in accordance with the provisions of Regulation Number 3, Part C, Sections IV.B.3. and IV.B.4."

Applicable Requirement

In Regulation Number 3, Part A, Section I.B.9., the Commission defines applicable requirement consistently with that definition found in 40 C.F.R. Part 70, Section 70.2. Based on these definitions the mandatory GHG Reporting Rule requirements codified in 40 C.F.R. Part 98 do not meet the definitions of applicable requirements at this time; however, any GHG BACT requirement or other federally enforceable GHG requirements, including GHG synthetic minor permit conditions necessary to avoid major source or major stationary source thresholds are considered applicable requirements.

Regulation Number 3, Part C, Section V.B.4. requires that any operating permit address "all applicable requirements," however existing Title V sources that do not undergo PSD review should not trigger any GHG applicable requirements.

"Subject to Regulation or Requirement"

Prior to this rulemaking the Title V operating permit requirements of Regulation Number 3, Part C, Sections II.A.1.g., II.E.1. and II.E.2. already contained the language "subject to regulation or requirement", followed by a specific reference to the Federal Act or another part of Regulation Number 3. The phrase "subject to regulation" was addressed in the Johnson Memo, "EPA's Interpretation of Regulations that Determine Pollutants Covered by the Federal Prevention of Significant Deterioration (PSD) Permit Program" and later codified in the GHG Tailoring Rule and Regulation Number 3, Part A, Section I.B.44. See 75 Fed. Reg. 17004 (March 29, 2010). For the purpose of these sections, the definition of "subject to regulation" is not applicable and the full phrase "subject to regulation or requirement" relates to the reference at the end of those statements.

Rescission Clause

The Commission recognizes the uncertainty facing GHG stationary sources, given the potential for future federal legislation and the extensive pending legal challenges to GHG regulation under the CAA. The Commission intends GHG regulation in Colorado be consistent with the Federal Act, and has inserted a rescission clause making the effectiveness of the term Subject To Regulation dependent upon federal enforceability. Should either federal legislation or Court rulings from the District of Columbia Circuit Court of Appeals or the U.S. Supreme Court limit or render ineffective the regulation of GHG emissions under the PSD or Title V provisions of the Federal Act, then GHGs shall only be subject to regulation under this Regulation Number 3 for the affected permitting program(s) to the same extent. Example 1: if the regulation of GHGs under both PSD and Title V is vacated in whole, then all GHG emissions limitations or requirements included in any construction or operating permit issued under this Regulation Number 3 shall no longer be enforceable. Example 2: if the Court remands the regulation of GHG emissions to EPA such that GHG regulation under the Federal Act is temporarily ineffective, either in whole or in part, any GHG emissions limitation or requirement included in any permit issued under this Regulation Number 3 shall be limited or rendered ineffective to the same extent. Sources may actively seek to maintain those permit conditions if they so choose pursuant to Regulation Number 3, Part A, Section I.A. These examples are not intended to address all potential outcomes, but rather to provide some degree of implementation guidance. The Commission intends that this rescission will be automatically and immediately effective final of applicable court action or legislation. When triggered, this clause prevents regulation of GHG under Regulation Number 3 to the same extent of the federal action or court ruling and may require a new rulemaking action by the Commission to regulate GHGs for the affected permitting program, including any new details of such future regulation.

Synthetic Minor Permits for GHGs

No minor source air pollution construction permits are required at this time for GHGs, except where stationary sources voluntarily seek federally enforceable limits for GHGs to avoid major source PSD and Title V permitting requirements. (Regulation Number 3, Part B, Section II.A.7.) An application for a voluntary synthetic minor construction permit must include GHG emissions reported on Division-approved forms. Construction permits shall be issued based on production/process rates requested in the application, and the emission limit requested shall be a permit condition. (Regulation Number 3, Part B, Section II.A.4.)

If the above-mentioned rescission clause is triggered, any federally enforceable GHG emission limits contained in synthetic minor permits are no longer enforceable. The stationary source is requested to submit a cancellation request to the Division to cancel GHG emissions points and permits.

Regulation Number 3 Revisions:

The revisions to Regulation Number 3 as approved by the Commission are summarized below.

Part A

- Add Regulation Outline
- Add new definitions of Greenhouse Gas and Carbon Dioxide Equivalent. The CO2e definition incorporates by reference EPA's GWP codified via the GHG Mandatory Reporting Rule (Sections I.B.10., I.B.23.)
- Revise Major Source definition so that it applied to regulated NSR pollutant (which includes GHG) as well as to air pollutants (which does not included GHG) so that GHG is addressed and the definition may be used to establish the mass based GHG threshold (Section I.B.25.b.)

- Add new definition of Subject to Regulation consistent with EPA's GHG Tailoring Rule and include the rescission clause as discussed above (Section I.B.44.)

- Revise annual emission fees to exclude GHGs (Section VI.D.)

Part B

- Revise general permitting requirements to authorize the Division to issue synthetic minor permits for GHGs where stationary sources voluntarily choose to seek federally enforceable limits for GHG if they would otherwise be subject to PSD or Title V Permitting Programs (Sections II.A.4., II.A.7.)

Part C

- Clarify that complete Title V Operating Permit applications include the reporting of GHG emissions as they are pollutants which may be subject to requirements applicable to the source, but not air pollutants, under Regulation 3 definitions (Section III.C.3.a.).

Part D

- Revise the Definitions (Section II.A.):

- Revise BACT, Major Modification and Major Stationary Source Definition to use the term Regulated NSR Pollutant for consistency and remove italics consistent with EPA's GHG Tailoring Rule so that these definitions become effective by January 2, 2011 (Sections II.A.8., II.A.22., II.A.24.a., II.A.24.a.(ii) and II.A.24.b.)

- Revise Regulated NSR Pollutant definition and remove italics consistent with EPA's GHG Tailoring Rule so that it becomes effective by January 2, 2011 (Section II.A.38.)

Additionally, the Commission approves typographical, grammatical and formatting changes, as necessary.

I.UU. Adopted January 7, 2011

Regulation Number 3, Part D (Concerning Major Stationary Source New Source Review and Prevention of Significant Deterioration) and Part F (Best Available Retrofit Technology (BART) and Reasonable Progress for Regional Haze)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S, and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted under Colorado Revised Statutes, Sections 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); 25-7-114.4(1) (authority to adopt rules for the administration of permits); and 40-3.2-208 (authority to incorporate emission reduction plans for rate-regulated utilities within the state's Regional Haze State Implementation Plan).

Basis and Purpose

PART D

These revisions to Regulation Number 3, Part D change the review and revision period for the Regional Haze Long Term Strategy (LTS) from every three years to every five years. This change aligns the reporting periods for the Regional Haze LTS and the Regional Haze progress reports that are required every five years pursuant to 40 C.F.R. Section 51.308(g).

PART F

On July 1, 1999, the U.S. Environmental Protection Agency (EPA) promulgated the final Regional Haze Rule (Rule), which went into effect, on August 30, 1999, and which requires each state to submit a State Implementation Plan (SIP) to address regional haze. The Rule is intended to achieve the national visibility goals as expressed in Section 169(a) of the Clean Air Act, 42 U.S.C. Section 7491. Colorado must develop a SIP revision in coordination and consultation with other states, tribes, federal land managers, EPA and Regional Planning Organizations (RPOs) designated by EPA. In the west, the RPO is the Western Regional Air Partnership (WRAP).

Regional Haze is a visibility impairment that is caused by multiple sources over a broad geographic region. EPA's Regional Haze Rule requires every state to submit a SIP designed to improve visibility in its mandatory Class I federal areas (Class I areas). Class I areas are areas of great scenic importance, such as national parks and wilderness areas. There are 12 Class I areas in Colorado, and 156 nationwide.

A key element of EPA's regional haze program is Best Available Retrofit Technology (BART) for certain emission sources. Section 169A(b)(2)(A) of the Clean Air Act requires BART for certain existing major facilities, placed into operation between August 7, 1962 and August 7, 1977, that have the potential to emit more than 250 tons of visibility-reducing pollution a year. EPA's Regional Haze Rule requires SIPs to include BART emission limits for each subject-to-BART source that may reasonably be anticipated to impair visibility in any Class I area, unless the state demonstrates that an emissions trading program or other alternative measures will achieve greater reasonable progress toward natural visibility conditions. See 40 CFR Part 51 Section 308(e). EPA promulgated a BART Rule separate from its Regional Haze Rule. EPA's BART Rule includes guidelines (Appendix Y) regarding how states should make BART determinations. See 70 Fed. Reg. 39104 (July 6, 2005). EPA also promulgated a "BART Alternative" Rule. See 71 Fed. Reg. 60612 (October 13, 2006). The BART Alternative Rule allows an alternative program to source-by-source BART, if the program results in greater reasonable progress than would occur pursuant to individual BART.

States were required to submit their regional haze SIPs to EPA by December 17, 2007. The Regional Haze Rule establishes the year 2064 as the date by which a goal of visibility at natural background levels is desired in all Class I areas. The Rule divides the 2007-2064 time periods into numerous planning periods. States were required to submit their initial RH SIP by December 31, 2007, then a revised Regional Haze SIP to EPA by July 31, 2018, and every ten years thereafter. See 40 CFR Section 51.308(f).

Colorado submitted much of its regional haze SIP (including most of its BART determinations) to EPA in early 2008 for review. Following additional revisions, the Commission approved the remainder of Colorado's BART determinations in December 2008, and submitted Colorado's Regional Haze SIP to EPA's Region 8 for review in 2009.

Upon review, EPA Region 8 informed Colorado that its regional haze SIP submittal was not approvable and needed to be revised before EPA could reconsider it for inclusion in the State Implementation Plan. EPA has identified deficiencies with Colorado's Regional Haze Element of the SIP, including the basis for and enforceability of BART determinations and the lack of reasonable progress goals (RPGs) and RP source determinations. These alleged deficiencies must be addressed in order for EPA to approve the Regional Haze element of the SIP. This regulation is the second part of a bifurcated rulemaking process in which the Commission adopted the remaining outstanding Regional Haze SIP elements.

EPA made a finding on January 15, 2009 that 37 states, including Colorado, had failed to make all or part of the required Regional Haze SIP submissions. See 74 Fed. Reg. 2393 (January 15, 2009). This action started a clock by which states must have approved SIPs, or EPA must promulgate Federal Implementation Plans (FIPs) within two years (*i.e.*, by January 15, 2011). EPA initiated actions in Colorado to begin preparing a FIP, and this action by the Commission is taken to complete the adoption of a regional haze element of the SIP, address the deficiencies that Region 8 EPA has identified, and to prevent such a federal action in Colorado, with its attendant consequences (*e.g.*, federal determinations of BART, federal reasonable progress determinations, federal permits, and state loss of CAA grant monies so EPA can prepare a FIP).

During the 2010 legislative session, the Colorado legislature passed House Bill 10-1365, the "Clean Air - Clean Jobs Act" (CACJA). The CACJA sets forth requirements applicable to investor owned utilities in Colorado (Public Service Company of Colorado (PSCo) and Black Hills Energy) and certain of their electric generating units. The CACJA requires the investor owned utilities to submit emission reduction plans to the Colorado Public Utilities Commission (PUC), and provides that the Commission shall consider the air quality provisions of the emission reduction plans for incorporation into the regional haze element of Colorado's SIP. See Section 40-3.2-208, C.R.S. PSCo and Black Hills submitted their emission reduction plans to the PUC on August 13, 2010, and the PUC approved the plans on December 15, 2010.

The Commission adopted into Regulation Number 3 BART determinations for PSCo's Hayden and Comanche plants, two units at CENC's Golden plant, CEMEX's Lyons Portland cement plant, and Colorado Springs Utilities' Drake power plant. The Commission also adopted an Alternative to BART program for two units at Tri-State Generation and Transmission Association's Craig power plant. The Commission determined that, for nitrogen oxide (NOx) emissions, the appropriate BART control for Craig Units 1 and 2 would be emission rates associated with the assumed installation and operation of selective non-catalytic reduction (SNCR). As an alternative to BART, it was proposed and the Commission adopted, a more stringent NOx emissions control plan that consists of emission limits associated with the assumed operation of SNCR for Unit 1 and the assumed operation of SCR for Unit 2. The state has determined that the alternative program achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART, and thus meets the requirements of the regional haze rule.

The Commission also adopted into Regulation Number 3 a BART Alternative for a number of PSCo plants and incorporated it into the Regional Haze SIP. The BART Alternative is based on reductions achieved as a result of a combination of shutdowns and retrofit emissions controls at certain PSCo facilities planned as part of HB 10-1365. The BART Alternative includes ten units at four PSCo facilities. The facilities included in the BART Alternative include Arapahoe Units 3 and 4, Cherokee Units 1-4, Valmont and Pawnee. The BART 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 by 2017 and reduce their NOx and SO2 emissions as a result of enforceable facility retirement dates and, for one unit, fuel switching to natural gas as a peaking unit. For the BART sources, Cherokee 4, Pawnee and Valmont, Valmont will be retired by 2018, Pawnee will be fully controlled by mid-2015, and Cherokee will operate on natural gas by 2018. The state has determined that the BART Alternative achieves greater reasonable progress than would be achieved through the installation and operation of source-by-source BART and RP determinations at the covered sources, and thus meets the requirements of the Regional Haze rule. PSCo has designed and proposed the BART Alternative to meet the state CACJA. The Commission determined that to the extent there is any inconsistency between the CACJA and older, more generic legal requirements, the more recent and specific CACJA controls. The state has used simplifying assumptions to compare the emission reductions and visibility impacts associated with the PSCo BART Alternative, and believes that the BART Alternative is clearly superior to, and will result in greater reasonable progress than, source-by-source BART. For example, the state has determined and demonstrated that PSCo's BART Alternative emissions reductions are greater than, and would provide greater reasonable progress than, the presumptive or source-by-source BART limits. The Commission also adopted retirement dates of "no later than" July 1, 2012 and December 31, 2016 for Cherokee Units 1 and 3, respectively. In doing so, the Commission is no way rejecting any portion of PSCo's emission reduction plan as approved by the PUC on December 15, 2010 (Decision No. C10-1328). Rather, the Commission's action is intended to provide flexibility and consistency in light of PSCo's pending application for rehearing, reargument or reconsideration (RRR) before the PUC, in which PSCo states that the revised dates are important for providing sequencing of activities that will ensure electrical system reliability in the Denver Metropolitan area. These dates are also wholly consistent with the PUC's decision because PSCo can comply with the dates established by both the PUC and the Commission, regardless of how the PUC rules on PSCo's RRR application. The Commission also notes that Hayden, another PSCo BART source, is not part of the BART Alternative program. The PUC approved controls for Hayden as part of PSCo's emission reduction plan under HB 10-1365, consistent with the state's BART determination for that source.

The Commission also established non-binding 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. See 40 C.F.R. Section 51.308(d)(1). The reasonable progress goals (RPGs) provide for improvement in visibility for the most-impaired (20% worst) days over the period of the SIP and ensure no degradation in visibility for the least-impaired (20% best) days over the same period. The Commission adopted into Regulation Number 3 emission limits for "reasonable progress" sources that have a significant impact on visibility impairment in Class I areas, in order to help the state make reasonable progress towards improving visibility in this first planning period. These sources include Black Hills Energy Clark Station (a HB10-1365 facility), the Holcim Cement Plant, Tri-State Generation and Transmission Association's Craig Station Unit 3 and Nucla Station, Platte River Power Authority's Rawhide Station, Colorado Springs Utilities' Nixon Power Plant, PSCo's Cameo plant, and CENC's Unit 3.

For all BART and BART Alternative determinations made by the Commission in the November 2010 – January 2011 proceedings, a source that has installed BART or implemented a state-approved BART Alternative is exempted from the imposition of further regional haze controls during this first regional haze planning period (i.e., through December 31, 2017). This exemption applies only to regional haze, and does not apply to controls or emission reductions that may be required or otherwise imposed pursuant to other air pollution programs (including, but not limited to, ozone standards).

The revisions to Regulation Number 3, Part F also apply Monitoring, Recordkeeping and Recording (MRR) Provisions to BART, BART Alternative and Reasonable Progress emission limits.

In addition to the regulatory changes described above, the Commission adopted changes to Colorado's Regional Haze SIP. Many of the changes are non-substantive edits while other changes address comments from Federal Land Managers, incorporate the justification for the BART and reasonable progress determinations, and provide the justification for the reasonable progress goals. The following presents an overview of the content of Colorado's Regional Haze SIP document:

Chapter 1 – Overview

Chapter 2 – Plan Development and Consultation

Chapter 3 – Monitoring Strategy

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

Chapter 5 – Sources of Impairment in Colorado

Chapter 6 - Best Available Retrofit Technology

Chapter 7 – Visibility Modeling and Apportionment

Chapter 8 – Reasonable Progress

Chapter 9 – Long Term Strategy

Chapter 10 – Commitment to Consultation, Progress Reports, Periodic Evaluations of Plan Adequacy, and Future SIP Revisions

Chapter 11 – Resource and Reference Documents

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

The revised chapters are intended to fully replace previously adopted SIP chapters.

Additional Considerations

The Commission provides the following additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

(I) Colorado's proposed Regional Haze regulations and SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. There is no binding requirement on how a State may "consider" the federal statutory and regulatory factors in determining BART and RP and establishing RPGs. 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. See 70 Fed. Reg. 39104, 39170 (July 6, 2005). State discretion is a cornerstone of the regional haze rule.See id., at 39137 ("Congress evinced a special concern with insuring that States would be the decision makers."). States also have flexibility to consider 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). Federal law also allows states flexibility to adopt alternative programs that provide greater reasonable progress than BART. The Commission has adopted such alternatives for PSCo and Tri-State sources. The Commission finds that the revisions adopted in this hearing are wholly consistent with the discretion and expertise to be applied by state agencies under the federal act. Accordingly, the proposed revisions are no more stringent or different than federal law, and Sections 25-7-110.5 and 110.8 do not appear to apply.

Additionally, HB10-1365 provides, in part, that the Commission must vacate this rulemaking proceeding and must initiate a new proceeding for the consideration of alternative proposals for the appropriate controls for those units covered by the utility plans for inclusion in the regional haze element of the state implementation plan if, among other things, the Commission rejects any portion of the plans as approved by the PUC. Section 40-3.2-208(2)(b), C.R.S. If the Commission were to reject any portion of the utility plans, this proceeding would be vacated and a new proceeding initiated, making it impossible for Colorado to submit a timely and complete SIP revision to address Regional Haze, and resulting in a FIP. Under these circumstances, it is reasonable to conclude that the Commission rules regarding "1365" sources are being adopted to implement prescriptive state requirements, that the Commission has no significant policy-making options with respect to these sources, and that many provisions of Sections 25-7-110.5 and 110.8 do not apply. See Section 25-7-110.5(2), C.R.S.

Despite the foregoing, certain elements of this proceeding could be viewed (as certain parties have alleged) as exceeding the federal act or differing from the federal act. For example, the closure or repowering of PSCo facilities would not be required solely by EPA's Regional Haze Rule. Accordingly, the Commission is providing this additional statement, consistent with Sections 25-7-110.5(5)(a) and 110.8, C.R.S.

(II) EPA's regional haze requirements are performance based, and the regional haze rule sets forth factors that states must consider when assessing controls and emission limits for sources emitting visibility impairing pollutants. Section 169A of the federal Clean Air Act (1977) sets 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." 42 U.S.C. Section 7491. To help facilitate this goal, EPA finalized the regional haze rule in 1999. The Rule requires States to adopt SIPs to address visibility impairment in the Class I areas. Critical components of such SIPs (particularly the SIP for the first planning period) are BART and RP. EPA provides flexibility to states regarding how to apply the relevant factors to BART and RP analyses.

(III) Applicable federal requirements specifically address the issues regarding visibility impairment in Class I areas that are of concern to Colorado. Applicable federal requirements do not specifically address all of the issues that are of concern to Colorado. House Bill 10-1365 is intended to address Colorado's compliance with a number of federal Clean Air Act requirements in a comprehensive and more efficient fashion than in a step-by-step (or regulation by regulation) approach. The legislation specifically declares that it is intended to create "a coordinated plan of emissions reductions…to meet the requirements of the federal act…at a lower cost than a piecemeal approach." Section 40-3.2-202(1), C.R.S. While regional haze is an important consideration in the context of HB10-1365, it is not the only one. HB10-1365 aims to address other air pollution issues as well, including national standards for ozone. See, e.g., Sections 40-3.2-204(1), 204(2)(b)(II)(B) and 205(1)(c), C.R.S. Data regarding visibility impairing emissions and control technologies was considered in the federal process leading up to the promulgation of the Regional Haze Rule. See, e.g., EPA's "Technical Support Document for BART SO2 Limits for Electric Generating Units," April 1, 2005, and "Technical Support Document for BART NOx Limits for Electric Generating Units and Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet," April 15, 2005, Memoranda to Docket Number 2002-0076. These Memoranda reflect an analysis of all individual BART-eligible units in the country, including Colorado.See 70 Fed. Reg. at 39131-35. See also EPA's "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. Additionally, the state determines that the regulatory requirements do not exceed the requirements of the federal act because the state is not imposing the BART alternative measures on an unwilling entity. Rather, the sources voluntarily proposed the packages as BART alternative measures and, in the case of PSCo, in order to comply with HB10-1365.

(IV) The adopted rule will provide certainty to sources, by providing necessary monitoring, recordkeeping and reporting mechanisms and clear timing requirements to ensure the achievability of the specified closure or performance based standards. With respect to the "1365" sources in particular, the requirements improve the utilities' ability to comply in a cost-effective manner while preventing or reducing the need for costly retrofits to meet more stringent requirements later.

(V) If the state does not take action by January 2011, EPA has indicated it will promulgate a FIP. The state and federal rules also have similar time frames for implementation. BART controls must be installed as soon as practicable but in no event later than five years after EPA approval of the regional haze SIP, and all BART, BART alternatives and RP controls must be implemented within this first planning period (i.e., before January 1, 2018).

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources subject to the rule by providing the same standards for similarly situated sources. BART and RP determinations are very source specific; different controls and emission limits are to be expected and reflect the State's source-specific consideration of federal statutory and legal factors, and of the state's implementation of HB10-1365.

(VIII) If the state rule were not adopted, EPA has indicated it will promulgate a FIP. This would likely result in more costly control requirements for sources which would be passed on to consumers.

(IX) The Regional Haze Rule requires associated State procedural, reporting and monitoring and recordkeeping requirements. The procedural, reporting, monitoring and recordkeeping requirements provided in Colorado's rule do not differ from, and often incorporate by reference, federal requirements.

(X) Demonstrated technology is available to control and monitor visibility impairing emissions.

(XI) The adopted rule will contribute to the prevention of pollution by reducing visibility impairing emissions.

(XII) A no action alternative would not address the required standard, and could result in EPA's promulgation of a FIP.

(XIII) All regulatory changes in this proceeding are based on reasonably available, validated, reviewed, and sound scientific methodologies. All information made available by interested parties has been reviewed and considered by the Commission.

(XIV) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction of pollutants that contribute to regional haze.

(XV) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health or environment, and provide other benefits (e.g., protection of visibility) that justify the cost to government, the regulated community, and to the public to implement and comply with the rule.

(XVI) The Commission has chosen the alternative that is the most cost effective, provides the regulated community flexibility, and which achieves the necessary reductions in air pollution. The alternative will maximize the air quality benefits of regulation in the most cost effective manner. The Commission notes that no parties provided alternate proposals to the PSCo BART Alternative during this proceeding. The Commission also notes that in approving PSCo's emission reduction plan, the Colorado Public Utilities Commission thoroughly considered the economic impacts and concluded that that the approved plan comes at a lower cost to ratepayers than an all-controls option. Even if for some reason PSCo's BART Alternative were not determined to be the most cost effective option, the Commission finds that approval of the BART Alternative and incorporation of the alternative into the Regional Haze SIP is consistent with the legislature's intent in adopting the CACJA.

I.VV. Adopted October 20, 2011

Regulation Number 3, Part A, B, C and D – addressing federal changes to the New Source Review (NSR) Program related to PM2.5 National Ambient Air Quality Standards (NAAQS), several recent Environmental Protection Agency (EPA) State Implementation Plan (SIP) actions in which EPA partially disapproved various SIP revisions, EPA's Deferral of Biogenic Sources of CO2 Emissions, other miscellaneous revisions, and typographical, grammatical and formatting errors.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S, and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (AQCC) promulgates this regulation pursuant to the authority granted under Colorado Revised Statutes, Sections 25-7-105(1)(c), (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

EPA promulgated federal changes to the New Source Review (NSR) Program, which must be incorporated into Regulation Number 3 in order to maintain consistency with the federal NSR Program related to PM2.5 National Ambient Air Quality Standards (NAAQS). Subsequently, EPA disapproved and proposed to disapprove Air Pollutant Emission Notice (APEN) exemption provisions in Regulation Number 3, associated with Colorado's September 1997, April 2003 June 2003, July 2005, August 2006, and August 2007 SIP submittals. Also, EPA proposed its Deferral of Biogenic Sources of CO2 Emissions, deferring biogenic carbon dioxide (CO2) from regulation under the federal Prevention of Significant Deterioration (PSD) and Title V Permitting Programs for three years. In addressing the above actions, several additional Regulation Number 3 provisions were identified in need of revision.

Sources affected by this proposal include PM2.5 and CO2 emission sources, as well as open burning sources, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors.

PM2.5 Related Rules

On February 21, 2008, the AQCC adopted revisions to Regulation Number 3, Parts A and B to identify PM2.5 as a criteria pollutant, triggering reporting and minor source permitting requirements. However, the AQCC did not make corresponding revisions to major stationary source permitting requirements under the New Source Review (NSR) Program as the EPA had not yet promulgated the associated PM2.5 implementation rules. Since that time, EPA promulgated a series of rules regarding the regulation of PM2.5 under the NSR program. See "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers (PM2.5)" (*73 FR 28321,* May 16, 2008), "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5) – Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)" (*75 FR 64864,* October 20, 2010), "Requirements for Preparation, Adoption, and Submittal of Implementation Plans" (76 FR 18870, April 6, 2011), and "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM2.5); Final Rule to Repeal Grandfather Provision" (*76 FR 28646,* May 18, 2011). The 2008 and 2010 rules, combined with the December 21, 2010 promulgation of the methodology to test for PM2.5, provide a complete framework establishing how to apply PM2.5 to the NSR Program. Prior to the promulgation of the December 2010 rules, application of PM2.5 to the NSR Program made little sense. See *75 FR 80118.* Consequently, the AQCC chose to wait to adopt the suite of PM2.5 implementation rules until after the last of the PM2.5 implementation rules and the 2010 PM2.5 testing methodology were finalized.

The May 16, 2008 rule provided flexibility in designating PM2.5 precursor pollutants. While sulfur oxides (SO2) must be treated as a PM2.5 precursor in all areas of the state, more flexibility is afforded to nitrogen oxides (NOx), volatile organic compounds (VOCs) and ammonia (NH3). This rule requires that NOx be presumed a PM2.5 precursor state-wide unless a state demonstrates that NOx is not a "significant contributor" to PM2.5 concentrations within any area. See*73 FR 28328.*However, VOCs and NH3 are not required to be treated as PM2.5 precursors, except that high molecular weight VOCs (equal to or greater than 25 carbon atoms and low vapor pressure) will be addressed as a condensable particulate. See *73 FR* 28329-283330.

At this time, the AQCC has identified SO2 and NOx as PM2.5 precursors, state-wide. Based on the limited PM2.5 modeling and monitoring data available for Colorado, the AQCC determined that there is insufficient evidence to claim either way that NOx emissions do or do not contribute significantly to the concentration of PM2.5 in any area in Colorado. Without evidence to narrow the identification of NOx as a precursor to specific areas, Colorado must identify NOx as a PM2.5 precursor state-wide. Less is known about VOCs and NH3 and their contribution to PM2.5 in Colorado, and so Colorado has chosen to not identify them as PM2.5 precursors at this time.

EPA Partial Disapproval Actions

On October 3, 2011, EPA's action granting partial disapproval and partial approval of revised Air Pollution Emission Notice (APEN) and permitting exemptions that the Commission submitted to EPA as SIP revisions in September 1997, June 2003, July 2005, August 2006, and August 2007, was published in the Federal Register. See *76 FR 61054.* EPA partially disapproved APEN exemptions for open burning, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors. The basis for EPA's disapproval of the subject provisions and the revisions intended to address each provision are as follows:

Open burning APEN exemption was corrected to reference federally enforceable Regulation Number 1 (Part A, Section II.D.1.q.). EPA commented that the change in reference from Regulation Number 1, which is part of Colorado's SIP, to Regulation Number 9, which is not part of Colorado's SIP, was not approvable.

Mobile sources APEN exemption was clarified (Part A, Section II.D.1.ppp.) and associated revisions were made to the insignificant activities list (Part C, Section II.E.3.uuu.). EPA commented that these exemptions only apply to stationary sources, not non-road engines and not sources being used for transportation purposes.

Stationary internal combustion engine APEN exemption was repealed (Part A, Section II.D.1.sss.) and related revisions were made to the associated permitting exemption (Part B, Sections II.D.2.c., and II.D.2.c.(i)-(iii)) and insignificant activities list (Part C, Section II.E.3.nnn.). EPA commented that the APEN exemption should require recordkeeping and reporting. The AQCC repealed the APEN exemption and revised the permit exemption to be consistent with current SIP approved language instead of requiring additional recordkeeping and reporting. Note that while the categorical exemption is being repealed, sources may still utilize the general one and two ton APEN exemptions found in Part A, Section II.D.1.a.

Emergency generator APEN exemption was repealed (Part A, Section II.D.1.ttt.), and related revisions were made to the associated permitting exemption (Part B, Sections II.D.2.c., and II.D.2.c.(i)-(iii)) and insignificant activities list (Part C, Section II.E.3.nnn.). EPA commented that the APEN exemption should require recordkeeping and reporting. The AQCC repealed the APEN exemption, and revised the permit exemption to be consistent with current SIP approved language instead of requiring additional recordkeeping and reporting. Note that while the categorical exemption is being repealed, sources may still utilize the general one and two ton APEN exemptions found in Part A, Section II.D.1.a.

Surface water impoundment APEN exemption was clarified (Part A, Section II.D.1.uuu.) and related revisions were made to the associated permitting exemption (Part B, Section II.D.1.m.) and insignificant activities list (Part C, Section II.E.3.yyy.). EPA commented that the APEN exemption should be clarified to confirm that the exemption applied to oil and gas produced water. In addition to making this revision, the AQCC also clarified exceptions to these exemptions and insignificant activity.

Deaerator/vacuum pump exhaust APEN exemption was repealed (Part A, Section II.D.1.xxx.) and associated revisions were made to the insignificant activities list (Part C, Section II.E.3.uuu.). EPA commented that it was unclear what these activities were. The AQCC is unaware of any source making use of this exemption, and thus has removed this exemption and associated insignificant activity.

Air curtain destructor APEN exemption removal (Part A, Section II.D.1.ffff.). EPA commented that because air curtain destructors meet the SIP approved definition of an incinerator and as such are required to submit APENs and obtain permits, that this exemption should be removed.

On February 4, 2011, EPA's action granting partial approval and partial disapproval of SIP revisions submitted to EPA in April 2003 and June 2003, was published in the Federal Register. See *76 FR 6331.* Those 2003 SIP revisions to Regulation Number 3 revised APEN exemptions and permitting exemptions in Regulation Number 3, Parts A and B, respectively. To address EPA's concerns, the following provisions that EPA disapproved or on which EPA otherwise provided comment, were revised or removed as follows:

Stationary internal combustion engines 10 ton per year permitting exemption in attainment areas (Part B, Sections II.D.1.c., and II.D.1.c.(iii)). EPA commented that Colorado did not make the anti-backsliding demonstration necessary to increase the permitting exemption threshold from 5 tons per year to 10 tons per year. The AQCC opted to revert back to the 5 tons per year threshold that EPA previously approved instead of making the necessary demonstration at this time. Note that this revision does not prevent any source from making use of the facility-wide permit exemptions found in Part B, Sections II.D.2. or II.D.3.

Non-road engine state-only requirements (Part A, Sections I.B.31.c. and I.B.31.d.). EPA commented that it could not approve provisions which are identified as state-only provisions. The AQCC agrees and has further placed "(State-only Requirement)" at the beginning of these sections to clearly identify that they are state-only provisions.

Biogenics Deferral Revisions:

On June 3, 2010, EPA's "Prevention of Significant Deterioration and Title V Greenhouse Gas (GHG) Tailoring Rule," commonly called the GHG Tailoring Rule, was published in the Federal Register. See *75 FR 31514.* EPA's GHG Tailoring Rule was designed to tailor the applicability criteria that determine which stationary sources and modification projects become subject to permitting requirements for GHGs under the Prevention of Significant Deterioration (PSD) and Title V Permitting Programs of the Clean Air Act (CAA).

On July 20, 2011, EPA's "Deferral for CO2 Emissions from Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs," commonly called the Biogenic Deferral, was published in the Federal Register. See *76 FR 43490.* Beginning July 1, 2011, EPA's Biogenic Deferral temporarily excludes biogenic CO2 emissions from the definition of "subject to regulation" to allow biogenic sources of carbon dioxide (CO2) emissions a three year deferral from the PSD and Title V permitting requirements; the three year deferral applies even if the source's GHG emissions exceed the threshold established in the Tailoring Rule. To maintain consistency with implementation of federal requirements associated with the Tailoring Rule and the associated Biogenic Deferral, the AQCC incorporated EPA's Biogenic Deferral into Colorado's PSD and Title V Permitting Programs, as follows:

Revise the existing definition of Subject to Regulation consistent with EPA's proposed Biogenic Deferral (Part A, Section I.B.44.b.).

Other Revisions:

In addressing the above actions, the AQCC made several additional Regulation Number 3 revisions that relate to: revising the time frame for reporting the Notice of Startup to the Division from thirty days prior to fifteen days after commencing operation, which is consistent with Colorado's House Bill 10-1042, as codified in 25-7-114.5(12)(a), C.R.S.; including NOx as a precursor to ozone in ozone significant monitoring concentration (SMC) and removing the total suspended solid SMC, both consistent with federal requirements; and making typographical, grammatical and formatting corrections.

Additional Considerations

These adopted rules are mandated by federal law and necessary to maintain EPA approval of Colorado's SIP. The revisions associated with the PM2.5 Implementation Rules and Biogenics Deferral mirror the federal requirements. While the PM2.5 Implementation Rules do allow States the opportunity to deviate from the specified PM2.5 precursor pollutants, Colorado does not have sufficient modeling and monitoring data available to support a decision to identify VOC and NH3 as PM2.5 precursors or narrow the area in which NOx is identified as a PM2.5 precursor in Colorado. The related revisions adhere to federal requirements [as required by Sections 25-7-105(1), 25-7-201(a) and 25-7-203, and 25-7-302, C.R.S.], and therefore the provisions of Sections 25-7-110.5(5) and 110.8, C.R.S. do not apply to these revisions.

With respect to EPA's SIP disapproval actions, while the AQCC must address EPA's comments, Colorado has some flexibility in addressing those comments. Here, the provisions of Sections 25-7-110.5(5) and 110.8, C.R.S. apply to this rulemaking. Thus, the AQCC makes the following determinations only as they pertain to the SIP disapproval actions, and only where the AQCC has flexibility in addressing EPA's comments.

Pursuant to 25-7-110.5(5). C.R.S., the AQCC makes the determination that:

(I) EPA's SIP disapproval actions are federal requirements that may apply to this rulemaking.

(II) The applicable federal requirements imposing emission reporting and permitting are performance based. While the AQCC must address EPA's comments, there is some flexibility in how best to address those comments.

(III) Regarding EPA's comments on the APEN exemptions, accurate actual emissions data for open burning sources, mobile sources, stationary internal combustion engines, emergency generators, oil and gas surface water impoundments, deaerator/vacuum pump exhaust, and air curtain destructors is limited, although more is known about the engines, generators and air curtain destructors. The AQCC concluded that the adopted rule will clarify and generally improve Colorado's inventory of emissions from these sources in Colorado, and thus the reporting components are essential to this effort.

(IV) With respect to APEN associated permitting exemption revisions, these revisions strike an appropriate balance between exempting small emission sources, ensuring that Colorado has a reasonably accurate inventory, as well as ensuring that reporting and permitting requirements are reasonably uniform and equitable.

(V) The AQCC is not aware of any timing issue that could justify changing the timeframe in which these rules are implemented. There are deadlines by which states are expected to implement federally mandated changes, with potential sanctions for failing to meet these deadlines.

(VI) The APEN and associated permitting exemption and insignificant activity requirements in question are not specifically designed with a margin for accommodation, but instead will rely on the opportunity for future revisions, as necessary, to adjust for uncertainty and future growth.

(VII) The adopted revisions establish reasonable equity for sources subject to the revisions by providing the same requirements for similarly situated sources.

(VIII) If revisions to the APEN and permitting exemptions and insignificant activities are not adopted, while there would be no change in cost to industry, Colorado's emissions inventory accuracy will not improve. Emissions inventories are essential tools in protecting public health and the environment. A less accurate emissions inventory may translate into a public health and welfare and environmental cost, by delaying the time necessary to improve the inventory when developing plans to address future NAAQS.

(IX) The proposed revisions include no requirements that differ from applicable federal requirements.

(X) Demonstrated technology is available to comply with the particulate matter permitting requirements. Sources are already using the control devices intended to be used to comply with this rule.

(XI) The adopted rules will contribute to prevention of pollution, by having sources more accurately assess emissions to determine if APEN reporting or permitting requirements apply. Understanding emissions is essential in preventing pollution.

(XII) Because these rules are federally mandated, no alternative rules would address the requirements in question.

Further, pursuant to 25-7-110.8(1), C.R.S., the AQCC makes the determination that:

(I) The rule is based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the AQCC has considered all information submitted by interested parties.

(II) These amendments are largely administrative in nature as they relate to APEN reporting, permitting exemptions and insignificant activities.

(III) Evidence in this record supports the finding that the rule shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rule.

(IV) The rule is the most cost effective, provides the regulated community flexibility, and achieves any necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

I.WW. Adopted December 20, 2012

Regulation Number 3, Parts A, B, C, D, and Appendix B of Part A – revising language for conformity with the New Source Review (NSR) Program and approved State Implementation Plan ("SIP"); streamlining the permit issuance process; and correcting other typographical, grammatical, and formatting errors.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-201 though 25-7-206, 25-7-210, 25-7-301, and 25-7-302, C.R.S. authorize the Air Quality Control Commission ("Commission") to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") and prevent significant deterioration ("PSD") of air quality in conformance with the Federal and Colorado Acts. Section 25-7-105(1)(c) further states that definitions used in the PSD program shall not differ from definitions pertaining to the federal PSD program in the Clean Air Act Section 169. Section 25-7-105(12) authorizes the Commission to promulgate regulations necessary to implement the provisions of the emission notice, construction permit, and Title V programs. Section 25-7-106(7)(a) authorizes the Commission to develop a program to apply and enforce relevant provisions of the SIP including the imposition of any fees necessary to administer the program. Section 25-7-114.7 requires owners or operators of air pollution sources to pay permit application processing fees. Section 25-7-114.4 authorizes the Commission to promulgate regulations necessary and proper for the orderly and effective administration of construction permits and renewable operating permits. And, Section 25-7-114.5 authorizes the Commission to designate which projects or activities requiring a construction permit application warrant public comment.

Basis and Purpose

The Commission revised the Permit Processing Fees, Section VI.B.5., to streamline construction permit issuance by allowing the Division to issue a construction permit prior to receiving full payment for the assessed permit processing fees. Currently, the Division cannot issue an approved construction permit until the Division receives the applicant's complete processing fees payment, which delays the applicant's ability to commence construction due to the invoicing and payment process. This revision eliminates this delay as, under the revised issuance process, applicants will receive the approved construction permit and be able to commence construction during the invoicing and payment process. Also under the revised issuance process, failure to pay the assessed permit processing fees may result in late fees according to Section 25.7.114.7(2)(a)(I)(A.5), C.R.S. and/or revocation of the permit utilizing the current Division revocation procedures. Applicants will be notified of the potential consequences of nonpayment as well as corrective actions in the written request for processing fees and the written request for late processing fees, if applicable. This revision will not negatively impact permit applicants who pay their permit processing fees on time.

The Commission amended Appendix B to Part A to identify non-criteria reportable pollutants first alphabetically by Chemical Bin ("BIN") and then by chemical abstract service ("CAS") number to increase the clarity and usability of the Appendix.

The Commission amended the Part B, Section III.C.1.a., Public Comment and Hearing Requirements to include attainment/maintenance areas.

The Commission removed the italic font and deleted the underlined text throughout the regulation, primarily in Part D, in response to EPA's approval of the corresponding language into Colorado's SIP on January 9, 2012 (*77 Fed. Reg. 1027*), and April 10, 2012 (*77 Fed. Reg. 21453*). The provisions under review by EPA were italicized to indicate the text was not yet effective while other text was underlined to indicate it would only be effective until EPA approved the italicized text into the SIP. Based on EPA's final actions in January and April, the italicized rule language, minus the underlined text, became effective on May 10, 2012. Paragraph (b) of the definition of Representative Actual Annual Emissions, II.A.40.5, was also deleted to conform with the NSR Program and SIP because, though not underlined in Regulation Number 3, the NSR Program removed the entire definition from 40 C.F.R. Part 51.

The Commission corrected the PM2.5 Major Source Baseline Date, Part D, Section II.A.23.c., which was inadvertently adopted as October 20, 2011, to reference the major source baseline date of October 20, 2010, set by EPA on October 20, 2010 (*75 Fed. Reg. 64864*).

The Commission corrected a regulatory reference in Requirements Applicable to Nonattainment Areas, Part D, Section V.A.6., to reference Section XIII.A. Section V.A.6. currently refers Federal Land Manager involvement to Section XII.A., Innovative Control Technology, instead of XIII.A., Federal Class I Areas.

I.XX. Adopted February 20, 2014

Regulation Number 3, Parts A, B, C, D, and Appendices A and B of Part A – removing requirements for a source subject to a NSPS or NESHAP/MACT incorporated into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether the source's emissions exceed the reporting of permitting thresholds ("catch-all provisions"); simplifying the Part A, Appendix A de minimis determination for non-criteria reportable pollutants; removing the crude oil storage tank exemptions; and correcting other typographical, grammatical, and formatting errors.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. C.R.S. § 25-7-105(1)(a)(I) authorizes the Commission to revise Colorado's State Implementation Plan whenever necessary and appropriate. C.R.S. § 25-7-105(1) authorizes the Commission to promulgate regulations necessary to implement the provisions of the Colorado emission notice, minor source permit, and Title V programs. C.R.S. § 109(3) authorizes the Commission to promulgate emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. C.R.S. § 25-7-109.3(3)(c) directs the Commission to exempt classes of minor or insignificant sources of emissions of hazardous air pollutants from the Colorado hazardous air pollutant control and reduction program requirements. Section 25-7-109.3(5)(c) directs the Commission to establish de minimis emission levels for each hazardous air pollutant beneath which emissions are considered to be of minor significance.

Basis and Purpose

As part of a larger rule revision package, the Commission incorporated the federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 C.F.R. Part 60, Subpart OOOO ("NSPS OOOO") in full, as amended, into Regulation Number 6, Part A and made the corresponding revisions to Regulation Number 3 described below. The Commission also revised Regulation Number 7 for consistency with and to complement NSPS OOOO and to include additional emission control measures for oil and gas production operations and equipment. Finally, the Commission revised Regulation Number 7 storage tank control requirements with the intent that industry could utilize such controls when determining whether a storage tank was subject to NSPS OOOO.

These Regulation Number 3 revisions were important to the comprehensive proposal because they reduced reporting and permitting burdens that would otherwise occur when NSPS OOOO was adopted in full. These Regulation Number 3 revisions apply broadly to all emission sources and are not solely applicable to oil and gas operations.

Catch-all Provisions

The Commission removed the catch-all provisions in Part A, Sections II.D.1. and Part B, Sections II.A.5. and II.D. so that sources subject to a New Source Performance Standard ("NSPS"), National Emission Standard for Hazardous Air Pollutants ("NESHAP"), or Maximum Achievable Control Technology ("MACT") incorporated into Regulation Numbers 6 or 8 are not automatically required to file an APEN and obtain a minor source permit, regardless of whether the source's uncontrolled actual emissions exceeded reporting or permitting thresholds.

These rule changes reduced the administrative reporting and permitting burden for the Division and the regulated community, both for sources subject to NSPS OOOO and other future NSPS and NESHAP/MACT. For example, NSPS OOOO affected facilities with uncontrolled actual emissions less than the reporting and permitting thresholds no longer automatically have to file APENs and obtain minor source permits. This reduced permitting burden will allow the Division to reallocate permitting resources to more complicated sources with the greater impact to Colorado's air quality, as well as to develop and maintain other guidance and compliance assistance tools. The environmental impacts of this revision were minimal and no emissions increases were anticipated because the revisions did not exempt any source from complying with the requirements of an applicable NSPS, NESHAP, or MACT.

Part A, Appendix A

The Commission revised the Part A, Appendix A method for determining non-criteria reportable pollutant de minimis levels in order to standardize the de minimis reporting threshold and set a 250 pounds per year threshold for all non-criteria reportable pollutants. This revised threshold applies statewide. This revision simplified non-criteria reportable pollutant reporting by eliminating the determination of reporting level based on release point, property boundary, and pollutant bin. Prior to revision, these reporting determinations were complicated and confusing, and sources often utilized the most stringent reporting threshold with the applicable Bin category, rather than attempt to follow the methodology. This revision increased regulatory clarity and reduced the administrative reporting burdens for both the Division and the regulated community by simplifying the process. No emissions increases were anticipated as a result of this revision because this revision was administrative in nature and did not change the applicability of controls or regulations to sources.

Crude Oil Storage Tanks

The Commission removed the crude oil storage tank permitting exemptions in Part B, Section II.D.1.n. and Part C, Section II.E.3.ddd. The emissions from crude oil storage tanks can be significant and permitting exemptions are meant to be limited to emission points with negligible impacts on air quality.

Crude Oil and Condensate Truck Loading Equipment

The Commission corrected an error in Part B, Section II.D.1.l. by removing the last sentence of the crude oil truck loading equipment minor source permitting exemption. In 2006, the Regulation Number 3 APEN exemption inadvertently merged the original exemption language with the 2002 exemption revision so that in 2008, when the Commission removed the APEN exemption to build the emissions inventory and moved the exemption in Part B to maintain the associated permitting exemption, the erroneous language persisted. This revision corrected that error.

I.YY. Adopted November 20, 2014

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

Regulation Number 3, Part F – revising the NOx emission limit, compliance date and BART determination for Tri-State Generation and Transmission Association ("Tri-State"), Craig Station Unit 1.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7, including a comprehensive state implementation plan which will prevent significant deterioration of air quality. Section 25-7-109(1)(a) authorizes the Commission to require the use of air pollution controls. Section 109(2) authorizes the Commission to adopt emission control regulations pertaining to visible pollutants and nitrogen oxides.

Purpose

The Colorado Air Quality Control Commission ("Commission") revises Regulation Number 3, Part F, Section VI., containing the Regional Haze Best Available Retrofit Technology ("BART") determinations that the Commission adopted and the EPA approved as part of Colorado's Regional Haze State Implementation Plan ("SIP").

After EPA approved Colorado's Regional Haze SIP, WildEarth Guardians and the National Parks Conservation Association challenged portions of this approval by filing suit against EPA in the Tenth Circuit. As part of this lawsuit, the plaintiffs contested the nitrogen oxides ("NOx") provisions for Craig Station Unit 1. In furtherance of settlement of this litigation, the Commission has revised Regulation Number 3, Part F, Section VI. to strengthen the NOx emission limit and set the compliance deadline for Craig Station Unit 1. The Commission revised Craig Station Unit 1's BART determination for NOx by revising the NOx emission limit from 0.28 lb/MMBtu to 0.07 lb/MMBtu, and revising the associated compliance deadline from January 30, 2018, to August 31, 2021. The Commission also clarified that compliance with the specified emission limits and compliance dates for both Units 1 and 2 constitute BART for this facility.

In addition to the regulatory changes described above, the Division proposes to make corresponding changes to Colorado's Regional Haze SIP: Chapter 6 - Best Available Retrofit Technology; Chapter 9 – Long Term Strategy; and Appendix C – Technical Support for the BART Determinations. The revisions to the Regional Haze SIP do not impact the emission limits or compliance deadline for Craig Station Unit 2. The revised chapters fully replace previously adopted SIP chapters.

Findings of Fact

Colorado's Regional Haze SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. Accordingly, the revisions do not exceed the requirements of the federal act or differ from the federal act or rules. However, to the extent that these revisions could be viewed as exceeding or differing from the federal act, the Commission determines in accordance with C.R.S. § 25-7-110.5(5)(b):

(I) Colorado's Regional Haze SIP was drafted in accordance with EPA's Regional Haze Rule. The Regional Haze Rule provides states flexibility in how states may consider the federal statutory and regulatory factors when determining BART and reasonable progress goals.

(II) EPA's regional haze requirements are performance based. The Regional Haze Rule sets forth factors the states must consider when determining BART for sources reasonably anticipated to cause or contribute to the impairment of visibility in federal Class I areas. States have the discretion to select the appropriate controls for such sources.

(III) EPA's Regional Haze Rule guides how states must determine BART for their BART-eligible sources. However, state discretion is a cornerstone of the Regional Haze Rule (*70 FR 39137*). Colorado considered Colorado's issues of concern when developing these revisions.

(IV) The adopted revisions will improve Tri-State's ability to comply with the goals of the Regional Haze Rule while preventing or reducing the need for costly retrofits potentially required in Colorado's next reasonable progress planning period.

(V) The Regional Haze Rule requires source to comply with the BART determinations as expeditiously as possible but no later than five years after EPA approves the SIP. Concerning this revision, the Division must submit a proposed SIP revision to EPA no later than July 31, 2015, and EPA must take final action on the proposed SIP revision by December 31, 2016. The revised compliance deadline for Craig Station Unit 1 of August 31, 2021, is slightly less than five years after EPA's approval, which is within the time frame for implementation set by the Regional Haze Rule.

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources because the Regional Haze Rule applies the same standards for determining BART to all BART-eligible sources. BART determinations are source specific and different controls and emission limits are to be expected.

(VIII) If the revisions were not adopted, litigation would continue concerning the regional haze requirements for Craig Station that would entail associated costs and uncertainties as to the outcome.

(IX) These revisions do not modify the currently approved procedural, reporting, or monitoring requirements in Colorado's Regional Haze SIP.

(X) Demonstrated technology is available to comply with the revised NOx emission rate for Craig Station Unit 1.

(XI) The revisions will contribute to further reductions of NOx emissions and therefore contribute to the prevention of pollution.

(XII) Neither an alternative rule nor a no action alternative would address or achieve the emission reductions to be achieved through these revisions. Further, failure to adopt the revisions could result in further expensive and time consuming litigation concerning Colorado's regional haze provisions for Craig Station Unit 1.

As part of adopting the revisions to Regulation Number 3, Part F, Section VI., the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of NOx emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary reduction in air pollution and provide the regulated entity flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

The revisions also correct typographical, grammatical, and formatting errors.

I.ZZ. Adopted January 21, 2016

Regulation Number 3, Part A, Section I.B.44. – revising GHG permitting thresholds.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S., the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act"), and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

The Commission revised the definition of "subject to regulation" to correspond to revisions to the federal definition of subject to regulation.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-201 though 25-7-206, 25-7-210, 25-7-301, and 25-7-302, C.R.S. authorize the Commission to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") and prevent significant deterioration ("PSD") of air quality in conformance with the Federal and Colorado Acts. Section 25-7-105(1)(c) further requires the Commission to promulgate a PSD program in conformity with federal requirements, including definitions that do not differ from the federal definitions.

Purpose

In 2014, the United States Supreme Court held that EPA could not treat GHG as a pollutant for purposes of defining a "major emitting facility" (or a "modification" thereof) for Prevention of Significant Deterioration ("PSD") or a "major source" for Title V, essentially invalidating the Step 2 GHG permitting thresholds in EPA's Tailoring Rule. (see Util. Air Regulatory Grp. v. EPA, 134 S. Ct. 2427 (2014)) In 2015, the Court of Appeals vacated EPA regulations to the extent that they required a stationary source obtain a PSD or Title V permit solely because the source emitted GHG in excess of applicable GHG-major source thresholds. (see Coalition for Responsible Regulation v. EPA, Nos. 09-1322, 10-073, 10-1092, 10-1167 (2015)) On August 19, 2015 (80 Fed. Reg. 50199), EPA issued a final rule that removed the Step 2 GHG permitting thresholds from the definitions of subject to regulation at 40 CFR Sections 51.166 and 52.21.

In response to the court decisions and EPA's corresponding revisions, the Commission revised Section I.B.44.e. to correspond to the federal definition of subject to regulation.

Further, the Commission corrected any typographical, grammatical and formatting errors found within the regulation.

I.AAA. Adopted October 12, 2016

Regulation Number 3, Part D, Sections II.A.22.b., II.A.25.b., and II.A.44.a.

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Basis

The Commission revised the definition of "major stationary source" contained in Regulation Number 3, Part D, Section II. to include the ozone nonattainment area major source thresholds, consistent with federal requirements. The Commission also revised the definitions of "major emission unit" and "significant" in Regulation Number 3, Part D, Section II.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-105(1)(a), 25-7-301, and 25-7-302, C.R.S. authorize the Commission to promulgate a comprehensive State Implementation Plan ("SIP") which will assure attainment and maintenance of national ambient air quality standards ("NAAQS") in conformance with the Federal and Colorado Acts. Section 25-7-105(12) authorizes the Commission to promulgate regulations necessary to implement the provisions of the emission notice, construction permit, and Title V programs. Pursuant to Section 25-7-106, C.R.S., the Commission has the maximum flexibility in establishing an air quality control program and may promulgate regulations as necessary or desirable to carry out that program.

Purpose

Major Stationary Source Definition

Regulation Number 3, Part D, concerning Major Stationary Source New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD"), applies statewide to any new or existing major stationary source (Section I.) and it has been fully incorporated into Colorado's SIP. If a source is a "major stationary source" as defined in Section II.A.25.b., then it will need to comply with Sections V. (Requirements Applicable to Nonattainment Areas) and VI. (Requirements applicable to attainment and unclassifiable areas and pollutants implemented under Section 110 of the Federal Act (PSD Program)) of Part D, as applicable.

A major stationary source is defined as, "Any stationary source of air pollutants that emits, or has the potential to emit 100 tons per year or more of any regulated NSR pollutant for which the area is nonattainment." Unlike the federal definition, Colorado's definition of "major stationary source" does not step-down the thresholds for determining what is a major source based on ozone nonattainment area classification. *See* 40 C.F.R. § 51.165(a)(1)(iv)(A)(1) and 40 C.F.R. Part 51, Appendix S. Thus, if an ozone nonattainment area were ever classified or reclassified as serious or severe, in order to maintain permitting authority, Colorado would need to adopt the same lower major stationary source thresholds that would apply on a federal basis before permitting new or modified sources. Therefore, in order to ensure consistency with federal definitions and to provide regulatory certainty by avoiding any disruption to the permitting process should Colorado's ozone nonattainment area ever be reclassified to a more stringent classification beyond a moderate nonattainment area, the Commission has revised the definition of "major stationary source" contained in Part D, Section II.A.25.b. to include the ozone nonattainment area major source thresholds.

Major Emissions Unit Definition

Currently, Section II.A.22.b. defines a major emissions unit as, "Any emissions unit that emits or has the potential to emit an amount that is equal to or greater than the major stationary source threshold (as defined in Section II.A.25. of this part) for the [plant-wide applicability limitation (PAL)] pollutant for nonattainment areas." The definition of major emissions unit in Section II.A.22.b. then goes on to provide an example of when an emissions unit would be a major emissions unit for volatile organic compounds. This example is not required to maintain consistency with federal definitions and it does not provide additional clarity to the regulation. Therefore, the Commission is removing this example.

Significant Definition

Currently, the definition of significant contained in Section II.A.44.a. (in reference to a net emissions increase or the potential of a source to emit air pollutants) contains emission rates in tons per year, but it does not contain emission rates pertaining to serious, severe or extreme ozone nonattainment areas. In order to ensure consistency with federal definitions and provide certainty by avoiding any disruption in the permitting process, the Commission is adding emission rates for serious, severe and extreme ozone nonattainment areas.

Further, the Commission corrected any typographical, grammatical and formatting errors found within the regulation.

I.BBB. Adopted December 15, 2016

Regulation Number 3, Part F – Revising the BART and Reasonable Progress determinations for Craig Station Unit 1 ("Craig Unit 1") and Nucla ("Nucla").

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act, C.R.S. § 24-4-103, the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5, and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

Regulation Number 3, Part F – Revising the BART and Reasonable Progress determinations for Craig Unit 1 and Nucla, respectively.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7, including a comprehensive state implementation plan which will prevent significant deterioration of air quality. Section 25-7-109 authorizes the Commission to adopt emission control regulations pertaining to air pollutants.

Purpose

The Colorado Air Quality Control Commission ("Commission") makes targeted revisions to portions of Regulation Number 3, Part F, Section VI., containing the Regional Haze Best Available Retrofit Technology ("BART") and Reasonable Progress determinations that the Commission previously adopted as part of Colorado's Regional Haze State Implementation Plan ("SIP").

After the U.S. Environmental Protection Agency ("EPA") approved Colorado's Regional Haze SIP, WildEarth Guardians and the National Parks Conservation Association ("NPCA") challenged portions of the approval by filing suit in the Tenth Circuit (Guardians v. EPA, No. 13-9520 and NPCA v. EPA, No. 13-9525). As part of that lawsuit, the plaintiffs contested the nitrogen oxides ("NOX") provisions for Craig Unit 1, which is owned, in part, and operated by Tri-State Generation and Transmission Association, Inc. ("Tri-State"). In furtherance of settlement of that litigation, in 2014, the Commission approved revisions to Regulation Number 3, Part F, Section VI. to change the Craig Unit 1 NOX emission limit from 0.28 lb/MMBtu to 0.07 lb/MMBtu, and set the associated compliance deadline for Craig Station Unit 1 as August 31, 2021.

Since the Commission approved the 2014 revisions to Regulation Number 3, Part F and Colorado's Regional Haze SIP, an agreement has been reached involving Craig Unit 1 and Nucla Station ("Nucla"). The agreement includes the following commitments:

(I) 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;

(II) In the case of a conversion to natural-gas firing, a 30-day rolling average NOX emission limit of 0.07 lb/MMBtu will be effective after August 31, 2021;

(III) For both scenarios, Craig Unit 1 will be subject to a NOX emission limit of 0.28 lb/MMBtu, on a 30 day rolling average, effective January 1, 2017 (first compliance date January 31, 2017), until converting to natural gas or permanently shutting down;

(IV) Craig Unit 1 will be subject to an annual NOX emission limit of 4,065 tons per year effective on December 31, 2019 on a calendar year basis beginning in 2020;

(V) Nucla will close on or before December 31, 2022; and

(VI) Nucla will be subject to an annual NOX emission limit of 952 tons per year effective January 1, 2020 on a calendar year basis beginning in 2020.

The Air Pollution Control Division ("Division") conducted a BART reassessment for Craig Unit 1 and Reasonable Progress review for Nucla, respectively, taking into account the agreement. The agreement reflects a changing industry, economic, and regulatory landscape that does not necessarily favor the installation of costly post-combustion retrofit controls on aging coal-fired electric generating units. The agreement and these revisions will also result in greater emissions reductions than would result from the previously approved SIP. The Commission's adoption of these revisions will result in further reductions of visibility impairing pollutants, in addition to providing other environmental co-benefits.

In accordance with the BART reassessment and Reasonable Progress review, the Commission revises 3, Part F, Section VI to reflect the applicable elements of the agreement described herein.

In addition to the regulatory changes to Regulation Number 3, Part F, the Commission revises corresponding portions of Colorado's Regional Haze SIP: Chapter 6 – Best Available Retrofit Technology; Chapter 8 – Reasonable Progress; Appendix C – Technical Support for the BART Determinations; and Appendix D – Technical Support for the Reasonable Progress Determinations. The revised chapters fully replace previously adopted SIP chapters. The revisions to Colorado's Regional Haze SIP, Chapter 6 – Best Available Retrofit Technology and Appendix C – Technical Support Document - for the BART Determinations, include, among other things, revised cost comparisons as part of the NOx BART reassessment for Craig Unit 1. The Commission is aware of the fact that there are differing views among parties to the recent agreement as to what the appropriate amortization periods should be for use in calculating the cost effectiveness of SNCR and SCR in Scenario 1 (closure on or before December 31, 2025). The Commission finds that regardless of the amortization period used, under Scenario 1, both SNCR and SCR are not cost effective when the remaining useful life is shortened.

The revisions also correct any typographical, grammatical, and formatting errors.

Findings of Fact

Colorado's Regional Haze SIP revisions are consistent with EPA's federal requirements under the Regional Haze rule. Accordingly, the revisions do not exceed the requirements of the federal act or differ from the federal act or rules. However, to the extent that these revisions could be viewed as exceeding or differing from the federal act, the Commission determines in accordance with C.R.S. § 25-7-110.5(5)(b):

(I) Colorado's Regional Haze SIP was drafted in accordance with EPA's Regional Haze Rule. The Regional Haze Rule provides states flexibility in how states may consider the federal statutory and regulatory factors when determining BART and reasonable progress goals.

(II) EPA's regional haze requirements are performance based. The Regional Haze Rule sets forth factors the states must consider when determining BART for sources reasonably anticipated to cause or contribute to the impairment of visibility in federal Class I areas. States have the discretion to select the appropriate controls for such sources.

(III) EPA's Regional Haze Rule guides how states must determine BART for their BART-eligible sources. However, state discretion is a cornerstone of the Regional Haze Rule (70 FR 39137). Colorado considered Colorado's issues of concern when developing these revisions.

(IV) The adopted revisions will improve industry's ability to comply with the goals of the Regional Haze Rule in a more cost-effective way, by increasing certainty and preventing or reducing the need for costly retrofits.

(V) The timing of the adopted revisions has been considered. The timeframe of the adopted revisions allows for the avoidance of costly retrofits.

(VI) The adopted rule will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rule establishes reasonable equity for sources because the Regional Haze Rule applies the same standards for determining BART to all BART-eligible sources. BART determinations are source specific and different controls and emission limits are to be expected.

(VIII) Adoption of a more stringent rule would not reduce costs upon other entities.

(IX) These revisions do not modify the currently approved procedural, reporting, or monitoring requirements in Colorado's Regional Haze SIP.

(X) Technology is available to comply with the adopted revisions. The technology to convert to natural gas is a demonstrated and already utilized technology.

(XI) The revisions will lead to further reductions of air pollutant emissions, contribute to the prevention of pollution, and represent a more cost-effective environmental gain.

(XII) Neither an alternative rule nor a no action alternative would address or achieve the emission reductions to be achieved through these revisions. Further, failure to adopt the revisions could result in expensive and time consuming retrofits or litigation.

As part of adopting the revisions to Regulation Number 3, Part F, Section VI., the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.

(II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of air pollutant emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective to achieve the necessary reduction in air pollution and provide the regulated community flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Editor's Notes

History

Part A Section VI.D, Part F Section I.MM eff. 11/30/2007.

Part E (Best Available Retrofit Technology (BART) eff. 03/01/2008.

Entire rule eff. 04/30/2008.

Part F Section IV.B; Part G Section I.PP eff. 06/30/2008.

Part A Section VI.D, Part G Section I.QQ eff. 10/30/2008.

Part A Section II.D, Part B Section II D, Part C Section II E, Part F Section VI.B, Part G Sections I.RR, I.SS eff. 01/30/2009.

Entire rule eff. 12/15/2010.

Part D Section XIV.F; Part F, Part G Section I.UU eff. 02/14/2011.

Part A Sections I.B, II.C, II.D; Part B Sections II.D, III.G; Part C Sections I.A, II.E, X.A, XII.A; Part D Sections II.A, III.B, V.A, VI.A, VI.B, VI.D, X.A, XIII.B, XIII.D; Part F Sections I, III.A, IV.A, VI.B, VI.C, Part G Sections I.C, I.VV eff. 12/15/2011.

Part A Sections I.A, I.B.7, I.B.14 – I.B.16, I.B.28, I.B.31.d, I.B.38, I.B.43, II.D.1.dddd, V.I, VI.A – VI.B, Appendix B, Part B Section III.C.1.a, Part C Sections I.A.7, XIV, Part D Sections I – II, V.A.1 – V.A.7, VI.A, VI.B, XV, Part F, Part G Section I.WW eff. 02/15/2013.

Part A Sections II.B.3.b, II.D.1, II.D.1.b, Appendix A, Part B Sections II.A.5, II.D, II.D.1, II.D.1.l, II.D.1.n, Part C Section II.E.3.ddd, Part D Section XV.F.5, Part F Sections VII.A.3, VII.B.1.a, VII.B.1.b, VII.B.1.b.(ii), Part G Section I.XX eff. 04/14/2014.

Part A Sections I.B, II.C, V.C, V.I, VI.C, Appendix A, Appendix B, Part B Section III.C, Part C Section VI.A – VI.B, XII.B, Part D Sections I – II, V – VI, XV, Part G Section I.YY eff. 10/15/2014.

Part F Section VI.A, Part G Section I.YY eff. 01/14/2015.

Part A Section I.B.44.e., Part G Section I.ZZ eff. 03/16/2016.

Part D, Sections II.A.22.b, II.A.25.b, II.A.44.a, Part G, Section I.AAA eff. 11/30/2016.

Part F Section VI, Part G Section I.BBB eff. 02/14/2017.

Annotations

Air Pollution Control Division did not err by obtaining and reviewing the original visibility data from the National Park Service because the Division reviewed and analyzed that information in ultimately arriving at its own conclusion. *Citizens for Clean Air & Water v. Colo. Dep't of Pub. Health & Env't, 181 P.3d 393 (2008).*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-67:
EPA NO_2 Information

Basic Information about NO2

www.epa.gov/no2-pollution/basic-information-about-no2

July 6, 2016

On This Page:

- What is NO_2 and how does it get in the air?
- What are the harmful effects of NO_2?
- What is being done to reduce NO_2 pollution?

What is NO_2 and how does it get in the air?

Nitrogen Dioxide (NO_2) is one of a group of highly reactive gases known as oxides of nitrogen or nitrogen oxides (NO_x). Other nitrogen oxides include nitrous acid and nitric acid. NO_2 is used as the indicator for the larger group of nitrogen oxides.

NO_2 primarily gets in the air from the burning of fuel. NO_2 forms from emissions from cars, trucks and buses, power plants, and off-road equipment.

Effects of NO_2

Health effects

Breathing air with a high concentration of NO_2 can irritate airways in the human respiratory system. Such exposures over short periods can aggravate respiratory diseases, particularly asthma, leading to respiratory symptoms (such as coughing, wheezing or difficulty breathing), hospital admissions and visits to emergency rooms. Longer exposures to elevated concentrations of NO_2 may contribute to the development of asthma and potentially increase susceptibility to respiratory infections. People with asthma, as well as children and the elderly are generally at greater risk for the health effects of NO_2.

NO_2 along with other NO_x reacts with other chemicals in the air to form both particulate matter and ozone. Both of these are also harmful when inhaled due to effects on the respiratory system.

> Learn more about Particulate Matter and Ozone.

Environmental effects

NO_2 and other NO_x interact with water, oxygen and other chemicals in the atmosphere to form acid rain. Acid rain harms sensitive ecosystems such as lakes and forests.

> Learn more about Acid Rain.

The nitrate particles that result from NO_x make the air hazy and difficult to see though. This affects the many national parks that we visit for the view.

> Learn more about Visibility and Haze.

NO_x in the atmosphere contributes to nutrient pollution in coastal waters.

> Learn more about Nutrient Pollution.

What is being done to reduce NO_2 pollution?

EPA's national and regional rules to reduce emissions of NO_2 and NO_x will help state and local governments meet the National Ambient Air Quality Standard (NAAQS).

> Learn about how air quality standards help reduce NO_2

EPA identifies areas where the air quality does not meet the national NO_2 standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of NO_2 in the air.

Learn more about NO_2 air quality designations and state implementation plans (SIPs).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-68:
EPA Sulfur Dioxide Information

Sulfur Dioxide Basics

www.epa.gov/so2-pollution/sulfur-dioxide-basics

June 2, 2016

- What is SO_2 and how does it get in the air?
- What are the harmful effects of SO_2?
- What is being done to reduce SO_2 pollution?

What is SO_2 and how does it get in the air?

What is SO_2?

EPA's national ambient air quality standards for SO_2 are designed to protect against exposure to the entire group of sulfur oxides (SO_x). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SO_x). Other gaseous SOx (such as SO_3) are found in the atmosphere at concentrations much lower than SO_2.

Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SO_x. This may have the important co-benefit of reducing the formation of particulate sulfur pollutants, such as fine sulfate particles.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SO_x. The largest sources of SO_2 emissions are from fossil fuel combustion at power plants andother industrial facilities.

How does SO_2 get in the air?

The largest source of SO_2 in the atmosphere is the burning of fossil fuels by power plants and other industrial facilities. Smaller sources of SO_2 emissions include: industrial processes such as extracting metal from ore; natural sources such as volcanoes; and locomotives, ships and other vehicles and heavy equipment that burn fuel with a high sulfur content.

What are the harmful effects of SO_2?

SO_2 can affect both health and the environment.

What are the health effects of SO_2?

Short-term exposures to SO_2 can harm the human respiratory system and make breathing difficult. People with asthma, particularly children, are sensitive to these effects of SO_2.

SO_2 emissions that lead to high concentrations of SO_2 in the air generally also lead to the formation of other sulfur oxides (SO_x). SO_x can react with other compounds in the atmosphere to form small particles. These particles contribute to particulate matter (PM) pollution. Small particles may penetrate deeply into the lungs and in sufficient quantity can contribute to health problems.

Learn more about particulate matter

What are the environmental effects of SO_2 and other sulfur oxides?

At high concentrations, gaseous SOx can harm trees and plants by damaging foliage and decreasing growth.

SO_2 and other sulfur oxides can contribute to acid rain which can harm sensitive ecosystems.

Learn more about acid rain

Visibility

SO_2 and other sulfur oxides can react with other compounds in the atmosphere to form fine particles that reduce visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas.

Learn more about visibility and regional haze

Deposition of particles can also stain and damage stone and other materials, including culturally important objects such as statues and monuments.

What is being done to reduce SO_2 pollution?

EPA's national and regional rules to reduce emissions of SO_2 and pollutants that form sulfur oxides (SO_x) will help state and local governments meet the Agency's national air quality standards.

> Learn about how air quality standards help reduce SO_2

EPA identifies areas where the air quality does not meet EPA SO_2 standards. For these areas, state, local, and tribal governments develop plans to reduce the amount of SO_2 in the air.

> Learn more about SO_2 air quality designations and state implementation plans (SIPs)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-69:
EPA PM Information

Health and Environmental Effects of Particulate Matter (PM)

www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm

April 26, 2016

Health Effects

The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease
- nonfatal heart attacks
- irregular heartbeat
- aggravated asthma
- decreased lung function
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children, older adults, minority populations, and low socioeconomic status populations are the most likely to be affected by particle pollution exposure, either because they are more sensitive or may have higher exposures.

AirNow can help you monitor air quality near you, and protect yourself and your family from elevated PM levels.

Environmental Effects

Visibility impairment

Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. Learn more about visibility and haze

Environmental damage

Particles can be carried over long distances by wind and then settle on ground or water. Depending on their chemical composition, the effects of this settling may include:

- making lakes and streams acidic
- changing the nutrient balance in coastal waters and large river basins
- depleting the nutrients in soil
- damaging sensitive forests and farm crops
- affecting the diversity of ecosystems
- contributing to acid rain effects.

Materials damage

PM can stain and damage stone and other materials, including culturally important objects such as statues and monuments. Some of these effects are related to acid rain effects on materials.

Further Reading

Particle Pollution and Your Health (txt) (2 pp, 320 KB): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It is important to limit your exposure to smoke -- especially if you may be susceptible.

EPA research on airborne particulate matter: EPA supports research that provides the critical science on PM and other air pollutants to develop and implement Clean Air Act regulations that protect the quality of the air we breathe.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-70:
2018 BART

Best Available Retrofit Technology (BART) Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Table 1 lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

Table 1: Craig Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	1980	1979
Gross Boiler Rating, MMBtu/Hr for coal	4,417	4,417
Electrical Power Rating, Net Megawatts	428	428
Description	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization.
Air Pollution Control Equipment	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.	PM/PM_{10} – Pulse Jet Fabric Filter Baghouse NO_x – Ultra-low NO_x Burners with Over-Fire Air SO_2 – Wet Limestone FGD All updated control equipment commenced full operations in 2004.
Emissions Reduction (%)*	NO_x – 23.8% /53.9% SO_2 – 77.6%/93.8% PM – 99.6% PM_{10} – 99.4%	NO_x – 29.5%/54.7% SO_2 – 79.5%/93.8% PM – 99.9% PM_{10} – 99.5%

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For PM/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and in existence in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "Tri-State BART Submittals".

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses.

Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	5,190	0.278	5,372	0.271
SO_2	970	0.052	982	0.050
PM_{10}	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	ColoWyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

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

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

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0
Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

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

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

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

	SO_2 limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

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

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

Step 2: Eliminate Technically Infeasible Options

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

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division's request, Tri-State submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State examined potential upgrades to the Craig wet FGD systems, with the following results:

-*Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-*Installation of liquid distribution rings:* Liquid distribution rings were not installed during the YEP; however, Tri-State determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO_2 by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:

1. DBA has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

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

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

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.

2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.

3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.

5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.

6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.

7. Instrumentation and controls were modified to support all of the new equipment.

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

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit 1	0.081	0.052
Craig Unit 2	0.093	0.079

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98^{th} percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD).

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

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

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							
Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

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

Table 8: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

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

Step 6: Select BART Control

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

B. Filterable Particulate Matter (PM_{10})

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

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

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies
Tri-State identified five options for NO_x control:
New/modified Low NO_x Burners (LNBs) with 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

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 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.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give Tri-State a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: Tri-State received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. Tri-State states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

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

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: Tri-State noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: Tri-State noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control.

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

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

B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

[9] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

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

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners/Ultra-low NO_x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire 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 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

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 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.[11] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

Neural network system: Tri-State did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that Tri-State contacted.[12] It is unknown why Tri-State will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[13] The Tri-State-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[14]

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately $4,877 and $4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. [15,16] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[17] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from Tri-State. The costs for these two items are higher than other Colorado facility estimates.

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[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[18,19 20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,190	0.278	
Combustion control refinements	2	5,087	0.273	0.31
Neural network system	5	4,931	0.264	0.30
SNCR	15	4,412	0.236	0.27
SCR	78.0	1,142	0.061	0.070

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 13: Craig Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,372	0.271	
Combustion control refinements	2	5,264	0.265	0.31
Neural network system	5		0.257	0.30
SNCR	15	4,566	0.230	0.27
SCR	74	1,397	0.070	0.081

Table 14: Craig Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	104	$122,000	$1,175	$1,175
Neural network system	260	$280,000	$1,079	$1,015
SNCR	779	$3,797,000	$4,877	$6,776
SCR	4,048	$25,036,709	$6,184	$6,394

Table 15: Craig Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	107	$122,000	$1,136	$1,136
Neural network system	269	$280,000	$1,043	$980
SNCR	806	$3,797,000	$4,712	$4,712
SCR	3,975	$25,036,709	$6,298	$6,702

Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

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

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

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

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels.

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

For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD control).

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

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	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		207	57	150	123	12	111
	2	0.07							

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1	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	1.17	2.56	69%	$19,537,034
	2	0.07				

Step 6: Select BART Control

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

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

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

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

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

To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Once EPA approves this revision to the Regional Haze SIP, Tri-State will be required to meet the 0.07 lb/MMBtu NOx emission limit by August 31, 2021. Once the revised emission limit is approved, Tri-State will begin the design and development of bid documents, engage in a process to review bids and select a contractor for the multi-year construction project. Based on Tri-State's experience at Unit 2 (where construction and installation of SCR is already underway), and taking into consideration such factors as the weather in Craig, Colorado, the coordination necessary between the various owners of Unit 1, electric utilities and regional entities responsible for the bulk electric system, and compliance deadlines for other similar types of facilities in Colorado, Arizona and Wyoming, the Division has determined that the compliance deadline of August 31, 2021 is as expeditiously as practicable as SCR can be installed at Unit 1. This BART determination is the result of an agreement between Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state to resolve an appeal of EPA's decision to approve Colorado's Regional Plan.

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination In Table 19 below, an assumed amortization period of eight years of operation[23] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[24]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

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

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

[23] Operation period begins calendar year 2018 (December 31, 2017).

[24] EPA finalized revisions of the Air Pollution Cost Control Manual (Chapters 1 and 2) in May 2016; these revisions change the amortization period for SCR from 20 years to 30 years. The amortization period for SNCR remains 20 years.

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

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

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination.

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-71:
BART CALPUFF

BART CALPUFF
Class I Federal Area
Individual Source Attribution
Visibility Impairment Modeling Analysis
for
Tri-State Generation & Transmission Association
Craig Station Units 1 and 2
(Revised)

March 3, 2006

Colorado Department of Public Health & Environment
Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, Colorado 80246

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1. Executive Summary

Federal law requires Best Available Retrofit Technology (BART) for any BART-eligible source that ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Pursuant to federal regulations, states have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area.

The Division has proposed state regulations establishing criteria and procedures for determining which Colorado sources will be subject to the BART requirement. The Division’s proposal is scheduled for a March 16, 2006 hearing before the Air Quality Control Commission. In advance of the hearing, and in preparation for the submittal of a state implementation plan for regional haze, the Division has performed air quality modeling with the CALPUFF modeling system to assess which BART-eligible sources in Colorado are likely to be subject to BART based on the proposed state regulation.

According to 40 CFR Part 51, Appendix Y (BART guideline), a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the “contribution threshold.” Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to BART. In this report, the Division used a “contribution threshold” of 0.5 deciviews, as prescribed by the regulatory proposal pending before the Commission.

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is equal to or greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the “subject-to-BART” analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results. If additional modeling is performed, it should be consistent with recommendations in the Division’s modeling protocol. Subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency’s final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

The maximum 98th percentile delta-deciview value from Craig Station Units 1 and 2 at any Class I federal area is 2.689 deciviews, assuming natural background conditions and monthly

f(RH) values. The impact is above the contribution threshold of 0.5 deciviews. The maximum impact occurs at the Mount Zirkel Wilderness Area. For the three-year period modeled, there are 496 days with an estimated impact over the contribution threshold of 0.5 deciviews.

2. Introduction

Federal law requires Best Available Retrofit Technology (BART) for any BART-eligible source that ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Pursuant to federal regulations, states have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area.

Federal regulations implementing the BART requirement afford states some latitude in the criteria in determining whether a BART-eligible source is subject to BART. The Division has proposed state regulations establishing criteria and procedures for determining which Colorado sources will be subject to the BART requirement. The Division’s proposal is scheduled for a March 16, 2006 hearing before the Air Quality Control Commission. In advance of the hearing, and in preparation for the submittal of a state implementation plan for regional haze, the Division has performed air quality modeling with the CALPUFF modeling system to assess which BART-eligible sources in Colorado are likely to be subject to BART based on the proposed state regulation.

According to 40 CFR Part 51, Appendix Y (BART guideline), a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the “contribution threshold.” Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to BART. The Division has proposed a state regulation establishing a “contribution threshold” of 0.5 deciviews. In this report, the assumed “contribution threshold” is 0.5 deciviews.

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is equal to or greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the “subject-to-BART” analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results. If additional modeling is performed, it should be consistent with recommendations in the Division’s modeling protocol. Any subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency’s final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

Relevant language from the BART guideline is included, below, to show the modeling recommendations in context. Other sections of this report explain how the Division implemented the recommendations. The BART guidelines set out 40 CFR Part 51, Appendix Y, provide in part:

> ***III. HOW TO IDENTIFY SOURCES "SUBJECT TO BART"***
> *Once you have compiled your list of BART-eligible sources, you need to determine whether (1) to make BART determinations for all of them or (2) to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. If you decide to make BART determinations for all the BART-eligible sources on your list, you should work with your regional planning organization (RPO) to show that, collectively, they cause or contribute to visibility impairment in at least one Class I area. You should then make individual BART determinations by applying the five statutory factors discussed in Section IV below.*
>
> *On the other hand, you also may choose to perform an initial examination to determine whether a particular BART-eligible source or group of sources causes or contributes to visibility impairment in nearby Class I areas. If your analysis, or information submitted by the source, shows that an individual source or group of sources (or certain pollutants from those sources) is not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, then you do not need to make BART determinations for that source or group of sources (or for certain pollutants from those sources). In such a case, the source is not "subject to BART" and you do not need to apply the five statutory factors to make a BART determination. This section of the Guideline discusses several approaches that you can use to exempt sources from the BART determination process.*
>
> ***A. What Steps Do I Follow to Determine Whether A Source or Group of Sources Cause or Contribute to Visibility Impairment for Purposes of BART?***
> ***1. How Do I Establish a Threshold?***
> *One of the first steps in determining whether sources cause or contribute to visibility impairment for purposes of BART is to establish a threshold (measured in deciviews) against which to measure the visibility impact of one or more sources. A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART.*
>
> *Because of varying circumstances affecting different Class I areas, the appropriate threshold for determining whether a source "contributes to any visibility impairment" for the purposes of BART may reasonably differ across States. As a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews.*
>
> *In setting a threshold for "contribution," you should consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources'*

impacts.[5] *In general, a larger number of sources causing impacts in a Class I area may warrant a lower contribution threshold. States remain free to use a threshold lower than 0.5 deciviews if they conclude that the location of a large number of BART eligible sources within the State and in proximity to a Class I area justify this approach.*[6]

2. What Pollutants Do I Need to Consider?

You must look at SO2, NOx, and direct particulate matter (PM) emissions in determining whether sources cause or contribute to visibility impairment, including both PM10 and PM2.5. Consistent with the approach for identifying your BART-eligible sources, you do not need to consider less than de minimis emissions of these pollutants from a source.

As explained in section II, you must use your best judgement to determine whether VOC or ammonia emissions are likely to have an impact on visibility in an area. In addition, although as explained in Section II, you may use PM10 an indicator for particulate matter in determining whether a source is BART eligible, in determining whether a source contributes to visibility impairment, you should distinguish between the fine and coarse particle components of direct particulate emissions. Although both fine and coarse particulate matter contribute to visibility impairment, the long-range transport of fine particles is of particular concern in the formation of regional haze. Air quality modeling results used in the BART determination will provide a more accurate prediction of a source's impact on visibility if the inputs into the model account for the relative particle size of any directly emitted particulate matter (i.e. PM_{10} vs. $PM_{2.5}$).

3. What Kind of Modeling Should I Use to Determine Which Sources and Pollutants Need Not Be Subject to BART?

This section presents several options for determining that certain sources need not be subject to BART. These options rely on different modeling and/or emissions analysis approaches. They are provided for your guidance. You may also use other reasonable approaches for analyzing the visibility impacts of an individual source or group of sources.

Option 1: Individual Source Attribution Approach (Dispersion Modeling)

You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area and thus is not subject to BART. Under this option, you can analyze an individual source's impact on visibility as a result of its emissions of SO_2, NO_x and direct PM emissions. Dispersion modeling cannot currently be used to estimate the predicted impacts on visibility from an individual source's emissions of VOC or ammonia. You may use a more qualitative

[5] *We expect that regional planning organizations will have modeling information that identifies sources affecting visibility in individual class I areas.*

[6] *Note that the contribution threshold should be used to determine whether an individual source is reasonably anticipated to contribute to visibility impairment. You should not aggregate the visibility effects of multiple sources and compare their collective effects against your contribution threshold because this would inappropriately create a "contribute to contribution" test.*

assessment to determine on a case-by-case basis which sources of VOC or ammonia emissions may be likely to impair visibility and should therefore be subject to BART review, as explained in section II.A.3. above.

You can use CALPUFF[7] or other appropriate model to predict the visibility impacts from a single source at a Class I area. CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants.[8] It can also be used for some other purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_x.

There are several steps for making an individual source attribution using a dispersion model:

1. Develop a modeling protocol.

Some critical items to include in the protocol are the meteorological and terrain data that will be used, as well as the source-specific information (stack height, temperature, exit velocity, elevation, and emission rates of applicable pollutants) and receptor data from appropriate Class I areas. We recommend following EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts[9] for parameter settings and meteorological data inputs. You may use other settings from those in IWAQM, but you should identify these settings and explain your selection of these settings.

One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.

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[7] *The model code and its documentation are available at no cost for download from http://www.epa.gov/scram001/tt22.htm#calpuff .*

[8] *The Guideline on Air Quality Models, 40 CFR part 51, appendix W, addresses the regulatory application of air quality models for assessing criteria pollutants under the CAA, and describes further the procedures for using the CALPUFF model, as well as for obtaining approval for the use of other, nonguideline models.*

[9] *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,* U.S. Environmental Protection Agency, EPA-454/R-98-019, December 1998.

You should bear in mind that some receptors within the relevant Class I area may be less than 50 km from the source while other receptors within that same Class I area may be greater than 50 km from the same source. As indicated by the Guideline on Air Quality Models, 40 CFR part 51, appendix W, this situation may call for the use of two different modeling approaches for the same Class I area and source, depending upon the State's chosen method for modeling sources less than 50 km. In situations where you are assessing visibility impacts for source-receptor distances less than 50 km, you should use expert modeling judgment in determining visibility impacts, giving consideration to both CALPUFF and other appropriate methods.

In developing your modeling protocol, you may want to consult with EPA and your regional planning organization (RPO). Up-front consultation will ensure that key technical issues are addressed before you conduct your modeling.

2. [Run model in accordance] with the accepted protocol and compare the predicted visibility impacts with your threshold for "contribution."

You should calculate daily visibility values for each receptor as the change in deciviews compared against natural visibility conditions. You can use EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA-454/B-03-005 (September 2003) in making this calculation. To determine whether a source may reasonably be anticipated to cause or contribute to visibility impairment at Class I area, you then compare the impacts predicted by the model against the threshold that you have selected.

The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction. In addition, the monthly average relative humidity is used, rather than the daily average humidity – an approach that effectively lowers the peak values in daily model averages.

For these reasons, if you use the modeling approach we recommend, you should compare your "contribution" threshold against the 98th percentile of values. If the 98$_{th}$ percentile value from your modeling is less than your contribution threshold, then you may conclude that the source does not contribute to visibility impairment and is not subject to BART.

2.1. Modeling Process Overview

For each BART-eligible source that emits SO_2, NOx, and/or direct PM10, the constant emission rates shown in section 4 are used in the CALPUFF modeling system to estimate the daily change in visibility compared against natural background conditions (delta-deciview) at each Class I federal area in the modeling domain. The 98th percentile delta-deciview value at each Class I area is compared to the "contribution threshold" to determine if the source contributes to visibility impairment.

The CALPUFF[1] modeling system consists of CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields of variables such as wind and temperature. CALPUFF simulates the transport, dispersion, and transformation of pollutants emitted from the source and calculates hourly concentration and/or deposition flux values at each receptor in the modeling domain. CALPOST calculates time-averaged concentration and deposition flux values from the CALPUFF predictions and performs visibility calculations like those described in the section 2.2.

2.2. Visibility Calculations

The general theory for performing visibility calculations with the CALPUFF modeling system is described in several federal documents, including:

- "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" (IWAQM, 1998)
- "Federal Land Manager's Air Quality Related Values Workgroup (FLAG): Phase I Report" (FLAG, 2000)
- "A User's Guide for the CALPUFF Dispersion Model" (Scire, 2000)

In general, visibility is characterized either by visual range (the greatest distance that a large object can be seen) or by the light extinction coefficient, which is a measure of the light attenuation per unit distance due to scattering and absorption by gases and particles.

Visibility is impaired when light is scattered in and out of the line of sight and by light absorbed along the line of sight. The light extinction coefficient (b_{ext}) considers light extinction by scattering (b_{scat}) and light extinction by absorption (b_{abs}):

$$b_{ext} = b_{scat} + b_{abs}$$

The scattering components of extinction can be represented by these components:

- light scattering due to air molecules = Rayleigh scattering = $b_{rayleigh}$
- light scattering due to particles = b_{sp}

The absorption components of extinction can be represented by these components:

- light absorption due to gaseous absorption = b_{ag}

[1] CALPUFF is a non-steady-state Lagrangian puff model.

- light absorption due to particle absorption = b_{ap}

Particle scattering, b_{sp}, can be expressed by its components:

$$b_{sp} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse}$$

where:

- b_{SO4} = scattering coefficient due to sulfates = $3[(NH_4)_2SO_4]f(RH)$
- b_{NO3} = scattering coefficient due to nitrates = $3[NH_4NO_3]f(RH)$
- b_{OC} = scattering coefficient due to organic aerosols = 4[OC]
- b_{SOIL}= scattering coefficient due to fine particles = 1[Soil]
- b_{Coarse}= scattering coefficient due to coarse particles = 0.6[Coarse Mass]

Particle absorption from soot is defined as:

- b_{ap} = absorption due to elemental carbon (soot) = 10[EC]

The concentration values (in brackets) are expressed in micrograms per cubic meter. The numeric coefficient at the beginning of each equation is the dry scattering or absorption efficiency in meters-squared per gram. The f(RH) term is the relative humidity adjustment factor.

The total atmospheric extinction can be expressed as:

$$b_{ext} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse} + b_{ap} + b_{rayleigh}$$

In this equation, the sulfate (SO4) and nitrate (NO3) components are referred to as hygroscopic components because the extinction coefficient depends upon relative humidity. The other components are non-hygroscopic.

The variation of the effect of relative humidity on the extinction coefficients for SO4 and NO3 can be determined in several ways. According to the BART guideline, monthly f(RH) values should be used.

The CALPUFF modeling techniques in this report will provide ground level concentrations of visibility impairing pollutants. The concentration estimates from CALPUFF are used with the previously shown equations to calculate the extinction coefficient.

As described in the IWAQM Phase 2 Report, the change in visibility is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, b_{source}, and background extinction, $b_{background}$, as follows:

$$\Delta dv = 10\ ln((b_{background} + b_{source})/\ b_{background})$$

3. Source Description

The Craig Station is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units, located at 2101 S. Ranney, in Craig. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), are BART-eligible emissions units. Under a January 2001 Consent Order, the existing ESPs were replaced with baghouses and the wet scrubbers were upgraded. The baghouses control PM emissions and limestone scrubbers control SO_2 emissions. The units use low-NO_x burners to control NO_x emissions. In addition, over-fire air and related NO_x control upgrades are in place to meet the requirements of the Consent Decree (CDPHE, 2005).

4. Emission Estimates

According to the BART guideline, "*The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction*."

Short-term emission rates (≤24-hours) for SO_2, NOx, and PM10 (including condensible and filterable direct PM10[2]) were modeled since visibility impacts are calculated for a 24-hour averaging period. All BART-eligible units at the facility were modeled together in CALPUFF. The Division initially used allowable emission rates or federally enforceable emission limits. If 24-hour emissions limits did not exist, limits of a different averaging period were used. Specifically, if limits did not exist, maximum hourly emissions based on emission factors and design capacity were used.

If the source operator elects to develop emission rates for future subject-to-BART modeling, case-by-case procedures should be developed in consultation with the Division. In general, the following emission rates are acceptable:

- Short-term (≤24-hours) allowable emission rates (e.g., emission rates calculated using the maximum rated capacity of the source).
- Federally enforceable short-term limits (≤24-hours).
- Peak 24-hour actual emission rates (or calculated emission rates) from the most recent 3 to 5 years of operation that account for "high capacity utilization" during normal operating conditions and fuel/material flexibility allowed under a source's permit. In situations where a unit is allowed to use more than one fuel, the fuel resulting in the highest emission rates should be used for the modeling, even if that fuel has not been used in the last 3 to 5 years.

If short-term rates are not available, emissions rates based on averaging periods longer than 24-hours are acceptable only in cases where the modeling shows that the source has impacts equal to or greater than the contribution threshold.

For Craig units 1 and 2, the modeled emission rates are shown in Table 1. The stack parameters are based on the best available information in Division files. To simplify the emissions estimation process, only filterable PM10 emissions were used because modeling with SO_2, NOx, and filterable PM10 shows impacts equal to or greater than the contribution threshold. The basis for the emission rates are shown below:

[2] Common speciated PM species for CALPUFF include fine particulate matter (PMF), coarse particulate matter (PMC), soot or elemental carbon (EC), organic aerosols (SOA), and sulfate (SO4). H_2SO_4, for example, is a PM10 species emitted from coal-fired units that is typically modeled as SO4 in CALPUFF.

- PM: 0.03 lb/mmBtu heat input - January 2001 Consent Decree
- SO_2 : 0.160 lb/mmBtu heat input on a 30 day rolling average - January 2001 Consent Decree
- NOx: 0.34 lbs/mmBtu heat input when burning coal, as estimated by the source operator to reflect peak 24 hour average emissions

Table 1. Stack parameters and emission rates.

Craig Station
Unit 1

Stack Parameters		
Stack height	600	ft
Stack diameter	28	ft
Exit velocity	57.95	ft/s
Exit temperature	118	°F

Source: APEN dated April 27, 2005

Stack Location		
UTM Easting	280421.16	m
UTM Northing	4482341.4	m
Elevation	6345	ft

Source: USGS Aerial Photo, NAD 83, Zone 13 N

Emissions Information		
Design Input Rate	4318	mmBtu/hr
SO_2 Rate (30-day)	0.16	lb/mmBtu
NO_X Rate (3-hr)	0.34	lb/mmBtu
PM_{10} Rate (filterable only)	0.03	lb/mmBtu

Source: Colorado Department of Public Health & Environment

Model Inputs		
Stack height	182.9	m
Stack diameter	8.53	m
Exit velocity	17.66	m/s
Exit temperature	321	K
LCC X Easting	-197.885	km
LCC Y Northing	151.799	km
Elevation	1934	m
Converted with CALPUFF Coords		
SO_2 Rate	87.05	g/s
NO_X Rate	184.98	g/s
PM_{10} Rate	16.32	g/s

Craig Station
Unit 2

Stack Parameters		
Stack height	600	ft
Stack diameter	28	ft
Exit velocity	57.95	ft/s
Exit temperature	118	°F

Source: APEN dated April 27, 2005

Stack Location		
UTM Easting	280313.02	m
UTM Northing	4482345.1	m
Elevation	6345	ft

Source: USGS Aerial Photo, NAD 83, Zone 13 N

Emissions Information		
Design Input Rate	4318	mmBtu/hr
SO_2 Rate (30-day)	0.16	lb/mmBtu
NO_X Rate (3-hr)	0.34	lb/mmBtu
PM_{10} Rate (filterable only)	0.03	lb/mmBtu

Source: Colorado Department of Public Health & Environment

Model Inputs		
Stack height	182.9	m
Stack diameter	8.53	m
Exit velocity	17.66	m/s
Exit temperature	321	K
LCC X Easting	-197.996	km
LCC Y Northing	151.802	km
Elevation	1934	m
Converted with CALPUFF Coords		
SO_2 Rate	87.05	g/s
NO_X Rate	184.98	g/s
PM_{10} Rate	16.32	g/s

5. CALMET/CALPUFF Modeling Methodology

In this CALPUFF application, the CALMET/CALPUFF model setup is based on the January 2005 modeling performed by CH2M HILL for the Public Service Company Comanche Unit 3 PSD permit application because it underwent extensive review by the Division and by Federal Land Managers as part of the PSD permitting process. The Division modified the CALPUFF input files to include three additional Class I areas. It has also been modified as necessary to account for PM10 speciation. An additional post-processing step with POSTUTIL has been added to implement ammonia limiting. The CALPOST model setup was changed to make it consistent with the U.S. EPA's BART guideline. In addition, the Division reviewed available data to determine appropriate ammonia background values for various parts of Colorado. The Division also performed sensitivity tests to understand the response of the model to changes in ammonia background concentration levels. Since the currently available version of CALPOST does not generate 98th percentile results, the Division modified CALPOST to generate a file with a full distribution of daily delta-deciview values for each receptor. In addition, the Division wrote a FORTRAN processor to generate 98th percentile results.

This report is intended to provide sufficient technical documentation to support the application of CALPUFF at distances up to 300 kilometers. While CALPUFF has also been used at source-to-receptor distances less than 50 kilometers for some receptors, there is a Class I area within the 50 to 300 km range from every BART-eligible source in Colorado. Impacts at Class I areas greater than 300 km may be used, but it should be recognized that the use of puff splitting in CALPUFF would provide more accurate results for Class I areas beyond 300km.

According to "*Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*" (IWAQM Phase 2 Report):

> *In the context of the Phase 2 recommendation, the focus of the visibility analysis is on haze. These techniques are applicable in the range of thirty to fifty kilometers and beyond from a source. At source-receptor distances less than thirty to fifty kilometers, the techniques for analyzing visual plumes (sometimes referred to as 'plume blight') should be applied.*

For the few cases where BART-eligible source-to-receptors distances are less than 50 kilometers, both the topography and the meteorological fields are complex and the use of CALPUFF appears to be appropriate based on the possibility of recirculation, stagnation, and complex flows. The shortest source-to-receptor distance modeled is about 25 kilometers, but it involves an elevation change of about 3000 ft. In addition, in each case, only a portion of the Class I area is less than 50 km from the source; many of the receptors are greater than 50 km. If there were issues regarding the 50 km distance, PLUVUEII would be an appropriate model to consider for source-to-receptor distances less than 50 kilometers.

5.1. CALMET/CALPUFF Model Selection

The following model versions are used:

- CALPUFF: July 2004 beta version 5.711a, level 040716
- CALMET: July 2004 beta version 5.53a, level 040716
- POSTUTIL: May 2003 version 1.31, level 030528
- CALPOST: July 2003 version 5.51, level 030709
    - Modified by Division for this analysis:
        - CALPOST_BART98_v3.EXE (version 5.51_CO_v3, level 030709)
        - BART98_v3.EXE

The use of CALPUFF is recommended in 40 CFR 51 Appendix Y (BART guideline). The primary niche for CALPUFF is as a long-range transport model. It is a multi-layer, non-steady-state puff dispersion model that can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, chemical transformations, vertical wind shear, and deposition (Scire, 2000).

5.1.1. CALMET

The MM5/CALMET meteorological fields have been generated for 1996, 2001, and 2002. CALMET is based on the Diagnostic Wind Model (Douglas, S. and R. Kessler, 1988). It has been significantly enhanced by Earth Tech, Inc (Scire, 2000). For this particular study, the model uses a Lambert Conformal Projection coordinate system to account for the Earth's curvature.

CALMET uses a two-step approach to calculate wind fields. In the first step, an initial-guess wind field is adjusted for slope flows and terrain blocking effects, for example, to produce a Step 1 wind field. In the second step, an objective analysis is performed to introduce observational data into the Step 1 wind field.

In this application, the initial guess wind fields are based on 36-kilometer MM5[3] meteorological fields for 1996, 2001, and 2002 (i.e., IPROG=14). The MM5 files were provided to the Division by CH2M HILL as part of the Public Service Company (PSCo) Comanche Unit 3 PSD permit application. Alpine Geophysics extracted the MM5 data into a CALMET MM5.DAT format for 1996, 2001, and 2002. Both the 1996 and 2001 MM5 data were generated by the U.S. EPA. The 2002 MM5 data was originally developed for the Visibility Improvement State and Tribal Association of the Southeast (VISTAS).

The BART guideline does not specify the exact number of years of mesoscale meteorological data for use in CALPUFF. According to 40 CFR Part 51 Appendix W, the length of the modeled meteorological period should be long enough to ensure that worst-case meteorological conditions are adequately represented in the model results. The number of years of data needed to obtain a stable distribution of conditions depends on the variable of interest. U.S. EPA recommends that consecutive years from the most recent, readily available 5-year period are preferred. However, “less than five, but at least three,

[3] Fifth-Generation NCAR/Penn State Mesoscale Model.

years of meteorological data (need not be consecutive) may be used if mesoscale meteorological fields are available...."

At the time of this analysis, five years of agency-approved mesoscale meteorological data were not readily available at reasonable grid resolutions for Colorado. While the Division has the national 80km 1990 MM4 and 80km 1992 MM5 data sets, use of the coarse resolution 1990 and 1992 data sets would not improve the accuracy of the modeling results in Colorado.

5.1.1.1. CALMET Modeling Domain

The modeling domain is shown in Figure 1. It is based on a Lambert Conformal Conic projection. As determined by CH2M HILL, the Standard Parallels within the domain are 1/6th and 5/6th of the north-to-south extent instead of the 30-degree and 60-degree lines that are listed as defaults in CALMET. This was done to minimize distortion. See Figure 7 for specific parameter settings.

The domain includes all Class I areas in Colorado with the exception of Mesa Verde NP. Mesa Verde was excluded because it is more than 300 km from all of the BART-eligible sources in Colorado and because the BART-eligible sources in Colorado would have higher impacts at other Class I areas. That is, impacts are Mesa Verde would not be the controlling 98th percentile values for this analysis. The domain does not include Class I areas in any nearby states because the 98th percentile impacts from Colorado's BART-eligible sources are expected to be highest at Class I areas in Colorado. The CALMET domain includes almost the entire state of Colorado. It is about 480 km x 480 km in the longitudinal and meridonal directions, respectively, with 4-kilometer CALMET grid cells.

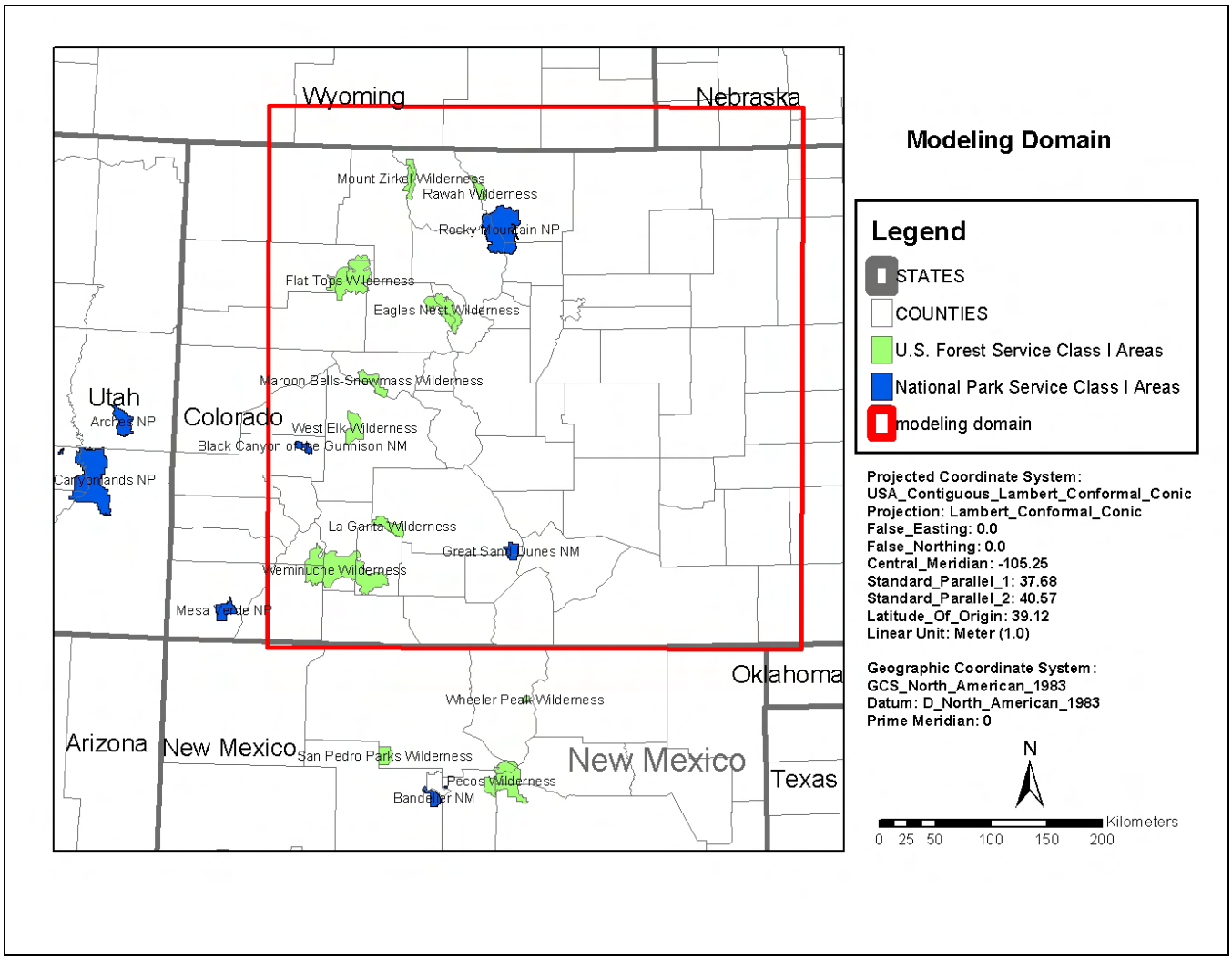

Figure 1. CALMET/CALPUFF modeling domain.

5.1.1.2. CALMET Performance Evaluation

The meteorological fields developed by the MM5/CALMET modeling system were evaluated by CH2M HILL for Xcel Energy as part of the PSCo Comanche Unit 3 PSD permit. Specifically, "CH2M HILL examined vector plots of selected periods within the CALMET output for validation of the wind fields with the CalDESK (Environmodeling Ltda.) program (CH2M HILL, 2005)." The Division replicated the CALMET modeling and performed additional review of the meteorological fields with the Lakes Environmental CALPUFF View software package. In general, the meteorological fields were found to be reasonable given the 36km MM5 resolution, although model performance could be improved with better resolution MM5/CALMET fields and the inclusion of more observations in CALMET.

5.1.1.3. Terrain

Gridded terrain elevations for the modeling domain are derived from 3 arc-second digital elevation models (DEMs) produced by the United States Geological Survey (USGS). The files cover 1-degree by 1-degree blocks of latitude and longitude. USGS 1:250,000 scale DEMs were used. The elevations are in meters relative to mean sea level and have a resolution of about 90 meters, shown in Figure 2.

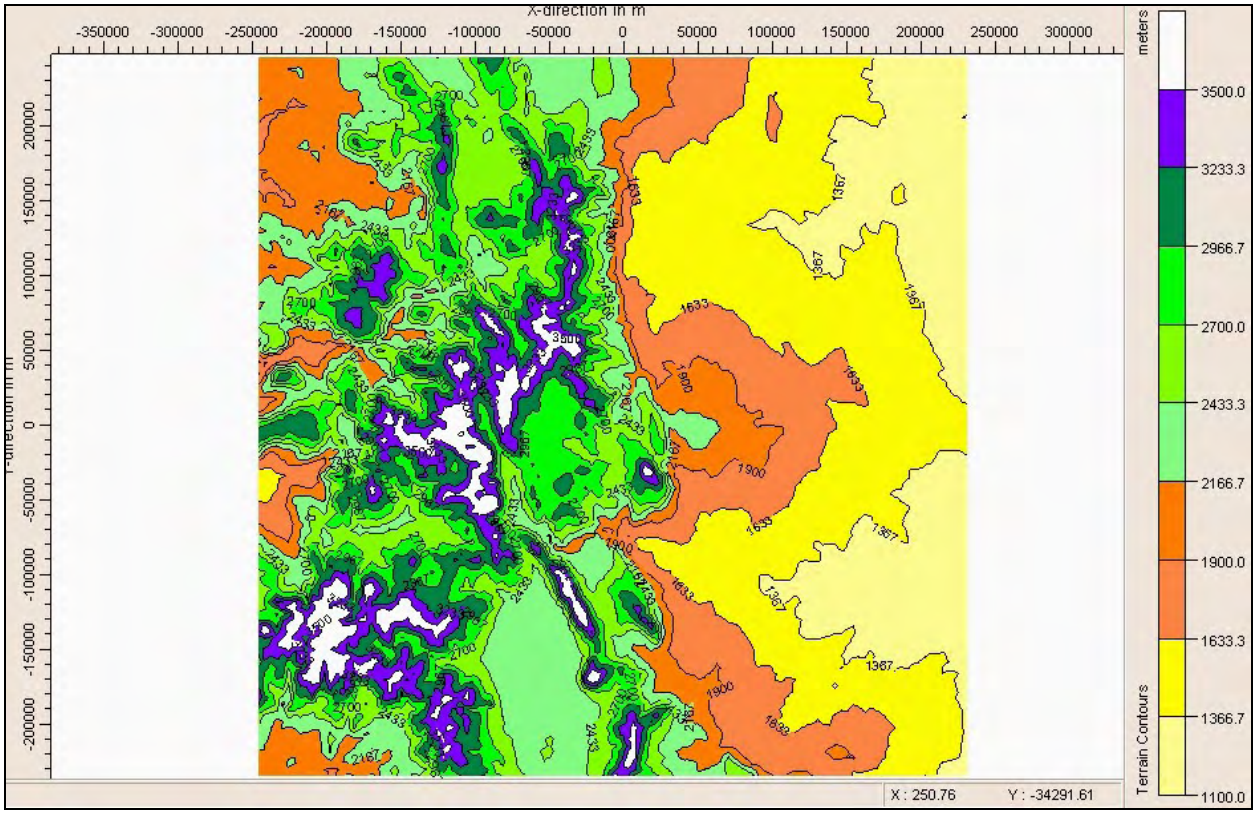

Figure 2. CALMET Terrain.

5.1.1.4. Land Use

The land use data is based on the Composite Theme Grid format (CTG) using Level I USGS land use categories were "mapped into the 14 primary CALMET land use categories (CH2M HILL, 2005)," shown in Figure 3. The land use categories are described in Figure 4.

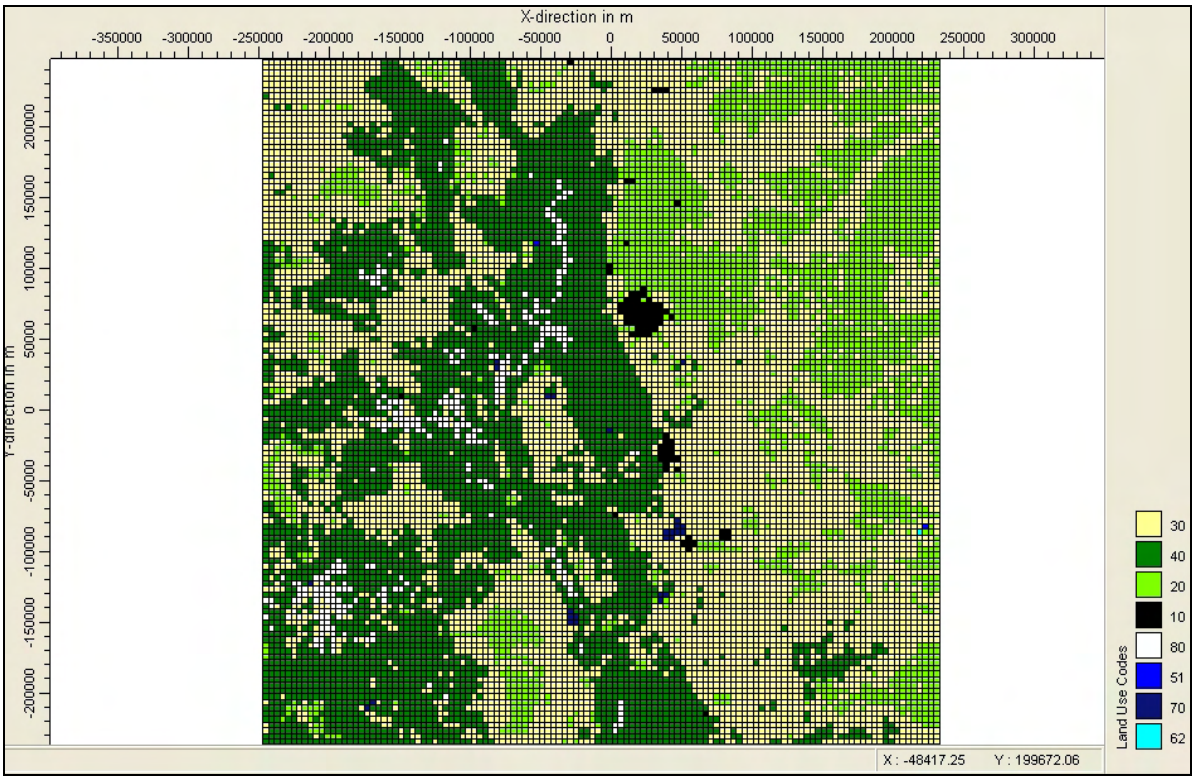

Figure 3. CALMET land use categories.

Default CALMET Land Use Categories and Associated Geophysical Parameters
Based on the U.S. Geological Survey Land Use Classification System
(14-Category System)

Land Use Type	Description	Surface Roughness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthropogenic Heat Flux (W/m^2)	Leaf Area Index
10	Urban or Built-up Land	1.0	0.18	1.5	.25	0.0	0.2
20	Agricultural Land - Unirrigated	0.25	0.15	1.0	.15	0.0	3.0
-20*	Agricultural Land - Irrigated	0.25	0.15	0.5	.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	.15	0.0	7.0
51	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
54	Bays and Estuaries	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Nonforested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	.15	0.0	0.05
80	Tundra	.20	0.30	0.5	.15	0.0	0.0
90	Perennial Snow or Ice	.20	0.70	0.5	.15	0.0	0.0

*Negative values indicate "irrigated" land use

Figure 4. Land use categories table from CALMET User's Guide.

5.1.1.5. CALMET ZFACE and ZIMAX Settings

Eleven vertical layers have been used with vertical cell face (ZFACE) heights at: 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, and 5000 meters.

ZIMAX was set to 4500 meters based on analyses of soundings for summer ozone events. The analysis suggests mixing heights in Denver are often well above the CALMET default value of 3000 meters during the summer. For example, on some summer days, ozone levels are elevated all the way to 6000 meters MSL or beyond during some meteorological regimes, including some regimes associated with high ozone episodes. A sounding from the evening of July 1, 2002 (see Figure 5), which is a day the 8-hour ozone standard was exceeded at Rocky Mountain National Park, suggests the mixing height was probably around 6000 meters MSL. The mixing height estimate is based on the relative uniformity of the water vapor mixing ratio below 6000 meters, the temperature profile, the inverted "V" in the sounding, and data from a NOAA ozonesonde from Boulder that shows relatively constant ozone levels with height. Although low mixing heights can occur during the summer, maximum summertime daytime mixing heights in the Denver area often range from about 12,000 feet (3700 m) to 20,000 feet (6000 m) MSL. Since the CALMET ZIMAX setting is above ground level (AGL), not above mean sea level (MSL), the maximum summer daytime mixing height range over the plains would be about 15000 feet (4500 m) AGL. Thus, a ZIMAX setting of 4500 m is used.

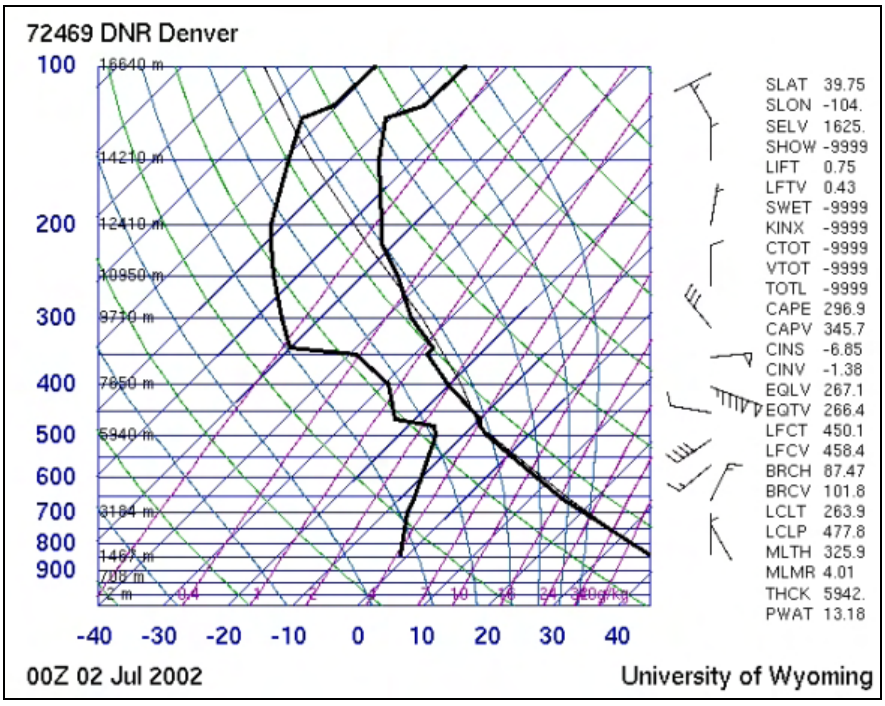

Figure 5. Example Denver summertime sounding.

5.1.1.6. CALMET BIAS Setting

The BIAS settings for each vertical cell determine the relative weight given to the vertically extrapolated surface meteorological observations and upper air soundings. The initial guess field is computed with an inverse distance weighting of the surface and upper air data. It can be modified by the layer-dependent bias factor (BIAS). The values for BIAS can range from –1.0 to 1.0. For example, if BIAS is set to +0.25, the weight of the surface wind observation is reduced by 25%. If BIAS is set to –0.25, the weight of the upper air wind observation is reduced by 25%. If BIAS is set to zero, there is no change in the weighting from the normal inverse distance squared weighting. As recommended by the NPS, the default values of 0.0 have been used for all 11 vertical layers in this analysis.

5.1.1.7. CALMET RMIN2 and IXTERP Settings

Vertical extrapolation of data from a surface station is skipped if the surface station is close to the upper air station. The variable RMIN2 sets the distance between an upper air station and a surface station that must exceeded in order for the extrapolation to take place. RMIN2 has been set to the default value of 4, as recommended by the NPS. The default value of –4 for IEXTRP is used. By setting IEXTRP to –4 (as opposed to +4), layer 1 data at upper air stations is ignored. When IEXTRP=±4, the van Ulden and Holtslag wind extrapolation method is used. The method uses similarity theory and observed data to extend the influence of the surface wind speed and direction aloft.

5.1.1.8. CALMET Settings: R1, R2, RMAX1, RMAX2, RMAX3

An inverse-distance method is used to determine the influence of observations in the Step 1 wind field. R1 controls weighting of the surface layer and R2 controls weighting of the layers aloft. For example, R1 is the distance from an observational station at which the observation and first guess field are equally weighted. In addition, RMAX1, RMAX2, and RMAX3 determine the radius of influence over land in the surface layer, over land in layers aloft, and over water, respectively. That is, an observation is excluded if the distance from the observational site to a given grid point exceeds the maximum radius of influence. As recommended by the NPS, R1 and RMAX1 have been set to 30 km so that the initial guess field does not overwhelm the surface observations. R2 is set to 50 km and RMAX2 is set to 100 km. RMAX3 is not much of a factor in Colorado given the lack of large water bodies. RMAX3 is set to 500 km.

5.1.1.9. CALMET Surface Stations

Eleven surface stations shown in Figure 6 were used, including Alamosa (ALS), Colorado Springs (CYS), Denver (DEN), Eagle (EGE), Limon (LIC), Pueblo (PUB), Trinidad (TAD), Cheyenne (CYS), Laramie (LAR), Rocky Mountain NP (ROM), and Gothic (GTH).

SURFACE STATIONS

Name	ID	X (km)	Y (km)	NLatitude (Deg)	WLongitude (Deg)	Time Zone	Anemometer Height (m)	Grid Coordinates X (Origin = (0,0))	Y
ALS	23061	-54.7	-187.7	37.427	105.868	7.0	9.1	48.061	12.333
CYS	24018	37.7	225.8	41.153	104.801	7.0	10.0	71.166	115.698
COS	93037	49.4	-33.2	38.820	104.681	7.0	6.7	74.086	50.952
DEN	3017	51.2	79.1	39.831	104.652	7.0	10.0	74.549	79.020
ROM	11111	-25.0	128.8	40.280	105.544	7.0	10.0	55.491	91.438
EGE	24675	-142.9	60.2	39.651	106.916	7.0	10.0	26.018	74.305
GTH	22222	-150.0	-16.8	38.956	106.981	7.0	10.0	24.239	55.053
LAR	25645	-35.1	244.6	41.323	105.669	7.0	10.0	52.976	120.412
LIC	24665	131.8	7.8	39.180	103.724	7.0	10.0	94.699	61.195
PUB	93058	65.4	-93.1	38.279	104.502	7.0	10.0	78.106	35.978
TAD	24645	81.4	-205.2	37.267	104.332	7.0	10.0	82.099	7.940

Figure 6. Surface meteorological stations.

5.1.1.10. CALMET Upper Air Stations

Two upper air stations were included: Grand Junction and Denver.

5.1.1.11. CALMET Precipitation Stations

CH2M HILL obtained precipitation data from the National Climatic Data Center (NCDC). All available data in fixed-length, TD-3240 format were ordered for the modeling domain. CH2M HILL processed the data with the PXTRACT and PMERGE processors. Stations with incomplete or poor quality data for a given year were excluded. The number of stations used for each year is as follows (CH2M HILL, 2005):

- 1996 - 84 stations
- 2001 - 82 stations
- 2002 - 86 stations

5.1.1.12. CALMET Sample Input File

Figure 7 summarizes some of the key CALMET parameters.

5.1.1.13. CALMET Parameter Summary

Figure 7 summarizes some of the key CALMET settings.

```
Map projection                                          Default: UTM     ! PMAP = LCC !
Latitude and Longitude (decimal degrees) of projection origin            ! RLAT0 = 39.12N !
                                                                         ! RLON0 = 105.25W !
Matching parallel(s) of latitude (decimal degrees) for projection        ! XLAT1 = 37.68N !
                                                                         ! XLAT2 = 40.57N !
(DATUM)                                             Default: WGS-G       ! DATUM = NAS-C  !
No. X grid cells (NX)                               No default           ! NX =   120  !
No. Y grid cells (NY)                               No default           ! NY =   121  !
Grid spacing (DGRIDKM)                              No default           ! DGRIDKM = 4. !
Reference grid coordinate of SW corner of grid cell (1,1)                ! XORIGKM = -246.984 !
                                                                         ! YORIGKM = -237.000 !
No. of vertical layers (NZ)                         No default           ! NZ =  11  !
Cell face heights in arbitrary vertical grid (ZFACE(NZ+1)):
   ! ZFACE = 0.,20.,100.,200.,350.,500.,750.,1000.,2000.,3000.,4000.,5000.!
NO OBSERVATION MODE                      (NOOBS)    Default: 0           ! NOOBS = 0  !
Number of surface stations               (NSSTA)    No default           ! NSSTA =  11  !
Number of precipitation stations         (NPSTA)    No default           ! NPSTA =  86  !
Griddid cloud fields:                    (ICLOUD)   Default: 0           ! ICLOUD =  0  !
Model selection variable (IWFCOD)                   Default: 1           ! IWFCOD =  1  !
Compute Froude number adjustment effects ? (IFRADJ) Default: 1           ! IFRADJ =  1  !
Compute kinematic effects ?              (IKINE)    Default: 0           ! IKINE  =  0  !
Use O'Brien procedure?                              Default: 0           ! IOBR =  0  !
Compute slope flow effects ?             (ISLOPE)   Default: 1           ! ISLOPE  =  1  !
Extrapolate surface wind obs to upper layers?       Default: -4          ! IEXTRP =  -4  !
Extrapolate surface winds even if calm? (ICALM)     Default: 0           ! ICALM  =  0  !
Layer-dependent biases. Default: NZ*0          ! BIAS =  0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0  !
                                                    Default: 4.          ! RMIN2 = 4 !
Use gridded prognostic wind field model output fields as input to the diagnostic
  wind field model (IPROG)                          Default: 0           ! IPROG =  14  !
Maximum radius of influence over land in the surface layer               ! RMAX1 = 30. !
Maximum radius of influence over land aloft (RMAX2)                      ! RMAX2 = 100. !
Maximum radius of influence over water                                   ! RMAX3 = 500. !
Minimum radius of influence used in the wind field interpolation (RMIN)
                                                    Default: 0.1         ! RMIN = 0.1 !
Radius of influence of terrain features (TERRAD)    No default           ! TERRAD = 40. !
Relative weighting of the first guess field and observations in the SURFACE layer
                                                    No default           ! R1 = 30. !
Relative weighting of the first guess field and observations in the layers ALOFT
                                                    No default           ! R2 = 50. !
Minimum overland mixing height                      Default:  50.        ! ZIMIN = 50. !
Maximum overland mixing height                      Default: 3000.       ! ZIMAX = 4500. !
Interpolation type (1 = 1/R ; 2 = 1/R**2)           Default:1            ! IRAD =  1  !
Radius of influence for temperature interpolation   Default: 500.       ! TRADKM = 500. !
```

Figure 7. CALMET parameter summary.

5.1.2. CALPUFF

The default technical options in CALPUFF were used, except as specified otherwise in this report.

5.1.2.1. Receptor Network and Class I Federal Areas

The modeling domain contains eleven Class I federal areas:

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

The discrete receptors for eight of the Class I federal areas were generated by the National Park Service (NPS) for CH2M HILL using the *NPS Convert Class I Areas* (NCC) computer program. For the remaining three areas not included in the CH2M HILL modeling, receptors were generated by the Division with the NCC program. Receptor elevations provided by the NPS conversion program have been used. The receptors for each Class I area are shown in Figure 9

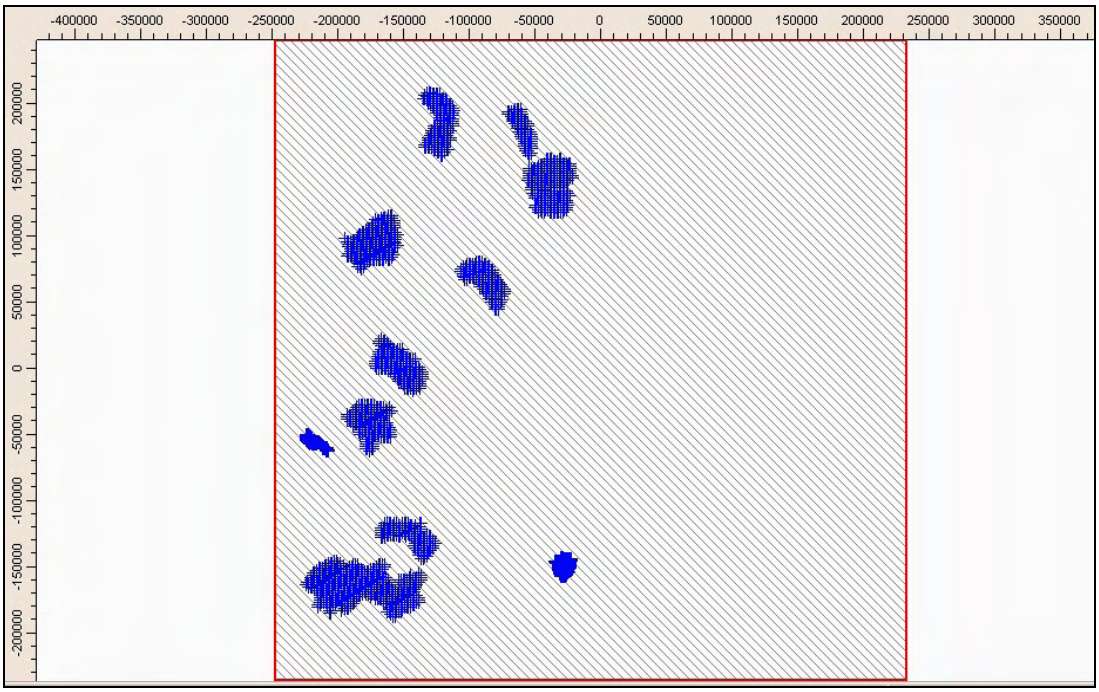

Figure 8. Class I federal area receptors.

All receptors are included in each CALPUFF simulation. In CALPOST, only the receptor ranges for specific Class I areas are processed. The range of receptors is shown in Figure 9.

	Receptors				
Class I Area	**start**	**end**	**leading 0's**	**sum**	**CALPOST setting for NCRECP**
Great Sand Dunes	1	195	0	195	195*1
RMNP	196	602	195	407	195*0, 407*1
La Garita	603	789	602	187	602*0, 187*1
Eagles Nest	790	1002	789	213	789*0, 213*1
Maroon Bells	1003	1281	1002	279	1002*0, 279*1
Weminuche	1282	2025	1281	744	1281*0, 744*1
West Elk	2026	2286	2025	261	2025*0, 261*1
Black Canyon of th	2287	2380	2286	94	2286*0, 94*1
Flat Tops	2381	2735	2380	355	2380*0, 355*1
Rawah	2736	2851	2735	116	2735*0, 116*1
Mt Zirkel	2852	3104	2851	253	2851*0, 253*1

Figure 9. Receptor numbers for specific Class I federal areas.

5.1.2.2. CALPUFF Meteorology

Refer to the CALMET section of the report for details.

5.1.2.3. CALPUFF Modeling Domain

The CALPUFF modeling domain is identical to the CALMET modeling domain.

5.1.2.4. CALPUFF Parameter Summary

Figure 10 summarizes some of the key CALPUFF settings.

```
Number of chemical species (NSPEC)                    Default: 5       ! NSPEC =  7 !
Number of chemical species emitted (NSE)              Default: 3       ! NSE =    5 !
(AVET)                                                Default: 60.0    ! AVET = 60. !
(PGTIME)                                              Default: 60.0    ! PGTIME = 60. !
Vertical distribution used in the near field (MGAUSS) Default: 1       ! MGAUSS =  1   !
Terrain adjustment method (MCTADJ)                    Default: 3       ! MCTADJ =  3   !
Subgrid-scale complex terrain flag (MCTSG)            Default: 0       ! MCTSG =   0   !
Near-field puffs modeled as elongated 0 (MSLUG)       Default: 0       ! MSLUG =   0   !
Transitional plume rise modeled?(MTRANS)              Default: 1       ! MTRANS =  1   !
Stack tip downwash? (MTIP)                            Default: 1       ! MTIP =    1   !
Vertical wind shear modeled above stack top? (MSHEAR) Default: 0       ! MSHEAR =  0   !
Puff splitting allowed? (MSPLIT)                      Default: 0       ! MSPLIT =  0   !
Chemical mechanism flag (MCHEM)                       Default: 1       ! MCHEM =   1   !
Aqueous phase transformation flag (MAQCHEM)           Default: 0       ! MAQCHEM =  0  !
Wet removal modeled ? (MWET)                          Default: 1       ! MWET =     1  !
Dry deposition modeled ? (MDRY)                       Default: 1       ! MDRY =     1  !
Method used to compute dispersion coefficients(MDISP) Default: 3       ! MDISP =    3  !
PG sigma-y,z adj. for roughness?                      Default: 0       ! MROUGH =  0  !
Partial plume penetration of elevated inversion?      Default: 1       ! MPARTL =  1  !
Strength of temperature inversion                     Default: 0       ! MTINV =  0  !
PDF used for dispersion under convective conditions?  Default: 0       ! MPDF =  0  !
Sub-Grid TIBL module used for shore line?             Default: 0       ! MSGTIBL = 0  !
Boundary conditions (concentration) modeled?          Default: 0       ! MBCON = 0  !
Configure for FOG Model output?                       Default: 0       ! MFOG =  0   !
Do options specified to see if they conform to regulatory values?      ! MREG =  1   !
    1 = Technical options must conform to USEPA Long Range Transport (LRT) guidance
```

Figure 10. CALPUFF parameter summary.

5.1.2.5. Chemical Mechanism

The MESOPUFF II pseudo-first-order chemical reaction mechanism (MCHEM=1) is used for the conversion of SO_2 to sulfate (SO4) and NOx to nitrate (NO4). Refer to the CALPUFF User's Guide for a description of the mechanism (Scire, 2000).

In the MESOPUFF II mechanism, the ammonia background concentration affects the equilibrium between nitric acid, ammonia, and ammonium nitrate. The equilibrium constant for the reaction is a non-linear function of temperature and relative humidity (Scire, 2000). Unlike sulfate, the calculated nitrate concentration is limited by the amount of available ammonia, which is preferentially scavenged by sulfate (Scire, 2000). In particular, the amount of ammonia available for the nitric acid, ammonium nitrate, and ammonia reactions is determined by subtracting sulfate from total ammonia.

While the chemical mechanism simulates both the gas phase and aqueous phase conversion of SO_2 to sulfate, the aqueous phase method, which is important when the plume interacts with clouds and fog, can significantly underestimate sulfate formation. In this report, as recommended by the IWAQM Phase 2 report, the "nighttime SO_2 loss rate (RNITE1)" is set to 0.2 percent per hour. The "nighttime

NOx loss rate (RNITE2)" is set to 2.0 percent per hour and the "nighttime HNO_3 formation rate (RNITE3)" is set to 2.0 percent per hour.

According to the 1996 "Mt. Zirkel Wilderness Area Reasonable Attribution Study of Visibility Impairment. Volume II: Results of Data Analysis and Modeling - Final Report,"

The CALPUFF chemical module is formulated around linear transformation rates for SO_2 to sulfate and NO_X to total nitrate. There are two options for specifying these transformation rates:

Option 1: An internal calculation of rates based on local values for several controlling variables (e.g., solar radiation, background ozone, relative humidity, and plume NO_X) as used in MESOPUFF-II. The parametric transformation rate relationships employed were derived from box model calculations using the mechanism of Atkinson et al. (1982).

Option 2: A user-specified input file of diurnally varying but spatially uniform conversion rates.

Morris et al. (1987) reviewed the MESOPUFF-II mechanism as part of the U.S. EPA Rocky Mountain Acid Deposition Model Assessment study. They found that it provided physically plausible responses to many of the controlling environmental parameters. However, the mechanism had no temperature dependence, which is an important factor in the Rocky Mountain region where there are wide variations in temperature. Furthermore, the MESOPUFF-II transformation scheme was based on box model simulations for conditions more representative of the Eastern U.S. than of the Rocky Mountains.

The largest deficiency in the MESOPUFF-II chemical transformation algorithm is the lack of explicit treatment for in-cloud (aqueous-phase) enhanced oxidation of SO_2 to sulfate. The MESOPUFF-II chemical transformation algorithm includes a surrogate reaction rate to account for aqueous-phase oxidation of SO_2 to sulfate as follows:

$$K_{aq} = 3 \times 10^{-8} \times RH^4 \text{ (\%/hr)} \qquad \text{(B.2-1)}$$

Thus, at 100% relative humidity (RH), the MESOPUFF-II aqueous-phase surrogate SO_2 oxidation rate will be 3% per hour. Measurements in generating station plumes suggest spatially- and temporally-integrated SO_2 oxidation rates due to oxidants in clouds to be 10 times this value.

Another issue is the amount of ammonia available for nitrate chemistry. According to a paper by EarthTech (Escoffier-Czaja and Scire, 2002),

"In the CALPUFF model, total nitrate (TNO3 = HNO3 + NO3) is partitioned into each species according to the equilibrium relationship between HNO3 and NO3. This equilibrium varies as a function of time and space, in response to both the ambient temperature and relative humidity. In addition, the formation of nitrate is subject to the availability of NH3 to form ammonium nitrate (NH4NO3), the assumed form of nitrate in the model. In CALPUFF, a continuous plume is simulated as a series of puffs, or discrete plume elements. The total concentration

at any point in the model is the sum of the contribution of all nearby puffs from each source. Because CALPUFF allows the full amount of the specified background concentration of ammonia to be available to each puff for forming nitrate, the same ammonia may be used multiple times in forming nitrate, resulting in an overestimate of nitrate formation. In order to properly account for ammonia consumption, a program called POSTUTIL was introduced into the CALPUFF modeling system in 1999. POSTUTIL allows total nitrate to be repartitioned in a post-processing step to account for the total amount of sulfate scavenging ammonia from all sources (both project and background sources) and the total amount of TNO3 competing for the remaining ammonia. In POSTUTIL, ammonia availability is computed based on receptor concentrations of total sulfate and TNO3, not on a puff-by-puff basis."

Ammonia-limiting methods have been used for repartitioning nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for over prediction due to overlapping puffs in CALPUFF. Specifically, the use of the MNIRATE=1 option in POSTUTIL is acceptable. At this time, other ammonia-limiting methods, including iterative techniques that use observational data to resolve backward the thermodynamic equilibrium equation between NO_3/HNO_3 for each hour to minimize available ammonia, are not acceptable. Generally, for regulatory CALPUFF modeling in Colorado, techniques that assume the atmosphere is always ammonia poor are not acceptable, particularly in eastern Colorado.

5.1.2.6. Chemical Mechanism – Ammonia Sensitivity Tests

To better understand the response of the modeling system to background ammonia when a single point source with significant emissions of SO_2 and NOx is modeled, the Division performed sensitivity tests for a source in northeast Colorado and a source in northwest Colorado using the 2002 MM5/CALMET meteorology. In the test case, SO_2, NOx, and filterable PM10 emissions were modeled. The ammonia background value was varied from 0 to 100 ppb. In the northeast Colorado test case, the SO_2 emission rate is about 3 times higher than the NOx emission rate. In the northwest Colorado test case, the modeled NOx emission rate is about 4.4 times higher than the SO_2 rate.

In both cases, when the background ammonia concentration is zero, the model produces no nitrate, as expected; however, it produces sulfate.

For the northeast Colorado sensitivity test (see Figure 11), where the modeled SO_2 emission rate is significantly higher than the NOx emission rate, the change in visibility (delta-deciview) is not very sensitive to the background ammonia concentration across the range from 1.0 ppb to 100.0 ppb because of the high SO_2 emission rates relative to NOx and the way sulfate is produced in the MESOPUFF II chemical mechanism. Visibility impacts drop significantly when the ammonia background is less than 1.0 ppb, but even at 0.0 ppb of ammonia, sulfate impacts remain relative high.

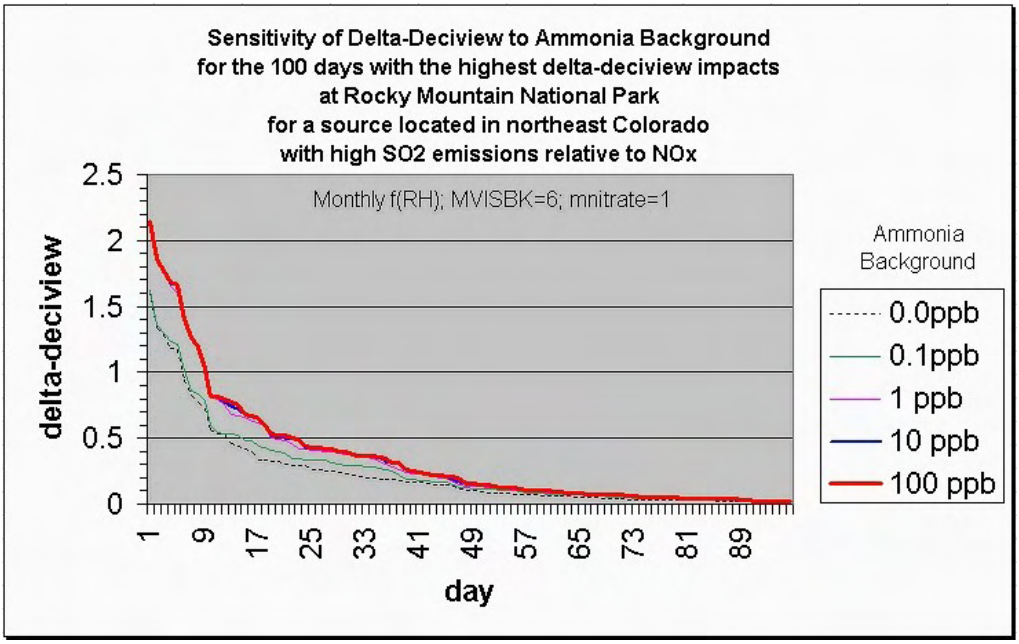

Figure 11. Sensitivity of CALPUFF visibility impacts (delta-deciview) to ammonia backgrounds from 0 ppb to 100 ppb from a source with high SO_2 emissions relative to NOx.

For the northeast Colorado case, on days with the highest visibility impacts, the relative contribution of nitrate and sulfate vary (see Figure 12 and Figure 13), but most of the modeled visibility impairment is due to sulfate. When comparing these figures, be aware the relative rank for some days is different. For example, day 85 is the 2nd worst day for the 0.1 ppb ammonia case, but it's the 3rd worst day for the 100 ppb case. On the day with the highest impact (day 84), the contribution from sulfate is 98.8% for the 0.1 ppb ammonia case and 72.7% for the 100 ppb ammonia case. For the 8th high delta-deciview value, the contribution from sulfate is 86.3% for the 0.1 ppb case and 67.9% for the 100 ppb case.

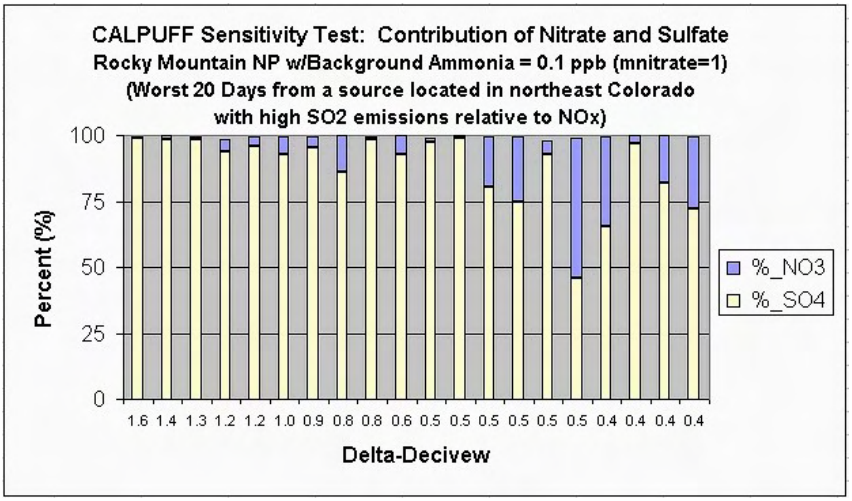

Figure 12. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 0.1 ppb in CALPUFF.

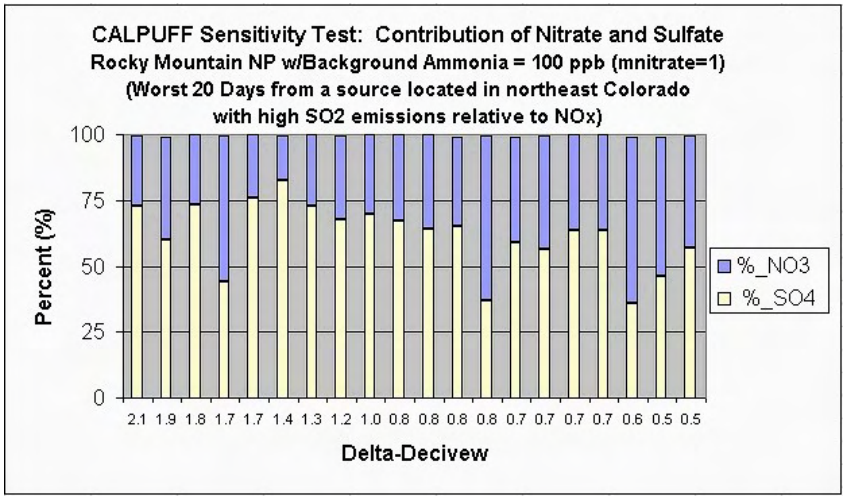

Figure 13. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 100 ppb.

For the northwest Colorado sensitivity test (see Figure 14), where the modeled NOx emission rate is significantly higher than the SO_2 emission rate, the change in visibility (delta-deciview) is not sensitive to the background ammonia concentration across the range from 10 ppb to 100 ppb. While there is a moderate drop in impacts when ammonia is dropped from 10 ppb to 1.0 ppb, the model is very sensitive to ammonia when the background ammonia level is less than 1.0 ppb.

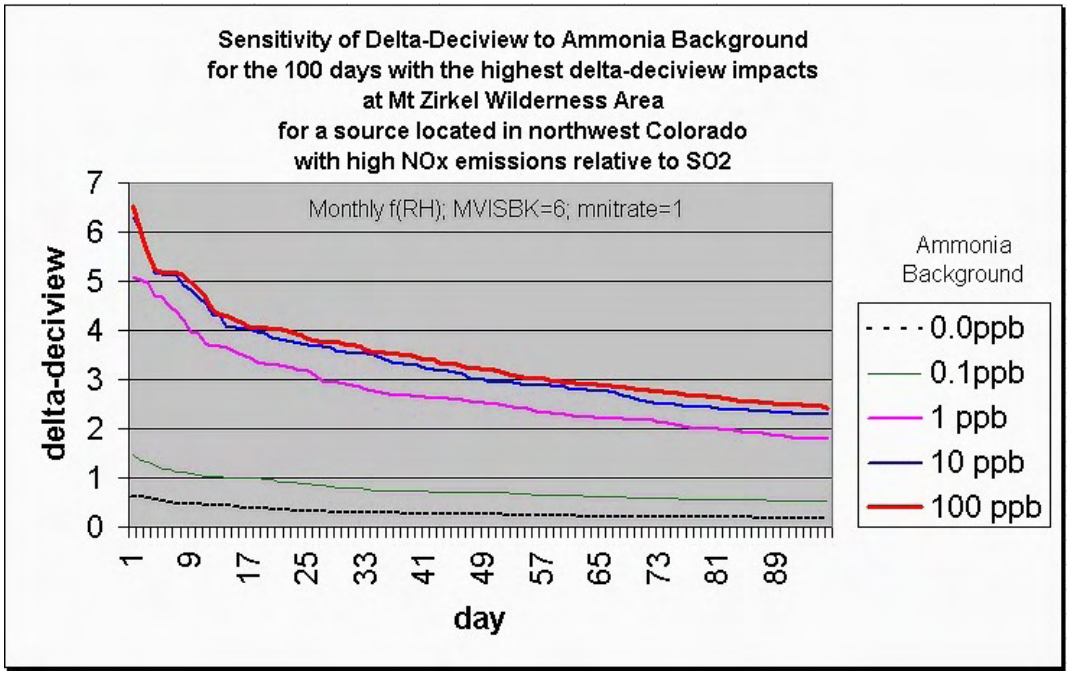

Figure 14. Sensitivity of CALPUFF visibility impacts (delta-deciview) to ammonia backgrounds from 0 ppb to 100 ppb from a source with high NOx emissions relative to SO_2.

For the northwest Colorado test case, according to CALPUFF as implemented here, impairment is primarily due to nitrate (see Figure 15 and Figure 16), but the contribution due to nitrate varies significantly depending on the assumed ammonia background level. For the 100 ppb background case, the nitrate contribution is greater than 90% for the top 20 days. However, for the 0.1 ppb case, the nitrate contribution varies from 43% to 81% for the top 20 days.

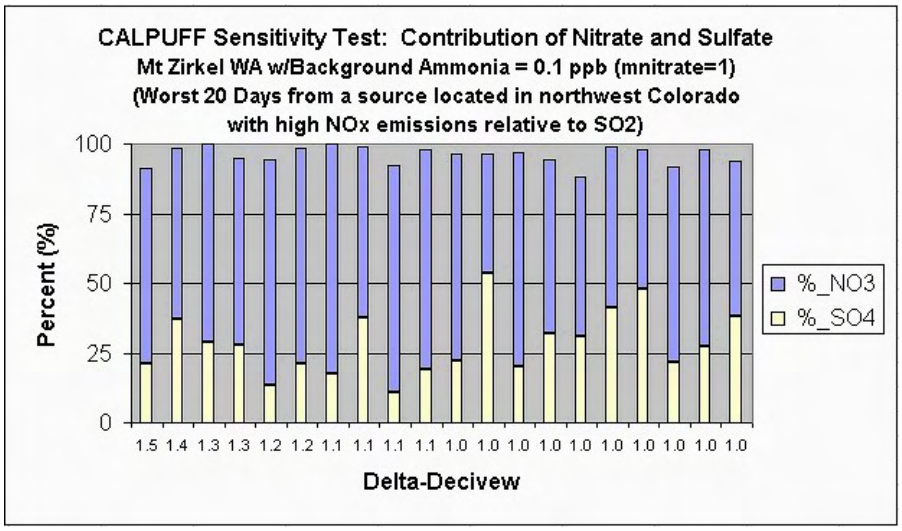

Figure 15. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 0.1 ppb in CALPUFF.

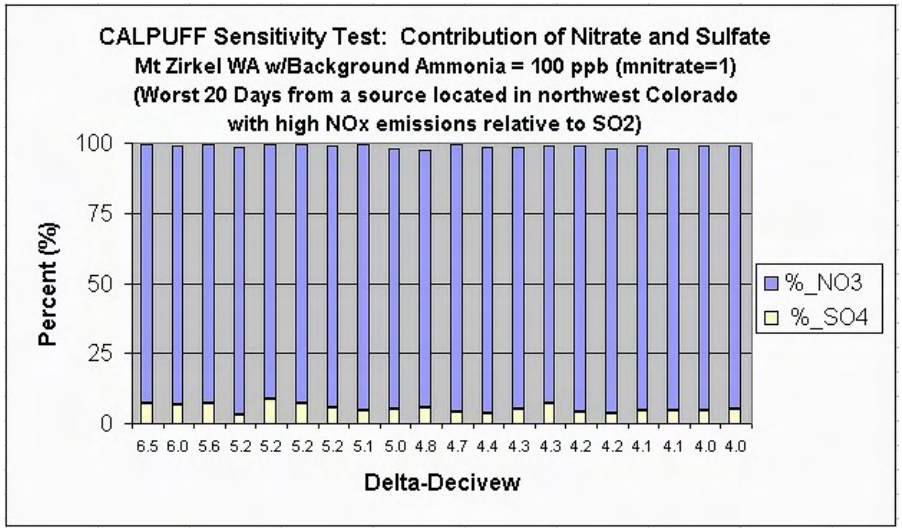

Figure 16. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 100 ppb in CALPUFF.

Caution should be used when extrapolating the results of these tests to other CALPUFF applications.

Since the MESOPUFF II chemical mechanism used in this analysis depends on several parameters, including ozone and ammonia background concentrations, the methods for determining the background ozone and ammonia concentration fields are discussed in more detail in the next two sections.

5.1.2.7. Ammonia Assumptions - Discussion

In CALPUFF, as used in this application, the background ammonia concentration is temporally and spatially uniform. It is likely that some portions of the modeling domain are ammonia poor and some are ammonia rich. Thus, setting a domain-wide background is problematic. As discussed in the previous section, when modeling a single large source with high SO_2 emission rates relative to NOx, the assumed background ammonia concentration is not a critical parameter for determining visibility impacts.

According to the IWAQM Phase 2 Report,

> *A further complication is that the formation of particulate nitrate is dependent on the ambient concentration of ammonia, which preferentially reacts with sulfate. The ambient ammonia concentration is an input to the model. Accurate specification of this parameter is critical to the accurate estimation of particulate nitrate concentrations. Based on a review of available data, Langford et al. (1992) suggest that typical (within a factor of 2) background values of ammonia are: 10 ppb for grasslands, 0.5 ppb for forest, and 1 ppb for arid lands at 20 C. Langford et al. (1992) provide strong evidence that background levels of ammonia show strong dependence with ambient temperature (variations of a factor of 3 or 4) and a strong dependence on the soil pH. However, given all the uncertainties in ammonia data, IWAQM recommends use of the background levels provided above, unless specific data are available for the modeling domain that would discredit the values cited. It should be noted, however, that in areas where there are high ambient levels of sulfate, values such as 10 ppb might overestimate the formation of particulate nitrate from a given source, for these polluted conditions. Furthermore, areas in the vicinity of strong point sources of ammonia, such as feed lots or other agricultural areas, may experience locally high levels of background ammonia.*

The Northern Front Range is assumed to be ammonia rich. “Sulfate along the Northern Front Range is completely neutralized by available ammonium and is present in the form of ammonium sulfate....The Northern Front Range is ammonia rich. There was sufficient ammonia, on most days during winter, to completely neutralize available nitric acid (NFRAQS, 1998).”

For northeast Colorado, a background ammonia concentration of 30.4 $\mu g/m^3$ (about 44 ppb) or less appears to be reasonable based on measurements for this modeling study. According to monitoring conducted for NFRAQS,

- *"With respect to gaseous measurements, only ammonia was acquired at all nine sites with the denuder difference method at the Brighton and Welby sites and with the filter-pack method (i.e., impregnated cellulose-fiber filters behind Teflon-membrane filters) at the other sites. Average ammonia concentrations*

were 30.4 ± 53.4 µg/m3 at the core sites and 10.3 ±12.6 µg/m3 at the satellite sites. The large standard deviation is mainly due to elevated ammonia concentrations found at the Evans site. Maximum 24-hour ammonia concentrations were 187.0 ± 5.4 µg/m3 at the Evans core site on 01/17/97 and 66.7 ± 3.5 µg/m3 at the Masters site on 01/20/97. Figure 6.3-5 shows that during the mid-January episode, 24-hour ammonia concentrations varied by orders of magnitude at the nine NFRAQS sites."

- *"For the 6- and 12-hour samples, Figure 6.4-3*[not included in this report] *ammonia concentrations were rather consistent throughout the day, with apparent site -to-site and season-to-season variation. Average ammonia concentrations at the Brighton site were double those at the Welby site during Winter 97. Summertime ammonia concentrations were ~1 to 2 µg/m3 higher than the wintertime at the Welby site. Since ammonia concentrations closely reflect the vicinity of the sampling area, site-to-site variations were more pronounced than seasonal or diurnal variations. This is evidenced by the graph in Figure 6.4-4*[not included in this report], *which shows ammonia concentrations were factors of 10 to 20 higher at the Evans site than at most of the other sites during Winter 97. Elevated concentrations exceeded 50 µg/m3 on 20% of the days at the Evans site. Twenty-four hour ammonia concentrations at the Masters and Longmont sites were also factors of 5 to 10 higher than at the other sites."*

For other areas like northwest Colorado, an annual background ammonia concentration of about 1 ppb or less is probably more reasonable, based on ammonia measurements from the Mt. Zirkel Visibility Study.

In the Aerosol Evolution Model (AEM) simulations done for the Mt Zirkel Study for a specific period, "*base case background air concentrations for ammonia were assumed to be 0.5 µg/m^3 and 30 ppb$_v$ for ozone, consistent with measured values at the Hayden VOR site*." An ammonia concentration of 0.5µg/m^3 is about 0.7 ppb.

In the CALPUFF modeling section of the Mt Zirkel Study report,

"The CALPUFF default value for background ammonia concentrations of 10 ppb was also considered far too high as a representative area-average. Measurements from the Buffalo Pass and Gilpin Creek sites were used to adjust ammonia concentration to episode and site-mean values."

Based on a review of CALUFF files used for the Mt. Zirkel Study, for the August simulations, the assumed ammonia background (BCKNH3) was 1.6 ppb; for the October simulation, the assumed background was 0.5 ppb; and for the September simulation, the assumed background was 0.8 ppb.

5.1.2.8. Ammonia Assumptions

Based on information in the previous section, for sources located in northeast Colorado and along the South Platte River, a domain-wide ammonia background

value of 44 ppb is used. For sources located in northwest Colorado, a background ammonia concentration of 1.0 ppb is used. For sources located in southeastern Colorado and for source located along the Arkansas River, a background value of 10 ppb is used.

5.1.2.9. Ozone Assumptions

According to the IWAQM Phase 2 Report,

> *CALPUFF provides two options for providing the ozone background data: (1) a single, typical background value appropriate for the modeling region, or (2) hourly ozone data from one or more ozone monitoring stations. The second and preferred option requires the creation of the OZONE.DAT file containing the necessary data. For the Demonstration Assessment, the domain was large (700 km by 1000 km) such that the second option was necessary. The IWAQM does not anticipate such large domains as being the typical application. Rather, it is anticipated that the more typical application will involve domains of order 400 km by 400 km or smaller. But even for smaller domains, the ability to provide at least monthly background values of ozone is deemed desirable. The problem in developing time (and perhaps spatial) varying background ozone values is having access to representative background ozone data. Ozone data are available from EPA's Aerometric Information Retrieval System (AIRS); however, AIRS data must be used with caution. Many ozone sites are located in urban and suburban centers and are not representative of oxidant levels experienced by plumes undergoing long range transport.*

In this study, "*CH2M HILL obtained hourly ozone data from the following stations located within the modeling domain for some or all of the years 1996, 2001, and 2002:*

- *Gothic (Gunnison County, Colorado)*
- *Rocky Mountain National Park*

Additional, hourly data for 1996, 2001, and 2002 were provided to CH2M HILL by the APCD for the following stations along the Front Range:

- *Greeley*
- *Highlands Ranch*
- *Colorado Springs*

Data recovery for the years 2001 and 2002 for the Greeley station was very low, and therefore data from the nearby Fort Collins station were used instead. Any data missing from the hourly records were replaced with a domain-wide default concentration of 60 parts per billion (ppb), as determined by the APCD/NPS (CH2M HILL, 2005)."

5.1.3. CALPOST Settings and Visibility Post-Processing

The CALPUFF results have been post-processed with a modified version of CALPOST (version 5.51_CO_v3, level: 030709), POSTUTIL (version 1.31, level 030528), and BART98_v3. The CALPOST modifications were performed by the Division and do not affect any of the calculations in CALPOST for the deciview values used in this report; however, some simple calculations were done within CALPOST in order to output delta-deciview values (instead of percent change values) for the individual species that contribute to the overall delta-deciview value, but these values are not used for the subject-to-BART modeling. Otherwise, the CALPOST code modification consists of a "write" statement and supporting code. It outputs all daily delta-deciview values for every receptor to a file called "deciview24.dat." The 98th percentile values are computed from "deciview24.dat" by a separate FORTRAN processor (BART98_v3) written by the Division specifically for this analysis.

For the initial modeling analysis, all PM10 was assumed to have a extinction efficiency of 1.0 since the contribution of direct PM10 emissions is expected to be relatively small compared to visibility impairment caused by SO_2 and NOx emissions. However, if modeled impacts were below the contribution threshold, condensible and filterable PM10 emissions were quantified and speciated or a sensitivity test was performed to determine if PM10 speciation could change the outcome of the analysis. If speciated PM10 emissions were modeled, the following species were considered: fine particulates (PMF), coarse particulates (PMC), elemental carbon (EC), organic carbon (SOA), and sulfate (SO4). To see how PM10 was modeled for this source, refer to sections 4 and 5.1.3.2.

In this study, to calculate background light extinction, MVISBK has been set to 6. That is, monthly RH adjustment factors are applied directly to the background and modeled sulfate and nitrate concentrations, as recommended by the BART guideline. The RHMAX parameter, which is the maximum relative humidity factor used in the particle growth equation for visibility processing, is not used when method 6 is selected. Similarly, the relative humidity adjustment factor (f(RH)) curves in CALPOST (e.g., IWAQM growth curve and the 1996 IMPROVE curve) are not used when MVISBK is equal to 6.

The natural background is based on the 20 percent best visibility days, as recommended by the BART guideline preamble:

> *Finally, these BART guidelines use the natural visibility baseline for the 20 percent best visibility days for comparison to the "cause or contribute" applicability thresholds. We believe this estimated baseline is likely to be reasonably conservative and consistent with the goal of natural conditions* (70 FR 39125).

The method for estimating natural background is presented in section 5.1.3.1. Specifically, for hygroscopic components, BKSO4 in CALPOST has been set to 0.0893 for all months. For non-hygroscopic components, BKSOIL has been set to 1.620 for all months. The BKSO4 and BKSOIL values have been computed specifically for the Colorado Class I areas in the modeling domain.

The extinction due to Rayleigh scattering (i.e., the scattering of light by natural particles much smaller than the wavelength of the light) has been set to 10 Mm^{-1} (BEXTRAY = 10.0).

5.1.3.1. Natural Conditions - Determining Hygroscopic And Non-Hygroscopic Values For the Best 20% Visibility Days

5.1.3.1.1. Natural Background - Objective

The spreadsheet shown in Figure 17 was created to determine the hygroscopic (3[BKSO4]) and non-hygroscopic (equivalent to [BKSOIL]) portions of natural background for the best 20% visibility days (Best Days) at all Class I areas in Colorado's BART modeling. These concentrations, [BKSO4] and [BKSOIL], are used in CALPOST with monthly relative humidity adjustment factors (f(RH)) to determine monthly natural background visibility that would, on average, represent the average natural background visibility for the best 20% days in EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003).

5.1.3.1.2. Natural Background - Discussion

"Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003), section 2.4, describes the calculation of the annual average background extinction (in 1/Mm) for a Class I area using the area's annual f(RH) and average natural concentrations based on the area's geographic location (east versus west). Annual average background extinction values (in 1/Mm) are converted to annual average Haze Index (HI) values (in deciview or dv). Then, the average HI value for the 20% best visibility days (Best Days (dv)) is estimated from 10th percentile of the annual average HI value for a Class I area assuming normal distribution. Thus, no average natural concentrations are provided for determining extinction for the 20% best visibility days.

For background extinction computation methods 2, 3, and 6 in CALPOST, background extinction is calculated with user-supplied monthly concentrations of SO4, NO3, PM coarse, organic carbon, soil, and elemental carbon species. In practice, concentrations for only 2 species, SO4 ([BKSO4]) and soil ([BKSOIL]), are supplied in the CALPOST input file to represent hygroscopic and non-hygroscopic portions of background extinction, respectively.

To determine background extinction for the BART analysis with CALPOST, average natural concentrations that represent average natural background visibility for the best 20% days need to be determined.

5.1.3.1.3. Natural Background - Method

Following EPA's approach of using regional average natural concentrations and the concept of using simplified inputs in CALPOST, the same hygroscopic ($3[BKSO4]_{best20}$) and non-hygroscopic ($[BKSOIL]_{best20}$) values would be used in CALPOST for all Class I areas in Colorado's BART modeling.

The spreadsheet calculates an average background (dv) based on monthly background extinction (1/Mm) for each Class I area in Colorado's BART modeling using the following equations:

1. Monthly background extinction in 1/Mm ($bext_{month}$) = $3[BKSO4]_{best20}f(RH)$ + $[BKSOIL]_{best20}$ + Rayleigh
2. Annual average background extinction in 1/Mm ($bext_{annual_ave}$) = ($bext_{Jan}$ + $bext_{Feb}$ + … + $bext_{Dec}$)/12
3. Calculated Best Days in dv = $10\ln(bext_{annual_ave}/10)$

EPA guidance provides f(RH) values based on the centroid of the Class I area (see Appendix B – Monthly f(RH) Values) and a Best Days (dv) value for each of the Class I areas (see Appendix A – Natural Background Values).

The hygroscopic (3[BKSO4]) and non-hygroscopic ([BKSOIL]) values determined yielded the lowest sum of the absolute differences between the published Best Days (dv) and calculated Best Days (dv) for all Class I areas in the analysis:

where: n = number of Class I areas in analysis

The "hygro (3[BKSO4])" and "non-hygro ([BKSOIL])" values of 0.268 and 1.620 were calculated in Microsoft Excel using the "solver add-in" tool for optimization and equation solving (Figure 17). As can be seen from the “difference” values in Figure 17, the annual 20% best visibility days background concentrations for each Class I area calculated with this method are within 0.01 deciviews or less of the annual 20% best visibility days background values recommended by EPA. For CALPOST, the hygroscopic component of extinction is divided by 3 (the extinction coefficient of sulfate and nitrate) and input as BKSO4 (i.e., BKSO4 = 0.268/3 = 0.0893). The non-hygroscopic component is used directly (i.e., BKSOIL = 1.620).

hygro (3[BKSO4])	**0.268**
non-hygro ([BKSOIL])	**1.620**

	f(RH)											Background Extinction (1/Mm)										
Month	BC	EN	FT	GSD	LG	MB	MZ	RW	RM	WEM	WELK	BC	EN	FT	GSD	LG	MB	MZ	RW	RM	WEM	WELK
1	2.4	2.2	2.3	2.4	2.3	2.2	2.2	2.1	1.7	2.4	2.3	12.3	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.3	12.2
2	2.2	2.2	2.2	2.3	2.2	2.1	2.2	2.1	1.9	2.2	2.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.1	12.2	12.2
3	1.9	2.0	2.0	2.0	1.9	2.0	2.0	2.0	1.9	1.9	1.9	12.1	12.2	12.2	12.2	12.1	12.2	12.2	12.2	12.1	12.1	12.1
4	1.9	2.0	2.0	1.9	1.8	2.0	2.1	2.1	2.1	1.7	1.9	12.1	12.2	12.2	12.1	12.1	12.2	12.2	12.2	12.2	12.1	12.1
5	1.9	2.1	2.0	1.9	1.8	2.1	2.2	2.3	2.3	1.7	1.9	12.1	12.2	12.2	12.1	12.1	12.2	12.2	12.2	12.2	12.1	12.1
6	1.6	1.9	1.8	1.8	1.6	1.7	1.9	2.0	2.0	1.5	1.7	12.0	12.1	12.1	12.1	12.0	12.1	12.1	12.2	12.2	12.0	12.1
7	1.7	1.8	1.7	1.9	1.7	1.9	1.7	1.8	1.8	1.6	1.8	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.0	12.1
8	1.9	2.0	1.9	2.3	2.1	2.2	1.9	2.0	2.0	2.0	2.1	12.1	12.2	12.1	12.2	12.2	12.2	12.1	12.2	12.2	12.2	12.2
9	2.0	2.0	1.9	2.2	2.0	2.1	2.0	2.0	1.9	1.9	2.0	12.2	12.2	12.1	12.2	12.2	12.2	12.2	12.2	12.1	12.1	12.2
10	1.8	1.9	1.8	1.9	1.8	1.8	1.9	1.9	1.8	1.7	1.8	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
11	2.1	2.1	2.2	2.4	2.2	2.1	2.1	2.1	1.8	2.1	2.1	12.2	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.2	12.2
12	2.3	2.1	2.2	2.4	2.3	2.1	2.1	2.0	1.7	2.3	2.2	12.2	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.2	12.2
										Annual Ave (dv)		1.95	1.96	1.95	1.98	1.95	1.96	1.96	1.96	1.93	1.93	1.95
							Target Annual Best Days (dv)					1.94	1.96	1.95	1.98	1.94	1.95	1.96	1.96	1.93	1.94	1.95
										Difference		0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.00
									Sum of Differences			0.039										

Figure 17. Spreadsheet showing the "hygro (3[BKSO4])" (0.268)and "non-hygro ([BKSOIL])" (1.620) values calculated in Microsoft Excel using the "solver add-in" tool for optimization and equation solving.

5.1.3.2. CALPOST and POSTUTIL Parameters

For this modeling analysis, if PM10 speciation was performed (see section 4), then example #1 from this section was used. If PM10 speciation was not performed, then example #2 from this section was used. In example #1, fine particulate emissions are speciated into PMF, PMC, EC, SOA, and SO4 and explicitly included as species in CALPUFF. Emission rates for each species are included in CALPUFF. Figure 18 summarizes some of the key CALPOST settings. The monthly f(RH) values (RHFAC), which are different for each Class I area, are from Appendix B – Monthly f(RH) Values.

```
Modeled species to be included in computing the light extinction
     Include SULFATE?          (LVSO4) -- Default: T   ! LVSO4  = T  !
     Include NITRATE?          (LVNO3) -- Default: T   ! LVNO3  = T  !
     Include ORGANIC CARBON?   (LVOC)  -- Default: T   ! LVOC   = T  !
     Include COARSE PARTICLES? (LVPMC) -- Default: T   ! LVPMC  = T  !
     Include FINE PARTICLES?   (LVPMF) -- Default: T   ! LVPMF  = T  !
     Include ELEMENTAL CARBON? (LVEC)  -- Default: T   ! LVEC   = T  !
Species name used for particulates in MODEL.DAT file
                   COARSE    (SPECPMC) -- Default: PMC ! SPECPMC = PMC !
                   FINE      (SPECPMF) -- Default: PMF ! SPECPMF = PMF !
MODELED particulate species:
               PM  COARSE      (EEPMC) -- Default: 0.6 ! EEPMC  = 0.6 !
               PM  FINE        (EEPMF) -- Default: 1.0 ! EEPMF  = 1.0 !
BACKGROUND particulate species:
               PM  COARSE    (EEPMCBK) -- Default: 0.6 ! EEPMCBK = 0.6 !
Other species:
              AMMONIUM SULFATE (EESO4) -- Default: 3.0 ! EESO4  = 3.0 !
              AMMONIUM NITRATE (EENO3) -- Default: 3.0 ! EENO3  = 3.0 !
              ORGANIC CARBON   (EEOC)  -- Default: 4.0 ! EEOC   = 4.0 !
              SOIL             (EESOIL)-- Default: 1.0 ! EESOIL = 1.0 !
              ELEMENTAL CARBON (EEEC)  -- Default: 10. ! EEEC   = 10.0 !
Method used for background light extinction
                               (MVISBK) -- Default: 2   ! MVISBK =  6  !

(RHFAC)  -- No default     ! RHFAC = 2.4,2.2,1.9,1.7,
                                     1.7,1.5,1.6,2.0,
                                     1.9,1.7,2.1,2.3 !
(BKSO4)  -- No default     ! BKSO4 = 0.0893, 0.0893, 0.0893, 0.0893,
                                     0.0893, 0.0893, 0.0893, 0.0893,
                                     0.0893, 0.0893, 0.0893, 0.0893 !
(BKNO3)  -- No default     ! BKNO3 = 0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0 !
(BKPMC)  -- No default     ! BKPMC = 0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0 !
(BKOC)   -- No default     ! BKOC  = 0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0 !
(BKSOIL) -- No default     ! BKSOIL= 1.620, 1.620, 1.620, 1.620,
                                     1.620, 1.620, 1.620, 1.620,
                                     1.620, 1.620, 1.620, 1.620 !
(BKEC)   -- No default     ! BKEC  = 0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0,
                                     0.0, 0.0, 0.0, 0.0 !
Extinction due to Rayleigh scattering is added (1/Mm)
                               (BEXTRAY) -- Default: 10.0 ! BEXTRAY = 10.0 !
```

Figure 18. CALPOST - key parameters (example #1 setup).

POSTUTIL is used to compute the partition for the total concentration fields with MNITRATE=1 and the appropriate ammonia background concentration. The ammonia background concentration, BCKNH3, in POSTUTIL is the same as the background value presented in section Figure 18. In POSTUIL, the input species include SO2, SO4, NOX, HNO3, NO3, SOA, PMF, PMC, and EC and the output species include SO4, HNO3, NO3, SOA, PMF, PMC, and EC. Key POSTUTIL parameters are shown in Figure 19.

```
Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 9 !
Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 7 !
Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 0 !
Number of CALPUFF data files that will be scaled
      (must be no greater than NFILES)
      (NSCALED)                      Default: 0       ! NSCALED = 0 !
Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                     Default: 0       ! MNITRATE  =  1  !
The following NSPECINP species will be processed:

 ! ASPECI =            SO4  !         !END!
 ! ASPECI =            SO2  !         !END!
 ! ASPECI =            NOx  !         !END!
 ! ASPECI =            NO3  !         !END!
 ! ASPECI =            HNO3 !         !END!
 ! ASPECI =            PMF  !         !END!
 ! ASPECI =            PMC  !         !END!
 ! ASPECI =            EC   !         !END!
 ! ASPECI =            SOA  !         !END!


The following NSPECOUT species will be written:

 ! ASPECO =             SO4  !         !END!
 ! ASPECO =             NO3  !         !END!
 ! ASPECO =             HNO3 !         !END!
 ! ASPECO =             PMF  !         !END!
 ! ASPECO =             PMC  !         !END!
 ! ASPECO =             EC   !         !END!
 ! ASPECO =             SOA  !         !END!
```

Figure 19. POSTUTIL - key parameters for cases with nitrate partitioning and speciated PM10 concentrations (example #1 setup).

In example #2, PM10 is included as a species in CALPUFF and ammonia limiting is performed. The CALPOST setup is the same as the example #1 setup (see Figure 18) except LVPMC=F, since there are is no coarse PM, and SPECPMF=SOIL because the PM10 emissions from CALPUFF are reallocated to the species SOIL and EC in the first of two POSTUTIL runs. The first POSTUTIL setup (see Figure 20) was intended to provide a post-processing opportunity to divide the PM10 concentrations into SOIL and EC components; however, in the setup shown in Figure 20, all of the PM10 was allocated to SOIL and none was allocated to EC.

```
Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 5 !
Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 6 !
Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 2 !
Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                    Default: 0       ! MNITRATE  =  0  !
The following NSPECINP species will be processed:
 ! ASPECI =          SO4 !          !END!
 ! ASPECI =          NO3 !          !END!
 ! ASPECI =         HNO3 !          !END!
 ! ASPECI =         PM10 !          !END!
 ! ASPECI =          SOA !          !END!

The following NSPECOUT species will be written:
 ! ASPECO =            SO4  !          !END!
 ! ASPECO =            NO3  !          !END!
 ! ASPECO =           HNO3  !          !END!
 ! ASPECO =             EC  !          !END!
 ! ASPECO =           SOIL  !          !END!
 ! ASPECO =            SOA  !          !END!

The following NSPECCMP species will be computed by scaling and summing
one or more of the processed input species.  Identify the name(s) of
the computed species and provide the scaling factors for each of the
NSPECINP input species (NSPECCMP groups of NSPECINP+1 lines each):

 ! CSPECCMP =     EC !
 !     SO4  =     0.0      !
 !     NO3  =     0.0      !
 !    PM10  =     0.00  !
 !     SOA  =     0.0      !
 !END!

 ! CSPECCMP =     SOIL !
 !     SO4  =     0.0      !
 !     NO3  =     0.0      !
 !    PM10  =     1.0  !
 !     SOA  =     0.0      !
 !END!
```

Figure 20. POSTUTIL setup for simulations where PM10 is divided into SOIL and EC species (example #2 setup).

In the second POSTUTIL setup for example#2, POSTUTIL is used to compute the partition for the total concentration fields with MNITRATE=1 and the appropriate ammonia background concentration. The ammonia background concentration, BCKNH3, in POSTUTIL is the same as the background value presented in section 5.1.2.8. In this POSTUIL setup, the input species include SO4, NO3, HNO3, EC, SOIL, and SOA and the output species include SO4, NO3, HNO3, EC, SOIL, and SOA. Key POSTUTIL parameters are shown in Figure 19.

```
      Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 6 !
      Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 6 !
      Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 0 !
      Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                    Default: 0       ! MNITRATE  =  1  !
The following NSPECINP species will be processed:

 ! ASPECI =            SO4  !         !END!
 ! ASPECI =            NO3  !         !END!
 ! ASPECI =            HNO3 !         !END!
 ! ASPECI =            EC   !         !END!
 ! ASPECI =            SOIL !         !END!
 ! ASPECI =            SOA  !         !END!

The following NSPECOUT species will be written:

 ! ASPECO =            SO4  !         !END!
 ! ASPECO =            NO3  !         !END!
 ! ASPECO =            HNO3 !         !END!
 ! ASPECO =            EC   !         !END!
 ! ASPECO =            SOIL !         !END!
 ! ASPECO =            SOA  !         !END!
```

Figure 21. POSTUTIL setup for simulations where ammonia limiting is performed using the output file generated from the POSTUTIL setup in Figure 20 (example#2 setup).

5.1.3.3. 98th Percentile Methods

According the BART guideline:

...you should compare your "contribution" threshold against the 98th percentile of values. If the 98th percentile value from your modeling is less than your contribution threshold, then you may conclude that the source does not contribute to visibility impairment and is not subject to BART. (70 FR 39162)

The BART guideline does not contain a specific method for calculating the "98th percentile value" and CALPOST version 5.51 does not generate a 98th percentile delta-deciview value. Consequently, the Division developed a FORTRAN program (BART98_v3) to compute 98th percentile results. The program implements several methods because, at the time the code was written, U.S. EPA had not yet specified an explicit method for determining the 98th percentile value.

The U.S.EPA recommends using the 98th percentile value from the distribution of values containing the highest modeled delta-deciview value for each day of the simulation from all modeled receptors at a given Class I area. The 98th percentile delta-deciview value can be determined in several ways:

- The 8th highest value for each year modeled
- The 3-year average of the annual 8th high values
- The 22nd highest value for the 3-year modeling period

The highest value from the methods above is compared to the contribution threshold. The contribution threshold has an implied level of precision equal to the level of precision reported from CALPOST. Specifically, the 98th percentile results are reported to three decimal places.

The Division's processor BART98_v3 calculates the 98th percentile value with the method recommended by U.S. EPA. The Division refers to the method as the "day-specific method" or "method 1." The first step in the method is to find the highest modeled delta-deciview value for each day of the simulation from all modeled receptors for the selected time period. While this set of delta-deciview values is generated by CALPOST in an unranked format, the Division's processor BART98_v3 outputs all daily delta-deciview values for each receptor from CALPOST and finds the highest impact for each day. Next, the processor ranks the daily delta-deciview maxima in descending order for the number of days processed in CALPOST. Then, the processor determines the 98th percentile value from the distribution of ranked modeled daily maximum values, irrespective of receptor location. For example, for a 365-day simulation, the 98th percentile value would be the 8th highest modeled delta-deciview value from the list of ranked delta-deciview values. That is, the top 7 days are ignored, even though the values being ignored may be at different receptors. Similarly, for a 3-year period, the 98th percentile would be the 22nd highest modeled delta-deciview value.

The processor BART98_v3 also generates 98th percentile values using the "receptor-specific method" or "method 2." This method, which calculates 98th percentile values on a receptor-by-receptor basis, is not used for the subject-to-BART modeling in Colorado.

In order to make the processor more general and to handle missing data, the "8th high" (for one year) and "22nd high" (for 3 years) values recommended by U.S. EPA are not hardwired into the processor; rather, the processor contains an algorithm that calculates the appropriate "nth high" value from the distribution of data. The 8th high and 22nd high values recommended by U.S. EPA are consistent with the values that would be generated from the equations in 40 CFR 50 Appendix N - "Interpretation of the National Ambient Air Quality Standards for PM2.5" – for determining 98th percentile values for PM2.5 monitoring. Thus, the Appendix N method is used in the processor. For the exact algorithm, see Appendix N, the BART98_v3 source code, or the BART98_v3 "readme" file.

6. Results

The CALPUFF modeling results include eleven of the twelve Class I areas in Colorado. Mesa Verde was excluded because it is more than 300 km from all of the BART-eligible sources in Colorado. In addition, the BART-eligible sources in Colorado would have higher impacts at other Class I areas. That is, impacts at Mesa Verde would not be the controlling 98th percentile values for this analysis. The modeling domain does not include Class I areas in any nearby states because the maximum 98th percentile impact from the Craig Station is expected to occur at a Class I area in Colorado.

The results for source-to-receptor distances beyond 300 kilometers may be used, but they may overestimate impacts because puff splitting has not been used. The model setup used here should provide reasonable estimates for source-to-receptor distances up to 300 kilometers. Figure 22 shows the 50km and 300 km radius circles around the modeled BART-eligible source.

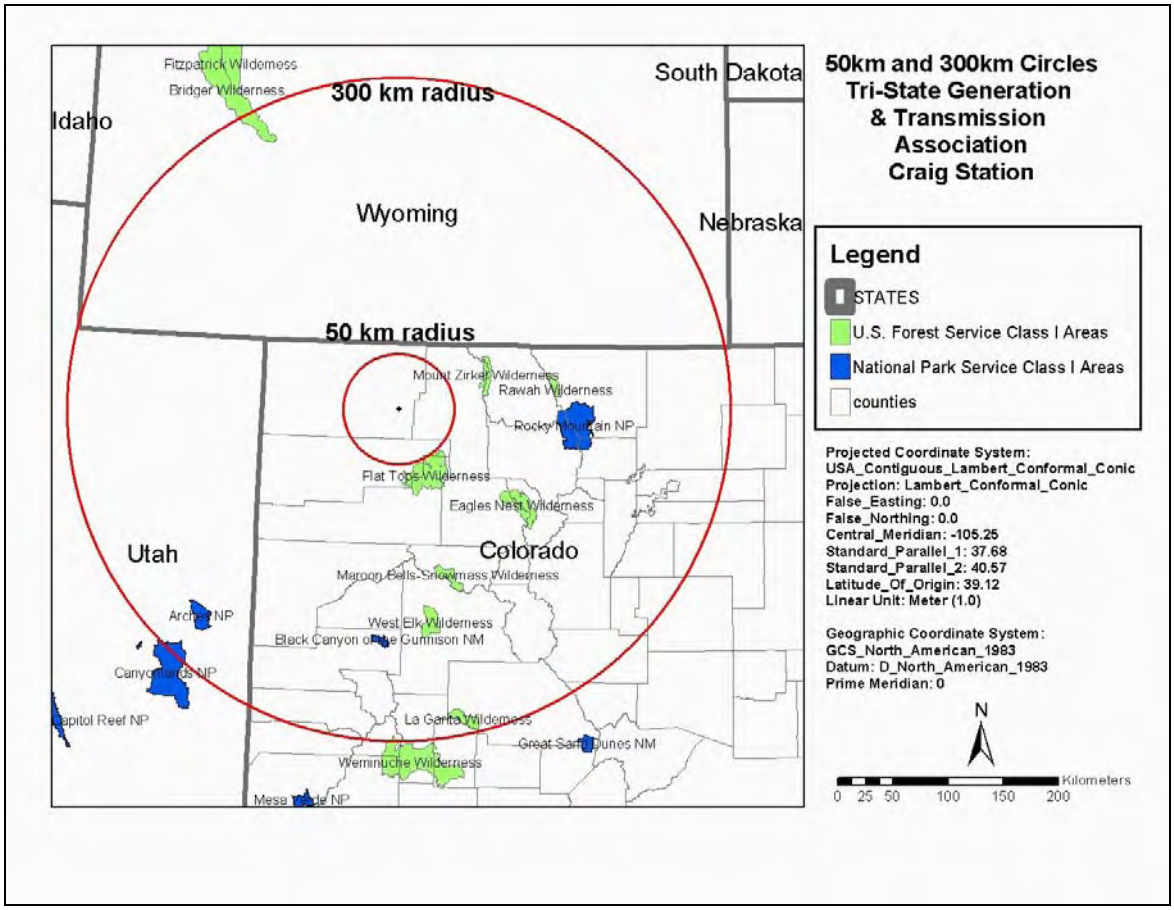

Figure 22. Class I areas within 50 and 300 kilometers of the BART-eligible source.

6.1. Results

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the "subject to BART" analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results in this report. If additional modeling is performed, it should be consistent with recommendations in the Division's modeling protocol. Any subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency's final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

Table 2 and Figure 23 show the 98th percentile daily delta-deciview values for each Class I area in the modeling domain. The 98th percentile delta-deciview value is determined several ways:

- The 8th highest value for each year modeled
- The 3-year average of the annual 8th high values
- The 22nd highest value for the 3-year modeling period

The highest value from the methods above is compared to the contribution threshold. The contribution threshold has an implied level of precision equal to the level of precision reported from CALPOST. Specifically, the 98th percentile results are reported to three decimal places.

The maximum 98th percentile delta-deciview value from Craig Station Units 1 and 2 at any Class I federal area is 2.689 deciviews, assuming natural background conditions and monthly f(RH) values. The impact is above the contribution threshold of 0.5 deciviews. The maximum impact occurs at the Mount Zirkel Wilderness Area. For the three-year period modeled, there are 496 days with an estimated impact over the contribution threshold of 0.5 deciviews.

Table 3 shows the summary report generated by the Division's 98th percentile postprocessor (BART98_v3) for the maximum 98th percentile value. Figure 24 and Figure 25 show the distribution of delta-deciview values used to generate the maximum 98th percentile value. Figure 24 shows the top 25 delta-deciview values at the Class I federal area with the maximum impact from this BART-eligible source.

Table 2. Maximum 98th percentile value, 98th percentile values calculated with several methods, and the number of days the impact is equal to or greater than 0.5 deciviews for the entire period modeled.

CALPUFF Individual Source Attribution Analysis					**Maximum 98th Percentile Value =**	**2.689**
BART-eligible source name:	Craig Station - Units 1 & 2					
	98th Percentile Daily Change in Visibility from BART-Eligible Source Compared Against Natural Background Conditions					
	8th High Delta-Deciview Value					
Class I federal area	**1996[1]**	**2001**	**2002**	**3-year Average**	**22nd High Delta-Deciview Value from 3-year Modeling Period**	**Number of Days Impact >0.5dv (1996, 2001, 2002)**
Flat Tops WA	2.093	1.615	2.095	1.934	1.996	168
Rawah WA	1.587	1.393	1.929	1.636	1.588	190
Mt Zirkel WA	2.131	2.226	2.689	2.349	2.315	496
Weminuche WA	0.172	0.097	0.194	0.154	0.165	4
Rocky Mountain NP	1.753	1.267	1.935	1.652	1.765	205
Maroon Bells-Snowmass WA	0.983	0.621	0.563	0.722	0.652	37
La Garita WA	0.279	0.154	0.234	0.222	0.205	3
Great Sand Dunes NP	0.468	0.323	0.360	0.384	0.403	11
West Elk WA	0.566	0.505	0.433	0.501	0.515	26
Eagles Nest WA	1.560	1.106	1.211	1.292	1.260	109
Black Canyon of the Gunnison NP	0.467	0.265	0.338	0.357	0.382	17

[1] *1996, 2001, and 2002 are the years of meteorological data modeled.*

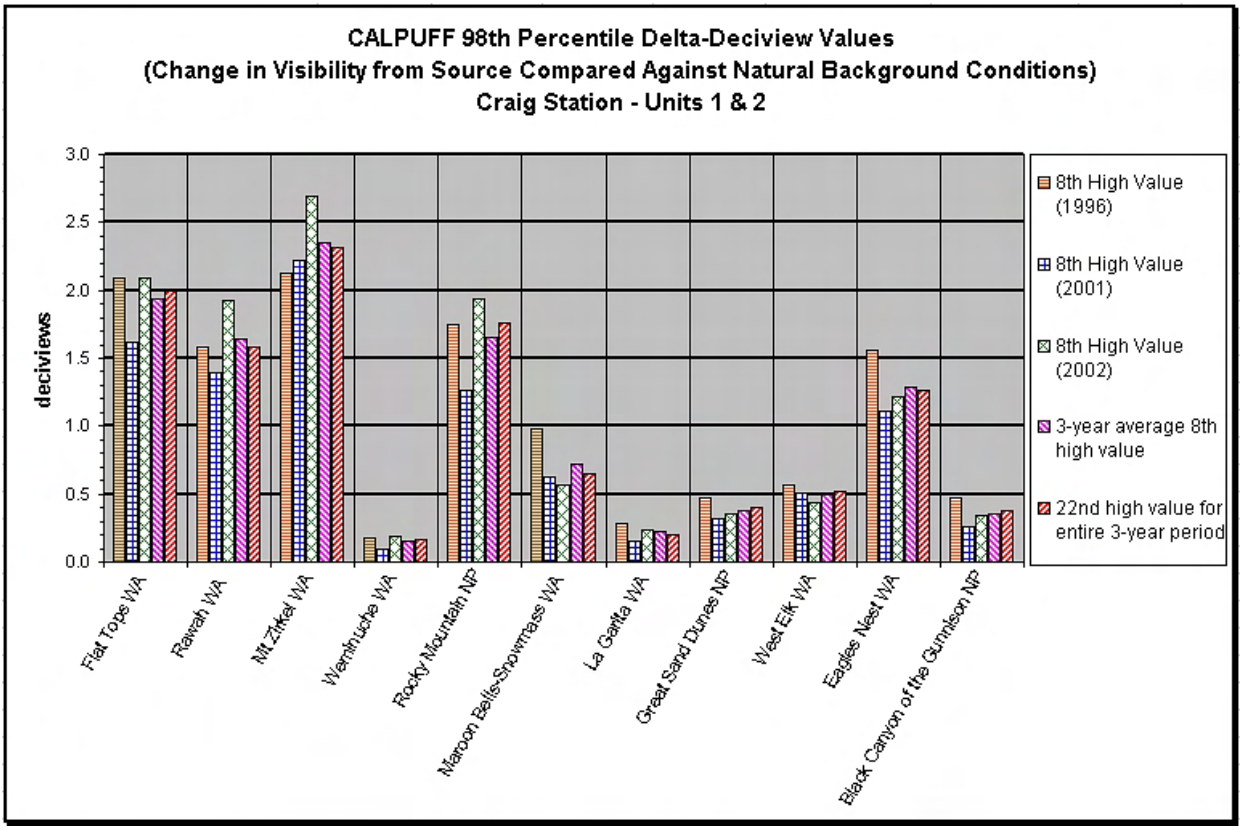

Figure 23. Comparison of 98th percentile daily change in visibility values (delta-deciviews). The highest value is compared to the contribution threshold of 0.5 deciviews.

Table 3. Summary report with results from the Division's 98th percentile postprocessor (BART98_v3) that correspond to the maximum delta-deciview value from Table 2. The 98th percentile value from "Method 1" (in bold) corresponds to the method recommended by U.S. EPA.

```
Title from CALPOST:
APCD BART - Mt Zirkel WA (MOZ); 2/22/06 v1_so2at0.16NOxat0.34_mnitrate1ppb
MVISBK=6; EPA2003 centroid monthly f(RH); EPA2003 20%bestdays natural backgrd
2002 36km MM5, 4km CALMET, hourly ozone; BART-eligible source= CRAIG

Days processed:  364
Receptors processed:      253
CALPOST species: ALL
Contribution threshold: 0.5

Summary of delta-deciview results:

The 'High  1st High' from the model is:   3.489 dv
    Number of days 'High 1 High' delta-deciview => 0.5: 199
    Number of days 'High 1 High' delta-deciview => 1.00:  96


98th Percentile Results:
-------------------------------------------------------------
Method 1. DAY-SPECIFIC - closest modeled value:
    The ' 8 High' value from the model is:  2.689 dv
       at receptor    3021 on day  118(2002)

Method 2a. RECEPTOR-SPECIFIC - closest modeled value:
    The 'High  8 High' value from the model is:  2.041 dv
       at receptor    2868 on day  325(2002)
    Number of days with delta-deciview => 0.5: 198
    Number of days with delta-deciview => 1.00:  95

Method 2b. RECEPTOR-SPECIFIC - Weighted Average at X[(n+1)p]:
    The calculated 98th percentile value
    using a weighted averaging method is:    2.050 dv
       at receptor    2868
       using days   12(2002) and 325(2002)
-------------------------------------------------------------
```

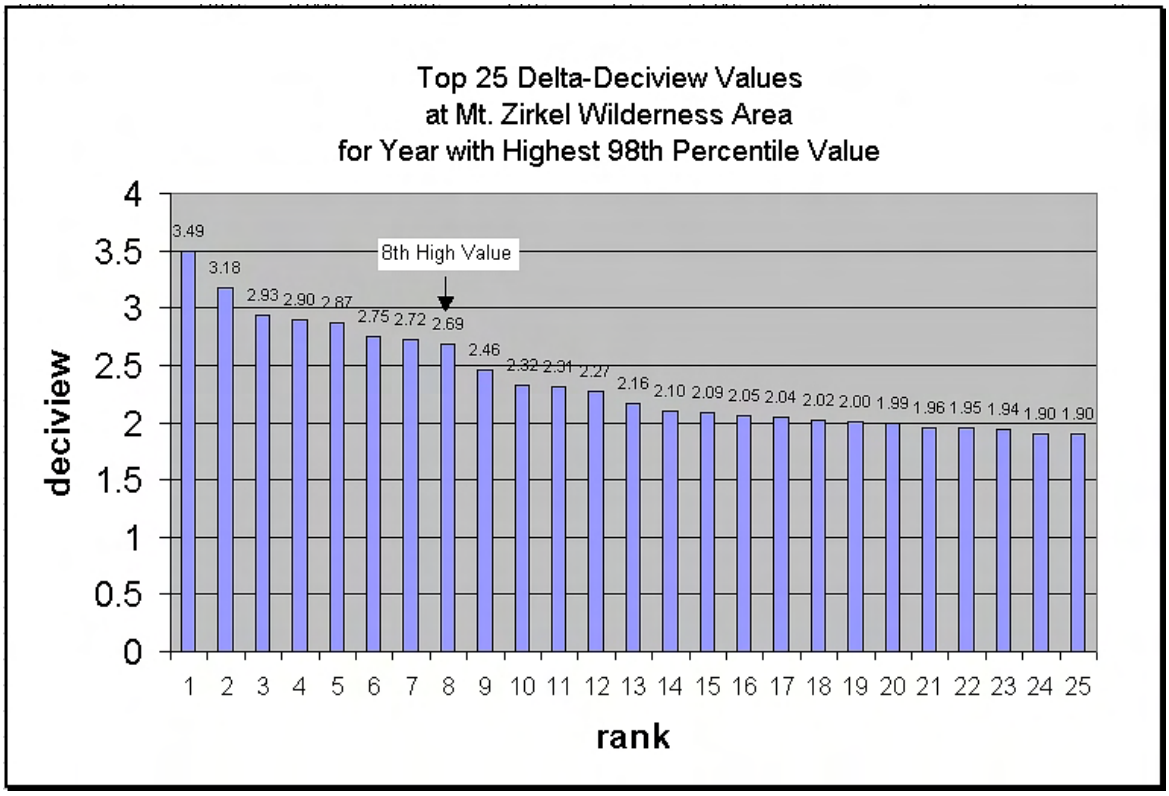

Figure 24. Distribution of delta-deciview values used to generate the maximum 98th percentile value.

YEAR	DAY	RECEPTOR	DV(Total)	DV(BKG)	DELTA DV	F(RH)	%_SO4	%_NO3	%_OC	%_EC	%_PMC	%_PMF
2002	359	2948	5.463	1.974	3.489	2.1	13.11	85.07	0	0	0	1.82
2002	38	2880	5.175	1.996	3.179	2.2	14.75	84.68	0	0	0	0.57
2002	335	3075	4.907	1.974	2.932	2.1	9.33	89.78	0	0	0	0.89
2002	34	3075	4.894	1.996	2.898	2.2	14.56	84.88	0	0	0	0.56
2002	332	2880	4.84	1.974	2.866	2.1	11.01	86.83	0	0	0	2.16
2002	30	2855	4.749	1.996	2.753	2.2	10.62	85.03	0	0	0	4.34
2002	293	2949	4.653	1.93	2.723	1.9	20.07	79.15	0	0	0	0.77
2002	118	3021	4.663	1.974	**2.689**	2.1	11.02	84.89	0	0	0	4.08
2002	145	2852	4.457	1.996	2.461	2.2	13.94	83.72	0	0	0	2.34
2002	124	2855	4.32	1.996	2.324	2.2	7.85	87.48	0	0	0	4.67
2002	344	3011	4.285	1.974	2.311	2.1	9.64	89.05	0	0	0	1.31
2002	360	2868	4.242	1.974	2.268	2.1	8.63	87.81	0	0	0	3.56
2002	298	3075	4.092	1.93	2.162	1.9	10.59	86.24	0	0	0	3.17
2002	341	3075	4.075	1.974	2.101	2.1	9.22	89.47	0	0	0	1.31
2002	84	3075	4.042	1.952	2.09	2	11.32	86.58	0	0	0	2.1
2002	12	2868	4.05	1.996	2.054	2.2	11.58	87.69	0	0	0	0.73
2002	325	2868	4.016	1.974	2.041	2.1	10.67	87.59	0	0	0	1.73
2002	137	2855	4.013	1.996	2.017	2.2	11.59	86.75	0	0	0	1.66
2002	326	2915	3.976	1.974	2.002	2.1	9.79	89.47	0	0	0	0.74
2002	255	3011	3.94	1.952	1.988	2	9.08	87.74	0	0	0	3.18
2002	85	2852	3.91	1.952	1.958	2	12.86	84.85	0	0	0	2.28
2002	292	2855	3.878	1.93	1.948	1.9	20.83	77.8	0	0	0	1.37
2002	51	2852	3.94	1.996	1.944	2.2	5.78	89.7	0	0	0	4.52
2002	297	3032	3.832	1.93	1.901	1.9	12.23	83.26	0	0	0	4.51
2002	302	2915	3.83	1.93	1.9	1.9	10.98	85.65	0	0	0	3.36

Figure 25. Top 25 delta-deciview (DELTA DV) values from the Mt Zirkel Wilderness Area for the year with the highest 98th percentile value.

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Appendix A – Natural Background Values

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Acadia NP	ME	44.35	-68.24	21.40	7.61	3.77	11.45
Agua Tibia Wilderness	CA	33.42	-116.99	15.86	4.61	2.05	7.17
Alpine Lake Wilderness	WA	47.55	-121.16	16.99	5.30	2.74	7.86
Anaconda-Pintler Wilderness	MT	45.95	-113.5	16.03	4.72	2.16	7.28
Arches NP	UT	38.73	-109.58	15.58	4.43	1.87	6.99
Badlands NP	SD	43.81	-102.36	16.06	4.74	2.18	7.30
Bandelier NM	NM	35.79	-106.34	15.62	4.46	1.90	7.02
Bering Sea	AK	60.46	-172.75				
Big Bend NP	TX	29.33	-103.31	15.48	4.37	1.81	6.93
Black Canyon of the Gunnison NM	CO	38.57	-107.75	15.68	4.50	1.94	7.06
Bob Marshall Wilderness	MT	47.68	-113.23	16.17	4.80	2.24	7.36
Bosque del Apache	NM	33.79	-106.85	15.54	4.41	1.85	6.97
Boundary Waters Canoe Area	MN	48.06	-91.43	20.89	7.37	3.53	11.21
Breton	LA	29.87	-88.82	21.57	7.69	3.85	11.53
Bridger Wilderness	WY	42.99	-109.49	15.71	4.52	1.96	7.08
Brigantine	NJ	39.49	-74.39	21.05	7.44	3.60	11.28
Bryce Canyon NP	UT	37.57	-112.17	15.58	4.43	1.87	6.99
Cabinet Mountains Wilderness	MT	48.18	-115.68	16.27	4.87	2.31	7.43
Caney Creek Wilderness	AR	34.41	-94.08	21.14	7.49	3.65	11.33
Canyonlands NP	UT	38.23	-109.91	15.60	4.45	1.89	7.01
Cape Romain	SC	32.99	-79.49	21.22	7.52	3.68	11.36
Capitol Reef NP	UT	38.06	-111.15	15.63	4.47	1.91	7.03
Caribou Wilderness	CA	40.49	-121.21	16.05	4.73	2.17	7.29
Carlsbad Caverns NP	NM	32.12	-104.59	15.61	4.46	1.90	7.02
Chassahowitzka	FL	28.69	-82.66	21.46	7.63	3.79	11.47
Chiricahua NM	AZ	32.01	-109.34	15.47	4.36	1.80	6.92
Chiricahua Wilderness	AZ	31.86	-109.28	15.45	4.35	1.79	6.91
Cohutta Wilderness	GA	34.93	-84.57	21.39	7.60	3.76	11.44
Crater Lake NP	OR	42.92	-122.13	16.74	5.15	2.59	7.71
Craters of the Moon NM	ID	43.39	-113.54	15.80	4.57	2.01	7.13
Cucamonga Wilderness	CA	34.24	-117.59	15.85	4.61	2.05	7.17
Denali Preserve NP	AK	63.31	-151.19	16.27	4.86	2.30	7.42
Desolation Wilderness	CA	38.9	-120.17	15.80	4.57	2.01	7.13
Diamond Peak Wilderness	OR	43.53	-122.1	16.84	5.21	2.65	7.77
Dolly Sods Wilderness	WV	39	-79.37	21.13	7.48	3.64	11.32
Dome Land Wilderness	CA	35.84	-118.23	15.70	4.51	1.95	7.07
Eagle Cap Wilderness	OR	45.22	-117.37	16.12	4.78	2.22	7.34

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Eagles Nest Wilderness	CO	39.67	-106.29	15.72	4.52	1.96	7.08
Emigrant Wilderness	CA	38.18	-119.77	15.81	4.58	2.02	7.14
Everglades NP	FL	25.35	-80.98	20.77	7.31	3.47	11.15
Fitzpatrick Wilderness	WY	43.24	-109.6	15.73	4.53	1.97	7.09
Flat Tops Wilderness	CO	39.95	-107.3	15.70	4.51	1.95	7.07
Galiuro Wilderness	AZ	32.6	-110.39	15.40	4.32	1.76	6.88
Gates of the Mountains Wilderness	MT	46.86	-111.82	15.93	4.66	2.10	7.22
Gearhart Mountain Wilderness	OR	42.51	-120.86	16.33	4.90	2.34	7.46
Gila Wilderness	NM	33.21	-108.47	15.51	4.39	1.83	6.95
Glacier NP	MT	48.64	-113.84	16.48	5.00	2.44	7.56
Glacier Peak Wilderness	WA	48.21	-121	16.88	5.24	2.68	7.80
Goat Rocks Wilderness	WA	46.52	-121.47	16.93	5.26	2.70	7.82
Grand Canyon NP	AZ	36.3	-112.79	15.51	4.39	1.83	6.95
Grand Teton NP	WY	43.82	-110.71	15.74	4.53	1.97	7.09
Great Gulf Wilderness	NH	44.3	-71.28	21.10	7.47	3.63	11.31
Great Sand Dunes NM	CO	37.77	-105.57	15.74	4.54	1.98	7.10
Great Smoky Mountains NP	TN	35.6	-83.52	21.39	7.60	3.76	11.44
Guadalupe Mountains NP	TX	31.91	-104.85	15.64	4.47	1.91	7.03
Haleakala NP	HI	20.71	-156.16	16.02	4.71	2.15	7.27
Hawaii Volcanoes NP	HI	19.41	-155.34	16.33	4.91	2.35	7.47
Hells Canyon Wilderness	OR	45.54	-116.59	16.09	4.76	2.20	7.32
Hercules-Glades Wilderness	MO	36.68	-92.9	21.03	7.43	3.59	11.27
Hoover Wilderness	CA	38.11	-119.37	15.78	4.56	2.00	7.12
Isle Royale NP	MI	48.01	-88.83	20.91	7.38	3.54	11.22
James River Face Wilderness	VA	37.59	-79.44	20.96	7.40	3.56	11.24
Jarbidge Wilderness	NV	41.77	-115.35	15.75	4.54	1.98	7.10
John Muir Wilderness	CA	36.97	-118.88	15.80	4.58	2.02	7.14
Joshua Tree NM	CA	33.92	-115.88	15.72	4.52	1.96	7.08
Joyce-Kilmer-Slickrock Wilderness	TN	35.44	-83.99	21.40	7.61	3.77	11.45
Kaiser Wilderness	CA	37.28	-119.17	15.80	4.57	2.01	7.13
Kalmiopsis Wilderness	OR	42.26	-123.92	16.74	5.15	2.59	7.71
Kings Canyon NP	CA	36.92	-118.61	15.79	4.57	2.01	7.13
La Garita Wilderness	CO	37.95	-106.83	15.69	4.50	1.94	7.06
Lassen Volcanic NP	CA	40.49	-121.41	16.08	4.75	2.19	7.31
Lava Beds NM	CA	41.76	-121.52	16.37	4.93	2.37	7.49
Linville Gorge Wilderness	NC	35.88	-81.9	21.36	7.59	3.75	11.43
Lostwood	ND	48.59	-102.46	16.11	4.77	2.21	7.33

B - 3

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Lye Brook Wilderness	VT	43.13	-73.02	20.99	7.41	3.57	11.25
Mammoth Cave NP	KY	37.2	-86.15	21.58	7.69	3.85	11.53
Marble Mountain Wilderness	CA	41.51	-123.21	16.65	5.10	2.54	7.66
Maroon Bells-Snowmass Wilderness	CO	39.1	-107.02	15.70	4.51	1.95	7.07
Mazatzal Wilderness	AZ	34.13	-111.56	15.44	4.35	1.79	6.91
Medicine Lake	MT	48.49	-104.35	16.07	4.74	2.18	7.30
Mesa Verde NP	CO	37.25	-108.45	15.73	4.53	1.97	7.09
Minarets Wilderness	CA	37.74	-119.19	15.78	4.56	2.00	7.12
Mingo	MO	37	-90.19	21.03	7.43	3.59	11.27
Mission Mountains Wilderness	MT	47.48	-113.87	16.21	4.83	2.27	7.39
Mokelumne Wilderness	CA	38.57	-120.06	15.80	4.58	2.02	7.14
Moosehorn	ME	45.09	-67.29	21.22	7.52	3.68	11.36
Mount Adams Wilderness	WA	46.2	-121.49	16.86	5.22	2.66	7.78
Mount Baldy Wilderness	AZ	33.95	-109.54	15.51	4.39	1.83	6.95
Mount Hood Wilderness	OR	45.37	-121.73	16.83	5.21	2.65	7.77
Mount Jefferson Wilderness	OR	44.61	-121.84	16.91	5.25	2.69	7.81
Mount Rainier NP	WA	46.86	-121.72	17.05	5.34	2.78	7.90
Mount Washington Wilderness	OR	44.3	-121.88	17.03	5.33	2.77	7.89
Mount Zirkel Wilderness	CO	40.75	-106.68	15.71	4.52	1.96	7.08
Mountain Lakes Wilderness	OR	42.33	-122.11	16.50	5.01	2.45	7.57
North Absaroka Wilderness	WY	44.74	-109.8	15.74	4.53	1.97	7.09
North Cascades NP	WA	48.83	-121.35	16.86	5.22	2.66	7.78
Okefenokee	GA	30.82	-82.33	21.41	7.61	3.77	11.45
Olympic NP	WA	47.77	-123.74	17.02	5.32	2.76	7.88
Otter Creek Wilderness	WV	38.99	-79.65	21.14	7.49	3.65	11.33
Pasayten Wilderness	WA	48.89	-120.44	16.84	5.21	2.65	7.77
Pecos Wilderness	NM	35.9	-105.62	15.65	4.48	1.92	7.04
Petrified Forest NP	AZ	34.99	-109.79	15.54	4.41	1.85	6.97
Pine Mountain Wilderness	AZ	34.31	-111.8	15.47	4.36	1.80	6.92
Pinnacles NM	CA	36.48	-121.19	16.12	4.78	2.22	7.34
Point Reyes NS	CA	38.06	-122.9	16.20	4.83	2.27	7.39
Presidential Range-Dry River Wilderness	NH	44.2	-71.34	21.15	7.49	3.65	11.33
Rainbow Lake Wilderness	WI	46.42	-91.31	20.99	7.42	3.58	11.26
Rawah Wilderness	CO	40.69	-105.95	15.72	4.52	1.96	7.08
Red Rock Lakes	MT	44.64	-111.78	15.81	4.58	2.02	7.14
Redwood NP	CA	41.44	-124.03	16.90	5.25	2.69	7.81
Rocky Mountain NP	CO	40.35	-105.7	15.67	4.49	1.93	7.05

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Roosevelt Campobello International Park	ME	44.85	-66.94	21.22	7.52	3.68	11.36
Saguaro NM	AZ	32.17	-110.61	15.35	4.28	1.72	6.84
Salt Creek	NM	33.6	-104.41	15.58	4.43	1.87	6.99
San Gabriel Wilderness	CA	34.27	-117.94	15.86	4.61	2.05	7.17
San Gorgonio Wilderness	CA	34.12	-116.84	15.74	4.54	1.98	7.10
San Jacinto Wilderness	CA	33.75	-116.64	15.78	4.56	2.00	7.12
San Pedro Parks Wilderness	NM	36.11	-106.81	15.63	4.47	1.91	7.03
San Rafael Wilderness	CA	34.76	-119.81	16.03	4.72	2.16	7.28
Sawtooth Wilderness	ID	43.99	-115.06	15.82	4.59	2.03	7.15
Scapegoat Wilderness	MT	47.16	-112.74	16.05	4.73	2.17	7.29
Selway-Bitterroot Wilderness	ID	46.12	-114.86	16.09	4.76	2.20	7.32
Seney	MI	46.25	-86.09	21.23	7.53	3.69	11.37
Sequoia NP	CA	36.51	-118.56	15.79	4.57	2.01	7.13
Shenandoah NP	VA	38.47	-78.49	20.98	7.41	3.57	11.25
Shining Rock Wilderness	NC	35.38	-82.85	21.40	7.61	3.77	11.45
Sierra Ancha Wilderness	AZ	33.85	-110.9	15.46	4.36	1.80	6.92
Simeonof	AK	54.91	-159.28	17.21	5.43	2.87	7.99
Sipsey Wilderness	AL	34.32	-87.44	21.28	7.55	3.71	11.39
South Warner Wilderness	CA	41.31	-120.2	16.09	4.76	2.20	7.32
St. Marks	FL	30.11	-84.15	21.54	7.67	3.83	11.51
Strawberry Mountain Wilderness	OR	44.29	-118.74	16.37	4.93	2.37	7.49
Superstition Wilderness	AZ	33.5	-111.27	15.40	4.32	1.76	6.88
Swanquarter	NC	35.39	-76.39	20.91	7.38	3.54	11.22
Sycamore Canyon Wilderness	AZ	35.01	-112.09	15.53	4.40	1.84	6.96
Teton Wilderness	WY	44.04	-110.17	15.74	4.53	1.97	7.09
Theodore Roosevelt NP	ND	46.96	-103.46	16.08	4.75	2.19	7.31
Thousand Lakes Wilderness	CA	40.7	-121.58	16.10	4.76	2.20	7.32
Three Sisters Wilderness	OR	44.04	-121.91	17.01	5.31	2.75	7.87
Tuxedni	AK	60.14	-152.61	16.58	5.06	2.50	7.62
UL Bend	MT	47.54	-107.89	15.87	4.62	2.06	7.18
Upper Buffalo Wilderness	AR	36.17	-92.41	21.04	7.44	3.60	11.28
Ventana Wilderness	CA	36.21	-121.6	16.09	4.76	2.20	7.32
Virgin Islands NP [b]	VI	18.35	-64.74				
Voyageurs NP	MN	48.47	-92.8	20.64	7.25	3.41	11.09
Washakie Wilderness	WY	44.1	-109.57	15.73	4.53	1.97	7.09
Weminuche Wilderness	CO	37.61	-107.25	15.68	4.50	1.94	7.06
West Elk Wilderness	CO	38.75	-107.21	15.71	4.51	1.95	7.07

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Wheeler Peak Wilderness	NM	36.57	-105.4	15.70	4.51	1.95	7.07
White Mountain Wilderness	NM	33.48	-105.85	15.56	4.42	1.86	6.98
Wichita Mountains	OK	34.75	-98.65	20.60	7.23	3.39	11.07
Wind Cave NP	SD	43.58	-103.47	15.97	4.68	2.12	7.24
Wolf Island	GA	31.33	-81.3	21.33	7.58	3.74	11.42
Yellowstone NP	WY	44.63	-110.51	15.77	4.56	2.00	7.12
Yolla Bolly Middle Eel Wilderness	CA	40.09	-122.96	16.25	4.85	2.29	7.41
Yosemite NP	CA	37.85	-119.54	15.81	4.58	2.02	7.14
Zion NP	UT	37.32	-113.04	15.56	4.42	1.86	6.98

(a) Values for the best and worst days are estimated from a statistical approach described in Section 2.6 of this document.
(b) *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available. As such no estimates for Natural Visibility Conditions are presented at this time.

Appendix B – Monthly f(RH) Values

Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Acadia	Acadia	1	ACAD1	ME	44.37	68.26	3.3	2.9	2.8	3.4	3.1	3.0	3.4	3.8	4.0	3.8	3.6	3.5
Agua Tibia	Agua Tibia	100	AGTI1	CA	33.41	116.98	2.4	2.4	2.4	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.1	2.2
Alpine Lakes	Snoqualmie Pass	80	SNPA1	WA	47.42	121.42	4.3	3.8	3.5	3.9	2.9	3.2	2.9	3.1	3.3	3.9	4.5	4.5
Anaconda - Pintler	Sula	71	SULA1	MT	45.98	113.42	3.3	2.9	2.5	2.4	2.4	2.3	2.0	1.9	2.1	2.5	3.2	3.3
Ansel Adams	Kaiser	110	KAIS1	CA	37.65	119.20	3.0	2.7	2.4	2.1	1.9	1.7	1.6	1.6	1.6	1.8	2.3	2.7
Arches	Canyonlands	50	CANY1	UT	38.64	109.58	2.6	2.3	1.8	1.6	1.6	1.3	1.4	1.5	1.6	1.6	2.0	2.3
Badlands	Badlands	59	BADL1	SD	43.74	101.94	2.6	2.7	2.6	2.4	2.8	2.7	2.5	2.4	2.2	2.3	2.7	2.7
Bandelier	Bandelier	33	BAND1	NM	35.78	106.27	2.2	2.1	1.8	1.6	1.6	1.4	1.7	2.1	1.9	1.7	2.0	2.2
Bering Sea (a)					60.45	172.79												
Big Bend	Big Bend	31	BIBE1	TX	29.31	103.19	2.0	1.9	1.6	1.5	1.6	1.6	1.7	2.0	2.1	1.9	1.8	1.9
Black Canyon of the Gunnison	Weminuche	55	WEMI1	CO	38.58	107.70	2.4	2.2	1.9	1.9	1.9	1.6	1.7	1.9	2.0	1.8	2.1	2.3
Bob Marshall	Monture	73	MONT1	MT	47.75	113.38	3.6	3.1	2.8	2.6	2.7	2.7	2.3	2.2	2.6	2.9	3.5	3.5
Bosque del Apache	Bosque del Apache	38	BOAP1	NM	33.79	106.83	2.1	1.9	1.6	1.4	1.4	1.3	1.8	2.0	1.9	1.6	1.8	2.2
Boundary Waters Canoe Area	Boundary Waters	23	BOWA1	MN	47.95	91.50	3.0	2.6	2.7	2.4	2.3	2.9	3.1	3.4	3.5	2.8	3.2	3.2
Breton	Breton	20	BRET1	LA	29.73	88.88	3.7	3.5	3.7	3.6	3.8	4.0	4.3	4.3	4.2	3.7	3.7	3.7
Bridger	Bridger	65	BRID1	WY	42.98	109.76	2.5	2.4	2.3	2.2	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Brigantine	Brigantine	5	BRIG1	NJ	39.46	74.45	2.8	2.6	2.7	2.6	3.0	3.2	3.4	3.7	3.6	3.3	2.9	2.8
Bryce Canyon	Bryce Canyon	49	BRCA1	UT	37.62	112.17	2.6	2.4	1.9	1.6	1.5	1.3	1.3	1.5	1.5	1.6	2.0	2.4
Cabinet Mountains	Cabinet Mountains	75	CABI1	MT	48.21	115.71	3.8	3.3	2.9	2.6	2.7	2.7	2.3	2.2	2.6	3.0	3.7	3.9
Caney Creek	Caney Creek	29	CACR1	AR	34.41	94.08	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3.5
Canyonlands	Canyonlands	50	CANY1	UT	38.46	109.82	2.6	2.3	1.7	1.6	1.5	1.2	1.3	1.5	1.6	1.6	2.0	2.3
Cape Romain	Cape Romain	15	ROMA1	SC	32.94	79.66	3.3	3.0	2.9	2.8	3.2	3.7	3.6	4.1	4.0	3.7	3.4	3.2
Capitol Reef	Capitol Reef	52	CAPI1	UT	38.36	111.05	2.7	2.4	2.0	1.7	1.6	1.4	1.4	1.6	1.6	1.7	2.1	2.5
Caribou	Lassen Volcanic	90	LAVO1	CA	40.50	121.18	3.7	3.1	2.8	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.0	3.4
Carlsbad Caverns	Guadalupe Mountains	32	GUMO1	TX	32.14	104.48	2.1	2.0	1.6	1.5	1.6	1.6	1.8	2.1	2.2	1.8	1.9	2.1
Chassahowitzka	Chassahowitzka	18	CHAS1	FL	28.75	82.55	3.8	3.5	3.4	3.2	3.3	3.9	3.9	4.2	4.1	3.9	3.7	3.9
Chiricahua NM	Chiricahua	39	CHIR1	AZ	32.01	109.39	2.0	2.0	1.6	1.3	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Chiricahua W	Chiricahua	39	CHIR1	AZ	31.84	109.27	2.0	1.9	1.6	1.2	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Cohutta	Cohutta	12	COHU1	GA	34.92	84.58	3.3	3.1	3.0	2.8	3.4	3.8	4.0	4.2	4.2	3.8	3.4	3.5
Crater Lake	Crater Lake	86	CRLA1	OR	42.90	122.13	4.6	3.9	3.7	3.4	3.2	3.0	2.8	2.9	3.1	3.6	4.6	4.6
Craters of the Moon	Craters of the Moon	69	CRMO1	ID	43.47	113.55	3.1	2.7	2.3	2.0	2.0	1.8	1.4	1.4	1.6	2.0	2.8	3.0
Cucamonga	San Gabriel	93	SAGA1	CA	34.25	117.57	2.5	2.4	2.4	2.2	2.1	2.1	2.1	2.2	2.2	2.2	2.1	2.2
Denali	Denali	102	DENA1	AK	63.72	148.97	2.5	2.3	2.1	1.9	1.9	2.2	2.5	3.0	2.8	2.9	3.0	3.1
Desolation	Bliss	95	BLIS1	CA	38.98	120.12	3.2	2.8	2.4	2.0	1.8	1.6	1.5	1.6	1.7	1.9	2.4	3.0
Diamond Peak	Crater Lake	86	CRLA1	OR	43.53	122.10	4.5	4.0	3.6	3.7	3.2	3.1	2.9	2.9	3.1	3.7	4.6	4.6
Dolly Sods	Dolly Sods	8	DOSO1	WV	39.11	79.43	3.0	2.8	2.8	2.6	3.1	3.4	3.5	3.9	3.9	3.3	3.0	3.1

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Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Dome Land	Dome Land	109	DOME1	CA	35.70	118.19	2.5	2.3	2.2	1.9	1.8	1.8	1.8	1.8	1.8	1.9	2.0	2.2
Eagle Cap	Starkey	76	STAR1	OR	45.10	117.29	3.8	3.2	2.5	2.1	2.0	1.9	1.6	1.6	1.6	2.3	3.4	4.0
Eagles Nest	White River	56	WHRI1	CO	39.69	106.25	2.2	2.2	2.0	2.0	2.1	1.9	1.8	2.0	2.0	1.9	2.1	2.1
Emigrant	Yosemite	96	YOSE1	CA	38.20	119.75	3.2	2.8	2.5	2.1	1.9	1.7	1.5	1.6	1.6	1.9	2.4	2.9
Everglades	Everglades	19	EVER1	FL	25.39	80.68	2.7	2.6	2.6	2.4	2.4	2.7	2.6	2.9	3.0	2.8	2.6	2.7
Fitzpatrick	Bridger	65	BRID1	WY	43.27	109.57	2.5	2.3	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Flat Tops	White River	56	WHRI1	CO	39.97	107.25	2.3	2.2	2.0	2.0	2.0	1.8	1.7	1.9	1.9	1.8	2.2	2.2
Galiuro	Chiricahua	39	CHIR1	AZ	32.56	110.32	2.0	1.8	1.5	1.2	1.2	1.1	1.5	1.8	1.6	1.5	1.6	2.1
Gates of the Mountains	Gates of the Mountains	74	GAMO1	MT	46.87	111.81	2.9	2.6	2.4	2.3	2.3	2.3	2.0	1.9	2.1	2.4	2.8	2.8
Gearhart Mountain	Crater Lake	86	CRLA1	OR	42.49	120.85	4.0	3.4	3.1	2.8	2.7	2.5	2.3	2.3	2.4	2.8	3.7	3.8
Gila	Gila Cliffs	42	GICL1	NM	33.22	108.25	2.1	1.9	1.6	1.3	1.4	1.2	2.1	2.0	1.8	1.6	1.8	2.2
Glacier	Glacier	72	GLAC1	MT	48.51	114.00	4.0	3.5	3.2	3.1	3.2	3.4	2.8	2.6	3.2	3.5	3.8	3.9
Glacier Peak	North Cascades	81	NOCA1	WA	48.21	121.04	4.2	3.7	3.4	3.8	2.9	3.2	2.9	3.1	3.3	3.9	4.4	4.4
Goat Rocks	White Pass	79	WHPA1	WA	46.54	121.48	4.3	3.8	3.4	4.2	2.8	3.4	3.0	3.2	3.1	3.8	4.4	4.6
Grand Canyon	Grand Canyon, Hance	48	GRCA2	AZ	35.97	111.98	2.4	2.3	1.9	1.5	1.4	1.2	1.4	1.7	1.6	1.6	1.9	2.3
Grand Teton	Yellowstone	66	YELL2	WY	43.68	110.73	2.6	2.4	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.6
Great Gulf	Great Gulf	4	GRGU1	NH	44.31	71.22	2.8	2.6	2.6	2.8	2.9	3.2	3.5	3.8	4.0	3.4	3.1	2.9
Great Sand Dunes	Great Sand Dunes	53	GRSA1	CO	37.73	105.52	2.4	2.3	2.0	1.9	1.9	1.8	1.9	2.3	2.2	1.9	2.4	2.4
Great Smoky Mountains	Great Smoky Mountains	10	GRSM1	TN	35.63	83.94	3.3	3.0	2.9	2.7	3.2	3.9	3.8	4.0	4.2	3.8	3.3	3.4
Guadalupe Mountains	Guadalupe Mountains	32	GUMO1	TX	31.83	104.80	2.0	2.0	1.6	1.5	1.6	1.5	1.9	2.2	2.2	1.8	1.9	2.2
Haleakala	Haleakala	108	HALE1	HI	20.81	156.28	2.7	2.6	2.6	2.5	2.4	2.3	2.5	2.4	2.4	2.5	2.8	2.7
Hawaii Volcanoes	Hawaii Volcanoes	107	HAVO1	HI	19.43	155.27	3.2	2.9	3.0	3.0	3.0	2.9	3.1	3.2	3.2	3.2	3.7	3.2
Hells Canyon	Hells Canyon	77	HECA1	OR	45.34	116.57	3.7	3.1	2.5	2.2	2.1	2.0	1.6	1.6	1.8	2.4	3.5	3.9
Hercules - Glade	Hercules - Glade	28	HEGL1	MO	36.69	92.90	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Hoover	Hoover	97	HOOV1	CA	38.14	119.45	3.1	2.8	2.5	2.1	1.9	1.6	1.5	1.5	1.6	1.8	2.3	2.8
Isle Royale	Isle Royale	25	ISLE1	MI	47.99	88.83	3.1	2.5	2.7	2.4	2.2	2.6	3.0	3.2	3.8	2.7	3.3	3.3
James River Face	James River Face	7	JARI1	VA	37.62	79.48	2.8	2.6	2.7	2.4	3.0	3.3	3.4	3.7	3.6	3.2	2.8	3.0
Jarbidge	Jarbidge	68	JARB1	NV	41.89	115.43	3.0	2.6	2.1	2.1	2.2	2.2	1.6	1.4	1.4	1.6	2.4	2.8
John Muir	Kaiser	110	KAIS1	CA	37.39	118.84	2.9	2.6	2.4	2.1	1.9	1.7	1.7	1.7	1.7	1.9	2.2	2.6
Joshua Tree	Joshua Tree	101	JOSH1	CA	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Joyce Kilmer - Slickrock	Great Smoky Mountains	10	GRSM1	TN	35.43	84.00	3.3	3.1	2.9	2.7	3.3	3.8	4.0	4.2	4.2	3.8	3.3	3.5
Kaiser	Kaiser	110	KAIS1	CA	37.28	119.18	3.0	2.7	2.5	2.1	1.9	1.7	1.6	1.7	1.7	1.9	2.3	2.7
Kalmiopsis	Kalmiopsis	89	KALM1	OR	42.27	123.93	4.5	3.9	3.8	3.5	3.5	3.3	3.2	3.2	3.3	3.6	4.4	4.3
Kings Canyon	Sequoia	98	SEQU1	CA	36.82	118.76	2.8	2.6	2.4	2.1	1.9	1.8	1.7	1.7	1.8	1.9	2.3	2.5
La Garita	Weminuche	55	WEMI1	CO	37.96	106.81	2.3	2.2	1.9	1.8	1.8	1.6	1.7	2.1	2.0	1.8	2.2	2.3
Lassen Volcanic	Lassen Volcanic	90	LAVO1	CA	40.54	121.57	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5

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Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Lava Beds	Lava Beds	87	LABE1	CA	41.71	121.34	4.0	3.4	3.1	2.7	2.6	2.4	2.3	2.3	2.4	2.7	3.5	3.8
Linville Gorge	Linville Gorge	13	LIGO1	NC	35.89	81.89	3.3	3.0	3.0	2.7	3.3	3.9	4.1	4.5	4.4	3.7	3.2	3.4
Lostwood	Lostwood	62	LOST1	ND	48.60	102.48	3.0	2.9	2.9	2.3	2.3	2.6	2.7	2.4	2.3	2.4	3.2	3.2
Lye Brook	Lye Brook	3	LYBR1	VT	43.15	73.12	2.7	2.6	2.6	2.6	2.8	3.0	3.3	3.6	3.7	3.3	2.9	2.8
Mammoth Cave	Mammoth Cave	9	MACA1	KY	37.22	86.07	3.4	3.1	2.9	2.6	3.2	3.5	3.7	3.9	3.9	3.4	3.2	3.5
Marble Mountain	Trinity	104	TRIN1	CA	41.52	123.21	4.4	3.8	3.7	3.3	3.4	3.2	3.2	3.2	3.2	3.4	4.1	4.2
Maroon Bells - Snowmass	White River	56	WHRI1	CO	39.15	106.82	2.2	2.1	2.0	2.0	2.1	1.7	1.9	2.2	2.1	1.8	2.1	2.1
Mazatzal	Ike's Backbone	46	IKBA1	AZ	33.92	111.43	2.1	1.9	1.7	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Medicine Lake	Medicine Lake	63	MELA1	MT	48.50	104.29	3.0	2.9	2.9	2.3	2.2	2.5	2.5	2.2	2.2	2.4	3.2	3.2
Mesa Verde	Mesa Verde	54	MEVE1	CO	37.20	108.49	2.5	2.3	1.9	1.5	1.5	1.3	1.6	2.0	1.9	1.7	2.1	2.3
Mingo	Mingo	26	MING1	MO	36.98	90.20	3.3	3.0	2.8	2.6	3.0	3.2	3.3	3.5	3.5	3.1	3.1	3.3
Mission Mountains	Monture	73	MONT1	MT	47.40	113.85	3.6	3.1	2.7	2.5	2.6	2.6	2.3	2.2	2.5	2.9	3.5	3.6
Mokelumne	Bliss	95	BLIS1	CA	38.58	120.03	3.2	2.8	2.4	2.0	1.9	1.6	1.5	1.6	1.7	1.9	2.4	2.9
Moosehorn	Moosehorn	2	MOOS1	ME	45.12	67.26	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.2	3.2
Mount Adams	White Pass	79	WHPA1	WA	46.19	121.50	4.3	3.8	3.4	4.4	2.9	3.5	3.1	3.3	3.1	3.9	4.5	4.6
Mount Baldy	Mount Baldy	43	BALD1	AZ	34.12	109.57	2.2	2.0	1.7	1.4	1.3	1.2	1.6	1.9	1.7	1.6	1.8	2.2
Mount Hood	Mount Hood	85	MOHO1	OR	45.38	121.69	4.3	3.8	3.5	3.9	3.0	3.2	2.9	3.0	3.1	3.9	4.5	4.6
Mount Jefferson	Three Sisters	84	THSI1	OR	44.55	121.83	4.4	3.9	3.6	3.7	3.1	3.1	2.9	2.9	3.0	3.8	4.6	4.5
Mount Rainier	Mount Rainier	78	MORA1	WA	46.76	122.12	4.4	4.0	3.6	4.7	3.1	3.7	3.3	3.5	3.4	4.1	4.7	4.7
Mount Washington	Three Sisters	84	THSI1	OR	44.30	121.87	4.4	3.9	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Mount Zirkel	Mount Zirkel	58	MOZI1	CO	40.55	106.70	2.2	2.2	2.0	2.1	2.2	1.9	1.7	1.9	2.0	1.9	2.1	2.1
Mountain Lakes	Crater Lake	86	CRLA1	OR	42.34	122.11	4.3	3.6	3.3	3.0	2.9	2.6	2.5	2.5	2.6	3.1	4.1	4.3
North Absaroka	North Absoraka	67	NOAB1	WY	44.77	109.78	2.4	2.3	2.2	2.2	2.1	1.9	1.7	1.6	1.8	2.0	2.4	2.4
North Cascades	North Cascades	81	NOCA1	WA	48.54	121.44	4.1	3.7	3.4	3.7	2.9	3.2	2.9	3.2	3.5	3.9	4.4	4.4
Okefenokee	Okefenokee	16	OKEF1	GA	30.74	82.13	3.5	3.2	3.1	3.0	3.6	3.7	3.7	4.1	4.0	3.8	3.5	3.6
Olympic	Olympic	83	OLYM1	WA	47.32	123.35	4.5	4.1	3.8	4.1	3.2	3.5	3.1	3.5	3.7	4.4	4.8	4.8
Otter Creek	Dolly Sods	8	DOSO1	WV	39.00	79.65	3.0	2.8	2.8	2.6	3.2	3.5	3.7	4.1	4.0	3.3	3.0	3.1
Pasayten	Pasayten	82	PASA1	WA	48.85	120.52	4.2	3.7	3.4	3.7	2.9	3.2	2.9	3.2	3.3	3.9	4.4	4.5
Pecos	Wheeler Peak	35	WHPE1	NM	35.93	105.64	2.3	2.1	1.8	1.7	1.7	1.5	1.8	2.1	2.0	1.7	2.0	2.2
Petrified Forest	Petrified Forest	41	PEFO1	AZ	35.08	109.77	2.4	2.2	1.7	1.4	1.3	1.2	1.5	1.8	1.7	1.6	1.9	2.3
Pine Mountain	Ike's Backbone	46	IKBA1	AZ	34.31	111.80	2.2	2.0	1.7	1.4	1.3	1.1	1.4	1.8	1.6	1.5	1.7	2.1
Pinnacles	Pinnacles	92	PINN1	CA	36.49	121.16	3.2	2.8	2.6	2.4	2.3	2.0	2.0	2.1	2.1	2.3	2.5	2.9
Point Reyes	Point Reyes	91	PORE1	CA	38.12	122.90	3.6	3.3	3.1	2.7	2.5	2.3	2.5	2.6	2.6	2.7	2.9	3.3
Presidential Range - Dry River	Great Gulf	4	GRGU1	NH	44.21	71.35	2.8	2.6	2.6	2.8	3.0	3.4	3.7	4.0	4.3	3.5	3.1	3.0
Rawah	Mount Zirkel	58	MOZI1	CO	40.70	105.94	2.1	2.1	2.0	2.1	2.3	2.0	1.8	2.0	2.0	1.9	2.1	2.0
Red Rock Lakes	Yellowstone	66	YELL2	WY	44.67	111.70	2.7	2.5	2.3	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.6	2.7

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Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Redwood	Redwood	88	REDW1	CA	41.56	124.08	4.4	3.9	4.6	3.9	4.5	4.7	4.9	4.7	4.3	3.7	3.8	3.4
Rocky Mountain	Rocky Mountain	57	ROMO1	CO	40.28	105.55	1.7	1.9	1.9	2.1	2.3	2.0	1.8	2.0	1.9	1.8	1.8	1.7
Roosevelt Campobello	Moosehorn	2	MOOS1	ME	44.88	66.95	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.3	3.2
Saguaro	Saguaro	40	SAGU1	AZ	32.25	110.73	1.8	1.6	1.4	1.1	1.1	1.1	1.4	1.8	1.6	1.4	1.6	2.1
Saint Marks	Saint Marks	17	SAMA1	FL	30.12	84.08	3.7	3.4	3.4	3.4	3.5	4.0	4.1	4.4	4.2	3.8	3.7	3.8
Salt Creek	Salt Creek	36	SACR1	NM	33.61	104.37	2.1	1.9	1.5	1.5	1.7	1.6	1.8	2.0	2.1	1.8	1.8	2.1
San Gabriel	San Gabriel	93	SAGA1	CA	34.27	117.94	2.5	2.5	2.4	2.2	2.2	2.1	2.2	2.2	2.2	2.3	2.1	2.2
San Gorgonio	San Gorgonio	99	SAGO1	CA	34.18	116.90	2.7	2.8	2.6	2.3	2.2	1.9	1.8	1.9	1.9	1.9	1.9	2.2
San Jacinto	San Gorgonio	99	SAGO1	CA	33.75	116.65	2.5	2.4	2.4	2.2	2.1	2.0	2.1	2.1	2.1	2.1	2.0	2.1
San Pedro Parks	San Pedro Parks	34	SAPE1	NM	36.11	106.81	2.3	2.1	1.8	1.6	1.6	1.4	1.7	2.0	1.9	1.7	2.1	2.2
San Rafael	San Rafael	94	RAFA1	CA	34.78	119.83	2.8	2.7	2.7	2.4	2.3	2.3	2.5	2.5	2.4	2.5	2.3	2.5
Sawtooth	Sawtooth	70	SAWT1	ID	44.18	114.93	3.3	2.9	2.3	2.0	2.0	1.8	1.4	1.4	1.5	2.0	2.9	3.3
Scapegoat	Monture	73	MONT1	MT	47.17	112.73	3.2	2.8	2.6	2.4	2.5	2.4	2.1	2.0	2.3	2.6	3.1	3.1
Selway - Bitterroot	Sula	71	SULA1	MT	45.86	114.00	3.5	3.0	2.6	2.3	2.4	2.3	1.9	1.9	2.1	2.6	3.3	3.5
Seney	Seney	22	SENE1	MI	46.26	86.03	3.3	2.8	2.9	2.7	2.6	3.1	3.6	4.0	4.1	3.4	3.6	3.5
Sequoia	Sequoia	98	SEQU1	CA	36.50	118.82	2.5	2.4	2.4	2.2	1.9	1.8	1.7	1.6	1.8	1.9	2.3	2.3
Shenandoah	Shenandoah	6	SHEN1	VA	38.52	78.44	3.1	2.8	2.8	2.5	3.1	3.4	3.5	3.9	3.9	3.2	3.0	3.1
Shining Rock	Shining Rock	11	SHRO1	NC	35.39	82.78	3.3	3.0	2.9	2.7	3.4	3.9	4.1	4.5	4.4	3.8	3.3	3.4
Sierra Ancha	Sierra Ancha	45	SIAN1	AZ	33.82	110.88	2.1	2.0	1.7	1.3	1.3	1.1	1.5	1.8	1.6	1.5	1.7	2.1
Simeonof	Simeonof	105	SIME1	AK	54.92	159.28	4.3	4.1	3.6	3.9	3.9	4.3	5.0	5.2	4.5	3.8	4.0	4.3
Sipsey	Sipsey	21	SIPS1	AL	34.34	87.34	3.4	3.1	2.9	2.8	3.3	3.7	3.9	3.9	3.9	3.6	3.3	3.4
South Warner	Lava Beds	87	LABE1	CA	41.33	120.20	3.6	3.1	2.7	2.4	2.3	2.1	1.9	1.9	2.0	2.3	3.1	3.4
Strawberry Mountain	Starkey	76	STAR1	OR	44.30	118.73	3.9	3.3	2.8	2.9	2.3	2.4	2.0	2.0	1.9	2.6	3.7	4.1
Superstition	Tonto	44	TONT1	AZ	33.63	111.10	2.1	1.9	1.6	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Swanquarter	Swanquarter	14	SWAN1	NC	35.31	76.28	2.9	2.7	2.6	2.5	2.9	3.2	3.4	3.5	3.4	3.1	2.8	2.9
Sycamore Canyon	Sycamore Canyon	47	SYCA1	AZ	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Teton	Yellowstone	66	YELL2	WY	44.09	110.18	2.5	2.4	2.2	2.1	2.1	1.9	1.6	1.5	1.7	2.0	2.4	2.5
Theodore Roosevelt	Theodore Roosevelt	61	THRO1	ND	47.30	104.00	2.9	2.8	2.8	2.3	2.3	2.5	2.4	2.2	2.2	2.3	3.0	3.0
Thousand Lakes	Lassen Volcanic	90	LAVO1	CA	40.70	121.58	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5
Three Sisters	Three Sisters	84	THSI1	OR	44.29	122.04	4.5	4.0	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Tuxedni	Tuxedni	103	TUXE1	AK	60.15	152.60	3.5	3.3	2.9	2.7	2.7	2.9	3.6	4.0	3.9	3.5	3.5	3.7
UL Bend	UL Bend	64	ULBE1	MT	47.55	107.87	2.7	2.5	2.5	2.3	2.2	2.2	2.0	1.8	1.9	2.2	2.7	2.7
Upper Buffalo	Upper Buffalo	27	UPBU1	AR	35.83	93.21	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3
Ventana	Pinnacles	92	PINN1	CA	36.22	121.59	3.2	2.9	2.8	2.4	2.3	2.1	2.2	2.3	2.2	2.4	2.5	2.9
Virgin Islands (b)	Virgin Islands	106	VIIS1	VI	18.33	64.79												
Voyageurs	Voyageurs	24	VOYA2	MN	48.59	93.17	2.8	2.4	2.4	2.3	2.3	3.1	2.7	3.0	3.2	2.6	2.9	2.8

Guidance for Tracking Progress Under the Regional Haze Rule

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Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Washakie	North Absoraka	67	NOAB1	WY	43.95	109.59	2.5	2.3	2.2	2.1	2.1	1.8	1.6	1.5	1.8	2.0	2.4	2.5
Weminuche	Weminuche	55	WEMI1	CO	37.65	107.80	2.4	2.2	1.9	1.7	1.7	1.5	1.6	2.0	1.9	1.7	2.1	2.3
West Elk	White River	56	WHRI1	CO	38.69	107.19	2.3	2.2	1.9	1.9	1.9	1.7	1.8	2.1	2.0	1.8	2.1	2.2
Wheeler Peak	Wheeler Peak	35	WHPE1	NM	36.57	105.42	2.3	2.2	1.9	1.8	1.8	1.6	1.8	2.2	2.1	1.8	2.2	2.3
White Mountain	White Mountain	37	WHIT1	NM	33.49	105.83	2.1	1.9	1.6	1.5	1.5	1.4	1.8	2.0	2.0	1.7	1.8	2.1
Wichita Mountains	Wichita Mountains	30	WIMO1	OK	34.74	98.59	2.7	2.8	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8
Wind Cave	Wind Cave	60	WICA1	SD	43.55	103.48	2.5	2.5	2.5	2.5	2.7	2.5	2.3	2.3	2.2	2.2	2.6	2.6
Wolf Island	Okefenokee	16	OKEF1	GA	31.31	81.30	3.4	3.1	3.1	3.0	3.3	3.7	3.7	4.1	4.0	3.7	3.5	3.5
Yellowstone	Yellowstone	66	YELL2	WY	44.55	110.40	2.5	2.4	2.3	2.2	2.2	1.9	1.7	1.6	1.8	2.1	2.5	2.5
Yolla Bolly - Middle Eel	Trinity	104	TRIN1	CA	40.11	122.96	4.0	3.4	3.1	2.8	2.7	2.5	2.4	2.5	2.6	2.7	3.3	3.6
Yosemite	Yosemite	96	YOSE1	CA	37.71	119.70	3.3	3.0	2.8	2.3	2.1	1.8	1.5	1.5	1.5	1.8	2.4	2.8
Zion	Zion	51	ZION1	UT	37.25	113.01	2.7	2.4	2.0	1.6	1.5	1.3	1.2	1.4	1.4	1.6	2.0	2.4

a: No particulate matter sampling or visibility monitoring is conducted in the Bering Sea Wilderness.
b: *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-72:
EPA Carbon Dioxide Information

Carbon Dioxide Emissions

www.epa.gov/ghgemissions/carbon-dioxide-emissions

January 7, 2025

Properties of Carbon Dioxide

Chemical Formula: CO_2
Lifetime in Atmosphere: See reference[1]
Global Warming Potential (100-year): 1

On this page:

- Sources of Carbon Dioxide Emissions
- Carbon Dioxide Trends
- Reducing Carbon Dioxide Emissions

Sources of Carbon Dioxide Emissions

Carbon dioxide (CO_2) is the primary greenhouse gas emitted through human activities. In 2022, CO_2 accounted for 80% of all U.S. greenhouse gas emissions from human activities.

Carbon dioxide is naturally present in the atmosphere as part of the Earth's carbon cycle (the natural circulation of carbon among the atmosphere, oceans, soil, plants, and animals). Human activities are altering the carbon cycle, both by adding more CO_2 to the atmosphere and by influencing the ability of natural sinks, like forests and soils, to remove and store CO_2 from the atmosphere. While CO_2 emissions come from a variety of natural sources, human-related emissions are responsible for the increase that has occurred in the atmosphere since the industrial revolution.[2]

U.S. CO_2 Emissions, by Source

U.S. Carbon Dioxide Emissions, by Economic Sector

The net CO_2 flux from Land Use, Land-Use Change, and Forestry in the United States is not shown in the above diagram. All emission estimates are sourced from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022*. Note: "Other" includes CO_2 emissions from the following sources: Natural Gas Systems, Petrochemical Production, Petroleum Systems, Incineration of Waste, Lime Production, Ammonia Production, Other Process Uses of Carbonates, Urea Consumption for Non-Agricultural Purposes, Urea Fertilization, Carbon Dioxide Consumption, Liming, Coal Mining, Glass Production, Soda Ash Production, Titanium Dioxide Production, Aluminum Production, Ferroalloy Production, Zinc Production, Phosphoric Acid Production, Lead Production, Carbide Production and Consumption, Carbon Capture and Storage, Abandoned Oil and Gas Wells, Substitution of Ozone Depleting Substances and Magnesium Production and Processing.

The main human activity that emits CO_2 is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation. Certain industrial processes and land-use changes also emit CO_2. The main sources of CO_2 emissions in the United States are:

- **Transportation**. The combustion of fossil fuels such as gasoline and diesel to transport people and goods was the largest source of CO_2 emissions in 2022, accounting for 35% of total U.S. CO_2 emissions and 28% of total U.S. greenhouse gas emissions. This category includes domestic transportation sources such as highway and passenger vehicles, air travel, marine transportation, and rail.
- **Electricity**. Electricity is a key source of energy in the United States and is used to power homes, business, and industry. In 2022, the combustion of fossil fuels to generate electricity was the second largest source of CO_2 emissions in the nation, accounting for 30% of total U.S. CO_2 emissions and 24% of total U.S. greenhouse gas emissions. The types of fossil fuel used to generate electricity emit different amounts of CO_2. To produce a given amount of electricity, burning coal will produce more CO_2 than natural gas or oil.
- **Industry**. Many industrial processes emit CO_2 through fossil fuel consumption. Several processes also produce CO_2 emissions through chemical reactions that do not involve combustion, and examples include the production of mineral products such as cement, the production of metals such as iron and steel, and the production of chemicals. The fossil fuel combustion component of various industrial processes accounted for 16% of total U.S. CO_2 emissions and 13% of total U.S. greenhouse gas emissions in 2022. Many industrial processes also use electricity and therefore indirectly result in CO_2 emissions from electricity generation.
- **Land Use, Land-Use Change, and Forestry (LULUCF)**. In the United States, the management of forests and other land (e.g., cropland, grasslands, etc.) has acted as a net sink of CO_2, which means that more CO_2 is removed from the atmosphere, and stored in plants and trees, than is emitted. This carbon sink offset about 13% of total emissions in 2022.

Carbon dioxide is constantly being exchanged among the atmosphere, ocean, and land surface as it is both produced and absorbed by many microorganisms, plants, and animals. Emissions and removals of CO_2 by these natural processes, however, tend to balance over

time, absent anthropogenic impacts. Since the Industrial Revolution began around 1750, human activities have contributed substantially to climate change by adding CO_2 and other heat-trapping gases to the atmosphere.

To find out more about the role of CO_2 in warming the atmosphere, visit the Climate Change Indicators page.

Carbon Dioxide Trends

Carbon dioxide emissions in the United States decreased by 1.5% between 1990 and 2022, excluding LULUCF sinks. Since the combustion of fossil fuel is the largest source of greenhouse gas emissions in the United States, changes in emissions from fossil fuel combustion have historically been the dominant factor affecting total U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population growth, economic growth, changing energy prices, new technologies, changing behavior, and seasonal temperatures. In 2022, the increase in CO_2 emissions from fossil fuel combustion corresponded with an increase in energy use as a result of economic activity rebounding after the height of the COVID-19 pandemic, in addition to an increase in coal use in the electric power sector.

U.S. Carbon Dioxide Emissions, 1990-2022

Note: All emission estimates are sourced from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022*.

Image to save or print

Reducing Carbon Dioxide Emissions

The most effective way to reduce CO_2 emissions is to reduce fossil fuel consumption. Many strategies for reducing CO_2 emissions from energy are cross-cutting and apply to homes, businesses, industry, and transportation.

Strategy	Examples of How Emissions Can be Reduced
Energy Efficiency	Improving the insulation of buildings, traveling in more fuel-efficient vehicles, and using more efficient electrical appliances are all ways to reduce energy use, and thus CO_2 emissions. • See EPA's ENERGY STAR® program for more information on energy-efficient appliances and ways to save at home and work. • See EPA's and DOE's fueleconomy.gov site for more information on fuel-efficient vehicles. • Learn about EPA's motor vehicle standards that improve vehicle efficiency and save drivers money.
Energy Conservation	Reducing personal energy use by turning off lights and electronics when not in use reduces electricity demand. Reducing distance traveled in vehicles reduces petroleum consumption. Both are ways to reduce energy CO_2 emissions through conservation. Learn more about What You Can Do at Home, at School, in the Office, and on the Road to save energy and reduce your carbon footprint.
Fuel Switching	Producing more energy from renewable sources and using fuels with lower carbon contents are ways to reduce carbon emissions.
Carbon Capture and Sequestration (CCS)	Carbon dioxide capture and sequestration is a set of technologies that can potentially greatly reduce CO_2 emissions from new and existing coal- and gas-fired power plants, industrial processes, and other stationary sources of CO_2. For example, a CCS project might capture CO_2 from the stacks of a coal-fired power plant before it enters the atmosphere, transport the CO_2 via pipeline, and inject the CO_2 deep underground at a carefully selected and suitable subsurface geologic formation, such as a nearby abandoned oil field, where it is securely stored. Learn more about CCS.

Strategy	Examples of How Emissions Can be Reduced
Changes in Uses of Land and Land Management Practices	Learn more about Land Use, Land Use Change and Forestry Sector.

Examples of Reduction Opportunities for Carbon Dioxide

References

[1] Atmospheric CO_2 is part of the global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Some of the excess carbon dioxide will be absorbed quickly (for example, by the ocean surface), but some will remain in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments.

[2] IPCC (2021). Climate Change 2021: The Physical Science Basis. *Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2391 pp.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-73:
Craig Station Operating Permit

Colorado Department of Public Health and Environment

OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

96OPMF155

FACILITY ID: 081/0018

RENEWED: July 1, 2021
EXPIRATION DATE: July 1, 2026
MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON
Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010
And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation
Primary SIC: 4911

RESPONSIBLE OFFICIAL
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

FACILITY CONTACT PERSON
Name: Mike Tomasovic
Title: Environmental Supervisor
Phone: (970) 824-4411

SUBMITTAL DEADLINES –
Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31
Semi-Annual Monitoring Reports: Due February 1 & August 1
Annual Compliance Periods: January 1 – December 31
Annual Compliance Certification: Due February 1

Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

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

5. Compliance Assurance Monitoring (CAM)

5.1 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-control 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 in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling and Storage – Unit 3	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse
			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

Table 1 - Craig Station Emission Unit Summary

SECTION II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.) 4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1) SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)		CEMS	Continuous
Acid Rain	1.11	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual NO_x limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply 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 building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **NO_x limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV) 0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2) NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)		CEMS	Continuous
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 3 – Unit 2 Emissions and Requirements Summary

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

2.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

2.5 **Opacity**

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply 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 building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

2.10 Colorado Regulation No. 23, Regional Haze

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

2.11 **Acid Rain**

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

2.12 **40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units**

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

2.13 **Compliance Assurance Monitoring (CAM)**

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da) 0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 4 – Unit 3 Emissions and Requirements Summary

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10})** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of SO_2**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of SO_2 per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are

monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 **6,752 tons of NO_x per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly

NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

3.6 Opacity

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 5 - Subpart UUUUU Table 2 Requirements

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

5.4 **§63.10007 What methods and other procedures must I use for the performance tests?**

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

5.8 **§63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?**

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

5.10 **§63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?**

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

5.11 **§63.10030 What notifications must I submit and when?**

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 6 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	6.4	See Condition 6.4			
Equipment Operation	6.5	See Condition 6.5			
NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6	

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and PM_{10} emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 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 as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 8 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		

		F102g F102l			
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	7.4	See Condition 6.4			
Required Controls	7.5	See Condition 7.5			
NSPS Y	7.6	Opacity not to exceed 20%		See Condition 7.6	
CAM	7.7	Condition 7.7			

Table 9 - P102 Emissions and Requirements Summary

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 10 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Limestone Delivery	8.1				Recordkeeping	Annually
PM & PM_{10}	8.2	F201a		PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4				
Equipment Operation	8.5	See Condition 8.5				
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%				

Table 11 – P201 Emissions and Requirements Summary

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 12 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 14 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Ash Processed	10.1			Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c	PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4			

Table 15 – P203 Emissions and Requirements Summary

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 16 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%		
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28		

				Unpaved: 3.6 EF in lb per vehicle mile traveled		
Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4				

Table 17 – P204 Emissions and Requirements Summary

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 18 – S401 & S402 Emissions and Requirements Summary

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 19 – S403 Emissions and Requirements Summary

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether 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 (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **SO_2, NO_x (and diluent), CO_2, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet SO_2 and CO_2 monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **SO_2, NO_x, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

	2016	2017	2018	2019	2020	2021
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149
NO_X Limits	C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2))					

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Non-Applicable Requirement	Justification
B001 & B002 - Units 1 & 2	Construction Permit 10MF579 reference to May 1, 1973 Subpart D	The Units are subject to the most current version of Subpart D.
Facility-Wide	Colorado Regulation No. 1, V	Applies to coke ovens at Iron and steel plant operations only.
	Colorado Regulation No. 1, VII	Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado
	Colorado Regulation No. 1, VIII	Applies to listed stationary sources in the Denver PM_{10} nonattainment area only.
	Colorado Regulation No. 1, IX	Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide
	Colorado Regulation No. 4, and General Condition 31 of this permit	Sale and use of wood burning devices does not apply to the Craig Station
	Colorado Regulation No. 7, except for Part B, Section III	Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only.
	Colorado Regulation No. 8, Part D	Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision
	Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program	Subject matter does not cover the Craig facility.

	Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions	Geographic area of applicability does not include the Craig facility.
	Colorado Regulation No. 13 - The Oxygenated Fuels Program	Area of geographic applicability does not include the Craig facility.
	Colorado Regulation No. 16 - Street Sanding	Geographic area of applicability does not include the Craig facility.
	5CCR 1001-20 - Nonattainment Areas	Craig facility is not located in geographic areas classified as nonattainment.
	Colorado Regulation No. 19 - Lead Based Paint Abatement	Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards
	40 CFR Part 55 - Outer Continental Shelf Air Regulations	Craig facility is outside the geographic scope of this provision.
	40 CFR Part 56 - Regional Consistency	Relates to authorities within the various offices of the EPA.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Emission Unit Description & Number	Applicable Requirement	Justification
Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent.
Section II, Conditions 3.2.2 & 3.3.3	NSPS Da definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition.
Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Required quarterly reports	The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27%	This requirement is less strict than the BACT limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu	This requirement is less strict than the BACT PM limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements	Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits	Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations	The opacity condition has been streamlined out under BACT wherein records are already required
Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu	This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits.
Section II, Condition 4 (Units 1, 2, & 3)	NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2)	So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements.

Section II, Condition 13.1	Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * 10^6 gallons/year	This limit is merely the annualized PTE of the short term limit.
Section II, Condition 17.2 (Units 1 & 2)	Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing	Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent.
Section II, Condition 19 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section IV – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1, 2, & 3)	40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 (NO_x, SO_2, CO_2, and flow)	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.

SECTION V - General Permit Conditions (ver 1/21/2020)

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

A. Appendix A - Inspection Information

A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

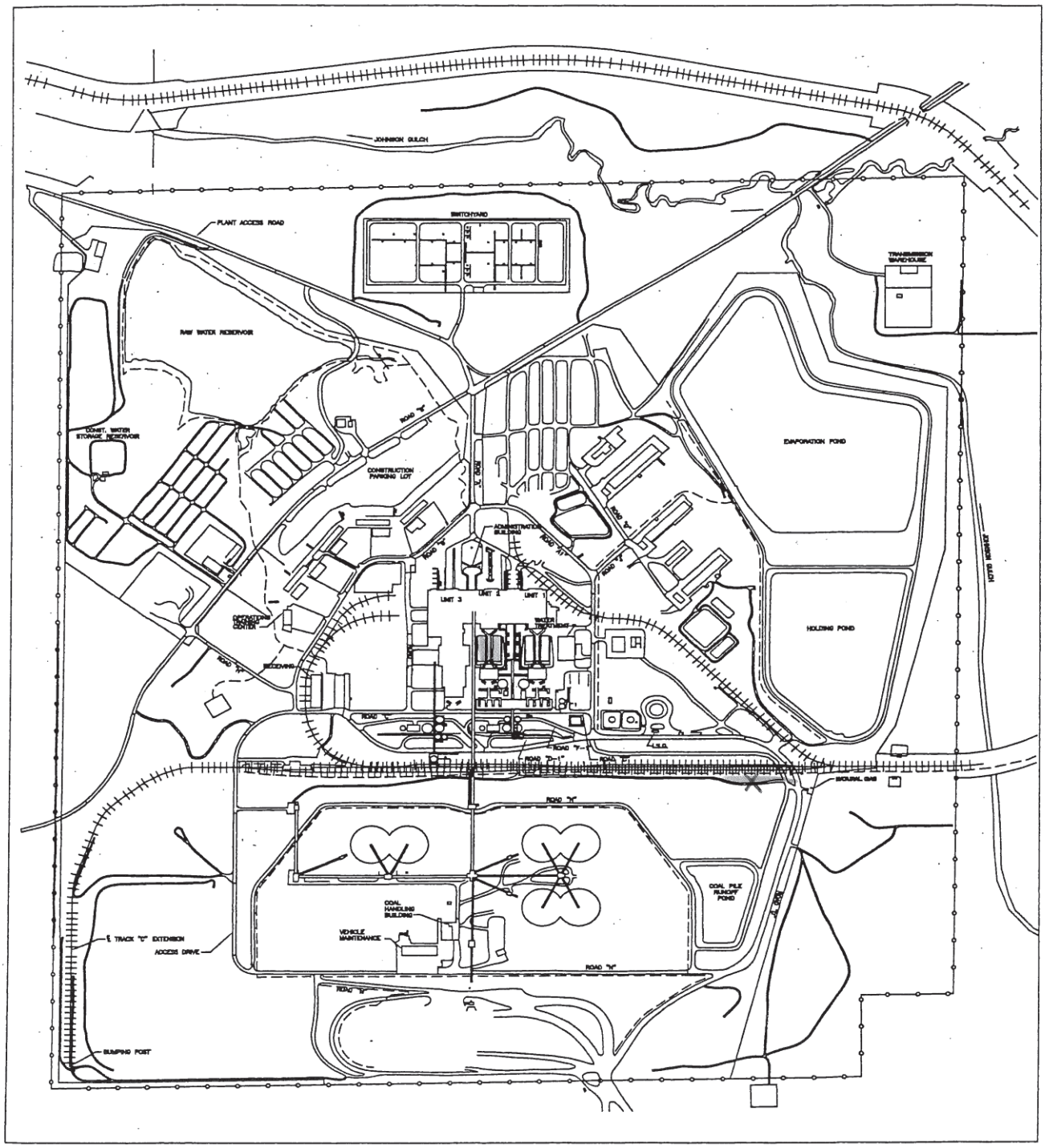
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

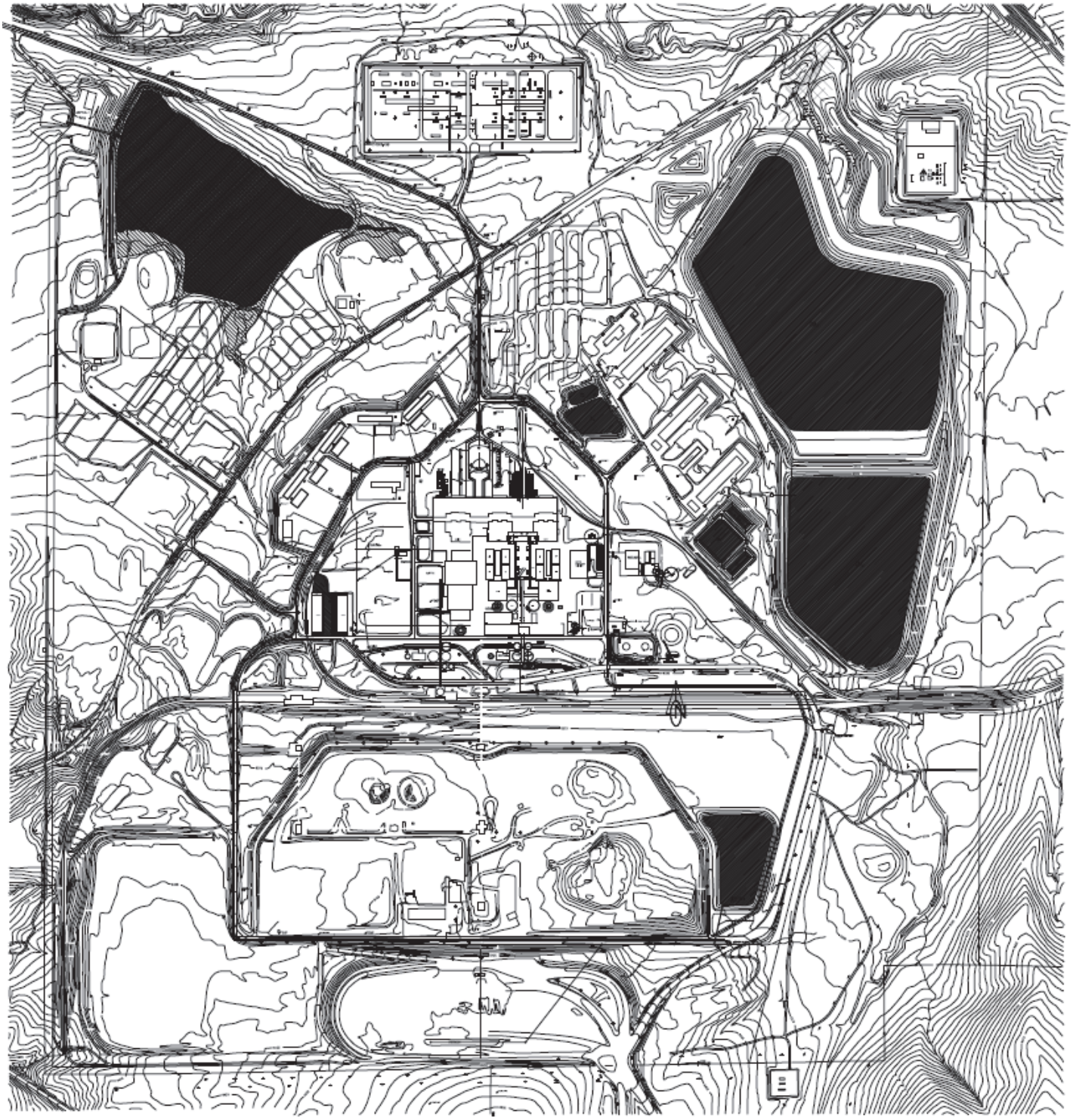
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
EVAPORATION POND
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
HOLDING POND
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUMPING POST



B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

Emission Unit	Facility ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/Emergency Condition Reported During Period?	
			YES	NO		YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157					
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156					
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602					
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2					
		F101b – Coal unloading to grizzly – Units 1 & 2					
		F101c – Coal surge pile					
		S101d – Primary coal crushing – Units 1 & 2					
		S101e – Secondary coal crushing building – Units 1 & 2					
		S101f – Common Coal Transfer Building Belt A					
		S101g – Common Coal Transfer Building Belt B					
		S101h – Coal stackout building – Units 1 & 2					
		F101i – Coal stackout – Units 1 & 2					
		F101j – Coal storage piles – Units 1 & 2					
		S101k – Coal reclaim A – Units 1 & 2					

		S101l – Coal reclaim B – Units 1 & 2					
		S101m – Coal tripper deck & silos – Units 1 & 2					
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2					
		S203b – Ash storage silo B – Units 1 & 2					
		F203c – Ash truck loading – Units 1 & 2					
		S203d – Silo B dry ash unloading – Units 1 & 2					
		S203e – Silo A dry ash unloading – Units 1 & 2					
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling					
		S201b – Limestone truck unloading					
		S201c – Limestone silo #1 – Units 1 & 2					
		S201d – Limestone silo #2 – Units 1 & 2					
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3					
		S102b – Coal conveyor portal building – Unit 3					
		S102c – Coal conveyor portal building – Unit 3					
		S102d – Secondary coal crushing (2 crushers) – Unit 3					
		S102e – Coal stackout building – Unit 3					
		F102f – Coal stackout – Unit 3					
		F102g – Coal storage pile – Unit 3					
		S102h – Coal reclaim system – Unit 3					
		S102i – Coal tripper deck & silos – Unit 3					
		S102j – Loadout coal to railcars – Unit 3					
		S102k – Common coal transfer building extension					
		F102l – Coal train loading					
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3					
		F204b – Ash truck loading – Unit 3					
		S204c – Recycle ash truck					
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3					
Lime Handling – Unit 3	P202	F202a – Lime hauling					
		S202b – Lime unloading					
		S202c – Lime conveying and silo					

		S202d – Lime day bin					
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74					
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74					
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79					
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower					
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower					
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower					
General Conditions							
Insignificant Activities							

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

B.II. Appendix B – Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction _____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

B.III. Appendix B – Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature of Responsible Official Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Emission Unit	Facility ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
			Previous	Current	YES	NO	YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157						
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156						
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602						
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2						
		F101b – Coal unloading to grizzly – Units 1 & 2						
		F101c – Coal surge pile						
		S101d – Primary coal crushing – Units 1 & 2						
		S101e – Secondary coal crushing building – Units 1 & 2						
		S101f – Common Coal Transfer Building Belt A						
		S101g – Common Coal Transfer Building						

		Belt B						
		S101h – Coal stackout building – Units 1 & 2						
		F101i – Coal stackout – Units 1 & 2						
		F101j – Coal storage piles – Units 1 & 2						
		S101k – Coal reclaim A – Units 1 & 2						
		S101l – Coal reclaim B – Units 1 & 2						
		S101m – Coal tripper deck & silos – Units 1 & 2						
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2						
		S203b – Ash storage silo B – Units 1 & 2						
		F203c – Ash truck loading – Units 1 & 2						
		S203d – Silo B dry ash unloading – Units 1 & 2						
		S203e – Silo A dry ash unloading – Units 1 & 2						
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling						
		S201b – Limestone truck unloading						
		S201c – Limestone silo #1 – Units 1 & 2						
		S201d – Limestone silo #2 – Units 1 & 2						
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3						
		S102b – Coal conveyor portal building – Unit 3						
		S102c – Coal conveyor portal building – Unit 3						
		S102d – Secondary coal crushing (2 crushers) – Unit 3						
		S102e – Coal stackout building – Unit 3						
		F102f – Coal stackout – Unit 3						
		F102g – Coal storage pile – Unit 3						
		S102h – Coal reclaim system – Unit 3						
		S102i – Coal tripper deck & silos – Unit 3						
		S102j – Loadout coal to railcars – Unit 3						
		S102k – Common coal transfer building extension						
		F102l – Coal train loading						
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3						
		F204b – Ash truck loading – Unit 3						

		S204c – Recycle ash truck						
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3						
Lime Handling – Unit 3	P202	F202a – Lime hauling						
		S202b – Lime unloading						
		S202c – Lime conveying and silo						
		S202d – Lime day bin						
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74						
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74						
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79						
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower						
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower						
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower						
General Conditions								
Insignificant Activities[4]								

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

D. Appendix D – Notification Addresses

D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

E. Appendix E – Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
SO_2 - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

F. Appendix F – Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

G.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).
II. Indicator Range	An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13.

G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM/PM_{10} requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons PM_{10}/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable PM/PM_{10}, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

H.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average.

H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

I.II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions	Differential Pressure Monitoring
Measurement Approach	Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active.	The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold.

	Indicator 1	Indicator 2
II. Indicator Range	An excursion is defined as any visible emissions seen during the Method 22 test. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria		
a. Data Representativeness	Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device.
b. Verification of Operational Status	The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation.	The pressure measurement system will alert the operator if the system is not functioning properly.
c. QA/QC Practices and Criteria	Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained.	The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source.
d. Monitoring Frequency	Monthly	Daily
e. Data Collection Procedures	The EPA Reference Method 22 procedures shall be followed.	The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged.
f. Averaging Time	N/A	N/A

I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

J. Appendix J – Units 1 and 2 Wet Limestone SO_2 Scrubbers Compliance Assurance Monitoring Plan

J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous SO_2 emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control SO_2 emissions.

J.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)

	Indicator 1
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control SO_2 emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with SO_2 CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 Regional Haze limits is acceptable monitoring for CAM.

J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

K. Appendix K – Unit 3 Lime Spray Dryer SO_2 Compliance Assurance Monitoring Plan

K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of SO_2, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of SO_2 per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous SO_2 emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control SO_2 emissions.

K.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu or any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control SO_2 emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an SO_2 CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 BACT and Regional Haze limits are acceptable monitoring for CAM.

K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous NO_x emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of NO_x emissions.

L.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control NO_x emissions.

L.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a NO_x CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous NO_x emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of NO_x emissions.

M.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control NO_x emissions.

M.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream.

M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a NO_x CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

N.I. Coal Sampling

N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

N.II. Sample Preparation and Laboratory Analyses

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

N.III. Chain-Of-Custody Method

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

N.IV. Coal Shipment and Sample Analysis Records

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-74:
March 2025 Field Inspection Report

COLORADO
Department of Public Health & Environment

Air Pollution Control Division
Field Inspection Report

DP
APCD RECEIVED 4/28/2025

COUNTY NUMBER: **081** SOURCE NUMBER: **0018**

DATE OF INSPECTION: **March 25, 2025** DATE REPORT SUBMITTED: **April 28, 2025**

COUNTY: **Moffat** INSPECTOR: **Christopher S. Reinhardt**

COMPANY: **Tri-State Generating and Transmission, Inc. – Craig Generating Station**

SITE LOCATION: **Craig Station 2101 South Ranney, Craig, Colorado 80234**

MAILING ADDRESS: **PO Box 33695, Craig, Colorado 80234**

CONTACT PERSON: **Brian Massengale** TIME: **9:00 AM**

TELEPHONE NO.: **720-539-0155** EMAIL: **bmassengale@tristategt.org**

PERMIT NO.: **96OPMF155**

SOURCE CLASS: Major ☒ SM-80 ☐ Syn Minor ☐ Minor ☐

INSPECTION TYPE: Full Compliance Evaluation ☒ Onsite Evaluation ☒
Partial Compliance Evaluation ☐ Offsite Evaluation ☐

Additional Inspection Records in File? Yes ☒ No ☐

HOURS: Travel & Prep: **30.0** Inspection: **3.0** Report: **17.0** Total: **50.0**

COMPLIANCE STATUS: IN COMPLIANCE ☐ OUT OF COMPLIANCE ☒

INTRODUCTION

An on-site full compliance inspection of the Tri-State Generation and Transmission Association, Inc. (Tri-State) – Craig Generating Station (Craig) coal fired boiler electricity generation facility located at 2101 S. Ranney, Craig, Moffat County, Colorado was conducted on March 25, 2025. Mr. Christopher S. Reinhardt, Field Enforcement Inspector for the Air Pollution Control Division (Division) contacted Mr. Brian Massengale, Senior Engineer, Environmental Services for Tri-State and scheduled the inspection. Mr. Massengale, Ms. Judy Thomas, Environmental Supervisor for Tri-State, Ms. Brenda Hershiser, Environmental Coordinator for Tri-State, Mr. Daniel Salgado, Senior Manager Air Quality for Tri-State, Mr. Stan Darveau, Operations Supervisor for Tri-State and Mr. Marc Mayzes, Senior Environmental Planner for Tri-State for Tri-State were present for the inspection. Mr. Massengale, Mr. Darveau, Ms. Thomas, and Ms. Hershiser provided a tour of the facility and process and production information to demonstrate compliance with Operating Permit 96OPMF155 Renewal 1, issued on July 1, 2021. Mr. Michael Kirby, CEMS Specialist for Tri-State was also present during portions of the inspection.

Source is in compliance with the permit expiration and renewal provisions of the General Permit Conditions of Operating Permit 96OPMF155. Operating Permit 96OPMF155 was renewed on July 1, 2021. A renewal Application will be due no later than July 1, 2025.

Craig Station is a coal-fired power plant with a total net electric generating capacity of ~1,303 megawatts from three individual combustion units. Units 1 and 2 each have a combustion design rating of 4,318 MMBtu/hour

each, and each unit has a net electrical generation capacity of 428 megawatts. Unit 1 began operating in 1980 and Unit 2 began operating in 1979. Unit 3 has a combustion design rating of 4,600 MMBtu/hour and a net electrical generation capacity of 447 megawatts. Unit 3 began operating in 1984. Units 1 and 2 originally were equipped with hot-side electrostatic precipitators (ESPs) to control PM emissions and wet limestone scrubbers to control SO_2 emissions; the Unit 1 and 2 ESPs were replaced with fabric filter baghouses in October 2003 and April 2004 respectively, at which times both units' wet scrubbers were upgraded and low NOx burners with over-fire air were added. Unit 3 is equipped with a baghouse to control PM emissions and a spray dryer scrubber to control SO_2 emissions. All three units are equipped with low-NOx burners with over-fire air to control NOx emissions and can use natural gas, propane, or fuel oil for start-up, shutdown, and flame stabilization. Unit 2 is equipped with Selective Catalytic Reduction (SCR) System for control of NOx that commenced operation in December 2017 to meet Regional Haze requirements. Unit 3 is equipped with a Selective Non-Catalytic Reduction (SNCR) System for control of NOx that commenced operation in December 2017 to meet Regional Haze requirements. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NOx limits effective January 1, 1997. Additional activities permitted to emit air pollution at the Craig facility include three evaporative water cooling towers (one for each unit), coal handling systems, ash handling systems, limestone and lime handling systems, a waste ash staging area and landfilling activities. Tri-State also indicated that an auxiliary boiler exists at the facility which is not connected to fuel lines and has not been operational for many years.

Unit 3 underwent a capacity increase project; the existing turbine generator was enhanced, allowing the unit to generate about 30 more megawatts than it could previously. Associated auxiliary equipment was enhanced. The project is permitted under PSD Permits 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4 and 98MF0141. The project was completed May 2009. Operating Permit 96OPMF155 with renewal on July 1, 2021 now covers Unit 3 operations and its associated equipment.

Boral Material Technologies, Inc. (Boral) which is also located at the facility owned and operated a fly ash transfer and loading area and equipment which was used to pneumatically transfer fly ash from trucks to rail (AIRS Point 048). The equipment was rarely used as demand for railcar fly ash was low and had not been used at all for several years. This equipment operated under Operating Permit 10OPMF367.CN. Operating Permit 10OPMF367.CN was cancelled effective June 16, 2021 and is not addressed in this inspection. The remaining flyash handling activities conducted by Boral are covered under Operating Permit 96OPMF155.

This compliance evaluation is focused on the time period of February 2024 – January 2025 ("inspection period").

POINT AIRS ID/PERMIT NUMBERS

The following points are covered by Operating Permit 96OPMF155, Issued July 1, 2021: (February 2024 – January 2025)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
and Storage – Unit 3			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

SOURCE COMPLIANCE HISTORY

- Sierra Club v. Tri-State et al., Civil Action No 96-N-2368 - Litigation initiated by the Sierra Club Inc. in 1996 alleged that Tri-State violated State and Federal laws related to opacity limits and failed to operate the facility consistent with good air pollution control practices from 1991 through 1996. A Consent Decree, signed by both parties on March 19, 2001, identified the specific issues, timelines for corrective actions, and consequences for continued non-compliance. The Consent Decree required Tri-State to construct baghouses to replace the electrostatic precipitators on Units 1 and 2 by December 31, 2003 (Unit 1) and June 30, 2004 (Unit 2). Compliance testing performed January 13, 2004 on Unit 1 indicated an average PM emission rate 0.006 lb/mmBtu, in compliance with that Unit's 0.03 lb/mmBtu emission limit. Compliance testing performed July 13, 2004 on Unit 2 indicated an average PM emission rate 0.005 lb/mmBtu, in compliance with that Unit's 0.03 lb/mmBtu emission limit. Tri-State is classified as a major emission source of air pollution for both PSD and Title V permitting applicability.

For Boilers 1 and 2, their cooling towers and associated coal, limestone and ash handling, Title V Operating Permit 96OPMF155 was issued May 1, 2005 which replaced PSD Permits 10MF579, 11MF276, 11MF332, 11MF415, 11MF994F and Construction Permits 96MF195, and 01MF0003. Boiler 3, its cooling tower and associated coal, limestone and ash handling are subject to PSD Permits 12MF322-1, 2, 3, and 4 and Construction Permit 98MF0141. The 130 mmBtu/hr auxiliary boiler at the facility, which was in service at the time, was subject to PSD Permit 12MF322-1A. The aux boiler and its associated permit are no longer active. Furthermore, the Consent Decree was terminated in 2006.

- Case 2011-003: The Division alleged numerous compliance issues with a stack test program and alleged a PM emissions exceedance. The Division questioned the probe and filter temperatures for particulate testing and Orsat results. Tri-State questioned the use of Method 202 for determining PM_{10} emissions claiming Method 201A should be used instead. The enforcement action was closed by means of a No Further Action Letter dated May 27, 2011.

- A 2012 inspection by the Division found the facility out of compliance for various excess SO_2 emissions events which occurred on October 15, 2011 – October 16, 2011. The issues were resolved by means of a Verbal Warning.

- A 2014 inspection by the Division found the facility out of compliance for having emissions in excess of an applicable SO_2 and opacity limit during the inspection period. The issues were resolved by means of a Verbal Warning.

- A 2016 inspection reported Tri-State Craig Station was determined to be out of compliance with Construction Permit No. 12MF322-1 for having three hours in which Unit 3 operated with emissions in excess of the 0.4 lb/MMBtu (three hour rolling average) SO_2 emission limit. All excess emissions were determined to be caused by a valid malfunction or startup event pursuant to the Affirmative Defense Provisions of the Colorado AQCC Common Provisions Regulation. Craig Station was found to be in compliance with all other applicable Operating Permits, Construction Permits, and AQCC Regulations. Enforcement discretion was advised, and thus, enforcement was not recommended.

- A 2018 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits for the Unit #2 Boiler, as the result of a valid malfunction, failed to accurately calculate fugitive emissions, resulting from a misunderstanding regarding whether Tri-State or Boral was required to calculate fugitive emissions for a 300 foot section of road used by Boral to haul ash at the facility, and failed to submit self-certification by the specified deadline for the Unit #3 Boiler, resulting from the steam turbine failing and requiring repair. The Affirmative defense was granted for the opacity exceedances, and enforcement discretion was granted for failing to correctly calculate fugitive emissions and failing to submit self-certification by the specified deadline. No enforcement was pursued.

- A 2019 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits, as the result of a valid malfunction, and for fugitive dust emissions for the ash handling system, as the result of a valid malfunction. The affirmative defense was granted for both non-compliance issues and no enforcement was pursued.

- A 2021 inspection reported that Tri-State was determined to be out of compliance for exceeding opacity limits, as the result of a valid malfunction, and failed to conduct a boiler tune-up on the #2 Boiler by the specified deadline as required by MACT Subpart UUUUU, as a result of COVID-19 restrictions. The opacity exceedance occurred as the result of a valid upset and qualified for the affirmative defense from enforcement which was granted, and the Division provided enforcement discretion regarding the late #2 Boiler tune up as it was the result of restrictions related to the COVID-19 Pandemic. No enforcement action was pursued.

- A 2022 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits as the result of valid malfunctions, exceeding BACT CO emissions limits as the result of a valid malfunction and submitting an Excess Emissions Report that did not include complete and accurate information. The opacity exceedances and CO exceedances were determined to be valid malfunctions, qualifying for the affirmative defense from enforcement. A Verbal Warning was issued on August 11, 2022 to resolve the incomplete and inaccurate Excess Emissions report after a complete and accurate revised report was submitted.

- A 2023 inspection reported that Tri-State Craig Station was determined to be out of compliance for

exceeding opacity limits as the result of valid malfunctions, exceeding the BACT SO2 limit for #3 Boiler as the result of a valid malfunction, and exceeding the mercury emissions limit for the #1 Boiler. The opacity exceedances and SO2 exceedance were determined to be valid malfunctions, qualifying for the affirmative defense from enforcement. A Verbal Warning was issued on June 22, 2023 to resolve non-compliance associated with the mercury emissions limit exceedance on the #1 Boiler.

- A 2024 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding Unit 2 and Unit 3 opacity limits as the result of valid malfunctions, exceeding the Unit 3, pounds per million Btu, 3- hour rolling average SO2 emissions limit as the result of a valid malfunction. The report also indicated that Tri-State Craig Station was determined to be out of compliance for failing to conduct EPA Method 9 Readings as required on the S101e - Units 1 and 2 Secondary Coal Crushing Building Dust Collector as a result of the catching fire, and being taken out of service and the S101k - Units 1 and 2 Coal Reclaim A Dust Collector the result of mechanical failure of the unit and unavailability of parts to effect repairs. The violations for failing to conduct required Method 9 readings were resolved with enforcement discretion. Finally, the inspection reported that Tri-State Craig Station was determined to be out of compliance for failing to monitor emissions to mercury for Unit 3. A verbal Warning was issued on April 8, 2024 to resolve this violation. No additional enforcement action was pursued.

NSPS/NESHAP/MACT APPLICABILITY

New Source Performance Standards requirements of 40 CFR 60, Subpart D: Standards of Performance for Fossil Fuel Fired Steam Generators applies to Unit 1 and Unit 2 at the facility.

New Source Performance Standards requirements of 40 CFR 60, Subpart Da: Standards of Performance for Electric Utility Steam Generating Units applies to Unit 3 at the facility.

New Source Performance Standards requirements of 40 CFR Part 60, Subpart Y: Standards for Coal Preparation Plants apply to the F102a – Coal Train Unloading; S102b & S102c – Coal Conveyors; S102h – Coal Reclamation System; S102j – Coal Loadout to Railcars; and F102l – Coal Train Loading.

Maximum Achievable Control Technology requirements of 40 CFR 63, Subpart UUUUU ("MATS"): National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units applies to Unit 1, Unit 2 and Unit 3 at the facility. The rule, often called the Mercury and Air Toxics Standards, shall be referred to as "MATS" hereinafter.

REPORTS

Title V Semi Annual Monitoring Reports ("SAR")

Period	Due	Received
1/1/2024 – 6/30/2024	8/1/2024	7/18/2024
7/1/2024 – 12/31/2024	2/1/2025	1/28/2025

Except as noted below no deviations were reported for the period of January 1, 2024 through June 30, 2024. Deviations were reported for the period of July 1, 2024 through December 31, 2024. The source reported fugitive particulate emissions for the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area which were determined to have occurred as the result of a valid upset. See Malfunction Section.

40 CFR 63.10010(h)(6)(i), 40 CFR 63.10010(h)(6)(ii), and 40 CFR 63.10020(d) require that Tri-State report as deviations any non-quality assurance/quality control related monitor downtime events. Tri-State reported periods of monitor downtime as deviations for the Units 1, 2 and 3 SO2 and Hg monitoring systems pursuant to these

requirements during the periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 1, 2024. However, these deviations did not result in excessive monitor downtime for any of monitoring systems nor did these deviations result in any excess emissions.

The reports described above were certified by a responsible official in accordance with the provisions of General Permit Condition #2.a. Semi-Annual Monitoring Reports were submitted in accordance with the provisions of General Permit Condition #22(d).

Title V Annual Compliance Certifications ("ACC")

Period	Due	Received
1/1/2024 – 12/31/2024	2/1/2025	1/28/2025

The same deviations as were reported in Semi-Annual Monitoring a Deviation Report for the periods of January 1, 2024 through June 30, 2023 and July 1, 2023 through December 31, 2023 were reported in the Annual Compliance Certification for the period of January 1, 2023 through December 31, 2023. See Malfunction Section.

The reports described above were certified by a responsible official in accordance with the provisions of General Permit Condition #2.a. Annual Compliance Certifications were submitted in accordance with the provisions of General Permit Condition #2.

MACT/NSPS Reports

Excess Emissions Reports (EERs) are submitted to the Division for purposes of NSPS Subpart D and Da and MACT Subpart UUUUU. See EERs section below.

Excess Emissions Reports ("EERs")

Tri-State Craig Station Unit 1: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	No excess emissions or excessive downtime reported during the period.
Q3-2024	11/1/2024	10/28/2024	No excess emissions or excessive downtime reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

Tri-State Craig Station Unit 2: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	No excess emissions or excessive downtime reported during the period.
Q3-2024	11/1/2024	10/28/2024	No excess emissions or excessive downtime reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

Tri-State Craig Station Unit 3: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	13.90% downtime reported for the Hg CMMS (see Condition 5.7.2). No excess emissions reported and no additional downtime in excess of 5% reported during the period.
Q3-2024	11/1/2024	10/28/2024	9.19% downtime reported for the Hg CMMS (see Condition 5.7.2). No excess emissions reported and no additional downtime in excess of 5% reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

All Excess Emissions Reports were submitted to the Division in a timely manner.

40 CFR 63, Subpart UUUUU ("MATS")

Type	Due	Received
Initial Notification of Applicability	8/16/2012	7/31/2012

The following reports were submitted to EPA's Central Data Exchange via CEDRI. The Certification Date is considered the date received.

Unit #	Report	Certification Date	Notes
1	63.10031(f)(6) MATS Report	5/30/2024	Unit 1 PM LEE Test Report, 1/17/2024. Result 0.010 lb/mmBtu. Limit 0.030 lb/mmBtu
2	63.10031(f)(6) MATS Report	5/30/2024	Unit 2 PM LEE Test Report, 1/18/2024. Result 0.009 lb/mmBtu. Limit 0.030 lb/mmBtu
1	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
1	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024),

Unit #	Report	Certification Date	Notes
			No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	8/28/2024	Unit 3 PM LEE Test Report, 6/15/2024. Result 0.004 lb/mmBtu. Limit 0.030 lb/mmBtu
1	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/10/2024
2	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/11/2024
3	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/13/2023 and 6/13/2024
1	63.10031(f)(6) MATS Report	8/29/2024	Annual RATA Report – Hg Monitoring (Pass) 6/10/2024
2	63.10031(f)(6) MATS Report	8/29/2024	Annual RATA Report – Hg Monitoring (Pass) 6/11/2024
3	63.10031(f)(6) MATS Report	8/29/2024	Annual Primary and Backup Hg Sorbent Trap RATAs – 6/13/2024 and 6/14/2024 – Pass both
1	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
1	63.10031(f)(6) MATS Report	2/12/2025	MATS Semi-Annual Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	2/12/2025	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).

Unit #	Report	Certification Date	Notes
3	63.10031(f)(6) MATS Report	2/12/2025	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).

(1) 40 CFR 63.10010(h)(6)(i), 40 CFR 63.10010(h)(6)(ii), and 40 CFR 63.10020(d) require that Tri-State report as deviations any non-quality assurance/quality control related monitor downtime events. Tri-State reported periods of monitor downtime as deviations for the Units 1, 2 and 3 SO2 and Hg monitors pursuant to these requirements during the periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 1, 2024. However, these deviations did not result in excessive monitor downtime for any of monitoring systems nor did these deviations result in any excess emissions.

APENS

APENs were submitted in accordance with the provisions of General Permit Condition 22(e).

AIRS Number	Description	Date Last APEN Was Received
001	Coal fired boiler - Unit 1	4/8/2024
002	Coal fired boiler - Unit 2	4/8/2024
003	Coal fired boiler - Unit 3	4/8/2024
004	Coal handling Units 1 and 2	4/8/2024
016	Ash handling Units 1 and 2	4/8/2024
020	Limestone handling Units 1 and 2	1/24/2025
023	Coal handling Unit 3	4/8/2024
032*	Ash handling Unit 3; haul road for ash and scrubber sludge Units 1, 2, 3	3/27/2023
035	Lime handling Unit 3	4/8/2024
040	Units 1 and 2 cooling towers	3/28/2022
044	Unit 3 cooling tower	4/26/2022
048**	Fly ash transfer and loading owned and operated by Boral Materials Technologies	NA Cancelled 6/16/2022

*Points 033 and 034 have been combined into Point 032.
**There is no further discussion of this point in this report. AIRS ID Point 048 was cancelled effective June 16, 2022.

APENs are due to the Division every 5 years barring any modification to the process or significant increase in emissions. All APENs are up to date.

MALFUNCTION REPORT REVIEW

8/16/2024, 10:30 – 11:30

Source claims upset due to the S203a Ash Storage Silo A knife gate and flow control valve being stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area violating Permit Condition 10.4.1 requiring that ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses.

Eco Material Technologies (Eco) which purchases flay ash form Tri-State operates the fly ash truck loading at the facility.

As soon as Tri-State became aware of this issue, Tri-State scrubber personnel put on appropriate respiratory gear entered the fly ash unloading room and closed the emergency Shutoff valve. The valve is located upstream of the knife gate and the flow control valve. The knife gate and flow control valve were found to be stuck open with debris. Eco then cleaned out the silo after being cleared to reenter the area and normal operations resumed that day.

While the unloading room was minimally affected by dust the truck load out drive-through building area has a small pile of 1-2 tons of fly ash. High winds dusted the area to the east of the silo, including C road. The dust issues on the roads were immediately taken care of with the water truck once the fly ash leak was secured. The scrubber cleaning crew was diverted to the drive-through for clean up as well.

The source reported that the prompt investigation, emergency shut off, and cleaning activities served to minimize dust emissions and potential impacts associated with the event. No EPA Method 9 Visible Emissions Observations were conducted related to the event, and Tri-State reported that no off property transport of visible emissions was observed during the event.

Plat Operations works to vacuum out hoppers following a compartment outage but cannot always ensure that foreign material remains clear of the feeders. During silo outages an inspection is performed to clean and remove any foreign objects from the unloading chutes. Most findings are from years of accumulation and are considered unavoidable.

The week following this incident, ECO personnel went through training and retraining on where the emergency shut-off valve is located and the emergency response and hazard communication plan. Part of this training included updating their phone numbers for Tri-State and understanding who to call if this reoccurs.

Tri-State also moved the controls for emergency shut-off valve to a more easily accessible location outside of the fly ash unloading room and added a screen in the duct to prevent debris from reach the knife gate and flow control valve.

This event which occurred on a Friday was reported by telephone as a malfunction on the next following business day Monday, August 19, 2024. A follow-up report was received by the Division on January 28, 2025. This event is considered to be a valid malfunction.

COMPLIANCE ASSISTANCE/SOURCE ACTIONS

None.

PERMIT CONDITIONS AND COMPLIANCE STATUS

This section follows the conditions of Operating Permit No. ***96OPMF155*** *issued to Tri-State on July 1, 2021. Inspector comments for each condition are marked in* ***bold font*** *for ease of identification. (February 2024 – January 2025)*

Section I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless

otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

No additional activities requiring a permit were observed during the inspection.

Source is in compliance.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

Source is in compliance.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit $\geq$ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit $\geq$ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

Craig Station is categorized as a major source for PSD provisions. Emissions have not increased such that a PSD modification has become required.

Source is in compliance.

4. Accidental Release Prevention Program (112(r))

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

The facility is subject to the Accidental Release Prevention Program.

Source is in compliance.

5. Compliance Assurance Monitoring (CAM)

5.1 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-control 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 in Colorado Regulation No. 3, Part C, Section XIV:

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

The source is conducting the required monitoring under the CAM requirements. See condition 22.

Source is in compliance.

6. Summary of Emission Units

See Tables under the Point AIRS ID/Permit Number Section.

Source is in compliance.

Section II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP) 0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)			
Acid Rain	0	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 1 - Unit 1 Emissions and Requirements Summary

Unit 1 was operating during the inspection with the following emissions and operational parameters as provided by the DAHS.

Craig Station: Unit 1 Emissions and Operational Parameters (1-minute average) 10:00	
Load (gross MW)	162
Opacity of Emissions (%)	4.36(1)
CO2 (%)	7.2
Flow (scfh)	43,311,204
NOX (lb/MMBtu)	0.201
SO2 (lb/MMBtu)	0.022
SO2 Removal (%)	96.3(2)
Stack Temp (°F)	100.1

(1) Opacity was obtained from the monitor in the CEMS Shack at approximately the 11:00 hour.
(2) SO2 removal percentage was obtained from the scrubber control room reported as hourly data for the 11:00 hour.

Criteria pollutant emissions from Unit #1, as reported by Tri-State for calendar year 2024, are given in the table below. The permit imposes no annual mass emissions limits for Unit 1. Emissions factors shown are based on the burning of coal only. Tri-State also calculates and reports emissions from burning natural gas and fuel oil.

Tri-State G&T – Unit #1 Emissions Summary as Reported			
Pollutant	**Emissions Factor (uncontrolled)**	**2024 Emissions (tons/year)**	**Calculation Method**
PM (tons/year)	0.0100 lbs/mmBtu	93.4	2021 Stack Test
PM_{10} (tons/year)	0.0092 lbs/mmBtu	85.9	2021 Stack Test
SO_2 (tons/year)	NA	335.4	CEMS
NO_x (tons/year)	NA	2,176.6	CEMS

VOC (tons/year)	0.0002 lbs/mmBtu	1.9	1999 Stack Test
CO (tons/year)	0.5 lbs/ton coal	239.1	AP 42

1.1 Particulate matter (PM) emissions must not exceed the following limits:

1.1.1 0.10 lb PM/MMBtu heat input, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 0.03 lb PM/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 0.03 lb PM/MMBtu heat input, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To demonstrate compliance with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

PM testing was conducted on January 18, 2024 with passing results as approved by the Division on February 26, 2024. Quarterly and tri-annual performance testing has shown compliance with the above-mentioned limits. The baghouse appears to be maintained in accordance with Section II, Condition 16.1. See inspector comments for Conditions 16.1 for further details. The source monitors opacity using continuous opacity monitoring. Given the low frequency of opacity exceedances, it can be assumed that the baghouse is operated in a manner consistent with good air pollution control practices. Tri-State calculates annual PM emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

1.2.2 1.2 lb/MMBtu heat input, three-hour rolling average, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

1.2.3 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

The facility monitors compliance with the 30-day rolling average SO_2 emission limit using CEMS. According to records provided by the facility, Unit 1 did not exceed this limit during this inspection period.

Source is in compliance with this condition.

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must treat one hundred percent (100%) of the flue gas from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

1.2.4.3 SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

All exhaust gas from Unit 1 is treated by the wet flue gas desulfurization ("WFGD") unit to remove SO_2 and acid gasses prior to discharge into the atmosphere. The source reported that Unit 1 operated with no emissions in excess of any SO_2 limit for the compliance period, which indicates good air pollution control.

The facility monitors compliance with the 30-day SO_2 emission limit using CEMS. According to records provided by Tri-State, Unit 1 did not exceed this limit during this inspection period.

The facility monitors compliance with the 90-day SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

The facility monitors compliance with the Unit 1 SO_2 reduction requirements using outlet CEMS and coal

analysis. According to records provided by the facility, the unit did not fail to meet 90% reduction requirement in any 90 day rolling average during this inspection period. During the inspection, the Unit 1 SO_2 removal rate was 96.3% as measured by the CEMS.

According to facility records, in no cases did the unit operate without achieving any SO_2 reduction during this inspection period.

Source is in compliance with this condition.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State monitors emissions of SO_2 using a CEMS as required and calculates SO_2 emissions consistent with the specified methodologies above. Tri-State calculates annual SO_2 emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source. Tri-State conducts operation and maintenance of the scrubber consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

1.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

1.3.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat

input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

The facility monitors compliance with the rolling three-hour NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.7 lbs/mmBtu on a 3-hour rolling basis during the inspection period.

Source is in compliance with this condition.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

The facility monitors compliance with the annual NO_X limit using CEMS as required. According to facility records, there were no violations of the annual 0.30 lbs/MMBtu NO_X limit during the inspection period. Reported emissions for data year 2024 were 0.22 lb/MMBtu. The boiler is equipped with low-NOx burners utilizing two stage combustion with supplemental over fire air as required.

Source is in compliance with this condition.

1.3.3 0.28 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

The facility monitors compliance with the 30-day rolling average NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.28 lb/MMBtu calculated on a 30-day rolling average during the inspection period.

Source is in compliance with this condition.

1.3.4 Craig Unit 1 must meet an annual NO_x limit of 4,065 tons per year by December 31, 2020 on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

The facility monitors compliance with the annual NO_X limit using CEMS. Annual NOx emissions for the 2024 calendar year was provided and is included in the table below.

Year	Reported Annual NOx Emissions (tons/yr)	*Annual NOx Emissions Limit (tons/yr)*
2024	2,176.6	*4,065*

Source is in compliance with this condition.

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Tri-State monitors emissions of NO_X using a CEMS as required and calculates NO_x emissions consistent with

the specified methodologies above.

Source is in compliance with this condition.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State calculates annual NO_x emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State reports annual emissions from Unit 1 on APENs as required using the appropriate emissions factors listed in the permit and from 1999 stack test data. The permit imposes no annual mass emissions limits for VOC or CO. Annual SO_2 and NO_x emissions are measured using the CEMS as required. The permit imposes no annual NO_X or SO_2 mass emissions limits. See the table above §II, Condition 1.1 for annual emissions from data year 2024 as reported by Tri-State.

Source is in compliance with this condition.

1.5 Opacity

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 1 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. No exceedances of opacity limits were reported during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

Unit 1 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply 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 building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify

the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

Unit 1 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Unit 1 is equipped with COMS as required. The source did not report any six-minute opacity averages in excess of the 20% opacity standard. Opacity in excess of any standard is reported on quarterly EERs as

required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. Method 9 has not been utilized for compliance with opacity requirements. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.5 Partial streamlining of opacity limits into State Implementation Plan opacity limits – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

Unit 1 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Annual fuel consumption records are maintained as required. Actual fuel consumption by Unit 1 for Calendar year 2024 are shown in the table below. Belt scale calibration reports for 2024 were reviewed. Belt scales are calibrated at least annually as required. Coal samples are taken and analyzed daily. See inspector comments for Condition 20 for further details.

Tri-State G&T – Craig Station Unit 1 Fuel Use			
Year	**Coal Consumed (tons)**	**Fuel Oil Consumed (gallons)**	**Natural Gas Consumed (Mcf)**
2024	956,258	42,339	54,517
Limit:	*NA*	*NA*	*NA*

Source is in compliance with this condition.

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

Unit 1 is equipped with continuous Opacity, SO_2, NO_x, CO_2, Hg and Flow monitors as required. All CEMS equipment were reported to be operating appropriately during the inspection. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 [Excess emissions reports] Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Unit 1 is equipped with continuous Opacity, SO_2 and NO_x monitors that conform to the requirement for 40 CFR Part 60 as required. Excess Emissions Reports are submitted as required. Tri-State did not report any exceedances of opacity limits nor, SO_2 or NO_x limits during the inspection period. Tri-State complies with the requirements of 40 CFR Part 60, Subpart A as required. See Conditions 18 and 19.

Source is in compliance with this condition.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

No evidence was observed or discovered during the inspection to indicate that Tri-State is not operating and maintaining the subject equipment in a manner consistent with good air pollution control practices for minimizing emissions. Quarterly EERs are submitted as required containing the required information. No exceedances of NO_x or SO_2 limits were reported during the inspection period.

Source is in compliance with this condition.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual NO_x limit of 4,065 tons per year by December 31, 2019 on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State has instated and operates a continuous NOx monitor at the facility consistent with the requirements of 40 CFR Part 75 and 60. Tri-State submits quarterly EERs as required. No exceedances of the NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average were reported during the inspection period. CEMS Data and QA/QC records are maintained as required. CAM provisions are addressed as required in Semi-Annual Reports. Test reports are submitted as required. The facility monitors compliance with the annual NO_X limit using CEMS. Annual NOx emissions for the 2024 calendar year was provided and is included in the table below.

Year	Reported Annual NOx Emissions (tons/yr)	*Annual NOx Emissions Limit (tons/yr)*
2024	2,176.6	*4,065*

Source is in compliance with this condition.

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Tri-State is considered to be in compliance with the requirements of 40 CFR Part 63, Subpart UUUUU with regard to Unit 1. See Condition 5.

Source is in compliance with this condition.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

Tri-State is conducting monitoring under the CAM requirements as required. See Condition 22.

Source is in compliance with this condition.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP) 0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)			
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 2 – Unit 2 Emissions and Requirements Summary

Unit 2 was operating during the inspection with the following emissions and operational parameters as reported by the DAHS except as noted.

Craig Station: Unit 2 Emissions and Operational Parameters (1-minute average) 10:00	
Load (gross MW)	164
Opacity of Emissions (%)	2.35(1)
CO2 (%)	7.5
Flow (scf/h)	52,421,850
NOX (lb/MMBtu)	0.037
SO2 (lb/MMBtu)	0.027
SO2 Removal (%)	96.6(2)
Stack Temp (°F)	101.4

(1) Opacity data was obtained from the monitor in the CEMS Shack at approximately the 11:00 hour.
(2) SO2 removal percentage was obtained from the scrubber control room reported as hourly data for the 11:00 hour.

Criteria pollutant emissions from Unit 2, as reported by Tri-State for calendar year 2023, are given in the table below. The permit imposes no annual mass emissions limits for Unit 2. Emissions factors shown are based on the burning of coal only. Tri-State also calculates and reports emissions from burning natural gas and fuel oil.

Tri-State G&T – Unit 2 Emissions Summary as Reported			
Pollutant	**Emissions Factor (uncontrolled)**	**2024 Emissions (tons/year)**	**Calculation Method**
PM (tons/year)	0.0120 lbs/mmBtu	81.2	2021 Stack Test
PM_{10} (tons/year)	0.0110lbs/mmBtu	74.7	2021 Stack Test
SO_2 (tons/year)	NA	302.7	CEMS
NO_x (tons/year)	NA	618.0	CEMS
VOCs (tons/year)	0.0002 lbs/mmBtu	1.8	1999 Stack Test and AP 42
CO (tons/year)	0.5 lbs/ton coal	231.6	AP 42

2.1 Particulate matter (PM) emissions must not exceed the following limits:

2.1.1 0.10 lb/MMBtu heat input, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 0.03 lb PM/MMBtu heat input, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To demonstrate compliance with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

Performance testing performed July 13, 2004 averaged 0.005 lb/mmBtu. Quarterly filterable PM testing was

performed quarterly from the second quarter of 2015 through the first quarter of 2018 for purposes of qualifying as a low emitting EGU ("LEE") for MATS. MATS PM testing is now required every three years and was conducted again in the first quarter of 2024 on January 18, 2024 with passing results as approved by the Division on February 26, 2024. Quarterly performance testing and tri-annual performance testing has shown compliance with the above-mentioned limits. The baghouse is maintained in accordance with Section II, Condition 16.1. See inspector comments for Conditions 16.1 for further details. The source monitors opacity using continuous opacity monitoring. Given the low frequency of opacity exceedances, it can be assumed that the baghouse is operated in a manner consistent with good air pollution control practices. Tri-State calculates annual PM emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

2.2 Sulfur dioxide (SO_2) emissions must not exceed the following limits:

2.2.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

2.2.2 1.2 lb/MMBtu, three-hour rolling average, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

2.2.3 0.11 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

The facility monitors compliance with the 30-day rolling average SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

Source is in compliance with this condition.

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must treat one hundred percent (100%) of the flue gas from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

All exhaust gas from Unit 2 is treated by the wet flue gas desulfurization ("WFGD") unit to remove SO_2 and acid gasses prior to discharge into the atmosphere. The source reported that Unit 2 operated with no emissions in excess of any SO_2 limit for the compliance period, which indicates good air pollution control.

The facility monitors compliance with the 30-day SO_2 emission limit using CEMS. According to records provided by Tri-State, Unit 2 did not exceed this limit during this inspection period.

The facility monitors compliance with the 90-day SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

The facility monitors compliance with the Unit 2 SO_2 reduction requirements using outlet CEMS and coal analysis. According to records provided by the facility, the unit did not fail to meet 90% reduction requirement in any 90 day rolling average during this inspection period. During the inspection, the Unit 2 SO_2 removal rate was 96.6% as measured by the CEMS.

According to facility records, in no cases did the unit operate without achieving any SO_2 reduction during this inspection period.

Source is in compliance with this condition.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State monitors emissions of SO_2 using a CEMS as required and calculates SO_2 emissions consistent with the specified methodologies above. Tri-State calculates annual SO_2 emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source. Tri-State conducts operation and maintenance of the scrubber consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

2.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

2.3.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the

applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

The facility monitors compliance with the rolling three-hour NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 2 NO_X emissions did not exceed 0.7 lbs/mmBtu on a 3-hour rolling basis during the inspection period.

Source is in compliance with this condition.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

The facility monitors compliance with the annual NO_X limit using CEMS as required. According to facility records, there were no violations of the annual 0.30 lbs/MMBtu NO_X limit during the inspection period. Reported emissions for data year 2024 were 0.057 lb/MMBtu. The boiler is equipped with low-NOx burners utilizing two stage combustion with supplemental over fire air as required.

Source is in compliance with this condition.

2.3.3 0.08 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

The facility monitors compliance with the 30-day rolling average NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.08 lb/MMBtu calculated on a 30-day rolling average during the inspection period.

Source is in compliance with this condition.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Tri-State monitors emissions of NO_X using a CEMS as required and calculates NO_x emissions consistent with the specified methodologies above.

Source is in compliance with this condition.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State calculates annual NO_x emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State reports annual emissions from Unit 2 on APENs as required using the appropriate emissions factors listed in the permit and from 1999 stack test data. The permit imposes no annual mass emissions limits for VOC or CO. Annual SO_2 and NO_x emissions are measured using the CEMS as required. The permit imposes no annual NO_X or SO_2 mass emissions limits. See the table above §II, Condition 2.1 for annual emissions from data year 2024 as reported by Tri-State.

Source is in compliance with this condition.

2.5 Opacity

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 2 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

Unit 2 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 2.35%. The source did not report any exceedances of opacity limits during the inspection period.

Source is in compliance with this condition.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply 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 building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

Unit 2 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Unit 2 is equipped with COMS as required. The source did not monitor compliance with opacity requirements with EPA Method 9 during the inspection period. Opacity in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was operating, and the opacity as read by the COMS was 2.35%. Method 9 has not been utilized for compliance with opacity requirements. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.5 Partial streamlining of opacity limits into State Implementation Plan opacity limits – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions

2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

Unit 2 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was operating and the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Annual fuel consumption records are maintained as required. Actual fuel consumption by Unit 1 for Calendar year 2024 are shown in the table below. Belt scale calibration reports for 2024 were reviewed. Belt scales are calibrated at least annually as required. Coal samples are taken and analyzed daily. See inspector comments for Condition 20 for further details.

Tri-State G&T – Craig Station Unit 2 Fuel Use

Year	Coal Consumed (tons)	Fuel Oil Consumed (gallons)	Natural Gas Consumed (Mcf)
2024	926,371	29,484	66,030
Limit:	*NA*	*NA*	*NA*

Source is in compliance with this condition.

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

Unit 2 is equipped with continuous Opacity, SO_2, NO_x, CO_2, Hg and Flow monitors as required. All CEMS equipment were reported to be operating appropriately during the inspection. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Unit 2 is equipped with continuous Opacity, SO_2 and NO_x monitors that conform to the requirement for 40 CFR Part 60 as required. Excess Emissions Reports are submitted as required. Tri-State did not report any exceedances of opacity limits, nor SO_2 or NO_x limits during the inspection period. Tri-State complies with the requirements of 40 CFR Part 60, Subpart A as required. See Conditions 18 and 19.

Source is in compliance with this condition.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component,

unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

No evidence was observed or discovered during the inspection to indicate that Tri-State is not operating and maintaining the subject equipment tin a manner consistent with good air pollution control practices for minimizing emissions. Quarterly EERs are submitted as required containing the required information. No exceedances of NO_x or SO_2 limits were reported during the inspection period.

Source is in compliance with this condition.

2.10 Colorado Regulation No. 23, Regional Haze

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State submits quarterly EERs as required. No exceedances of the NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average were reported during the inspection period. CEMS Data and QA/QC

records are maintained as required. CAM provisions are addressed as required in Semi-Annual Reports. Test reports are submitted as required.

Source is in compliance with this condition.

2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Tri-State is in compliance with the requirements of 40 CFR Part 63, Subpart UUUUU with regard to Unit 2. See Condition 5.

Source is in compliance with this condition.

2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, And L.

Tri-State is conducting monitoring under the CAM requirements as required. See Condition 22.

Source is in compliance with this condition.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da)	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 3 – Unit 3 Emissions and Requirements Summary

Unit 3 was not operating during the inspection with the following emissions and operational parameters.

Tri-State G&T Craig Station Unit 3 Emissions and Operational Parameters (1-minute average)	
Load (gross MW)	0
Opacity of Emissions (%)	0
CO2 (%)	0
Flow (scf/h)	0
NOx (lb/MMBtu)	0
SO2 (lb/MMBtu)	0
SO2 Removal (%)	NA
CO lb/MMBtu	0
Stack Temp (°F)	NA

3.1 Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10}) emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 [Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 [Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 [Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 [Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 0.03 lb PM/MMBtu, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To demonstrate compliance with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

Tri-State is required to conduct stack testing bi-annually for compliance with BACT PM limits. The most recent testing for PM was conducted on June 5, 2024 with passing results. The Division reviewed and approved this testing on August 21, 2024. Tri-State is currently required to conduct testing for compliance with the MATS low emissions emitter (LEE) limit for PM every three years. The June 5, 2024 testing indicated compliance with the MATS LEE PM requirements. Tri-State is implementing the measures in the CAM Plan as required. The baghouse is operated and maintained as required. Annual emissions of PM and PM10 are calculated using the specified calculation methodology on a rolling 12-month total as required. Records of annual PM and PM 10 emissions were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual emissions limits.

Tri-State G&T Craig Station Unit 3 Annual Coal PM and PM10 Emissions		
Period	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	94.6	73.6
1/2024-12/2024	66.4	47.0
2/2024-1/2025	61.8	42.8
Limits:	*443*	*403*

Source is in compliance with this condition.

3.2 Sulfur dioxide (SO_2) emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 0.20 lb/MMBtu heat input, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 80% reduction of the potential combustion concentration of SO_2, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test

is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 2,125 tons of SO_2 per year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Compliance with the daily average limit and reduction limit is monitored using inlet and outlet SO_2 – diluent CEMS. Diluent capping is applied when applicable. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The source reported achieving 80% SO_2 reduction on a 30 day rolling average at all times during the inspection period. The source did not report any daily SO2 average emissions periods in excess of the 0.20 lb/MMBtu daily average limit during the inspection period.

The SO_2 outlet CEMS is used to calculated annual emissions of SO_2 on a rolling 12-month total as required. Annual SO_2 emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual SO_2 emissions limit.

Tri-State G&T Craig Station Unit 3 Annual SO_2 Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	SO_2
3/2022-2/2024	1,165.1
1/2024-12/2024	666.1
2/2024- 1/2025	603.0
Limits:	*2,125*

Source is in compliance with this condition.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup,

shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 0.4 lb/MMBtu heat input, 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 0.15 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Compliance with the SO_2 limits and SO_2 reduction limits are monitored using inlet and outlet SO_2 – diluent CEMS. The SO_2 CEMS are operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The source reported achieving 70% SO_2 reduction on a 30 day rolling average at all times during the inspection period. Tri-State did not report any exceedances of SO_2 limits during the inspection period. Annual emissions of SO_2 are calculated and reported as required. Operation and maintenance of the scrubber is conducted consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

3.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 6,752 tons of NO_x per year, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 0.28 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 0, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission

rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

Compliance with the NOx limits is monitored using a CEMS. The NOx CEMS is operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. Tri-State did not report any exceedances of NOx limits during the inspection period. Annual emissions of NOx are calculated and reported as required. Annual NOx emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual NOx emissions limit.

Tri-State G&T Craig Station Unit 3 Annual Coal NOx Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	NOx
3/2023-2/2024	2,209.7
1/2024-12/2024	1,485.0
2/2024- 1/2025	1,353.0
Limits:	*6,752*

Source is in compliance with this condition.

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to 1.25 lb/MMBtu on an 8-hour rolling average. The Source must comply with Best Available Control

Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 4,332 tons of CO per year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

Compliance with the CO limits is monitored using a CEMS. The CO CEMS is operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. Tri-State did not report any exceedances of CO limits during the inspection period. Annual emissions of CO are calculated and reported as required. Annual CO emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual CO emissions limit.

Tri-State G&T Craig Station Unit 3 Annual CO Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	CO
3/2023-2/2024	656.7
1/2024-12/2024	396.2
2/2024- 1/2025	351.1
Limits:	*4,332*

Source is in compliance with this condition.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 VOC: 58 tons per year

3.5.1.2 Lead (Pb): 0.054 tons per year

3.5.1.3 Sulfuric Acid Mist (SAM): 0.10 tons per year

3.5.1.4 Fluorides: 4.47 tons per year

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 3, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

Annual emissions of VOC, Lead (Pb), Sulfuric Acid Mist (SAM) and Fluorides are calculated using the specified methodology on a rolling 12-month total as required. Annual emissions records of VOC, Lead, Sulfuric Acid Mist and Fluorides were provided and are summarized in the table below. A review of records submitted indicates that the VOC, Lead, Sulfuric Acid Mist and Fluorides emissions limits have not been exceeded.

Tri-State G&T Craig Station Unit 3 Annual VOC, Pb, SAM and Fluorides Emissions				
Period	**Reported Annual Emissions (tons/yr)**			
	VOC	**Pb**	**SAM**	**Fluorides**
3/2023-2/2024	32.4	0.012	0.05	1.05
1/2024-12/2024	23.0	0.008	0.04	0.74
2/2024- 1/2025	21.4	0.007	0.04	0.69
Limit:	*58*	*0.054*	*0.10*	*4.47*

Source is in compliance with this condition.

3.6 Opacity

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection period. Opacity in excess of any standard is reported on quarterly EERs as required. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection period. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Compliance with opacity limits is monitored with a COMS. The COMs is operated and maintained consistent with the requirements of 40 CFR Part 60. The source did not monitor compliance with opacity with EPA Method 9 during the inspection period. The source was not operating at the time of the inspection. No visible emissions were observed during the inspection. (see Conditions 3.8 and 19)

Source is in compliance with this condition.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

Coal consumption is tracked by the source on a monthly and 12-month rolling basis as required. The 12-month rolling total coal consumption records were provided for the inspection period and are summarized in the table below. The facility uses coal delivery records to comply with this condition, and maintains copies of its coal suppliers' annual scale calibrations. A review of records provided indicates that Tri-State has not exceeded the annual coal consumption limit.

Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Tri-State G&T Craig Station Unit 3 Annual Coal Consumption	
Period	**Reported Annul Coal Consumption (tons/yr)**
3/2023-2/2023	1,072,611
1/2024-12/2024	739,506
2/2024- 1/2025	685,170
Limit:	*1,897,344*

Source is in compliance with this condition.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

This source has installed, certified and maintains a CEMS in accordance with the requirements of 40 CFR 60 and 40 CFR 75. Unit 3 is equipped with opacity, SO_2, NO_x, CO_2, CO and flow monitors. In addition, each inlet (inlet A, B, C and D) to the FGD is equipped with SO_2 and CO_2 monitoring systems to determine inlet SO_2 lbs/mmBtu rates. Those rates are compared to outlet emission rates to determine reduction efficiency of the FGD. Passing RATAs were performed on each CEMS on June 14, 2024. This RATA testing was reviewed and approved by the Division on August 21, 2024. RATAs were also performed on each inlet CEMS for each test program. The source performs Part 75 Linearity Checks on a quarterly basis as required. Daily calibrations are performed as required. Compliance with 40 CFR 60 CEMS requirements is assumed by complying with Part 75 requirements.

Source is in compliance with this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 Affirmative defense for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 Reporting requirements, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Tri-State is submitting NSPS Subparts Dc and A reports quarterly attached to excess emissions reports. No deviations from NSPS Subparts Dc and A requirements were reported during the inspection period.

Source is in compliance with this condition.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State maintains records for five years as required. Excess Emissions reports are submitted quarterly and contain the required information. Stack testing reports for PM emissions tests are submitted within 60 days as required. CAM excursions are reported as required in the Semi-Annual Monitoring Reports. APENs for the facility are submitted as required and are up to date.

Source is in compliance with this condition.

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Source is in compliance with the requirements of 40 CFR 63, Subpart UUUUU, see Condition 5.

Source is in compliance with this condition.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 0. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, And M.

Source is in compliance with CAM requirements, See conditions 3.1, 3.2, and 3.3. CAM requirements are monitored consistent with the requirements in Condition 22 and Appendices H, K, and M.

Source is in compliance with this condition.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

Tri-State maintains records of annual fuel usage and reports fuel use on annual APENs as required. The boilers operate almost exclusively on coal. The annual heat content of alternative fuels to coal did not exceed 5%, and there is no reason to reopen the permit.

Source is in compliance with this condition.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 4 - Subpart UUUUU Table 2 Requirements

Tri-State reported continuous compliance with applicable PM, SO2 and Hg emissions requirements for Units 1, 2 and 3 during the compliance period.

Tri-State provided the Division with a request to apply the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average as allowed by 40 CFR 63.9991(a)(1) that was received on May 2, 2023. The Division granted this request with an email on May 12, 2023 beginning when Unit 1 restarted after an outage on May 14, 2023.

Source is in compliance with this condition.

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during

startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect

monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

PM: Quarterly performance testing for PM was performed on Unit 1 and Unit 2 for 36 months beginning in the second quarter of 2015 and concluding in the first quarter of 2018 in accordance with the LEE provisions of MATS. PM testing for Unit 1 and Unit 2 is now required every 36 months. PM testing on Unit 1 was completed on January 18, 2024 and on Unit 2 on January 18, 2024. The Division reviewed and approved this testing on February 26, 2024. Quarterly performance testing for PM was performed on Unit 3 for 36 months beginning in the third quarter of 2015 and concluding in the second quarter of 2018 in accordance with the LEE provisions of MATS. PM testing for Unit 3 is now required every 36 months. PM Testing on Unit 3 was completed on June 15, 2024. The Division reviewed and approved the June 15, 2024 testing on August 21, 2024. The dates those tests were performed, the results of those tests, and the dates in which the test reports were submitted to CDX are shown in the Reports section of this inspection report. All tests have been approved by the Division as adequate demonstrations of LEE status.

HCl: Tri-State monitors SO_2 as a surrogate for HCl using SO_2 CEMS certified and maintained in accordance with the applicable provisions of 40 CFR 75. Tri-State reported no exceedances of the 0.20 lb/MMBtu limit since the compliance date of the rule.

Hg: Annual Hg performance testing was conducted on Unit 1 and Unit 2 to demonstrate LEE status for each EGU until July 2018. Unit 1 and Unit 2 failed to achieve LEE status based on the July 2018 testing. Subsequent to the July 2018 testing Tri-State conducted quarterly Hg testing on Unit 1 and Unit 2 consistent with the requirements of the MATS Rule until Continuous Mercury Monitoring Systems (CMMS) were installed on each of the Units with monitor certification having been completed on February 19, 2019 and February 20, 2019. Unit 1 is equipped with a Tekran Series 3300, Serial Number 6083 CMMS and Unit 2 is equipped with a Tekran Series 3300, Serial Number 6082 CMMS. The most recent RATAs on the Unit 1 and Unit 2 mercury monitors were conducted on June 14, 2024 and June 11, 2024 respectively. The Division reviewed and approved the results of these RATAs on August 21, 2024. The CMMS are certified and maintained in accordance with the applicable provisions of 40 CFR 75 and 40 CFR 63. Tri-State certified continuous compliance with the standard in their most recent Quarterly Compliance Certifications reporting no violations of an emission standard. No exceedances of the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average have been reported for Unit 1 since the Division approved use of the Alternative limit on May 12, 2022. No exceedances of the 30-day rolling average emission limit of 0.013 lb/GWh have been reported for Unit 2. No excessive monitor downtime was reported for Unit 1.

Tri-State provided the Division with a request to apply the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average as allowed by 40 CFR 63.9991(a)(1) that was received on May 2, 2023. The Division granted this request with an email on May 12, 2023 beginning when Unit 1 restarted after an outage on May 14, 2023.

According to Tri-State's MATS reporting, Unit 1 was tuned on November 11, 2022; Unit 2 was tuned on November 7, 2023; Unit 3 was tuned on August 2, 2024. None of the EGU's employ a neural network and thus each unit must be tuned within 36 calendar months of the last tune.

Tri-State complies with the work practice standards in Table 3.3.a and 3.4 as required. Each unit complies with Paragraph 1 of Table 3.3.a and uses clean fuels (natural gas or diesel) for startup. Craig Station uses the proposed MATS technical correction language as guidance for the compliance report, which indicates that reporting of startup/shutdown data is required only when paragraph 2 of the definition of "startup" in §63.10042 is followed. Controls are set into operation as required following startup. Records and monitoring data are maintained as required. Monitors are maintained and operated as required during shutdown.

Source is in compliance with this condition.

5.2 §63.10000 What are my general requirements for complying with this subpart?

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance

evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

Units 1, 2, and 3 are equipped with flue-gas desulfurization and SO_2 monitoring systems. The source monitors compliance with the alternative SO_2 limit on a continuous basis. All units use SO_2 as a surrogate for HCl emissions. SO_2 CEMS have been certified in accordance with the applicable requirements.

Unit 1 and Unit 2 and are equipped with a CEMS to continuously monitor Hg emissions from the exhaust. Unit 3 is equipped with a Sorbent Trap Continuous Monitoring System for Hg emissions. The monitoring systems are registered in the Craig Station Monitoring Plan. Tri-State certified continuous compliance with the standard since the compliance date of the rule in their semiannual Compliance Certifications reporting no violations of an emission standard.

For each of the three Units, performance tests are conducted to demonstrate compliance with PM requirements of this subpart and as of the date of the inspection, compliance tests have been performed and approved as required. Quarterly performance testing for each of the Units have been performed for three years to demonstrate Low Emitter EGU (LEE) status for PM. The low emitter limit is 0.015 lb/MMBtu. Test results indicate that emissions have qualified all three (3) units for LEE status. Quarterly PM testing has been completed and PM testing is currently required every three years.

Source is in compliance with this condition.

5.3 §63.10006 When must I conduct subsequent performance tests or tune-ups?

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 [Time between performance tests]

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for

the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

The source has performed performance tests and tune ups during the compliance period on schedule as required. The source has performed PM tests for LEE status as required by this subpart.

Source is in compliance with this condition.

5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

The source has conducted performance testing and conducts monitoring consistent with the requirements above and consistent with the requirements of 40 CFR 75 when applicable as required.

Source is in compliance with this condition.

5.5 §63.10009 May I use emissions averaging to comply with this Subpart?

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions

averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 [Equations] The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j) * Smm_j * Cfm_j)] + \sum_{k=1}^{m} Ter_k * Smt_k * Cft_k}{\sum(\sum_{j=1}^{p} Smm_j * Cfm_j) + \sum_{k=1}^{m} Smt_k * Cft_k} \quad \text{Eq. 1b}$$

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated ($MMBtu/lb_{steam}$ or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i * Rm_i))_p + \sum_{i=1}^{m}(Ter_i * Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p + \sum_{i=1}^{m} Rt_i} \quad \text{Eq. 2a}$$

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i} \quad \text{Eq. 2b}$$

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory.

Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p} \quad \text{Eq. 3a}$$

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p} \quad \text{Eq. 3b}$$

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging

option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

Tri-State does not use averaging to demonstrate compliance with applicable emissions limits.

Source is in compliance with this condition.

5.6 §63.10010 What are my monitoring, installation, operation, and maintenance requirements?

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

CMS units at the facility are installed consistent with the requirements of 40 CFR Part 63, Subpart UUUUU.

Source is in compliance with this condition.

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

CO2 diluent CEMS are installed on each of the Units at the facility. The CO2 CEMS are operated and maintained consistent with the requirements of 40 CFR Part 75 as required.

Source is in compliance with this condition.

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

Each of the Units at the facility is equipped with a stack flow monitor. The stack flow monitors are operated and maintained consistent with the requirements of 40 CFR Part 75 as required.

Source is in compliance with this condition.

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

Tri-State utilizes the moisture default values from 40 CFR Part 75 to estimate stack moisture.

Source is in compliance with this condition.

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl

or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

Tri-State does not operate HCl or HF CEMS at the facility.

Source is in compliance with this condition.

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

An SO_2 monitoring system is installed on the equipment at the facility as required. The source reported performing activities required by 40 CFR 75 Appendix B 2.1—2.3 (e.g. daily assessments, linearity checks) as required. The source calculates rolling emissions as required and only used unadjusted, quality-assured SO_2 concentration (ppm) values, which passed the annual RATAs on June 10, 2024 for Unit 1, June 11, 2024 for Unit 2 and June 14, 2024 for Unit 3. A bias adjustment factor was not used for any of the units.

Source is in compliance with this condition.

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

Unit 1 and Unit 2 are equipped with certified CEMS to continuously monitor Mercury emissions. The Mercury CEMS are operated and maintained consistent with the requirements of 40 CFR 63, Subpart UUUUU Appendix A requirements. Passing RATAs were conducted on the Mercury monitor installed on Unit 1 on June 14, 2024 and on Unit 2 on June 11, 2024. Unit 3 is equipped with a certified Mercury Sorbent Trap Monitoring System. The Mercury Sorbent Trap Monitoring System is operated and maintained consistent with the requirements of 40 CFR 63, Subpart UUUUU Appendix A requirements. A passing RATA was conducted on the Mercury Sorbent Trap Monitoring System installed on Unit 3 on June 14, 2024.

Source is in compliance with this condition.

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

Tri-State does no operate a PM CPMS at the facility.

Source is in compliance with this condition.

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

Monitoring and data collection are conducted consistent with the above requirements. Deviations are reported as required.

Tri-State reported 13.9% downtime for the mercury sorbent trap monitoring system on Unit 3 for the second quarter of 2024 and 9.19% downtime for the mercury sorbent trap monitoring system on Unit 3 for the third quarter of 2024.

Tri-State reported that during the second quarter of 2024 one set of traps failed to meet the QA/QC requirements as a result of the operator leaving the sample valves open amounting to 4.4% of the reported 13.9% downtime. Tri-State has initiated a procedure requiring the operator to photograph the sample

valves and send a photograph of the position of the sample valves to the Environmental Manager showing that valve are closed with each trap replacement to prevent a reoccurrence.

An additional 7.0% of the second quarter 2024 downtime was attributed to bad baseline calculations and failing to meet the stack gas flow rate to sample flow rate requirement of EPA Performance Specification 12B as a result of low operating load during startup, with unit load under 150 MW. Tri-State has implemented a new plan to monitor startups a on a separate set of traps to reduce downtime while also reducing the risk of bad baseline calculations on the sample run. If a baseline must be measured while the unit is in startup, the sample will be run until the unit reached 150 MW and then switch to a new sample to be run normally.

Tri-State reported that 9% of the third quarter downtime resulted from a configuration error in one of the mercury consoles after it was returned from maintenance at the manufacturer. The mercury consoles are intended to collect baseline data in a proportional flow based on a target ratio in order to meet the minimum sample mass requirement of EPA Performance Specification 12B. In this instance, the console was configured to sample at a fixed rate during the first hour of sampling and then reverted to proportional flow. The fixed sample rate ration did not match the proportional sample rate ratio, and did not meet the requirements of EPA Performance Specification 12B. The console configuration has been updated and baselines are now collected during an appropriate baseline period with proportional flow based on a target ratio.

Tri-State reported mercury emissions of 2.32 pound for the second quarter 2024 and 1.14 pounds for the third quarter of 2024. The Unit 3 mercury monitor downtime for the second and third quarters of 2024 is not considered to be excessive.

Source is in compliance with this condition.

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the

process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

Performance tune-ups of the units are conducted and recorded as required. The source operates Continuous Monitoring System equipment at all times. Records and monitoring data are maintained as required. All monitoring systems and control systems are maintained and operated as required. The source certifies compliance in semi-annual reports.

Source is in compliance with this condition.

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

Tri-State does not utilize the emissions averaging option.

Source is in compliance with this condition.

5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

Tri-State does not operate a PM CPMS at the facility.

Source is in compliance with this condition.

5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

The source has submitted the required notifications.

Source is in compliance with this condition.

5.12 §63.10031 What reports must I submit and when?

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g) (Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for

correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition 5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

The source certifies compliance in Semi-Annual Monitoring and Deviation reports and Annual Compliance Certifications as required. Reports are also submitted to CEDRI as required.

Source is in compliance with this condition.

5.13 §63.10032 What records must I keep?

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63, §63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

Records required by this section for the continuous monitoring of Hg are maintained by the source as required. All other records as required above are maintained.

Source is in compliance with this condition.

5.14 §63.10033 In what form and how long must I keep my records?

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

The source maintains records as required.

Source is in compliance with this condition.

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

Source is in compliance with the General Provisions.

Source is in compliance with 40 CFR Part 63, Subpart UUUUU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 5 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	6.4	See Condition 6.4				
Equipment Operation	6.5	See Condition 6.5				

NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6

Table 6 - P101 Emissions and Requirements Summary

6.1 Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

Unit 1 and 2 coal consumption records were provided for the 2024 calendar year and are included in the table below. The facility uses coal delivery records to comply with this condition, and maintains copies of its coal suppliers' annual scale calibrations.

Tri-State G&T Craig Station Units 1 & 2 Annual Coal Consumption		
Year	**Reported Annual Coal Consumption (tons/yr)**	***Annual Coal Consumption Limit (tons/yr)***
2024	1,548,198	*3,900,000*

Source is in compliance with this condition.

6.2 PM and PM_{10} emissions shall be calculated using the annual coal throughput, emission factors from Table 6 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 6 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The source calculates estimated emissions from Point 004 annually as required for APEN reporting. The most recent APEN, received by the Division on April 8, 2024, shows 2023 emissions from Units 1 and 2 coal handling as 9.5 tpy and 3.0 tpy for PM and PM_{10}, respectively. The source maintains records of coal handling emissions calculations; however no APEN update was required since the last submittal.

Annual Emissions of PM and PM10 from coal handling from Units 1 & 2 for the 2024 calendar year were provided and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Coal Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	9.35	2.95
Limit:	*NA*	*NA*

Source is in compliance with this condition.

6.3 Opacity

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Coal handing operating were observed to be operating at the time for the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Condition 15, see Condition 15.

Source is in compliance with this condition.

6.4 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 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 as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

Surfactant is added to the spray water used at the grizzly.

Tri-State contracts the Trapper Mine to treat its haul roads with magnesium chloride as necessary. Water trucks were observed at the facility during the inspection with no visible emissions were noted coming from the haul roads. No off property transport of visible emissions were observed during the inspection. Property boundaries extend many hundreds of meters past the haul roads and coal piles. The Division received no complaints regarding dust from the facility during the inspection period.

The coal-receiving hopper ("grizzly") is equipped with water/surfactant spray bars triggered by electric eye

when coal is dumped. No visible emissions were observed from coal unloading during the inspection.

The stackout tower is equipped with telescoping chutes as required. Quarterly fugitive emission inspections are performed as required. Tri-State provided records of inspections which were reviewed. No visible emissions were observed from coal loadout from the stackout tower during the inspection and no visible emissions were observed from the transfer point.

Source is in compliance with this condition.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

No evidence of leakage of air contaminants from process equipment was observed during this inspection. Crushers and conveyors are in complete enclosures.

Source is in compliance with this condition.

6.6 40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

Coal handing operating were observed to be operating at the time for the inspection. No visible emissions were observed during the inspection.

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 7 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F102g F102l				
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	7.4	See Condition 6.4			
Required Controls	7.5	See Condition 7.5			
NSPS Y	7.6	Opacity not to exceed 20%		See Condition 7.6	
CAM	7.7	Condition 7.7			

Table 8 - P102 Emissions and Requirements Summary

7.1 Coal consumption, Colorado Construction Permit 12MF322-2

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

The source tracks monthly and 12-month rolling coal handling as required. Tri-State provided throughput records that are summarized in the table below. The facility uses coal delivery records to comply with this condition and maintains copies of its coal suppliers' annual scale calibrations. The coal storage pile is not larger than 14.5 acres.

Tri-State G&T Craig Station Unit 3 Annual Coal Handling Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Total Coal Handling	**Coal Through the Tripper Deck/Coal Burned**
3/2023-2/2024	1,956,893	1,072,611
1/2024-12/2024	1,674,327	739,506
2/2024-1/2025	1,566,270	685,170
Limit:	*4,500,000*	*1,897,344*

The source did not exceed coal handling limits during the inspection period.

Source is in compliance with this condition.

7.2 PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 8 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 8 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains monthly and 12 month rolling records of PM emissions from Unit 3 coal handling operations as required. Records of the PM emissions for the Unit 3 coal handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 coal handling activities.

Tri-State G&T Craig Station Unit 3 Annual Coal Handling Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	0.88	0.39
1/2024-12/2024	0.79	0.35
2/2024-1/2025	0.76	0.34
Limit:	*1.7*	*0.7*

Source is in compliance with this condition.

7.3 Opacity

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Coal Handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

7.4 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

The source uses a partially enclosed coal unloading area equipped with spray bars. Sufficient moisture is maintained in the coal for dust mitigation. Adjustable chutes are used for dumping into the coal pile. Chemical stabilizer is added as needed to control dust. Records of quarterly inspections were provided and indicate the required measure are being implemented. The Division received no complaints regarding coal dust coming from Craig Station during the inspection period. The source was not operating at the time of the inspection with minimal visible emissions present.

Source is in compliance with this condition.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

The source utilizes fabric filter baghouses to control dust from crushing, transferring and reclaiming of coal as required. Tri-State is in compliance with the requirements of Permit Condition 16 (see Permit Condition 16)

Source is in compliance with this condition.

7.6 40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

Coal Handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

7.7 Compliance Assurance Monitoring (CAM)

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

Source is in compliance with CAM requirements, See condition 7.2. Cam requirements are monitored consistent with the requirements in Condition 22 and Appendix I.

Source is in compliance with this condition.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 9 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Limestone Delivery	8.1				Recordkeeping	Annually
PM & PM_{10}	8.2	F201a		PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4				
Equipment Operation	8.5	See Condition 8.5				
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%				

Table 10 – P201 Emissions and Requirements Summary

This section covers requirements for AIRS Point 020. Limestone handling was observed to be operating at the time of the inspection.

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

Tri-State maintains annual records of limestone delivered as required. Records were provided for the 2024 calendar year and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Limestone Delivered	
Year	**Reported Limestone Delivered (tons/yr)**
2024	24,699
Limit:	*NA*

Source is in compliance with this condition.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 10 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 10. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains records of limestone handling and calculates emissions as required. Annual Emissions of PM and PM10 from limestone handling from Units 1 & 2 for the 2023 calendar year were provided and are included in the table below. Baghouse maintenance records were provided indicating that the baghouses are operated and maintained consistent with the recommendations of the manufacturers and good engineering practices.

Tri-State G&T Craig Station Units 1 & 2 Annual Limestone Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	3.26	0.70
Limit:	*NA*	*NA*

Source is in compliance with this condition.

8.3 Opacity

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Limestone handling was operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

The limestone truck unloading facilities are vented to a baghouse as required. Records were provided indicating that that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 (see Permit Condition 16).

Source is in compliance with this condition.

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Records were provided indicating that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 on the baghouses associated with limestone handling (see Permit Condition 16).

Source is in compliance with this condition.

8.6 40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

Limestone handling was operating at the time of the inspection. No visible emissions were observed from limestone handling activities during the inspection. Source is in compliance with the requirements of Permit Condition 18 (see Permit Condition 18).

Source is in compliance with this condition.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 11 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 12 – P202 Emissions and Requirements Summary

9.1 Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

The source maintains monthly and 12-month rolling total records of lime delivery as required. The source provided records of lime delivery for the inspection period that are summarized in the table below. The source only receives lime via truck at this time. No lime was delivered via rail during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Lime Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Lime Delivered by Truck	**Lime Delivered by Rail**
3/2023-2/2024	14,935	0
1/2024-12/2024	8,560	0
2/2024-1/2025	9,577	0
Limit:	*28,000*	*28,000*

The source did not exceed the abovementioned delivery limits during the inspection period.

Source is in compliance with this condition.

9.2 PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 12 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 12. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

Tri-State maintains monthly and 12 month rolling records of PM emissions from Unit 3 lime handling operations as required. Records of the PM emissions for the Unit 3 lime handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 lime handling activities.

Tri-State G&T Craig Station Unit 3 Annual Lime Handling Emissions		
12-Month Period Ending	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	3.54	0.72
1/2024-12/2024	2.03	0.41
2/2024-1/2025	2.27	0.46
Limit:	*14.9*	*2.9*

The source did not exceed any PM emission limits during the inspection period.

Source is in compliance with this condition.

9.3 Opacity

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Limestone handling was not operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

9.4 Colorado Construction Permit 12MF322-4

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

The limestone truck and rail unloading facilities are vented to a baghouse as required. Records were provided indicating that that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 (see Permit Condition 16).

Source is in compliance with this condition.

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 13 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Processed	10.1				Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c		PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4				

Table 14 – P203 Emissions and Requirements Summary

This section covers requirements for AIRS Point 016. Ash handling for units 1 and 2 was operating at the time of the inspection.

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State provided annual ash handling records for the 2024 calendar year that are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Ash Handled	
Year	**Ash Handled (tons/yr)**
2024	24,920
Limit:	*NA*

Source is in compliance with this condition.

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 14 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Annual Emissions of PM and PM10 from ash handling for the 2024 calendar year were provided and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Ash Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	0.010	0.005
Limit:	*NA*	*NA*

Source is in compliance with this condition.

10.3 Opacity

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Ash handling for Units 1 & 2 was operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

10.4 Colorado Construction Permit 11MF332 (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Both ash silos and unloaders are equipped with baghouses as required. Ash for disposal is conditioned with water prior to being loaded into trucks. Quarterly fugitive dust and visible emissions inspections are performed as required. Inspection records were reviewed during the inspection show no indication of visible emissions. The source reported that ash is not transported on public roads. No mud or dirt deposition was observed on public roads around the facility during the inspection.

Tri-State reported fugitive emissions from the S203a Ash Storage Silo A dry ash truck loading that occurred on August 16, 2024 from 10:30 AM to 11:30 AM in violation of Condition 10.4.1. The event was properly reported as a malfunction, was determined to be a valid malfunction and to qualify for the affirmative defense form enforcement (see Malfunction Section).

Source is <u>not in compliance</u> with this condition.

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 15 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%		
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28 Unpaved: 3.6 EF in lb per vehicle mile traveled		

Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4			

Table 16 – P204 Emissions and Requirements Summary

This section covers requirements for AIRS Point 016. Ash handling for Unit 3 was not operating at the time of the inspection.

11.1 Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

The source tracks monthly and 12-month rolling ash handling as required. Tri-State provided throughput records that are summarized in the table below.

Tri-State G&T Craig Station Unit 3 Annual Ash Handling Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Fly Ash Handling	**Ash and Scrubber Sludge Handling**
3/2023-2/2024	109,709	91,875
1/2024-12/2024	68,469	60,744
2/2024-1/2025	65,102	55,919
Limit:	*174,649*	*237,247*

The source did not exceed ash handling limits during the inspection period.

Source is in compliance with this condition.

11.2 PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 16 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 16, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains monthly and 12 month rolling records of PM and PM10 emissions from Unit 3 ash handling operations as required. Records of the PM and PM10 emissions for the Unit 3 ash handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 ash handling activities.

Tri-State G&T Craig Station Unit 3 Annual Ash Handling Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	37.7	8.2
1/2024-12/2024	36.5	7.9
2/2024-1/2025	36.3	7.9
Limit:	*76.6*	*16.1*

Source is in compliance with this condition.

11.3 Opacity

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Ash handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

11.4 Colorado Construction Permit 12MF322-3 (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

The ash silo and dry ash unloader are vented to fabric filter baghouses as required. Ash hauling from Unit 3 was not operating during the inspection. Quarterly fugitive dust and visible emissions inspections are performed as required. Inspection records were reviewed during the inspection show no indication of visible emissions. The source stated ash is sufficiently moist during transport. No visible emissions were reported during the inspection. There is no evidence to suggest that the conveying system contains leaks.

Source is in compliance with this condition.

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 17 – S401 & S402 Emissions and Requirements Summary

12.1 The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

Tri-State reported that the maximum pumping capacity of the towers is 153,000 gal/min. No design changes have occurred that would result in an increase in pumping capacity. Tri-State certifies compliance with this requirement annually as required.

Source is in compliance with this condition.

12.2 Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration

shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

TDS samples are collected and analyzed weekly. Records for the inspection period were reviewed. Tri-State did not report any concentrations greater than 11,040 mg/l during the inspection period.

Source is in compliance with this condition.

12.3 PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

Tri-State provided annual records of PM and PM10 emissions calculations for the Units 1 and 2 Cooling Towers for the 2024 calendar year that are included in the table below. Emissions were calculated using the required methodology. Tri-State has not exceeded the annual PM and PM10 emissions limits.

Tri-State G&T Craig Station Units 1 and 2 Annual Cooling Tower PM and PM10 Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
2024	12.0	12.0
Limit:	*27.2*	*27.2*

Source is in compliance with this condition.

12.4 VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 17 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State provided annual records of VOC emissions calculations for the Units 1 and 2 Cooling Towers for the 2024 calendar year that are included in the table below. Emissions were calculated using the required methodology. Tri-State has not exceeded the annual VOC emissions limit.

Tri-State G&T Craig Station Units 1 and 2 Annual Cooling Tower VOC Emissions	
Period	**Reported Emissions (tons/yr)**
	VOC
2024	4.8
Limit:	*5.0*

Source is in compliance with this condition.

12.5 Opacity

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The Units 1 and 2 Cooling Towers were operating at the time of the inspection. No visible emissions were observed during the inspection. Maintenance procedures and maintenance records were reviewed during the inspection and were determined to be adequate.

Source is in compliance with this condition.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 18 – S403 Emissions and Requirements Summary

13.1 The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141.

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

An average flow rate of 170,328 gal/min was calculated for 2024 based on the total water processed. The maximum pumping capacity of the towers is 180,000 gal/min. No design changes have occurred that would result in an increase in pumping capacity. Tri-State certifies compliance with this requirement annually as required.

Source is in compliance with this condition.

13.2 Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration

shall be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

Tri-State samples the cooling tower water on a weekly basis and reported that TDS concentrations did not exceed 11,040 mg/liter during the inspection period. Typical TDS concentrations are between 2,000 and 6,000 mg/L. At no time during the inspection period did the source exceed the TDS limit.

Source is in compliance with this condition.

13.3 PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141.

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

Tri-State maintains monthly and 12 month rolling records of PM and PM10 emissions from Unit 3 cooling towers as required. The 12-month rolling total emissions from Unit 3 were provided and are summarized in the table below. The source did not exceed PM or PM10 emission limits during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Cooling Tower PM and PM10 Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	4.7	4.7
1/2024-12/2024	3.7	3.7
2/2024-1/2025	3.5	3.5
Limit:	*13.6*	*13.6*

Source is in compliance with this condition.

13.4 VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141.

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State maintains monthly and 12 month rolling records of VOC emissions from Unit 3 cooling towers as required. The 12-month rolling total emissions from Unit 3 were provided and are summarized in the table below. The source did not exceed the VOC emission limit during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Cooling Tower VOC Emissions	
Period	**Reported Emissions (tons/yr)**
	VOC
3/2023-2/2024	2.2
1/2024-12/2024	1.7
2/2023-2/2025	1.7
Limit:	*2.5*

Source is in compliance with this condition.

13.5 Opacity

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The Unit 3 Cooling Tower was not operating at the time of the inspection. No visible emissions were observed during the inspection. Maintenance procedures and maintenance records were reviewed during the inspection and were determined to be adequate.

Source is in compliance with this condition.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

Annual EPA Method 9 Visible Emissions Observations were performed on each of the engines by a certified observed as indicated in the table below. Annual EPA Method 9 Visible Emissions Observations were conduct on the Fire Pump Engine and the Unit 3 Emergency Diesel Generator during the 2024 calendar year and results are summarized in the table below. Tri-State reported that Tri-State reported that the Fire Pump Engine and the Unit 3 Emergency Diesel Generator operated minimally during the 2024 calendar year with 8.4 hours and 2.5 hours of operation respectively. The Units 1 and 2 Emergency Diesel Generator was reported to have not operated from April 2021 through the date of the inspection on March 25, 2025 due to a mechanical issue.

Engine	Method 9 Reading Date	Observed Opacity (%)
Fire Pump	8/14/2024	0
Units 1 & 2 Emergency Diesel Generator	NA	NA
Unit 3 Emergency Diesel Generator	8/14/2024	1.46

Source is in compliance with this condition.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

Tri-State reported that no engine startup events exceeded ten (10) minutes in duration during the inspection period. No EPA Method 9 Visible Emissions Observations were required under this condition during the inspection period.

Source is in compliance with this condition.

14.3 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this*

exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

Tri-State Craig is an Area Source for emissions of Hazardous Air Pollutants. The State of Colorado has not adopted the Area Source Provisions of MACT Subpart ZZZZ.

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

The facility was operating at the time of the inspection. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

The facility was operating at the time of the inspection. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be performed at least semiannually. If any such observation indicates an exceedance of the

applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

Semi-annual EPA Method 9 Visible Emissions Observations were conducted as required by certified observers. Records were provide and included in the tables below. A review of records provided indicates that Tri-State has not exceeded the opacity limits above. Maintenance records were provided and indicate that the baghouses are operated and maintained consistent with operating and maintenance procedures for the facility.

Tri-State G&T Craig Station P101 Units 1 and 2 Coal Handing System					
Stack ID	**Description**	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S101d	Primary coal crushing – Units 1 & 2	5/23/2024	0	9/26/2024	10.6
S101e	Secondary coal crushing building – Units 1 & 2	NA(1)	NA(1)	NA(1)	NA(1)
S101f	Common coal transfer building belt A	5/23/2024	0	7/25/2024	0
S101g	Common coal transfer building belt B	6/26/2024	0	7/25/2024	0
S101h	Coal stackout building – Units 1 & 2	5/23/2024	0	7/25/2024	0
S101k	Coal reclaim A – Units 1 & 2	6/10/2024	0	11/21/2024	0
S101l	Coal reclaim B – Units 1 & 2	6/26/2024	0	12/12/2024	0
S101m	Coal tripper deck & silos – Units 1 & 2	5/23/2024	0	12/12/2024	0

(1) Tri-State reported that the S101e Units 1 and 2 Secondary Coal Crushing Building Dust Collector caught fire in April 2023 and the unit has been off-line since that time.

Tri-State G&T Craig Station P102 Unit 3 Coal Handing System					
Stack ID	**Description**	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/20234	
		Date	Opacity (%)	Date	Opacity (%)
S102b	Coal conveyor portal building – Unit 3	1/24/2024	0	8/28/2024	0
S102c	Coal conveyor portal building – Unit 3	1/24/2024	0	8/28/2024	0

Tri-State G&T Craig Station P102 Unit 3 Coal Handing System (Continued)

Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S102d	Secondary coal crushing (2 crushers) – Unit 3	3/7/2024	0	7/25/2024	0
S102e	Coal stackout building – Unit 3	3/7/2024	0	7/25/2024	0
S102h	Coal reclaim system – Unit 3	3/7/2024	0	7/25/2024	0
S102i	Coal tripper deck & silos – Unit 3	3/7/2024	0	8/8/2024	0
S102j	Loadout coal to railcars – Unit 3	NA(1)	NA(1)	NA(1)	NA(1)
S102k	Common coal transfer building extension	5/23/2024	0	7/25/2024	0

(1) Tri-State reported that this emission point did not operate during the monitoring period.

Tri-State G&T Craig Station P201 Units 1 and 2 Lime Handing and Storage Facility					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S201b	Limestone truck unloading	6/27/2024	0	7/30/2024	0
S201c	Limestone silo #1 – Units 1 & 2	6/27/2024	0	7/30/2024	0
S201d	Limestone silo #2 – Units 1 & 2	6/27/2024	0	7/30/2024	0

Tri-State G&T Craig Station P202 Unit 3 Lime Handing And Storage Facility					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S202b	Lime unloading	6/27/2024	0	12/5/2024	0
S202c	Lime conveying and silo	6/27/2024	0	12/5/2024	0
S202d	Lime day bin	3/6/2024	0	18/28/2024	0

Tri-State G&T Craig Station P203 Units 1 and 2 Ash Handing System					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S203a	Ash storage silo A – Units 1 & 2	5/14/2024	0	8/28/2024	0
S203b	Ash storage silo B – Units 1 & 2	3/6/2024	0	7/30/2024	0
S203d	Silo B dry ash unloading – Units 1 & 2	3/6/2024	0	7/30/2024	0
S203e	Silo A dry ash unloading – Units 1 & 2	5/14/2024	0	8/28/2024	0

Tri-State G&T Craig Station P204 Unit 3 Ash Handing System					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S204a	Ash storage silo C – Unit 3	5/14/2024	0	8/28/2024	0
S204c	Recycle ash tank	3/6/2024	0	8/28/2024	0

Tri-State reported that S101k - Units 1 and 2 Coal Reclaim A Dust Collector was taken out of service in March 2023 as the result of a part failure and has not returned to service. The S102j Loadout coal to railcars – Unit 3 did not operate in 2024. Because these units did not operate in 2024, Method 9 readings were not required for the semi-annual periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 31, 2024.

Source is in compliance with this condition.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 [Unit 3 Baghouse Only] The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

Each baghouse compartment is monitored continuously for pressure changes and leaks. Compliance with opacity limits is monitored using COMS. The Unit 3 baghouse is equipped with a bag leak detection system as required. The bag leak detection system is operated and maintained in accordance with the manufacture's recommendations and good engineering practices as required. When a spike in opacity is discovered, faulty baghouse compartments are isolated for further inspection by plant personnel. Bags are replaced when necessary by plant personnel. No exceedances of visible emissions limits were reported during the inspection period. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

Scrubber maintenance is performed as needed. Compliance with SO_2 limits is monitored using SO_2 CEMS certified to 40 CFR 75 requirements as required. Removal efficiencies are monitored continuously based on coal sampling and outlet monitoring as required. Tri-State reported no exceedances of SO_2 emissions limits during the inspection period.

Source is in compliance with this condition.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-

enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

PM Testing on Unit 1 was conducted on January 18, 2024 and on Unit 2 on January 18, 2024. The Division reviewed and approved this testing on February 26, 2024. The testing conducted on January 18, 2024 indicated compliance with applicable emissions standards and qualified the two Units as LEE for PM under 40 CFR 63, Subpart UUUUU. PM testing was conducted on Unit 3 on June 15, 2024. The Division reviewed and approved this testing on August 21, 2024. The testing conducted on Unit 3 indicated compliance with applicable emissions standards and qualified the Unit as LEE for PM under 40 CFR 63, Subpart UUUUU. 40 CFR 60, Subpart Da requires that PM testing be conducted annually on Unit 3. PM Testing for 40 CFR 60, Subpart Da was conducted on Unit 3 on June 15, 2024. The Division reviewed and approved this testing on August 21, 2024 indicating passing results. Tri-State submits Test Protocols, and Test Reports within the specified submittal deadlines as required.

Source is in compliance with this condition.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM

performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

Tri-State established a baseline opacity of 6.4% for CAM monitoring during PM Testing conducted on June 15, 2024. Tri-State reported that no CAM excursions of the established CAM opacity limits occurred during the inspection period.

Source is in compliance with this condition.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether 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 (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

Tri-State maintains records of startup, shutdown and malfunction for the subject equipment as required. Tri-State submits quarterly Excess Emissions Reports (EERs) that included all emissions monitor downtime and any excess emissions. No evidence was observed or discovered during the inspection to indicate that the subject equipment is no operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions. No evidence was observed or discovered during the inspection to indicate that Tri-State was attempting to conceal emissions.

Source is in compliance with this condition.

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the Unit 3 CO CEMS is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The SO_2, NO_x (and diluent), CO_2, and flow monitors are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The Unit 3 stack inlet SO_2 and CO_2 monitors are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The COMS are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 QA/QC plans shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 [Units 1 & 2 COMS] The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The SO_2, NO_x, and CO CEMS are subject to the following requirements:

19.1.8.1 [Relative Accuracy Test Audits (RATA)] RATA shall be conducted in the units of

the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 [Data Acquisition and Handling System (DAHS)**]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

Each unit is equipped with all the required monitoring equipment. The monitoring systems are operated and maintained as required, and all Quality Assurance and Quality Control requirements under 40 CFR Part 60. 40 CFR Part 63, and 40 CFR Part 74 are implemented as required. The DAHS is capable of reporting and manipulating data to allow for evaluating compliance with all applicable standards for the facility.

Source is in compliance with this condition.

19.2 General Provisions

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

The source monitors unit emissions at all times when fuel is combusted and monitors opacity using COMS at all times when the fans are operating.

Source is in compliance with this condition.

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right

to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

The source maintains records of startup, shutdown and malfunction as required. Tri-State supplies quarterly QA/QC checks per 40 CFR Part 60, 40 CFR Part 63, and 40 CFR Part 75 with excess emissions reports. The source reported no alternative monitoring during the inspection period.

Source is in compliance with this condition.

19.3 Data Replacement Requirements

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 [COMS] When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to

exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

Data substitution procedures are properly implemented in accordance with applicable sections of 40 CFR 75.

Source is in compliance with this condition.

19.4 Recordkeeping and Reporting Requirements

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility (40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

The source submits quarterly EERs as required. The facility reported no excess emissions from Unit 1, Unit 2 or Unit 3 during the inspection period. All EERs were received by the Division in a timely manner. See the Reports section above for details regarding those reports.

Source is in compliance with this condition.

19.5 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

Tri-State maintains and operates CEMS for NOx, SO2, and CO2 as required. CEMS Data is calculated as required and reported quarterly in Excess Emissions Reports (EERs) as required. Data substitution is conducted consistent with the requirements of 40 CFR Part 75 when appropriate. The pressure drop for the mist eliminator is continuously monitored as required and is equipment with an alarm system that activates should the differential pressure deviated for the established normal range of 0.2 inches water column to 1.0 inches water column. Corrective action is implemented as expeditiously as possible anytime the differential pressure is out of range as required. No instances were reported when the differential pressure was out of range during the inspection period. Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Source is in compliance with this condition.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Source is in compliance with this condition.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

Tri-State calculates emissions using the specified emissions calculation methodologies consistent with the requirements of operating Permit 96OPMF155. APENS are submitted as required (see APEN Section).

Source is in compliance with this condition.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

Tri-State conducts CAM monitoring as required. CAM excursions were appropriately reported with respect to the 15% 6 minute average opacity requirement from Unit 1 and Unit 2 and were addressed consistent with the requirements of Appendix G.

Source is in compliance with this condition.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J. Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average SO2 limit of 0.11 lb/MMBtu for Unit 1 and Unit 2.

Source is in compliance with this condition.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix **Error! Reference source not found.**. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average NOx emissions limit of 0.08 lb/MMBtu for Unit 2.

Source is in compliance with this condition.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

Tri-State Conducts CAM monitoring as required. CAM excursions were appropriately reported with respect to the 7.5% 6 minute average opacity requirement and addressed consistent with the requirements of Appendix H.

No CAM excursions with regard to Condition 17.6 24-hour established baseline level opacity for Unit 3 occurred during the inspection period.

Source is in compliance with this condition.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average SO2 limit of 0.15 lb/MMBtu or the daily average SO2 limit of 0.20 lb/MMBtu.

Source is in compliance with this condition.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average NOx emissions limit of 0.28 lb/MMBtu for Unit 3.

Source is in compliance with this condition.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

Tri-State conducts CAM monitoring as required. No CAM excursion were reported for the Unit 3 Secondary Coal Crushing (S102d) with respect to visible emissions observed during Method 22 readings. No CAM excursions with differential pressure outside of the 5 to 8 inches water column range were reported.

Source is in compliance with this condition.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State includes all excursions in Semi-Annual Monitoring and Deviations Reports, and Annual Compliance Certifications as required.

Source is in compliance with this condition.

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs,

and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Tri-State conducts CAM monitoring as required. Excursions were reported during the inspection period. Tri-State reported that when an excursion occurs, appropriate corrective action consistent with the requirement of the CAM provision is implemented as expeditiously as possible. No modifications to the CAM requirement have been required.

Source is in compliance with this condition.

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

A QIP has not been required by the Division.

Source is in compliance with this condition.

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Tri-State maintains records as required. Monitor downtime is reported as required. Tri-State includes all excursions in Semi-Annual Monitoring and Deviations Reports, and Annual Compliance Certifications as required. A QIP has not been required by the Division.

Source is in compliance with this condition.

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the

requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Source is in compliance with this condition.

CONCLUSION

This compliance evaluation is based on observations made during the inspection, information provided by the source and a review of Division records. Tri-State Generation and Transmission, Inc. - Craig Station is determined to **not be in compliance** with the requirements of Operating Permit 95OPMF155 and Division regulations.

A. Pursuant to Operating Permit 96OPMF155, Permit Condition 10.4.1, Tri-State Generation and Transmission, Inc. - Craig Station is required to vent ash silos and dry ash unloaders (for commercial ash sale) to fabric filter baghouses. On August 16, 2024 from 10:30 AM to 11:30 AM, the S203a Ash Storage Silo A knife gate and flow control valve became stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area. Tri-State Generation and Transmission, Inc. - Craig Station failed to vent ash silos and dry ash unloaders (for commercial ash sale) to fabric filter baghouses in violation of Operating Permit 96OPMF155, Permit Condition 10.4.1.

This event was properly reported as malfunction, was determined to be a valid malfunction, and qualifies for the affirmative defense from enforcement (see Malfunction Section).

Source claims upset due to the S203a Ash Storage Silo A knife gate and flow control valve being stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area violating Permit Condition 10.4.1 requiring that ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses.

Eco Material Technologies (Eco) which purchases flay ash form Tri-State operates the fly ash truck loading at the facility.

As soon as Tri-State became aware of this issue, Tri-State scrubber personnel put on appropriate respiratory gear entered the flay ash unloading room and closed the emergency Shutoff valve. The valve is located upstream of the knife gate and the flow control valve. The knife gate and flow control valve were found to be stuck open with debris. Eco then cleaned out the silo after being cleared to reenter the area and normal operations resumed that day.

While the unloading room was minimally affected by dust the truck load out drive-through building area has a small pile of 1-2 tons of fly ash. High winds dusted the area to the east of the silo, including C road. The dust issues on the roads were immediately taken care of with the water truck once the fly ash leak was secured. The scrubber cleaning crew was diverted to the drive-through for clean up as well.

The source reported that the prompt investigation, emergency shut off, and cleaning activities served to minimize dust emissions and potential impacts associated with the event. No EPA Method 9 Visible Emissions Observations were conducted related to the event, and Tri-State reported that no off property transport of visible emissions was observed during the event.

Plat Operations works to vacuum out hoppers following a compartment outage but cannot always ensure that foreign material remains clear of the feeders. During silo outages an inspection is performed to clean and remove any foreign objects from the unloading chutes. Most findings are from years of accumulation and are considered unavoidable.

The week following this incident, ECO personnel went through training and retraining on where the emergency shut-off valve is located and the emergency response and hazard communication plan. Part of this training included updating their phone numbers for Tri-State and understanding who to call if this reoccurs.

Tri-State also moved the controls for emergency shut-off valve to a more easily accessible location outside of the fly ash unloading room and added a screen in the duct to prevent debris from reach the knife gate and flow control valve.

This event which occurred on a Friday was reported by telephone as a malfunction on the next following business day Monday, August 19, 2024. A follow-up report was received by the Division on January 28, 2025. This event is considered to be a valid malfunction.

Enforcement action is not recommended at this time.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-75:
Tri-State 2023 ERP Phase I Report

Colorado PUC E-Filings System

Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase I

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

April 22, 2024

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State's Responsible Energy Plan (REP) issued in January of 2020 called for eliminating 100 percent of the carbon dioxide ("CO_2") emissions from Tri-State-owned coal generation in Colorado by 2030 and for 70 percent of the electricity used by its Members to come from clean sources by 2030. Tri-State has pursued an Electric Resource Plan (ERP) that aligns with its REP commitments.[1]

This is Tri-State's Phase I ERP. The plan complies with Colorado Public Utilities Commission (Commission) Rule 3605 and relevant paragraphs of Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (2020 ERP Settlement Agreement) filed with the Commission on January 18, 2022, concluding Phase I of Tri-State's 2020 ERP. Attachment A to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year[2] resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year[3] period from 2026-2031. Although Tri-State evaluated "highly competitive"[4] bids for 2026 in Phase II of the 2020 ERP, given that no projects were ultimately procured, Tri-State included 2026 in the 2023 ERP RAP to assess whether additional near-term resources might be selected under updated modeling input assumptions. Tri-State selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements. The RAP also recognizes the extended lead-time for certain resource types.

Tri-State's preferred plan for its ERP is the IRA Scenario. The preferred plan is reliable, affordable, and responsible. The plan brings online 1,540 MW of new resources during the RAP, including:

- 700 MW of wind (200 MW of wind hybrids);
- 310 MW of storage (110 MW of standalone 100-hour iron air batteries; 100 MW of standalone 4-hour batteries; and 100 MW of 4-hr batteries with wind hybrids);
- 290 MW of combined-cycle natural gas in 2028 (with carbon capture and sequestration in 2031); and
- 240 MW of solar.

These resource additions are forecasted to result in one of the lowest present value revenue requirements (PVRR), among the scenarios modeled, over the planning period if Tri-State is awarded federal funding to

[1] The REP also identifies that Tri-State is striving for 100 percent clean energy in Colorado by 2040. While Phase I of the 2023 ERP does not yet forecast achievement of that stretch goal, Tri-State will continue to strive to make progress toward this aim in Phase II of the 2023 ERP and in the 2027 ERP. Notably, 2040 remains well outside of the Resource Acquisition Period (RAP) for the 2023 ERP.
[2] Commission Rule 3602(k).
[3] Commission Rules 3602(n) and 3605(a)(IV)(A).
[4] 2020 ERP Settlement Agreement, Section 3.4.4.2.

support generation additions and provide stranded asset relief under the U.S. Department of Agriculture's Empowering Rural America (New ERA) funding opportunity initiated by the Inflation Reduction Act of 2022 (IRA). The plan enables Tri-State to take full advantage of new direct pay of federal tax benefits for renewable and storage resources by increasing owned resources—while adding and maintaining PPA resources, which also helps to minimize renewable curtailment costs. The preferred plan also retires two coal-fired generation resources during the RAP, including:

- Craig Unit 3 (448 MW) on January 1, 2028; and
- Springerville Unit 3 (419 MW) on September 15, 2031.[5]

These significant shifts in Tri-State's generation portfolio over the coming years would result in an 89 percent greenhouse gas (GHG) emissions reduction related to Tri-State's wholesale sales of electricity in Colorado in 2030, over a 2005 baseline—more than any other scenario modeled in the 2023 ERP. The IRA Scenario results in the highest percentage of renewable generation capacity in 2030 (39 percent) while meeting all Level I and Level II reliability criteria, by maintaining sufficient dispatchable generation and bringing online new battery storage resources to ensure system performance during extreme weather events (EWEs).

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The IRA has the potential to fundamentally alter the landscape for cooperative utilities. The IRA has "…tilt[ed] the balance in favor of cooperatives to develop their own renewables instead of utilizing purchase power agreements (PPAs). Thanks to the "direct-pay" provision in the law, cooperatives may now have a cost advantage depending on significant new grants from the U.S. Department of Agriculture (USDA) and the new ability to monetize tax credits that previously were available only to traditional developers with taxable income. These changes will have a big impact, as we saw when we compared renewables built by a representative cooperative versus an equivalent PPA…"[6]

Without new resource additions and assuming no change to previously announced generation retirement dates, with the exception of moving the Craig 3 retirement date to January 1, 2028, Tri-State would remain in a capacity-long position only through 2028, as identified in the 10-year loads and resources (L&R) shown in Table 1 below.[7] Under the IRA Scenario, Tri-State would remain capacity-long throughout the planning period[8], as shown in Figure 2 below.

[5] Predicated on Tri-State receiving New ERA funding as requested and negotiation of contractual agreements impacted by the resource plan.

[6] https://www.mcr-group.com/wp-content/uploads/2023/06/Coops-IRA-White-Paper_v3.pdf

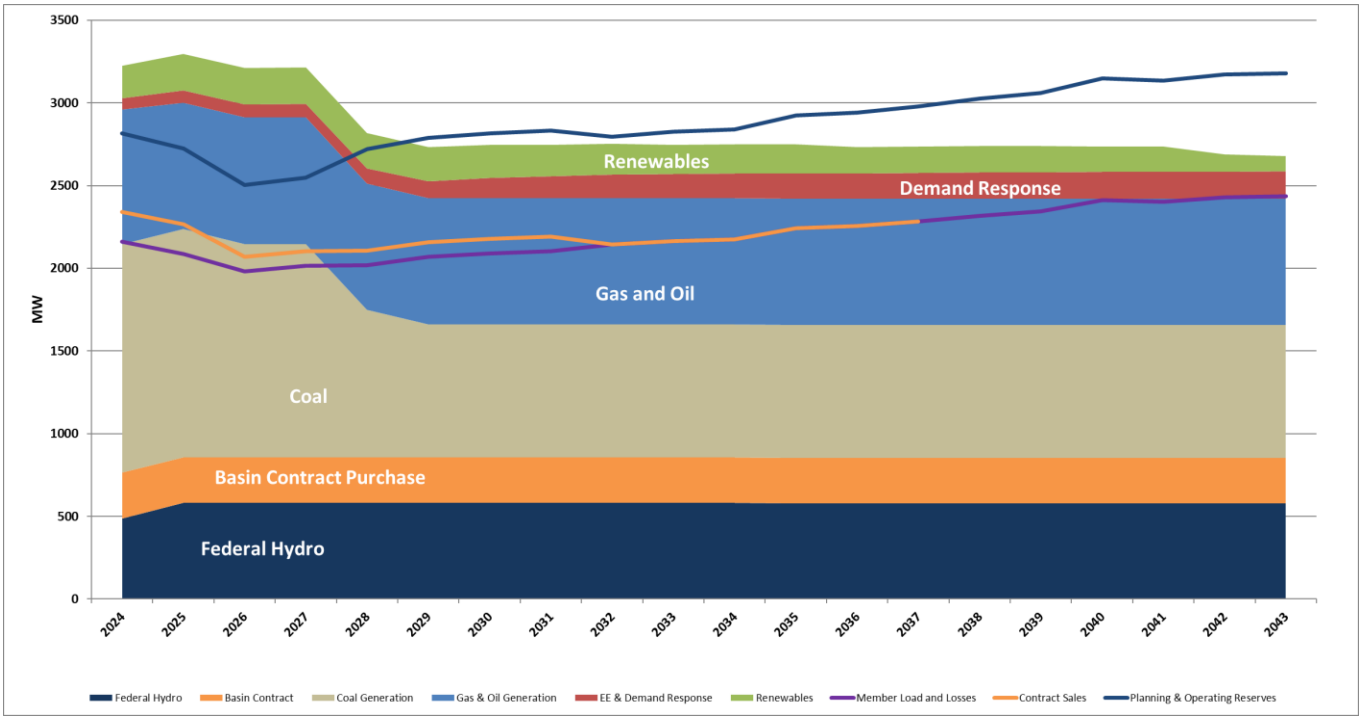
[7] In years where Tri-State files a Phase I ERP, the filing serves to comply with Commission Rule 3618(a) regarding ERP annual progress reports.

[8] The IRA scenario graph is reflective of all generic resources selected throughout the RPP but Tri-State will only be acquiring resources in the RAP (2026 to 2031).

Table 1: Load & Resources (L&R)[9]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3298	3212	3215	2818	2734	2746	2747	2753	2747
Total Obligations (MW)[10]	2815	2725	2505	2549	2722	2790	2816	2835	2797	2827
Excess (MW)	409	572	708	667	95	-57	-71	-88	-43	-80

Figure 1: Load & Resources (L&R)[11]



[9] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

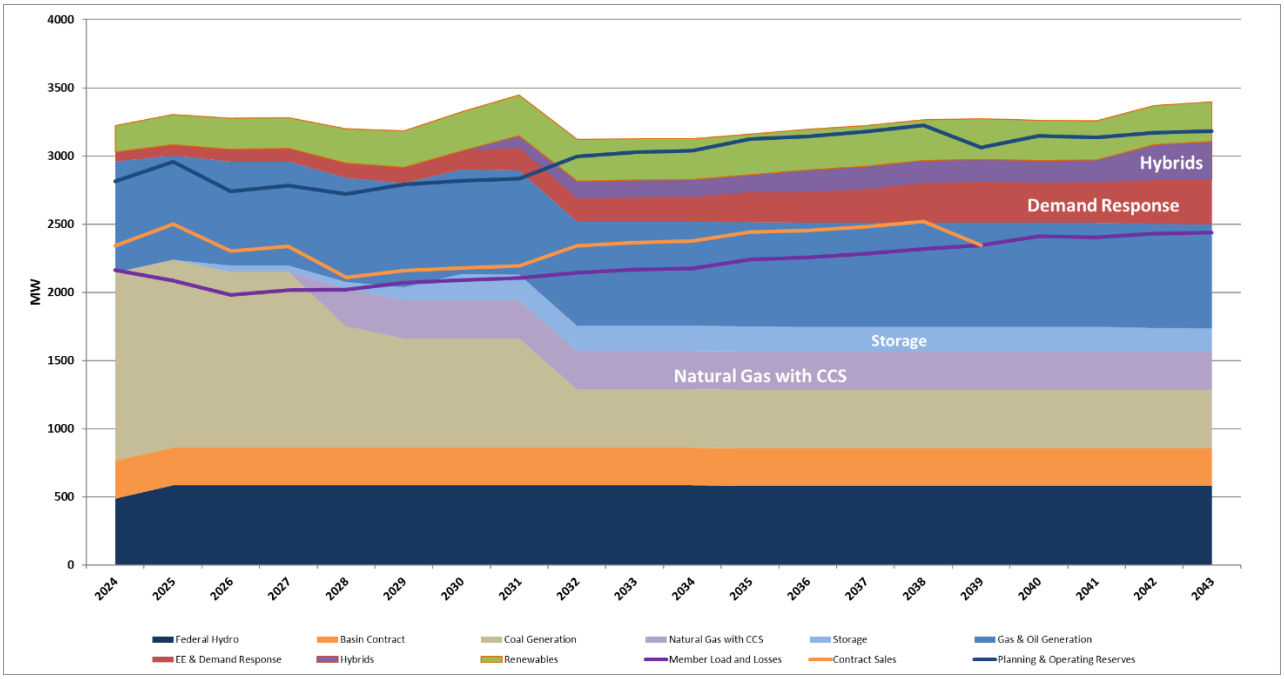
[10] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

[11] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

Table 2: Load & Resources (L&R), IRA Scenario

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	3276	3281	3201	3184	3332	3448	3124	3124
Total Obligations (MW)[12]	2815	2959	2739	2783	2722	2790	2816	2835	2997	3027
Excess (MW)	409	344	537	499	478	393	506	613	127	97

Figure 2: Load & Resources (L&R), IRA Scenario



Modeling Inputs and Assumptions

Tri-State updated and modified all input assumptions for its 2023 ERP to reflect the best available information at the time modeling began in July 2023. Significant base modeling assumptions are identified and described in Attachment B and unique assumptions for each scenario are identified in Attachment B-3.

In addition to base modeling input assumptions reflective of the Tri-State system, best available information from reputable sources (such as national labs and technology vendors), and stakeholder

[12] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

review and input, Tri-State also procured consultants to complete four studies that provide critical ERP inputs. The third-party completed studies are identified in Table 3 below.

Table 3: Third-Party Studies[13]

Third Party Study	Consultant	Description	Attachment
Effective Load Carrying Capability (ELCC) Study and PRM Analysis	Astrape	Determines reasonable capacity credits for wind, solar, and storage based on increasing resource penetration levels; and recommends updated planning reserve margin (PRM).	G-1
Benchmarking Study	Black & Veatch	Compares existing resources to generic resources in regard to cost and performance.	G-2
Beneficial Electrification Potential Study	Mesa Point Energy	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.	G-3
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.	G-3
Evaluation of Tri-State G&T Preferred Plan (IRA Scenario) Reliability	Astrape	Evaluates reliability of preferred plan (IRA Scenario) in 2032	G-4

Tri-State also received input from ACES to analyze Tri-State's forward power curve forecasting and potential benefits of offering new products in an organized market, as well as related model set-up.

Assessment of Existing Resources

Tri-State's assessment of existing resources is provided in Attachment C-3. Resources capable of self-supplying certain ancillary services are identified in Attachment B-4. Information on Tri-State's PPA and contract resources is provided in Attachment C-1. An analysis of the performance of Tri-State's existing resources was performed by the third-party consultant, provided as a Benchmarking Study (Attachment G-2).

Electric Energy and Demand Forecast

Attachments F and F-1 contain Tri-State's load forecast summary and graphical presentation of load forecast data, pursuant to Commission Electric Rule 3605(a)(IV)(B) and 3605(b).

[13] Commission Rule 3605(a)(IV)(O).

Scenario Modeling and Analysis Summary

Tri-State modeled five scenarios for Phase I of the 2023 ERP: 1) the Business-as-Usual (BAU), 2) IRA, 3) Early Springerville 3 Retirement (ESPV3), 4) System Wide Emissions Reductions (SWER), and 5) Aggressive Colorado Emissions Reductions (ACER). Both the BAU and IRA Scenarios include modeling input assumptions that Tri-State believes to be the most accurate and reflective of its system operations and Members' needs. Scenarios 3, 4, and 5 were modeled at the request of stakeholders.

Additionally, two[14] sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The EWE sensitivity modeling assumptions are provided in Attachment B-5 and results of the EWE sensitivity analyses are provided in this report. The assumptions and results for the HG sensitivity analysis are provided in Attachment E.

The Tri-State system is modeled as four planning regions. The planning regions are not state boundary restricted, rather they reflect significant power flow constraints within the Tri-State system:

- Wyoming / Electrically West Nebraska (WYO/WNE*)* – includes Tri-State owned or contracted resources capable of interconnecting north of TOT 3 in Wyoming and Nebraska located in the western interconnection and Western Area Colorado Missouri (WACM) Balancing Authority (BA);[15] and Tri-State load identified as WACM BA Wyoming loads.
- Eastern Colorado (ECO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado south of TOT 3, east of TOT 5, and in the western interconnection and WACM BA; and Tri-State load identified as WACM BA east loads and Tri-State loads in Public Service Company of Colorado (PSCO) BA.
- Western Colorado (WCO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado north of TOT 2, west of TOT 5, and east of TOT 1 in WACM BA; and Tri-State load identified as WACM BA west load.
- New Mexico (NM) – includes Tri-State load and owned or contracted resources physically located in or pseudo-tied into Public Service of New Mexico (PNM) BA. PNM BA is located in New Mexico and a portion of southeast Colorado.

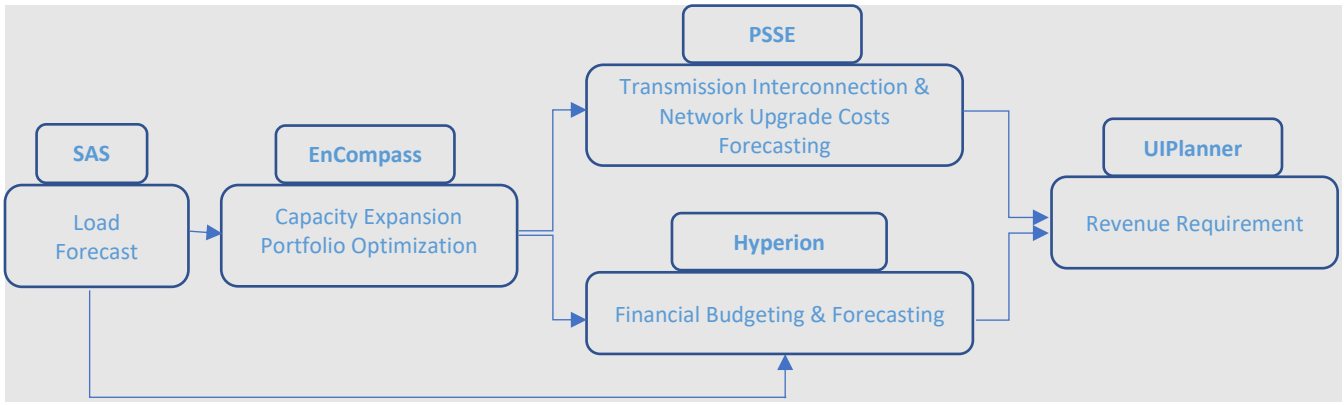
Additional detail on the Tri-State system reflected in the EnCompass model is available in Attachment B-6: Tri-State System Topology.

Figure 3 below identifies the software tools (SAS, EnCompass, PSSE, Hyperion, and UIPlanner) utilized by Tri-State for completing each component of the scenario analyses and the succession of data through each system.

[14] Tri-State contemplated performing a drought sensitivity analysis for one year of the BAU Scenario, however, at the time 2023 ERP modeling began the U.S. Bureau of Reclamation's latest five-year projection for the Colorado River system indicated 0 percent probability of minimum power pool through 2027, so Tri-State deferred drought analysis to a future ERP.

[15] TOTs represent a collection of transmission lines identified as a transfer path between regions.

Figure 3: Modeling Software Tools



Each scenario was evaluated in terms of its performance under reliability, financial, and environmental criteria, and state renewable policy compliance, as described below.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase I modeling, inputting the applicable modeling assumptions described in Attachment B[16] and reflecting the Tri-State system topology, provided as Attachment B-6.

Environmental Analyses

Based on the expansion plan and dispatch produced for each scenario, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon (SCoC) and social cost of methane (SCoM). SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[17]

For each scenario, Tri-State separately produced an Air Pollution Control Division (APCD) verification workbook (APCD Workbook) calculating forecasted carbon emissions reductions, provided in Attachment D.[18] Target-year emissions reductions percentages for each scenario, calculated from the APCD Workbooks, are provided in this report.

Tri-State used the most recent available EPA eGRID rates, year 2021, for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. The carbon emission rate assumption for market purchases and sales is 1,159 pounds per MWh through 2029 per 2021 RMPA eGRID rate and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Western Interconnection contract is 2,596 pounds per MWh 2024 through 2025 per 2021 LRS eGRID rate, 1,159 pounds per MWh 2026 through 2029 per 2021 RMPA eGRID rate, and 450 pounds per MWh (WECC), per APCD Workbook

[16] *See* Attachments B, B-1, B-2, and B-3.
[17] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[18] 2020 ERP Settlement Agreement, Section 3.11.1.

requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 996 pounds per MWh through 2029, which is the 2021 MROW[19] eGRID rate and 525 pounds per MWh (SPP), per APCD Workbook requirement starting in 2030.

Financial Analyses

Tri-State and 39 of our 42 Members serve 170 census tracts that are identified as Disadvantaged Communities, and 161 census tracts are identified as Low Income.[20] Pursuant to Rule 3605(g)(III)(C)(iii), Tri-State provided a financial analysis of each scenario, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- Curtailment MWhs by intermittent resource type seasonally and year.[21]

Transmission Analyses

Each scenario was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

Reliability Analyses

Tri-State utilizes industry standard reliability metrics for its resource planning, referred to in the ERP as "Level I Reliability Metrics," and has also developed an additional set of reliability metrics for assessing the plan's performance under simulated EWE conditions, and refers to those standards as "Level II Reliability Metrics." All metrics are given equal weight as minimum requirement thresholds for any scenario to be supported as a reliable, preferred plan for Tri-State.

These metrics are critical for mitigating risks associated with:

- Not meeting resource adequacy obligations as a load-serving entity (LSE);
- Reliability impacts during a single EWE as well as the impact of EWEs on reliability over the course of the RAP;
- Uncertainty of performance of emerging technologies and contribution of increased intermittent resources at higher levels;
- Lost productivity and cost of deploying emergency response measures during an EWE; and
- Member reliability expectations for high reliability across the system and limited load shedding or reduced system reliability during an EWE, and over time.

[19] Midwest Reliability Organization West

[20] Council on Environmental Quality Climate and Economic Justice Screening Tool (Explore the map - Climate & Economic Justice Screening Tool (geoplatform.gov), and USDA look-up map (Locations of Distressed and Disadvantaged Communities (arcgis.com).

[21] One of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order. In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

Level 1 reliability metric checks were performed on each scenario, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%). The third-party study of PRM (Attachment G-1) was developed using a Strategic Energy Risk Valuation Model (SERVM)—a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios and is thus able to identify potential risks to system reliability across the entire year, not just at system peak. The model, therefore, provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under many, varying conditions. The results of the model help determine the amount of reserves an electric system requires to adequately maintain system reliability.
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility.
- *Loss of Load Hours (LoLH)*[22]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability).[23]
        - 2024-2033 – annually cannot exceed 2.4 hours.[24]
        - 2034-2043 – cannot exceed 24 hours over entire period.
- *Expected Unserved Energy (EUE)*[25]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually.[26]

Level 2 reliability target checks were performed on each scenario's EWE sensitivity result, including:

- ≤ 12 loss of load hours during all EWEs in 2026-2031
- ≤ 3 loss of load hours per each year, 2026-2031
- EUE must be ≤ 20% of load in any hour[27]

[22] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.

[23] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

[24] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

[25] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

[26] This metric is reflective of lower load forecasted based on both member exits and Partial Requirements and is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2020 ERP Phase II.

[27] This metric is an equivalent to the Level I annual EUE target, reflected as an hourly target to assess reliability during EWE stress periods. According to NREL, ~26 percent of estimated load in ERCOT was curtailed during Winter Storm Uri in 2021.

- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.[28]

A detailed analysis of how additions of new intermittent capacity can serve load and maintain reliability is provided for each scenario.[29]

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each scenario and affirms that all scenarios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 4: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[30, 31]		**New Mexico RPS[32]**
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

Comparative Analysis

The analysis Tri-State completed to compare and assess results across scenarios can be found in the Comparative Analysis section of this report.

Commission Electric Rule 3605(g)(III)(C) and (D)

The Commission must consider the following factors in issuing a Phase I decision:

The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

Tri-State proposes an outline for the ERP Implementation Report to be filed in Phase II of the 2023 ERP, provided as Attachment LKT-3.

Tri-State proposes to procure utility-owned resources and PPAs, in alignment with the resource mix modeled in the IRA Scenario, shown in the table below. This approach would result in approximately 500 MW of owned resources and 1040 MW of PPA resources.

[28] In evaluating historical events, Tri-State confirmed that there was no reliance on third party capacity during extreme weather events. If market purchases occurred an equal or greater amount of Tri-State capacity was unused.
[29] 2020 ERP Settlement Agreement, Section 3.11.14.
[30] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[31] § 40-2-124(8)(b), C.R.S.
[32] N.M. Stat. Ann. § 62-15-34.

Table 5: Proposed MW of Utility-Owned and PPA Resources, by Technology, in IRA Scenario RAP

Technologies	Own	PPA
Solar		240
Wind		500
Wind Hybrid		200
4-hr Storage[33]	100	100
Iron Air Storage	110	
Natural Gas Combined Cycle (NGCC) with Carbon Capture and Sequestration (CCS) Conversion	290	
Total	**500**	**1040**

The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

Tri-State has utilized the most recent IWG on Social Cost of Greenhouse Gases, Technical Support Document for the SCoC at the time modeling began and suggests continuation of that practice is sufficient for reporting portfolio analysis results in Phase II of the 2023 ERP.

In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

If New ERA funding is received as requested, Tri-State requests that the IRA Scenario be the base case portfolio in Phase II. Tri-State proposes to model one portfolio that reflects the IRA Scenario resource selections and five portfolios that identifies back-up bid selections for each technology cohort. Tri-State requests limiting stakeholder-requested portfolios to two, given the number of back-up bid portfolios that will be necessary.

The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

Tri-State has provided cost, benefit, and PVRRs for five scenarios in Phase I, including a base case (Business as Usual Scenario), and would provide similar information for Phase II portfolios.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

Factors that Tri-State has considered in evaluation of its preferred plan, the IRA Scenario, are identified in the Executive Summary and Comparative Analysis sections of this report. Factors include reliability, financial, and environmental considerations.

[33] Owned storage is standalone and PPA storage is tied to 200 MW of wind (wind hybrid).

The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

Tri-State has proposed a Phase II timeline (Attachment LKT-2), which plans for the ERP Implementation Report to be filed 120 days after Bid Evaluation Complete (estimated to be January 2025). The proposed timeline for the ERP Implementation Report aims to ensure sufficient time for modeling preparation and completion, while recognizing RAP includes 2026.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase I resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in 2023 in advance of Tri-State beginning Phase I modeling and several additional meetings during development of the Phase I filing. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform participants of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase I. These stakeholder meetings occurred between January and October 2023, covering the following topics:

1. January 17, 2023: Phase I Scope, Timeline, Generic Resources, Storage Valuation, ELCCs, Scenarios/Sensitivities, and Phase II RFP[34]
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1[35]
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,[36] and Scenarios/Sensitivities[37]
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1[38]
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2[39]
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2[40]
9. April 24, 2023: Phase I Battery Modeling and ELCC Study[41]
10. April 26, 2023: DSM Roundtable Meeting #1
11. May 4, 2023: Phase I Scenario and Sensitivity Planning #3 (GHG Reduction Modeling)[42]
12. May 17, 2023: Phase I Pre-Modeling Assumptions Feedback[43]

[34] 2020 ERP Settlement Agreement, Sections 3.11.12., 3.11.13 and 3.11.15.
[35] 2020 ERP Settlement Agreement, Section 3.11.10.
[36] Per 2020 ERP Settlement Agreement, Sections 3.11.5, Tri-State held three meetings on DSM prior to December 31, 2022 which were identified in the 2020 ERP Phase II Implementation Report (April 27, June 14, and August 1, 2022). DSM modeling was also discussed during the February 23, 2023 stakeholder meeting.
[37] 2020 ERP Settlement Agreement, Sections 3.11.12, 3.11.13, and 3.11.14.
[38] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[39] 2020 ERP Settlement Agreement, Section 3.11.10.
[40] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[41] 2020 ERP Settlement Agreement, Section 3.11.13.
[42] 2020 ERP Settlement Agreement, Section 3.11.12.
[43] 2020 ERP Settlement Agreement, Section 3.11.12.

13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling[44]
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4[45]
15. September 27, 2023: Phase II Planning[46]
16. October 18, 2023: DSM Roundtable Meeting #2

Several other meetings, e-mail communications and updates to stakeholders also occurred in advance of and during Phase I modeling with the aim of ensuring communications on key ERP topics.[47] All 2023 ERP stakeholder meetings were identified on Tri-State's website[48] in advance of the meetings and were open for public participation.[49]

Tri-State maintains ongoing collaboration with interested stakeholders related to its ERP, federal funding pursuits, and organized market-related matters.

Scenario Results: Highlights

Key facets of the scenario modeling results, such as generic resource selection during the RAP, and unit retirements modeled and PVRRs over the RPP are summarized below. Detailed scenario results and comparisons across scenarios are in the sections that follow.

Generic Resource Selection in Scenario Modeling

Table 6 identifies the generic resource types selected across the scenarios modeled.

Table 6: Generic Resources Selected in Scenario Modeling During the RAP, by MW and Technology

Scenario	Gas	Storage[50]	Solar[51]	Wind	Wind Hybrid	Total
Scenario 1: BAU	290	250	140	0	300	**980**
Scenario 2: IRA	290	310	240	500	200	**1,540**
Scenario 3: ESPV3	290	350	140	0	300	**1,080**
Scenario 4: SWER	290	50	140	0	100	**580**
Scenario 5: ACER	290	100	140	0	200	**730**

Unit Retirement Selection in Scenario Modeling

Table 7 identifies the retirements dates modeled for resources during the RPP.

[44] 2020 ERP Settlement Agreement, Section 3.11.13.
[45] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[46] Decision No. C23-0437, at¶ 67.
[47] Of note, discussion of emissions rates occurred August 16, 2022, per 2020 ERP Settlement Agreement, Section 3.11.4, as identified in the 2020 ERP Phase II Implementation Report.
[48] https://tristate.coop/resource-planning
[49] 10 C.F.R. § 905.11(b)(4)
[50] Storage inclusive of standalone and hybrid batteries.
[51] Solar values are representative of selected generic resources during the RAP. Due to the cancellation of the Coyote Gulch after the start of modeling, 140 MW of solar replacement in 2026 will be pursued in Phase II and is reflected in this data.

Table 7: Retirements Modeled by Scenario

Scenario	Craig 3	SPV 3	LRS 2
Scenario 1: BAU	1/1/2028	1/1/2037	1/1/2043
Scenario 2: IRA	1/1/2028	9/15/2031	N/A
Scenario 3: ESPV3	1/1/2028	1/1/2031	N/A
Scenario 4: SWER	1/1/2028	1/1/2037	N/A
Scenario 5: ACER	1/1/2028	1/1/2037	1/1/2042

Scenario PVRRs

Error! Reference source not found. identifies the PVRRs resulting from each scenario modeled, over the RPP.

Table 8: PVRR by Scenario

Scenario	PVRR ($, Millions)
Scenario 1: BAU	$17,507.40
Scenario 2: IRA	$17,221.40
Scenario 3: ESPV3	$17,304.20
Scenario 4: SWER	$17,343.90
Scenario 5: ACER	$17,208.20

Phase I Scenario Results and Analysis

Each section that follows presents data and analytical results from each scenario modeled, addressed in the following order:

- Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales/Purchases
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

1. Business As Usual (BAU) Scenario

The BAU Scenario and assumptions served as the base case scenario for Phase I.[52] Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 1 (BAU) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, DSM selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

[52] Commission Rule 3605(a)(IV)(M).

Table 9: Expansion Plan (Scenario 1 – BAU)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[53]	West Colorado	140	1	140
2028	NGCC with CCS[54]	West Colorado	290	1	290
2030	Wind/Battery Hybrid	East Colorado	100	2	200
	100 hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery Hybrid	New Mexico	100	1	100
2032	Wind/Battery Hybrid	East Colorado	100	1	100
2033	Wind	East Colorado	100	1	100
2036	Wind/Battery Hybrid	East Colorado	100	1	100
2037	Wind/Battery Hybrid	New Mexico	100	1	100
2040	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2041	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2042	Wind/Battery Hybrid	East Colorado	100	2	200
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	2	200
2043	Solar	New Mexico	100	1	100
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[55]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[56]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.

The expansion plan also included the following Demand Response (DR) levels by region:[57]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[58]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2040.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2038.

[53] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[54] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[55] Commission Rule 3605(c)(I)(I).
[56] 2020 ERP Settlement Agreement at Section 3.11.6.
[57] Commission Rule 3605(c)(I)(I).
[58] 2020 ERP Settlement Agreement at Section 3.11.8.

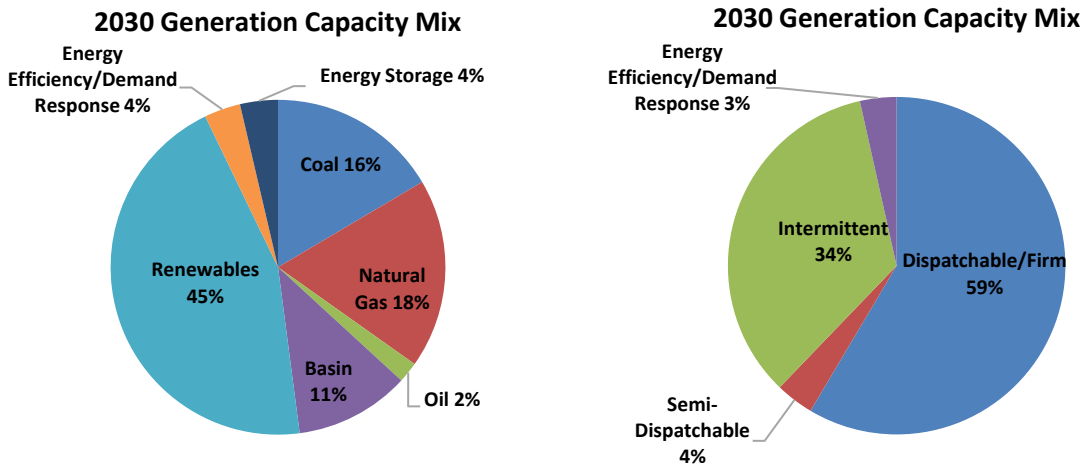
Unit retirements selected in the modeling are shown in the following table.[59]

Table 10: Modeled Retirements (Scenario 1 – BAU)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2043[60]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Resource Mix 2030 (Scenario 1 – BAU)[61, 62, 63]



[59] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[60] This a modeling result based on input assumptions for Tri-State's portion of Laramie River Station (LRS) Unit 2; at the time of this report, Tri-State does not have the right to unilaterally retire any Missouri Basin Power Project (MBPP) resource (LRS 2 or LRS 3). Tri-State along with MBPP participants will continue to evaluate changing industry regulations, system and market conditions to inform operational decisions related to its joint owned coal units.
[61] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[62] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[63] System Energy Mix reflects sales to Members and non-Members.

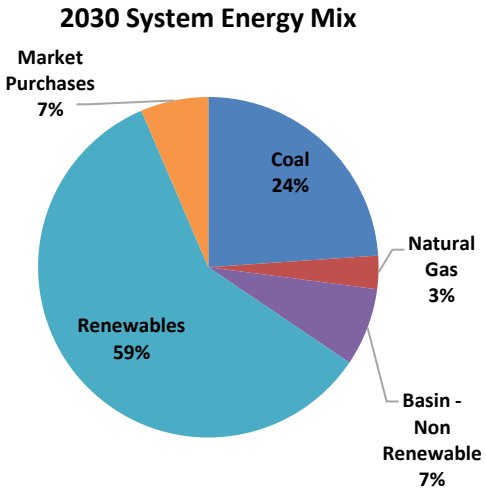


Table 11: Projected Annual Capacity Factors for Thermal Resources (Scenario 1 – BAU)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	98%	15%	27%	12%	15%	0%	0%	0%
Craig 3	79%	13%	22%	18%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	76%	74%	71%	70%
LRS 3	75%	63%	62%	55%	57%	48%	45%	51%
SPV 3	72%	67%	43%	42%	43%	36%	44%	42%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	0%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	28%	28%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 12: Forecasted Energy Sales and Purchases (Scenario 1 – BAU)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,534	1,506	3,095	2,877	3,344	2,774	3,286	3,911
Purchases (GWh)	344	946	523	884	610	717	926	742

Scenario 1 (BAU) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 13: Environmental Impact - System Wide (Scenario 1 – BAU)[64]

Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,834,465	7,750	10,740	0.0383	704	6,777,851,478	32,082
2025	10,918,985	5,416	6,423	0.0243	515	4,098,496,075	20,000
2026[66]	8,555,344	5,071	5,977	0.0230	413	3,640,953,702	18,040
2027	8,004,261	4,747	5,558	0.0204	378	3,239,042,574	16,444
2028	7,398,021	4,273	4,742	0.0182	384	3,109,973,662	14,569
2029	6,751,561	3,964	4,414	0.0161	336	2,752,993,696	12,908
2030	5,884,898	4,044	4,477	0.0161	350	2,732,958,152	13,397
2031	5,745,992	4,070	4,513	0.0166	370	3,287,323,551	13,629
2032	5,310,741	3,880	4,343	0.0153	333	3,053,750,612	12,597
2033	5,652,647	4,035	4,490	0.0162	361	3,227,998,157	13,431
2034	5,698,340	4,065	4,532	0.0163	362	3,244,468,138	13,533
2035	5,458,062	3,970	4,464	0.0157	339	3,116,848,744	12,923
2036	5,083,006	3,833	4,367	0.0149	302	2,923,162,545	12,018
2037	4,083,249	3,443	4,075	0.0130	206	2,443,989,009	9,470
2038	4,101,311	3,456	4,095	0.0130	206	2,447,420,964	9,511
2039	4,167,871	3,501	4,158	0.0132	208	2,466,937,312	9,661
2040	4,173,730	3,512	4,178	0.0131	207	2,460,238,397	9,674
2041	4,163,504	3,509	4,183	0.0130	205	2,442,136,997	9,651
2042	4,205,424	3,542	4,241	0.0130	205	2,439,323,762	9,744
2043	2,858,155	2,789	3,381	0.0071	127	1,651,568,018	6,808
Total	**124,049,570**	**82,870**	**97,350**	**0.337**	**6,512**	**61,557,435,546**	**270,090**
Pounds/Gallons per MWh[67]	857	0.57	0.67	0.000002	0.04	213	2.056

[64] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[65] In all scenarios the 2021 eGRID emission rate for LRS is used for calculating emissions of the Basin Western Interconnection Contract in 2024 and 2025. This is a change from reporting in the 2020 ERP which used regional eGRID rates in those years. From 2026 to 2029 the 2021 RMPA eGRID is used for this contract which then transitions to the APCD assigned rate for WECC in 2030.

[66] Load reduced due to partial requirements contracts in 2026 forward.

[67] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 14: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Carbon
2024	$1,390,597,459
2025	$995,687,914
2026	$810,659,426
2027	$787,912,259
2028	$755,247,562
2029	$714,655,955
2030	$645,736,709
2031	$653,860,869
2032	$626,587,101
2033	$691,336,216
2034	$722,286,260
2035	$716,850,786
2036	$691,597,305
2037	$575,435,014
2038	$598,539,612
2039	$629,766,814
2040	$652,840,646
2041	$670,965,445
2042	$705,605,295
2043	$494,486,160

Table 15: Social Cost of Methane Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Methane
2024	$82,734,317
2025	$54,056,308
2026	$51,119,484
2027	$48,825,849
2028	$45,233,558
2029	$41,884,087
2030	$45,409,865
2031	$48,392,878
2032	$46,826,362
2033	$52,235,896
2034	$55,037,923
2035	$54,924,746
2036	$53,357,940
2037	$43,900,675
2038	$46,012,180
2039	$48,752,421
2040	$50,897,483
2041	$52,750,303
2042	$56,102,875
2043	$40,040,866

Table 16: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 1 – BAU)

Year	Target[68]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	86%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 1 (BAU) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[68] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 17: Total Financial (Scenario 1 – BAU)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,507.4	$11,608.8	$800.2	$29,116.2	$29,916.4
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,806.8				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$598.2				

Table 18: Annual Financial (Nominal $) (Scenario 1 – BAU)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$987
2026	$898
2027	$966
2028	$1,053
2029	$1,218
2030	$1,262
2031	$1,283
2032	$1,305
2033	$1,399
2034	$1,503
2035	$1,519
2036	$1,562
2037	$1,461
2038	$1,490
2039	$1,514
2040	$1,534
2041	$1,544
2042	$1,566
2043	$1,734

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 19: Total Financial Under **EWE** Sensitivity (Scenario 1 – BAU)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,472.1

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 1 – BAU dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the investment tax credit (ITC) they do not have a production tax credit (PTC) penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 1 – BAU are $518,551.

Table 20: Curtailed Intermittent Energy, Annual MWh (Scenario 1 – BAU)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,653	0	0	**5,653**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**13,923**	**0**	**0**	**13,923**

Table 21: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 1 – BAU)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	125	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**150**	**11,870**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 22: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 1 – BAU)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$208,078
2027	0	$125,060
2028	0	$102,674
2029	0	$82,738
2030	0	0
2031	0	0
RAP Total	**$0**	**$518,550**

Scenario 1 (BAU) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the point of interconnection (POI), resulting from the scenario are shown in the table below.

Table 23: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 1 – BAU)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2030	100	Wind + Battery		$2.88	
2030	100	Battery	$1.40	$2.88	
2032	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2036	100	Wind + Battery		$10.20	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2042	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2031	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Solar		$1.68	

Scenario 1 (BAU) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 24: Planning Reserve Margin, % Annual (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	49%	42%	52%	54%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 25: Loss of Load Probability, Hours (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 26: Expected Unserved Energy, Annual MWh (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 1 – BAU)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 1 – BAU, 150 MW of 4-hour hybrid storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP, and support integration of intermittent resources.

Scenario 1 (BAU) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 27 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the Scenario 1 – BAU extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours in Scenario 1 – BAU.

Table 27: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 28 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 28: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed EWE performance for Scenario 1 – BAU in the post-RAP period and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 1 – BAU)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 1 – BAU, market was used for 6.4 GWh in 118 hours during the January EWE events between 2026-2031. The market was used for 11.9 GWh in 80 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

2. Inflation Reduction Act of 2022 (IRA) Scenario

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 2 (IRA) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 29: Expansion Plan (Scenario 2 – IRA)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	4hr – Battery	New Mexico	50	1	50
	100hr – Iron Air Battery	East Colorado	10	1	10
	Solar[69]	West Colorado	140	1	140
2028	Wind	Wyoming / W. Neb.	100	2	200
	NGCC with CCS[70]	West Colorado	290	1	290
2029	Solar	New Mexico	100	1	100
	4hr – Battery	East Colorado	50	1	50
	Wind	East Colorado	100	1	100
2030	Wind	East Colorado	100	1	100
	Wind	Wyoming / W. Neb.	100	1	100
	100hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery	New Mexico	100	2	200
2032	Wind/Battery	New Mexico	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2042	Wind/Battery	East Colorado	100	3	300
	Wind	Wyoming / W. Neb.	100	1	100
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[71]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[72]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

[69] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[70] NGCC installed in 2028 and CCS conversion startup anticipated 2031.
[71] Commission Rule 3605(c)(I)(I).
[72] 2020 ERP Settlement Agreement at Section 3.11.6.

- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

The expansion plan also included the following Demand Response (DR) levels by region:[73]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[74]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2035.
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2038.

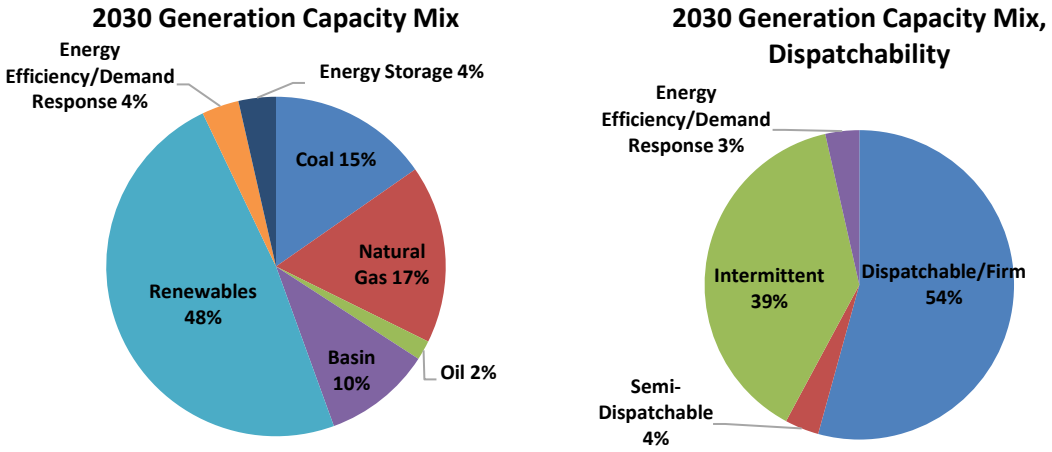
Unit retirements modeled are shown in the following table.[75]

Table 30: Modeled Retirements (Scenario 2 – IRA)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	9/15/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Scenario 2 – IRA)[76, 77, 78]



[73] Commission Rule 3605(c)(I)(I).
[74] 2020 ERP Settlement Agreement at Section 3.11.8.
[75] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[76] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[77] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[78] System Energy Mix reflects sales to Members and non-Members.

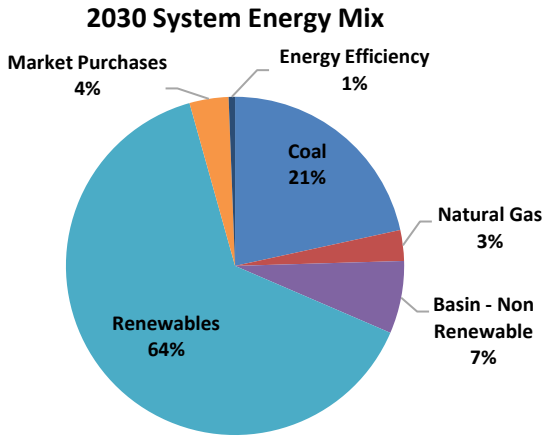


Table 31: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	97%	16%	35%	25%	34%	0%	0%	0%
Craig 3	78%	12%	22%	17%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	68%	63%	64%
LRS 3	75%	64%	72%	60%	57%	55%	49%	50%
SPV 3	64%	66%	42%	42%	42%	36%	42%	37%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	0%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	1%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	27%	25%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 32: Forecasted Energy Sales and Purchases (Scenario 2 – IRA)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,304	1,499	3,067	2,873	3,957	3,883	4,259	5,014
Purchases (GWh)	283	952	515	813	422	422	542	512

Scenario 2 (IRA) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 33: Environmental Impact - System Wide (Scenario 2 – IRA)[79]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,451,106	7,595	10,593	0.0376	674	6,622,378,196	31,305
2025	10,888,923	5,401	6,381	0.0243	515	4,078,147,420	19,913
2026[80]	8,468,490	4,994	5,893	0.0225	408	3,590,666,662	17,862
2027	7,993,868	4,710	5,504	0.0204	380	3,249,891,892	16,483
2028	7,253,155	4,178	4,625	0.0178	381	3,076,352,800	14,438
2029	6,563,974	3,928	4,348	0.0163	333	2,735,998,999	12,813
2030	5,608,261	3,884	4,262	0.0155	337	2,634,907,653	12,808
2031	4,831,239	3,643	4,079	0.0145	299	2,871,821,954	11,464
2032	3,824,819	3,280	3,865	0.0122	194	2,334,603,678	8,895
2033	3,933,841	3,345	3,952	0.0125	199	2,379,546,703	9,139
2034	3,964,238	3,367	3,982	0.0126	200	2,385,882,853	9,211
2035	3,927,079	3,349	3,971	0.0123	197	2,356,788,752	9,117
2036	3,985,696	3,392	4,021	0.0125	199	2,381,021,036	9,258
2037	4,022,648	3,417	4,064	0.0125	200	2,384,355,478	9,343
2038	4,021,708	3,421	4,072	0.0125	199	2,375,788,747	9,338
2039	3,974,658	3,373	3,968	0.0128	203	2,414,033,911	9,235
2040	3,998,873	3,400	4,018	0.0127	201	2,401,751,376	9,291
2041	3,983,443	3,399	4,036	0.0124	198	2,364,432,696	9,251
2042	4,027,793	3,434	4,095	0.0124	198	2,363,931,030	9,354
2043	4,013,781	3,433	4,106	0.0122	195	2,338,232,936	9,322
Total	**114,737,592**	**78,943**	**93,836**	**0.318**	**5,707**	**57,340,534,771**	**247,837**
Pounds/Gallons per MWh[81]	792	0.55	0.65	0.000002	0.04	198	1.886

[79] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[80] Load reduced due to partial requirements contracts in 2026 forward.

[81] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 34: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 2– IRA)

Year	Annual Social Cost of Carbon
2024	$1,356,930,446
2025	$992,946,534
2026	$802,429,547
2027	$786,889,198
2028	$740,458,538
2029	$694,799,728
2030	$615,381,995
2031	$549,767,216
2032	$451,270,783
2033	$481,120,934
2034	$502,482,209
2035	$515,774,643
2036	$542,296,523
2037	$566,894,764
2038	$586,922,384
2039	$600,572,264
2040	$625,490,158
2041	$641,947,763
2042	$675,801,518
2043	$694,419,551

Table 35: Social Cost of Methane Nominal Dollars – System Wide (Scenario 2 – IRA)

Year	Annual Social Cost of Methane
2024	$80,730,077
2025	$53,818,969
2026	$50,613,362
2027	$48,939,435
2028	$44,826,979
2029	$41,577,985
2030	$43,413,041
2031	$40,707,122
2032	$33,064,168
2033	$35,541,561
2034	$37,457,706
2035	$38,749,984
2036	$41,103,874
2037	$43,309,094
2038	$45,174,789
2039	$46,600,954
2040	$48,883,426
2041	$50,563,745
2042	$53,858,083
2043	$54,827,634

Table 36: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 2 – IRA)

Year	Target[82]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	89%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 2 (IRA) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[82] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 37: Total Financial (Scenario 2 – IRA)

$, Millions	Scenario PVRR (2023 WACC 4.12%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Scenario PVRR inclusive of SCoC NPV	Scenario PVRR inclusive of SCoC NPV & SCoM NPV
	$17,221.4	$10,726.7	$733.1	$27,948.1	$28,681.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$2,093.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$555.5				

Table 38: Annual Financial (Nominal $) (Scenario 2 – IRA)

Year	Total Annual Revenue Requirement ($, Millions)
2024	$1,017
2025	$969
2026	$904
2027	$962
2028	$1,104
2029	$1,231
2030	$1,258
2031	$1,301
2032	$1,285
2033	$1,317
2034	$1,349
2035	$1,379
2036	$1,416
2037	$1,440
2038	$1,464
2039	$1,506
2040	$1,566
2041	$1,593
2042	$1,601
2043	$1,700

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 39: Total Financial Under **EWE** Sensitivity (Scenario 2 – IRA)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,166.8

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 2 – IRA dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 2 – IRA are $503,718.

Table 40: Curtailed Intermittent Energy, Annual MWh (Scenario 2– IRA)

	Existing Wind	**Existing Solar**	**Generic Wind**	**Generic Solar**	**Total**
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	75	0	0	**75**
2027	0	0	0	0	**0**
2028	0	287	0	0	**287**
2029	0	583	0	1,197	**1,780**
2030	0	376	0	203	**579**
2031	0	632	154	3,633	**4,419**
RAP Total	**0**	**1,953**	**154**	**5,033**	**7,140**

Table 41: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 2 – IRA)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	0	75	0	0
2027	0	0	0	0
2028	7	280	0	0
2029	1	1,572	0	207
2030	0	579	0	0
2031	0	3,902	13	504
RAP Total	**8**	**6,408**	**13**	**711**

The following table reflects PPA pricing, penalties, and taxes.

Table 42: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 2 – IRA)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$2,816
2027	0	$0
2028	0	$9,596
2029	0	$122,947
2030	0	$29,692
2031	$8,765	$329,902
RAP Total	**$8,765**	**$494,953**

Scenario 2 (IRA) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 43: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 2 – IRA)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	10	Battery	$1.40	$2.88	
2029	50	Battery	$1.40	$2.88	
2029	100	Wind		$2.88	
2030	100	Wind		$2.88	
2030	100	Battery	$1.40	$2.88	
2036	100	Wind + Battery		$2.88	
2042	100	Wind		$10.20	
2042	100	Wind		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2028	100	Wind		$12.00	$109.00
2028	100	Wind		$4.20	
2030	100	Wind		$4.20	
2042	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.50	
New Mexico (NM) Transmission Area)					
2026	50	Battery		$2.88	
2029	100	Solar		$1.68	
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2032	100	Wind + Battery		$2.88	

Scenario 2 (IRA) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 44: Planning Reserve Margin, % Annual (Scenario2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	49%	47%	54%	50%	55%	60%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 45: Loss of Load Probability, Hours (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 46: Expected Unserved Energy, Annual MWh (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 2 – IRA)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 2 – IRA, 200 MW of short duration storage, 110 MW of long duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 2 (IRA) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)Table 47 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)

Event (Season/Year)	Date	Hour
All Event Periods	N/A	N/A

Table 48 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 48: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All Event Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 2 –IRA)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 2 – IRA, the market was used for 5.5 GWh in 97 hours during the January EWE events between 2026-2031. The market was used for 11.5 GWh in 79 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics.

Market purchases during these limited hours were confirmed to not lean on the market for capacity.

3. Early Springerville 3 Retirement Scenario (ESPV3)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 3 (ESPV3) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 49: Expansion Plan (Scenario 3 – ESPV3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[83]	West Colorado	140	1	140
2028	4hr – Battery	West Colorado	50	1	50
	NGCC with CCS[84]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2031	4hr – Battery	West Colorado	50	1	50
	Wind/Battery	New Mexico	100	2	200
	100hr – Iron Air Battery	East Colorado	100	1	100
2036	Wind	East Colorado	100	1	100
2037	Wind	East Colorado	100	2	200
2039	Wind/Battery	Wyoming / W. Neb.	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind/Battery	East Colorado	100	3	300
2043	Solar	New Mexico	100	1	100
	Wind/Battery	Wyoming / W. Neb	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[85]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[86]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.

[83] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[84] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[85] Commission Rule 3605(c)(I)(I).
[86] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[87]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[88]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031

Unit retirements selected in the modeling are shown in the following table.[89]

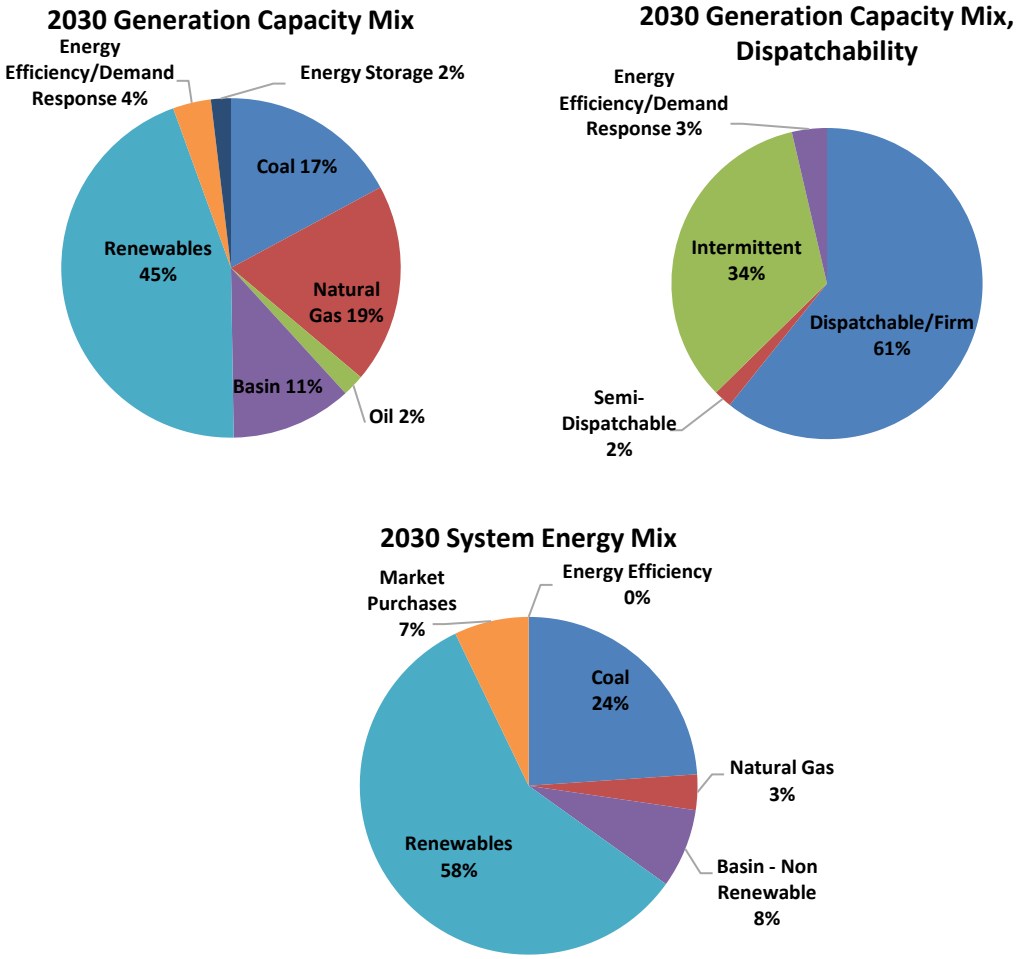
Table 50: Modeled Retirements (Scenario 3 –ESPV3)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

[87] Commission Rule 3605(c)(I)(I).
[88] 2020 ERP Settlement Agreement at Section 3.11.8.
[89] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

Figure 6: Projected Tri-State System Resource Mix 2030 (Scenario 3 – ESPV3)[90, 91, 92]



[90] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[91] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[92] System Energy Mix reflects sales to Members and non-Members.

Table 51: Projected Annual Capacity Factors for Thermal Resources (Scenario 3 – ESPV3)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	34%	23%	20%	0%	0%	0%
Craig 3	79%	14%	22%	16%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	69%	63%	64%
LRS 3	75%	64%	70%	60%	58%	51%	48%	54%
SPV 3	72%	67%	43%	42%	43%	37%	44%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	0%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	29%	28%	20%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 52: Forecasted Energy Sales and Purchases (Scenario 3 – ESPV3)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,505	1,506	3,044	2,850	3,312	2,712	3,018	3,098
Purchases (GWh)	355	946	545	852	623	722	1,004	1,167

Scenario 3 (ESPV3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 53: Environmental Impact - System Wide (Scenario 3 – ESPV3)[93]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,839,102	7,764	10,741	0.0383	704	6,772,194,117	32,129
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[94]	8,469,494	4,985	5,874	0.0224	409	3,579,117,374	17,834
2027	7,999,822	4,707	5,493	0.0203	381	3,238,736,958	16,456
2028	7,332,465	4,209	4,671	0.0177	380	3,069,522,031	14,392
2029	6,711,585	3,942	4,388	0.0160	333	2,727,887,902	12,834
2030	5,808,252	3,998	4,428	0.0157	345	2,680,280,773	13,221

[93] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[94] Load reduced due to partial requirements contracts in 2026 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2031	3,936,370	3,337	3,931	0.0126	201	2,399,903,106	9,134
2032	3,835,588	3,290	3,891	0.0121	193	2,324,000,130	8,911
2033	3,950,512	3,360	3,986	0.0124	198	2,369,472,111	9,166
2034	3,982,627	3,382	4,019	0.0125	199	2,377,578,327	9,240
2035	3,951,406	3,370	4,016	0.0122	196	2,345,304,444	9,165
2036	4,026,737	3,423	4,077	0.0125	199	2,380,608,886	9,347
2037	4,060,785	3,435	4,078	0.0128	203	2,416,104,215	9,428
2038	4,051,989	3,435	4,086	0.0126	201	2,399,586,707	9,406
2039	4,098,100	3,460	4,108	0.0129	204	2,432,494,784	9,515
2040	4,094,950	3,467	4,124	0.0128	203	2,419,226,942	9,510
2041	4,088,441	3,459	4,110	0.0128	203	2,420,432,239	9,492
2042	4,131,169	3,499	4,190	0.0127	201	2,399,136,160	9,588
2043	4,099,795	3,483	4,170	0.0125	199	2,380,264,589	9,520
Total	**115,388,344**	**79,453**	**94,833**	**0.318**	**5,667**	**57,231,644,003**	**248,282**
Pounds/Gallons per MWh[95]	797	0.55	0.65	0.000002	0.04	198	1.890

Table 54: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 3 – ESVP3)

Year	Annual Social Cost of Carbon
2024	$1,391,004,648
2025	$995,703,293
2026	$802,524,764
2027	$787,475,263
2028	$748,555,145
2029	$710,424,496
2030	$637,326,494
2031	$447,936,321
2032	$452,541,393
2033	$483,159,901
2034	$504,813,123
2035	$518,969,660
2036	$547,880,617
2037	$572,269,158
2038	$591,341,514
2039	$619,224,271
2040	$640,518,145
2041	$658,868,730
2042	$693,146,438
2043	$709,300,764

[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 55: Social Cost of Methane Nominal Dollars – System Wide (Scenario 3 – ESPV3)

Year	Annual Social Cost of Methane
2024	$82,855,374
2025	$54,041,930
2026	$50,535,594
2027	$48,861,264
2028	$44,684,056
2029	$41,645,072
2030	$44,814,668
2031	$32,432,806
2032	$33,124,403
2033	$35,647,372
2034	$37,577,397
2035	$38,954,135
2036	$41,497,117
2037	$43,705,831
2038	$45,503,307
2039	$48,013,151
2040	$50,034,448
2041	$51,880,457
2042	$55,205,912
2043	$55,991,156

Table 56: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 3 – ESPV3)

Year	Target[96]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	85%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 3 (ESPV3) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[96] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 57: Total Financial (Scenario 3 – ESPV3)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,304.2	$10,789.6	$734.8	$28,093.8	$28,828.6
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,983.6				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$590.6				

Table 58: Annual Financial (Nominal $) (Scenario 3 – ESPV3)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$988
2026	$904
2027	$962
2028	$1,060
2029	$1,178
2030	$1,441
2031	$1,335
2032	$1,345
2033	$1,361
2034	$1,382
2035	$1,404
2036	$1,428
2037	$1,450
2038	$1,474
2039	$1,495
2040	$1,514
2041	$1,529
2042	$1,546
2043	$1,562

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 59: Total Financial Under **EWE** Sensitivity (Scenario 3 – ESPV3)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,275.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 3 – ESPV3 dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 3 – ESPV3 are $520,955.

Table 60: Curtailed Intermittent Energy, Annual MWh (Scenario 3 – ESPV3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,640	0	0	**5,640**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	44	0	**44**
RAP Total	**0**	**13,910**	**44**	**0**	**13,954**

Table 61: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 3 – ESPV3)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	112	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	44	0	0
RAP Total	**137**	**11,914**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 62: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 3 – ESPV3)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$208,309
2027	$0	$124,914
2028	$0	$102,651
2029	$0	$82,570
2030	$0	$0
2031	$2,511	$0
RAP Total	**$2,511**	**$518,444**

Scenario 3 (ESPV3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 63: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 3 – ESPV3)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2031	100	Battery	$1.40	$2.88	
2036	100	Wind		$10.20	
2037	100	Wind		$2.88	
2037	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
2028	50	Battery	$1.40	$2.88	
2031	50	Battery	$1.40	$2.88	
Wyoming (WYO) Transmission Area					
2039	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 3 (ESPV3) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 64: Planning Reserve Margin, % Annual (Scenario 3 –ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	52%	44%	47%	48%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 65: Loss of Load Probability, Hours (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 66: Expected Unserved Energy, Annual MWh (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 3 – ESPV3)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 3 – ESPV3, 250 MW of 4-hr storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable

resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 3 (ESPV3) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 67 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 67: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 68 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 68: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 3 – ESPV3)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 3—ESPV3, the market was used for 7.4 GWh in 131 hours during the January EWE events between 2026-2031. The market was used for 14.3 GWh in 85 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

4. System-wide Emissions Reduction Scenario (SWER)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 4 (SWER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 69: Expansion Plan (Scenario 4 – SWER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[97]	West Colorado	140	1	140
2029	NGCC with CCS[98]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2033	Wind	New Mexico	100	1	100
	Wind/Battery	New Mexico	100	1	100
2034	Wind/Battery	East Colorado	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	New Mexico	100	1	100
2038	Wind/Battery	East Colorado	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind	East Colorado	100	1	100
	Wind/Battery	East Colorado	100	2	200
2043	Solar – Build Transfer	West Colorado	100	3	300
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[99]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[100]

The expansion plan also included the following Demand Response (DR) levels by region:[101]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[102]

[97] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[98] NGCC installed in 2029 and CCS conversion startup anticipated in 2031.
[99] Commission Rule 3605(c)(I)(I).
[100] 2020 ERP Settlement Agreement at Section 3.11.6.
[101] Commission Rule 3605(c)(I)(I).
[102] 2020 ERP Settlement Agreement at Section 3.11.8.

- 39 MW of Wyoming low level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2030.
- 117 MW New Mexico moderate level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2039.

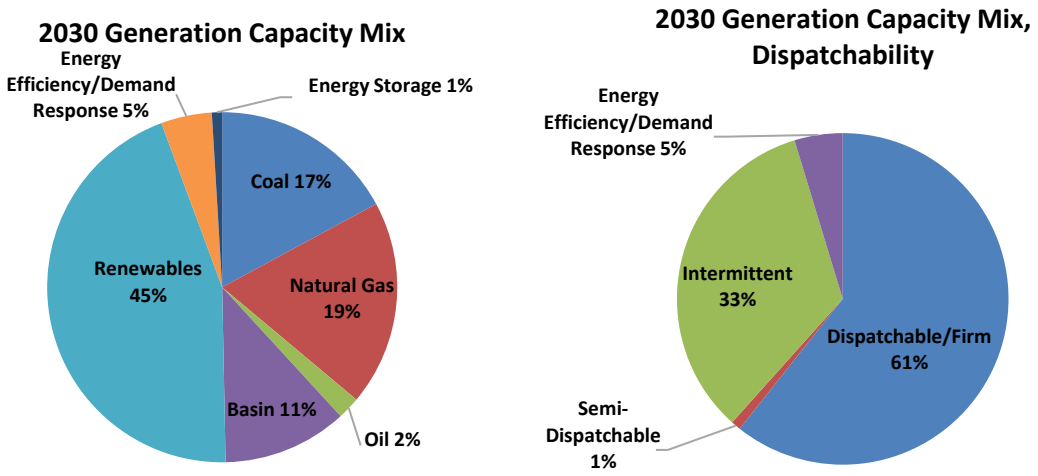
Unit retirements selected in the modeling are shown in the following table.[103]

Table 70: Modeled Retirements (Scenario 4 – SWER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 7: Projected Tri-State System Resource Mix 2030 (Scenario 4- SWER)[104, 105, 106]



[103] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[104] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[105] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[106] System Energy Mix reflects sales to Members and non-Members.

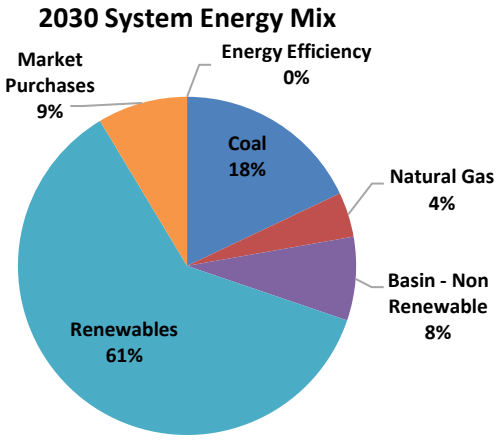


Table 71: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	17%	0%	0%	0%	0%	0%	0%
Craig 2	98%	16%	26%	13%	36%	0%	0%	0%
Craig 3	79%	13%	25%	19%	0%	0%	0%	0%
LRS 2	93%	89%	71%	72%	71%	67%	41%	16%
LRS 3	75%	64%	69%	57%	58%	50%	30%	13%
SPV 3	72%	67%	43%	42%	45%	36%	37%	36%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	27%	11%	0%	1%	1%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	29%	24%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 72: Forecasted Energy Sales and Purchases (Scenario 4 – SWER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,561	1,496	3,063	2,872	2,902	2,615	2,245	1,687
Purchases (GWh)	346	941	550	912	748	658	1,154	1,265

Scenario 4 (SWER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 73: Environmental Impact - System Wide (Scenario 4 - SWER)[107]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,863,704	7,761	10,763	0.0383	705	6,793,247,708	32,133
2025	10,919,812	5,420	6,407	0.0244	516	4,098,699,996	19,995
2026[108]	8,477,517	5,026	5,962	0.0225	404	3,583,422,154	17,903
2027	7,972,529	4,721	5,542	0.0202	374	3,210,051,302	16,365
2028	7,358,120	4,302	4,787	0.0182	377	2,927,811,446	14,845
2029	6,573,723	3,872	4,303	0.0156	327	2,680,149,760	12,556
2030	4,514,050	3,295	3,646	0.0108	262	1,990,503,327	10,296
2031	3,157,659	2,666	2,918	0.0062	212	1,818,549,023	7,869
2032	3,203,866	2,736	3,048	0.0067	205	1,845,960,399	7,905
2033	3,208,225	2,703	2,972	0.0063	213	1,829,638,245	7,985
2034	3,226,798	2,710	2,973	0.0064	215	1,851,008,307	8,024
2035	3,254,631	2,763	3,078	0.0069	208	1,876,225,341	8,012
2036	3,315,308	2,850	3,219	0.0077	200	1,929,252,664	8,076
2037	3,614,749	3,177	3,763	0.0110	179	2,178,755,684	8,428
2038	3,622,455	3,180	3,760	0.0111	181	2,189,879,374	8,448
2039	3,611,385	3,180	3,770	0.0110	178	2,169,009,462	8,423
2040	3,596,535	3,182	3,782	0.0108	176	2,145,151,059	8,397
2041	3,613,093	3,188	3,781	0.0109	178	2,160,677,499	8,433
2042	3,585,634	3,191	3,825	0.0104	171	2,091,352,778	8,369
2043	3,610,874	3,196	3,807	0.0107	175	2,135,484,251	8,432
Total	**106,300,669**	**73,119**	**86,106**	**0.266**	**5,456**	**51,504,829,781**	**230,898**
Pounds/Gallons per MWh[109]	734	0.50	0.59	0.000002	0.04	178	1.757

[107] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[108] Load reduced due to partial requirements contracts in 2026 forward.

[109] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 74: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 4 – SWER)

Year	Annual Social Cost of Carbon
2024	$1,393,165,248
2025	$995,763,266
2026	$803,284,931
2027	$784,788,638
2028	$751,174,190
2029	$695,831,712
2030	$495,316,652
2031	$359,323,495
2032	$378,007,746
2033	$392,375,842
2034	$409,008,952
2035	$427,456,666
2036	$451,083,112
2037	$509,411,285
2038	$528,656,041
2039	$545,681,555
2040	$562,557,798
2041	$582,264,404
2042	$601,614,118
2043	$624,713,086

Table 75: Social Cost of Methane Nominal Dollars – System Wide (Scenario 4 - SWER)

Year	Annual Social Cost of Methane
2024	$82,867,370
2025	$54,042,415
2026	$50,729,638
2027	$48,591,361
2028	$46,092,106
2029	$40,743,674
2030	$34,900,045
2031	$27,942,182
2032	$29,384,966
2033	$31,054,907
2034	$32,634,103
2035	$34,054,127
2036	$35,858,109
2037	$39,068,247
2038	$40,865,813
2039	$42,504,595
2040	$44,182,882
2041	$46,091,559
2042	$48,190,439
2043	$49,596,337

Table 76: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[110]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	82%

Table 77: System-wide GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[111]	Forecast
2027	20.9%	44%
2028	33.2%	44%
2029	45.4%	51%
2030	57.7%	61%
2031	70%	73%

See Appendix D for detailed GHG emissions calculations for the scenario.

[110] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.
[111] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Scenario 4 (SWER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

Table 78: Total Financial (Scenario 4 - SWER)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,343.9	$9,899.2	$679.1	$27,243.1	$27,922.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,694.1				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$546.3				

Table 79: Annual Financial (Nominal $) (Scenario 4 - SWER)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$978
2026	$894
2027	$957
2028	$1,003
2029	$1,092
2030	$1,232
2031	$1,270
2032	$1,434
2033	$1,459
2034	$1,497
2035	$1,512
2036	$1,534
2037	$1,421
2038	$1,445
2039	$1,497
2040	$1,518
2041	$1,536
2042	$1,557
2043	$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 80: Total Financial Under **EWE** Sensitivity (Scenario 4 – SWER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,315.4

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 4 – SWER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 4 – SWER are $531,366.

Table 81: Curtailed Intermittent Energy, Annual MWh (Scenario 4 - SWER)

	Existing Wind	**Existing Solar**	**Generic Wind**	**Generic Solar**	**Total**
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,854	0	0	**5,854**
2027	0	3,378	0	0	**3,378**
2028	0	2,821	0	0	**2,821**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,246**	**0**	**0**	**14,246**

Table 82: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 4 - SWER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	258	4,515	20	1,061
2027	0	3,057	45	276
2028	114	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**372**	**11,970**	**87**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 83: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 4 - SWER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$216,270
2027	$0	$126,321
2028	$0	$106,117
2029	$0	$82,658
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$531,366**

Scenario 4 (SWER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 84: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 4 - SWER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2034	100	Wind + Battery		$2.88	
2036	100	Wind + Battery		$2.88	
2038	100	Wind + Battery		$2.88	
2042	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2029	290	Gas	$1.50	$4.20	
2043	100	Solar		$2.88	
2043	100	Solar		$2.88	
2043	100	Solar		$1.68	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	
New Mexico (NM) Transmission Area)					
2033	100	Wind		$2.88	$238.50
2033	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 4 (SWER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 85: Planning Reserve Margin, % Annual (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	42%	46%	45%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 86: Loss of Load Probability, Hours (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 87: Expected Unserved Energy, Annual MWh (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 4 - SWER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 4 – SWER, 50 MW of short duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 4 (SWER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 88 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 88: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 89 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 89: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 4 – SWER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
    - NM Market HE 2 to HE 6 and HE 11 to 15

  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 4 – SWER, the market was used for 7.3 GWh in 133 hours during the January EWE events between 2026-2031. The market was used for 17 GWh in 99 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

5. Aggressive Colorado Emissions Reductions Scenario (ACER)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 5 (ACER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 90: Expansion Plan (Scenario 5 - ACER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[112]	West Colorado	140	1	140
2029	Wind/Battery	East Colorado	100	1	100
2030	NGCC with CCS[113]	West Colorado	290	1	290
2031	Wind/Battery	Wyoming / W. Neb.	100	1	100
2033	Wind	East Colorado	100	2	200
2035	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	East Colorado	100	1	100
	Wind/Battery	New Mexico	100	2	200
2040	Wind/Battery	Wyoming / W. Neb.	100	2	200
	Solar – Build Transfer	West Colorado	100	2	200
2042	Wind/Battery	East Colorado	100	4	400
	Wind/Battery	Wyoming / W. Neb.	100	3	300
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[114]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[115]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.

[112] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[113] NGCC installed in 2030 and CCS conversion startup anticipated in 2031.
[114] Commission Rule 3605(c)(I)(I).
[115] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[116]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[117]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 5 - ACER in 2038
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 5 – ACER starting in 2042.

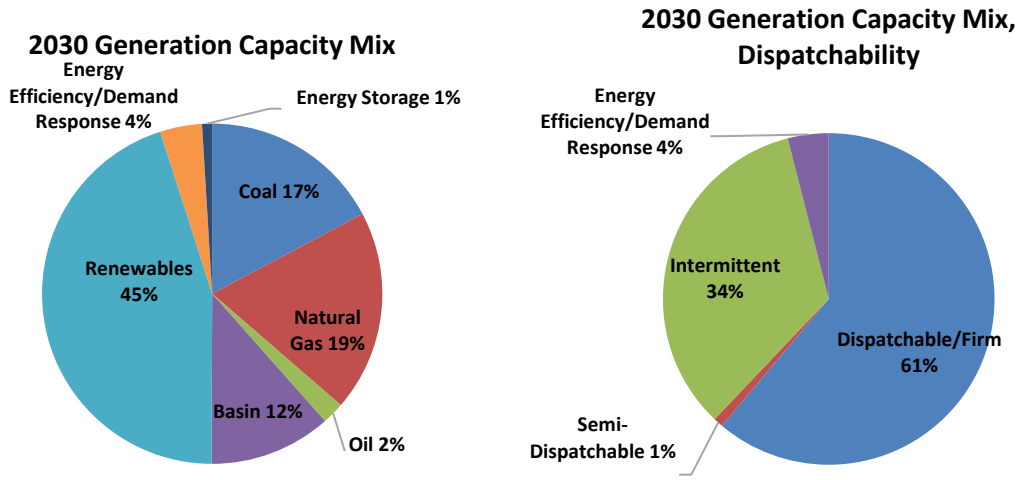
Unit retirements selected in the modeling are shown in the following table.[118]

Table 91: Modeled Retirements (Scenario 5 - ACER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2042

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Resource Mix 2030 (Scenario 5 - ACER)[119, 120, 121]



[116] Commission Rule 3605(c)(I)(I).
[117] 2020 ERP Settlement Agreement at Section 3.11.8.
[118] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[119] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[120] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[121] System Energy Mix reflects sales to Members and non-Members.

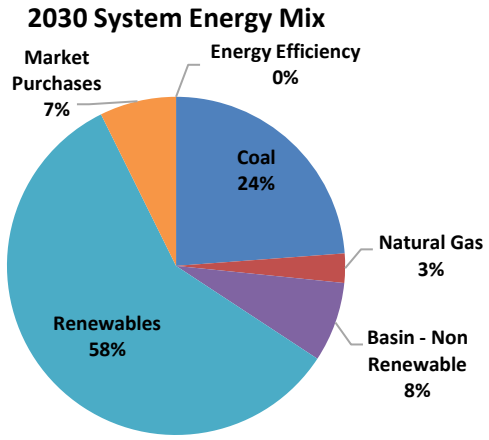


Table 92: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	17%	4%	9%	0%	0%	0%
Craig 3	79%	14%	15%	11%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	75%	71%	69%	69%
LRS 3	75%	64%	55%	48%	43%	40%	40%	45%
SPV 3	72%	67%	43%	42%	42%	36%	44%	43%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	1%	1%	1%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	0%	16%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 93: Forecasted Energy Sales and Purchases (Scenario 5 – ACER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,508	1,506	2,719	2,521	2,453	2,347	2,911	3,587
Purchases (GWh)	352	946	641	985	803	854	1,020	776

Scenario 5 (ACER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 94: Environmental Impact - System Wide (Scenario 5 - ACER)[122]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,841,198	7,764	10,744	0.0383	704	6,774,266,318	32,133
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[123]	8,046,894	4,781	5,543	0.0211	393	3,336,852,935	16,657
2027	7,524,321	4,471	5,149	0.0187	359	2,957,263,352	15,143
2028	6,758,931	4,045	4,479	0.0164	340	2,603,401,641	13,418
2029	6,279,584	3,827	4,253	0.0150	303	2,351,374,862	12,230
2030	5,720,642	3,969	4,393	0.0154	340	2,617,482,127	13,065
2031	5,621,064	3,993	4,418	0.0159	364	3,205,678,404	13,331
2032	5,229,420	3,827	4,281	0.0147	330	2,990,089,809	12,392
2033	5,542,856	3,963	4,395	0.0157	357	3,162,785,437	13,164
2034	5,600,099	3,999	4,444	0.0158	359	3,185,362,689	13,291
2035	5,341,998	3,895	4,362	0.0153	335	3,057,746,388	12,644
2036	4,976,911	3,771	4,291	0.0144	297	2,858,196,567	11,765
2037	3,872,884	3,313	3,900	0.0123	197	2,353,044,102	8,984
2038	3,889,235	3,328	3,924	0.0123	197	2,350,104,263	9,021
2039	3,958,518	3,372	3,983	0.0125	199	2,378,852,575	9,176
2040	3,928,034	3,352	3,944	0.0125	200	2,381,909,167	9,114
2041	3,954,875	3,371	3,977	0.0125	199	2,380,272,599	9,172
2042	2,550,838	2,573	3,064	0.0065	119	1,575,749,975	6,087
2043	2,537,465	2,577	3,059	0.0065	118	1,562,045,832	6,084
Total	**118,094,923**	**79,640**	**93,054**	**0.316**	**6,224**	**58,182,271,249**	**256,864**
Pounds/Gallons per MWh[124]	816	0.55	0.64	0.000002	0.04	201	1.955

[122] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[123] Load reduced due to partial requirements contracts in 2026 forward.

[124] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 95: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Carbon
2024	$1,391,188,757
2025	$995,703,293
2026	$762,481,386
2027	$740,668,558
2028	$690,004,358
2029	$664,696,921
2030	$627,713,272
2031	$639,644,830
2032	$616,992,472
2033	$677,908,422
2034	$709,833,808
2035	$701,607,194
2036	$677,161,912
2037	$545,789,145
2038	$567,589,551
2039	$598,133,480
2040	$614,409,701
2041	$637,343,954
2042	$427,991,342
2043	$439,003,933

Table 96: Social Cost of Methane Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Methane
2024	$82,865,100
2025	$54,041,930
2026	$47,200,356
2027	$44,961,643
2028	$41,658,773
2029	$39,685,014
2030	$44,283,639
2031	$47,333,383
2032	$46,063,578
2033	$51,195,405
2034	$54,050,793
2035	$53,741,866
2036	$52,234,099
2037	$41,644,283
2038	$43,640,015
2039	$46,305,451
2040	$47,955,236
2041	$50,131,697
2042	$35,047,588
2043	$35,786,521

Table 97: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 5 - ACER)

Year	Target[125]	Forecast
2025	47%	47%
2026	60%	66%
2027	67.8%	73%
2028	74.2%	76%
2029	80.6%	82%
2030	87.1%	88%
2031	90%	91%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 5 (ACER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[125] Modified targets per stakeholder-requested scenario assumptions identified in Attachment B-3, but still meets GHG reduction targets in 2020 ERP Settlement Agreement Sections 3.3.4. and 3.3.5.

Table 98: Total Financial (Scenario 5 - ACER)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,208.2	$11,026.8	$758.1	$28,235.0	$28,993.1
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,635.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$623.0				

Table 99: Annual Financial (Nominal $) (Scenario 5 - ACER)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$978
2026	$898
2027	$960
2028	$1,007
2029	$1,075
2030	$1,212
2031	$1,232
2032	$1,400
2033	$1,415
2034	$1,452
2035	$1,474
2036	$1,506
2037	$1,447
2038	$1,470
2039	$1,501
2040	$1,523
2041	$1,537
2042	$1,554
2043	$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 100: Total Financial Under **EWE** Sensitivity (Scenario 5 – ACER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,180.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 5 - ACER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 5 – ACER are $544,004.

Table 101: Curtailed Intermittent Energy, Annual MWh (Scenario 5 - ACER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,613	0	0	**5,613**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,955	0	0	**2,955**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,645**	**0**	**0**	**14,645**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 5 - ACER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	85	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,767	18	170
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**110**	**12,514**	**98**	**1,923**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 5 - ACER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$207,282
2027	$0	$125,001
2028	$0	$102,660
2029	$0	$109,061
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$544,004**

Scenario 5 (ACER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 5 - ACER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2033	100	Wind		$2.88	
2035	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2030	290	Gas	$1.50	$4.20	
2040	100	Solar		$2.88	
2040	100	Solar		$2.88	
Wyoming (WYO) Transmission Area					
2031	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2040	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2042	100	Wind + Battery		$4.20	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind + Battery		$4.20	
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2037	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 5 (ACER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 105: Planning Reserve Margin, % Annual (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	31%	44%	47%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 106: Loss of Load Probability, Hours (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
1	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 107: Expected Unserved Energy, Annual MWh (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
2	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 5 - ACER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario

5 – ACER, 100 MW of 4-hr storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 5 (ACER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 108 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 108: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 109 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 109: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and, Level II metrics were not met in the latter part of the RAP for Scenario 5 – ACER. Scenario 5 – ACER did not meet Level 2 reliability metric thresholds:

- Six hours of LOLH in 2037 (which is beyond the three hours per year threshold); and
- Two hours of capacity lean on the market (which is beyond the zero-tolerance threshold), in the following hours and capacity amounts:
    - July 12, 2042 HE2, 40 MW; and
    - July 13, 2043 HE2, 29 MW.

Analysis of Market Purchases and Available Capacity (Scenario 5 – ACER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
    - NM Market HE 2 to HE 6 and HE 11 to 15
    - 1 day in event no market depth

- Summer:
    - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
    - 1 day in event no market depth

In the EWE analysis for Scenario 5 – ACER, the market was used for 6.4 GWh in 115 hours during the January EWE events between 2026-2031. The market was used for 12.5 GWh in 78 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase I scenarios is provided below.

Environmental Analysis

The following tables identify each scenario's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

Figure 9: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Scenario

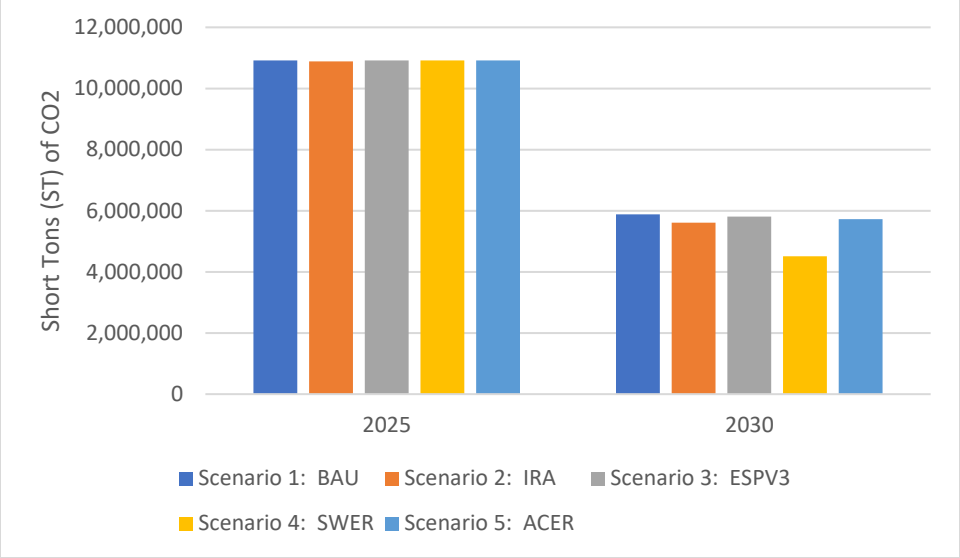
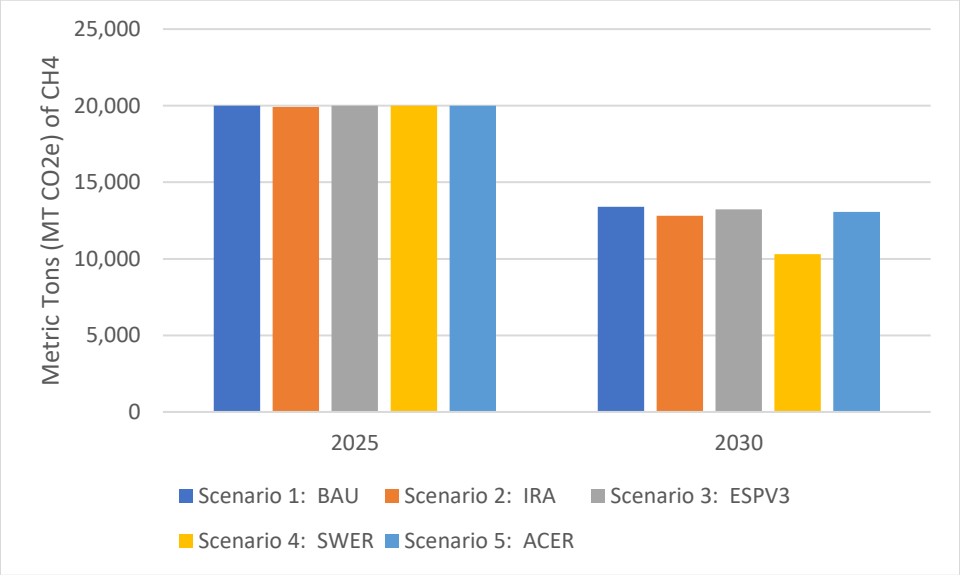


Figure 10: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Scenario



The following table identifies each scenario's forecasted achievements toward Colorado GHG reduction targets. As shown in Figure 9 and Table 110, all scenarios achieve a consistent level of CO_2 and GHG reductions in 2025. The trend of similar GHG reductions across all scenarios holds for 2026 and 2027 as well, with the exception of Scenario 5 (ACER) achieving slightly higher reductions earlier—a result of the underlying modeling input constraint requiring minimum emissions achievements for each year of the RAP (see Attachment B-3 of the ERP Report (LKT-1). Those underlying constraints on emissions for Scenario 5 (ACER) result in significant reductions in the capacity factors for Craig 2 and LRS 3 starting in 2026 and result in the new gas plant not being utilized until 2030. Market sales are also reduced during the RAP under Scenario 5 (ACER). Notably, Scenario 2 (IRA), achieves the highest GHG reduction by 2030, 89%, as compared to the other scenarios as show in Table 110 and Figure 11.

Additional discussion of Tri-State's consideration of the environmental results of the scenario analyses can be found in the Executive Summary; and in the Financial Analysis section below, which scenario identifies PVRRs with SCoC and SCoM.

Table 110: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Scenario 1: BAU	47%	60%	68%	86%
Scenario 2: IRA	47%	60%	67%	89%
Scenario 3: ESPV3	47%	60%	67%	85%
Scenario 4: SWER	47%	60%	68%	82%
Scenario 5: ACER	47%	66%	73%	88%

Figure 11: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

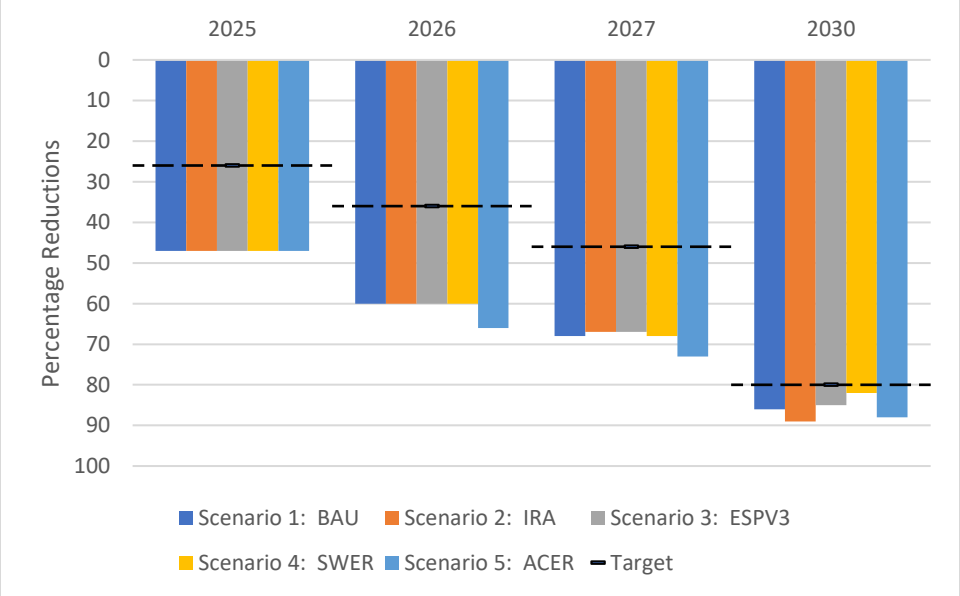
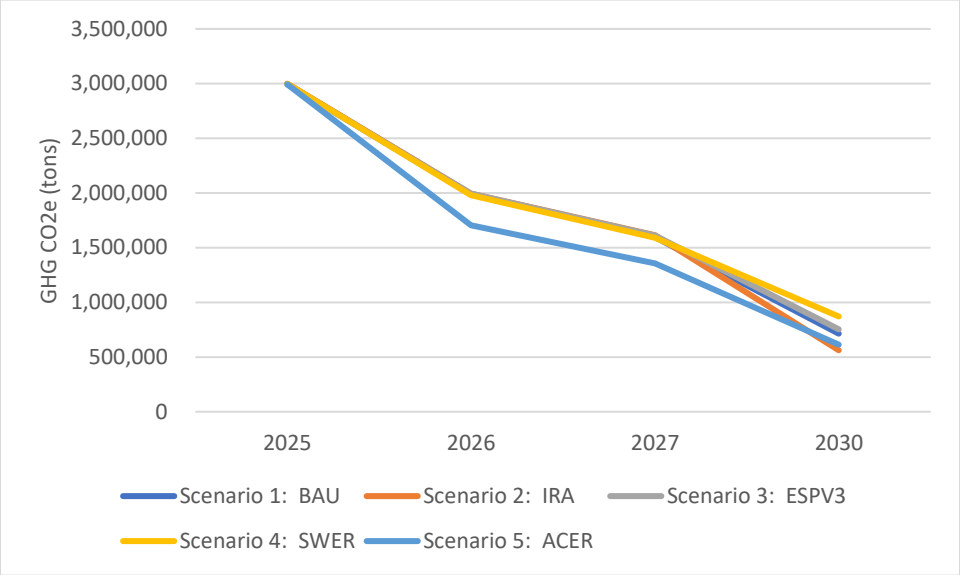


Figure 12: Comparison of Colorado CO2e



As shown in Figure 13 below, there is little deviation in the annual SCoC across the scenarios modeled, until after 2030. Scenario 1 (BAU) and Scenario 5 (ACER) have fairly similar SCoC levels in the early 2030s as Colorado greenhouse gas reduction levels are similar (roughly a 2 percent difference) in 2030; and from 2024 to 2033 the primary differences between the two scenarios being the timing of new resource additions. Neither Scenario 1 (BAU) or Scenario 5 (ACER) retires SPV 3 in the first ten years of the RPP. Scenario 2 (IRA) achieves a lower SCoC due to more renewable resources being added during the RAP, as well as the early retirement of SPV3. Scenario 3 (ESPV3) also results in lower levels of SCoC due to retirement of SPV 3 during the RAP. Scenario 4 (SWER) sets minimum system-wide emission reductions as underlying modeling input constraints, which result in the lowest SCoC levels across the scenarios. Similar trends across the scenarios are seen in Figure 14 below, for SCoM.

Figure 13: Comparison of SCoC

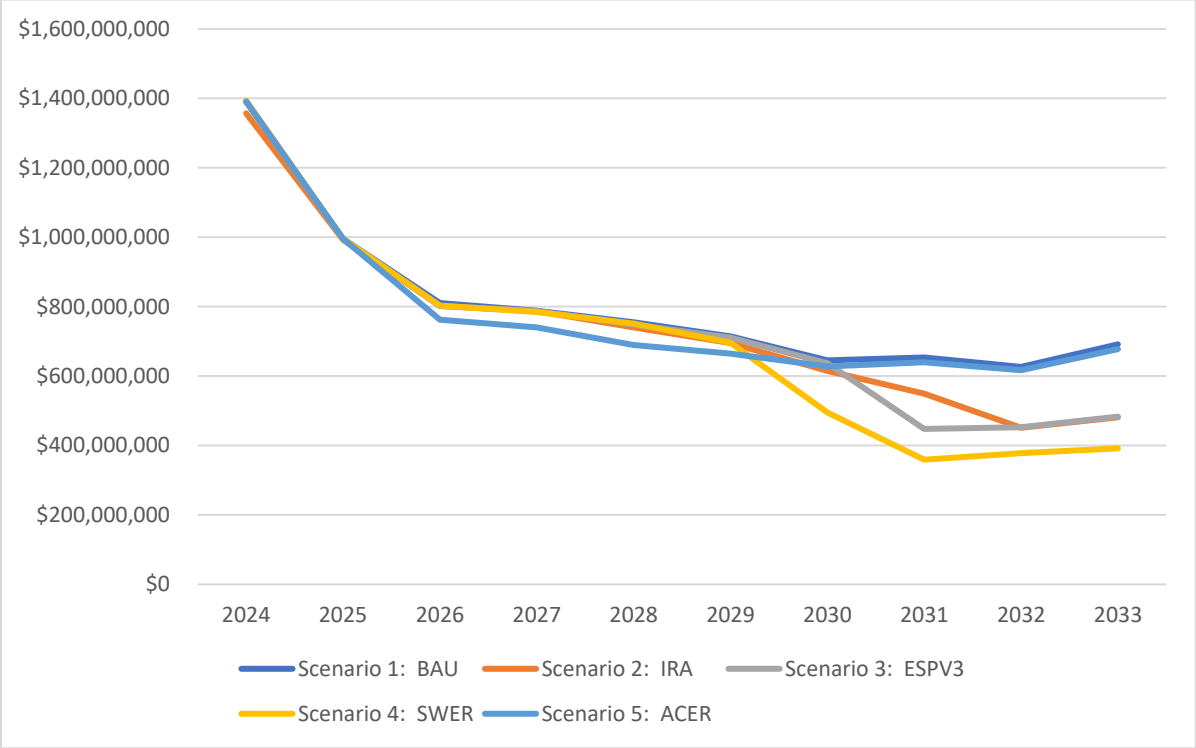
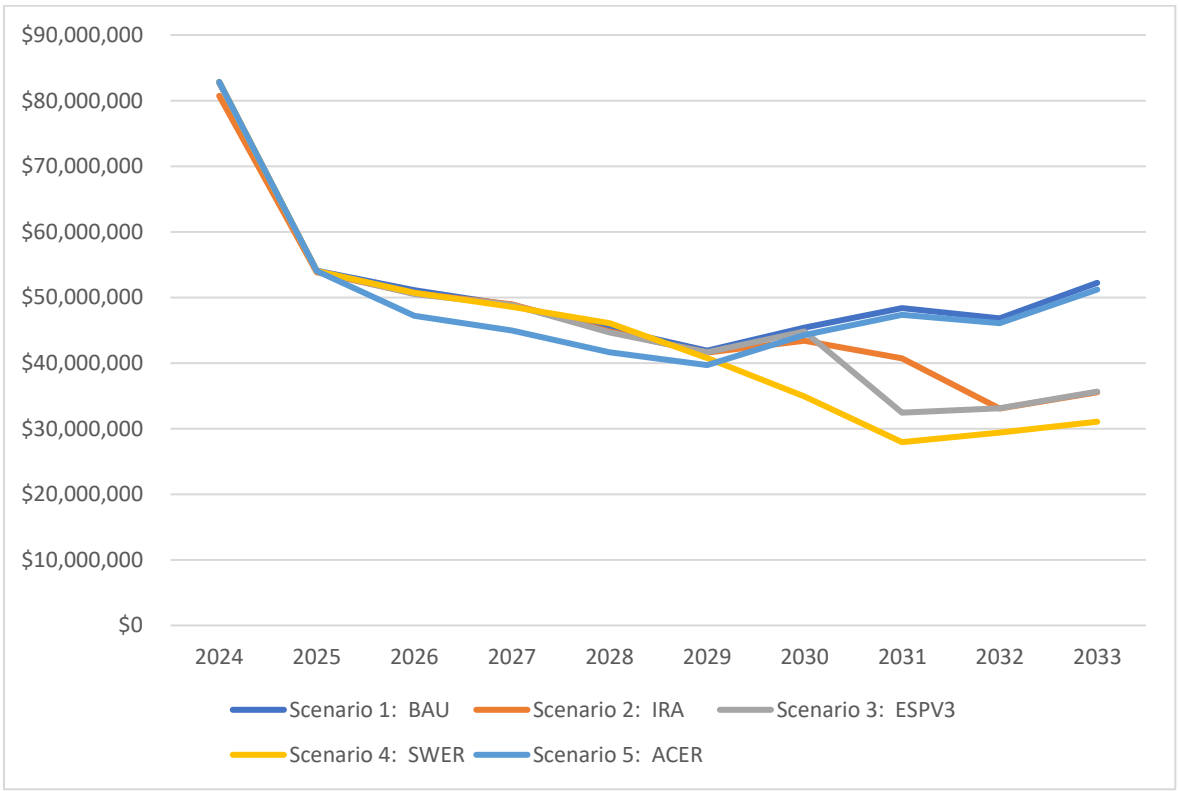


Figure 14: Comparison of SCoM



Financial Analysis

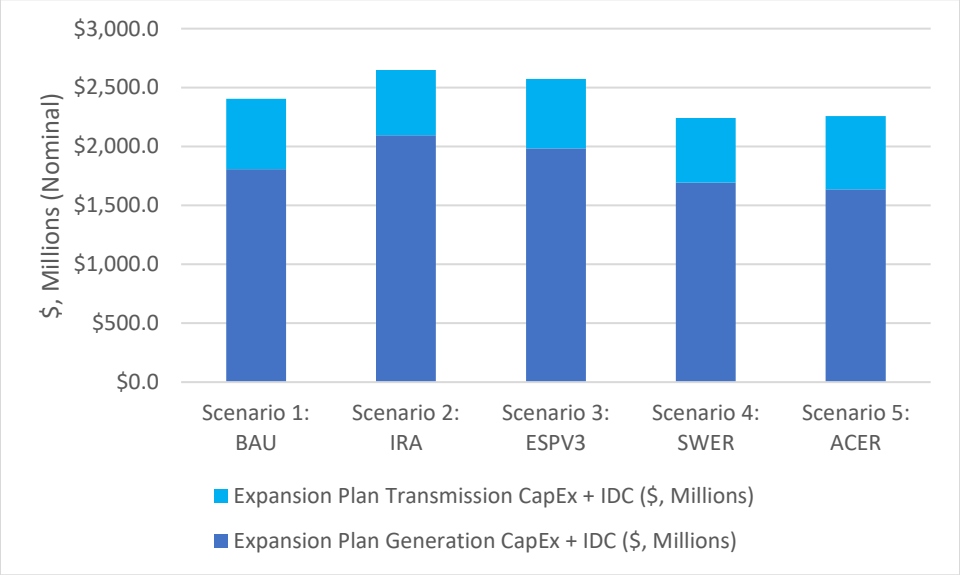
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is one of the lowest cost plans on a PVRR basis, and has the lowest renewable curtailment costs during the RAP. Scenario 2 (IRA) exceeds Colorado GHG reduction target for 2030, while maintaining reliability and affordability—which best serves Tri-State Members.

Table 111: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Scenario 1: BAU	$17,507.4	$29,916.4
Scenario 2: IRA	$17,221.4	$28,681.2
Scenario 3: ESPV3	$17,304.2	$28,828.6
Scenario 4: SWER	$17,343.9	$27,922.2
Scenario 5: ACER	$17,208.2	$28,993.1

Figure 15 below compares capital expenditures for resource additions and transmission interconnection and upgrades by scenario over the RPP. While the Scenario 2 (IRA) results in comparatively higher CapEx, the overall financial impact of the scenario is the lowest due to New ERA funding being pursued by Tri-State for the benefit of its Members.

Figure 15: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 112 below, all scenarios selected a 290 MW gas plant during the RAP (in 2028, 2029, or 2030), with conversion to CCS in 2031, and selected some amount of wind hybrids. All scenarios include 140 MW of solar to replace the Coyote Gulch PPA that was terminated in 2023. Scenario 1 (BAU) and Scenario 3 (ESPV3) have similar levels of MWs and resource additions during the RAP. Scenario 4 (SWER)

and Scenario 5 (ACER) have similar levels of MWs and resource additions. Scenario 2 (IRA) selects 1,400 MW of resources during the RAP, in addition to the 140 MW of replacement solar, more than double the total resource additions in Scenario 4 (SWER) and Scenario 5 (ACER) and significantly higher than the total resource additions in Scenario 1 (BAU) and Scenario 3 (ESPV3). The increase in resource selection during the RAP in Scenario 2 (IRA) is due to potential federal funding being available only through the RAP period. The funding would allow Scenario 2 (IRA) to bring on more resources during the RAP while improving affordability, maintaining reliability, and making strides toward evolving environmental requirements.

Table 112: Comparison of MW Additions by Scenario, by Technology over the RAP

	Scenario 1 – BAU	Scenario 2 – IRA	Scenario 3 – ESPV3	Scenario 4 – SWER	Scenario 5 – ACER
Wind	0	500	0	0	0
Solar	140	240	140	140	140
Standalone Storage	100	210	200	0	0
Gas	290	290	290	290	290
Wind Hybrid	300	200	300	100	200
Wind Hybrid – Battery Storage Component	150	100	150	50	100
RAP Total	**980**	**1,540**	**1,080**	**580**	**730**

Note: Wind Hybrid components share interconnect.

Table 113 below identifies the percentage of generation capacity that is intermittent or dispatchable/firm, and the percent of system energy that is renewable for each scenario in 2030. Scenario 2 (IRA) yields the highest percentage of renewables in terms of system energy mix in 2030, while maintaining a reasonable mix of intermittent and dispatchable/firm capacity at 39 percent and 54 percent, respectively.

Table 113: Comparison of Renewables, Intermittent and Dispatchable Resources in the 2030 Mix, by Scenario

	2030 Generation Capacity Mix, % Intermittent	2030 Generation Capacity Mix, % Dispatchable/Firm	2030 System Energy Mix, % Renewables
Scenario 1: BAU	34%	59%	59%
Scenario 2: IRA	39%	54%	64%
Scenario 3: ESPV3	34%	61%	58%
Scenario 4: SWER	33%	61%	61%
Scenario 5: ACER	34%	61%	58%

Note: Capacity from energy efficiency / demand response and semi-dispatchable resources are not reflected in either the intermittent or dispatchable/firm, therefore the sum of the capacity mix percentages does not total 100%.

Curtailments

The following tables identify the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type.

Table 114: Comparison of Wind PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0
2031	$0	$8,765	$2,511	$0	$0
RAP Total	**$0**	**$8,765**	**$2,511**	**$0**	**$0**

Table 115: Comparison of Solar PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$208,078	$2,816	$208,309	$216,270	$207,282
2027	$125,060	$0	$124,914	$126,321	$125,001
2028	$102,674	$9,596	$102,651	$106,117	$102,660
2029	$82,738	$122,947	$82,570	$82,658	$109,061
2030	$0	$29,692	$0	$0	$0
2031	$0	$329,902	$0	$0	$0
RAP Total	**$518,550**	**$494,953**	**$518,444**	**$531,366**	**$544,004**

Scenario 4 (SWER) and Scenario 5 (ACER) have the highest curtailment costs compared to the other scenarios. Scenario 2 (IRA) has the lowest curtailment costs while still achieving the highest GHG reduction in Colorado by 2030.

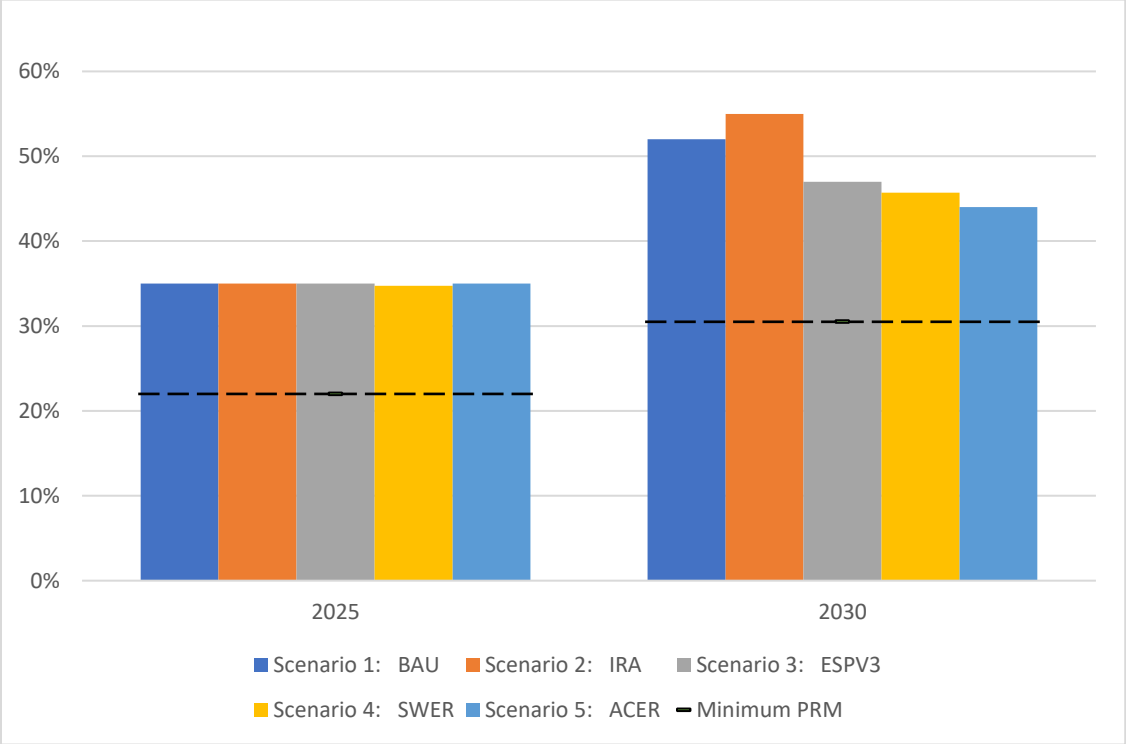
Table 116: Comparison of Total Wind + Solar Curtailment Costs during the RAP, by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
RAP Total	$518,550	$503,718	$520,955	$531,366	$544,004

Reliability Analysis

PRMs were relatively consistent across all scenarios through 2027. PRMs in 2030 range from 44 percent to 55 percent. The level of resource additions enabled by potential New ERA funding in Scenario 2 (IRA) resulted in higher PRMs during the RAP as compared to other scenarios.

Figure 16: Comparison of PRMs During the RAP



Each of the scenarios were able to meet Level I and II reliability metrics during the RAP. Scenario 2 (IRA) is the scenario that results in the greatest certainty in achieving reliability in the most cost-effective manner because it allows for the acquisition of more resources earlier in Tri-State's planning period. Tri-State's PRMs stay well above requirements, allowing for potential procurement or operational delays to more likely be addressed without reliability issues.

Conclusion

Given the comprehensive and thorough data obtained on the multiple scenarios modeled, the ERP Report supports approval of the IRA Scenario as Tri-State's preferred plan. As such, Tri-State requests the Commission: (1) find that the IRA Scenario within Tri-State's ERP Application meets the applicable rule requirements, (2) approve the IRA Scenario as Tri-State's Phase I preferred plan, and (3) approve Tri-State's Phase II procurement plans in this proceeding.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-76:
Power Engineering Fabric Filters Article

Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers

www.power-eng.com/environmental-emissions/real-world-performance-results/

August 1, 2012

By Tim Stark, Sales Applications Engineer, GE Energy Air Filtration

Fabric filters, or baghouses, have been used to capture particulate from combustion processes for more than 50 years. They grew popular in the power generation industry in the 1970s after the first installation of a reverse-air-style fabric filter. Pulse-jet, another type of fabric filter, was also implemented on coal-fired power generation applications in the early 1970s, with the first actual utility installation taking place in the early 1990s.

Reverse-Air Style Fabric Filter

Reverse-air was the original style of choice for dust collection in utility applications. In the 1970s, this style of collector was more suited for utility applications than pulse-jet because of the proven relatively low air-to-cloth/offline cleaning technology.

- Reverse-Air Technology
- Air-to-cloth ratio target: 2.5:1 or lower
- Large footprint
- Offline cleaning
- Woven fiberglass fabric
- Finish options: Teflonâ„¢ B, acid resistant, expanded polytetrafluoroethylene (ePTFE) membrane
- Dust collected on inside of filter-no support cage utilized
- Average bag life range: 5-10 years

Pulse-Jet-Style Fabric Filter

The pulse-jet-style fabric filter, while in service since the early 1970s on coal-fired applications, was not yet cost-effective enough and did not have the performance track record nor the technology advancements required to operate at the scale of a large utility boiler application. As technology advanced and performance objectives were proven on smaller-scale industrial boiler applications, the pulse-jet technology gradually became the choice on utility installations.

Pulse Jet Technology

- Air-to-cloth ratio target: 3.5:1 or lower
- Smaller footprint
- Online cleaning with ability for offline cleaning
- Fabric options: woven fiberglass, polyphenylene sulfide (PPS) felt, acrylic felt, P84â„¢ felt, aramid felt, fiber blends
- Finish options: acid resistant, singe, Teflon coatings, micro-denier, ePTFE membrane
- Dust collected on outside of filter
- Support cage utilized
- Average bag life range: 3-6 years

Lab vs. Real-World Conditions

While a fabric filter serves to remove particulate from the gas stream prior to the stack, it must do so while also controlling the fabric filter pressure drop so that there is proper ventilation during combustion and the cost of maintenance and fan energy consumption are minimized. This is a relatively simple task under conditions typically found in the lab.

Lab conditions

- Constant temperature
- Constant volume
- Constant moisture level
- Constant gas stream chemistry
- Constant grain loading

Using the above criteria for a gas stream in the laboratory yields acceptable performance results for most fabric and finish options. The real world has more challenging criteria for a fabric filter.

Real-world conditions

- Temperature: ranges from ambient to over 400 degrees Fahrenheit, depending on the scrubbing technology before the fabric filter
- Volume: dependent on load and temperature
- Moisture level: dew point excursions, tube leaks, fire suppression system upsets, door seal leakage, scrubber system upsets
- Gas stream chemistry: fuel changes, scrubber system upsets, ammonia levels when SCR technology is used, carbon present when activated carbon injection is used
- Grain loading: uneven gas stream distribution, material handling system upsets, fuel changes, offline cleaning

It is most important for the fabric filter to maintain pressure drop in an acceptable range, while also meeting emissions requirements, under all of the typical operating conditions that occur. Meeting these goals and doing it cost effectively boils down to dust-cake

management.

Standard Fabrics Used in Utility Coal-Fired Boiler Applications 1

	Acrylic	PPS	Aramid	Fiberglass	P84	Pleated elements
Max Operating Temp	265 F	375 F	400 F	500 F	500 F	Dependent on base fabric
	130 C	190 C	204 C	260 C	260 C	
Concerns in coal fired boiler applications	Lowest maximum operating temperature.	Susceptible to degradation at elevated temperatures coupled with oxygen levels over 12%.	Not as capable as PPS in chemically active gas stream environment.	Woven style fabric that is more fragile than other options. Requires tight tolerance to be maintained on bag-to-cage fit in pulse jet applications.	Dimensional stability at higher temps over 400 F. Requires oversizing of filter to maintain proper bag-to-cage fit.	Air to cloth ratio must be below 3.5 to 1. Applicable only when additional cloth area is needed to lower air to cloth ratio and eliminate inlet abrasion.
Relative Cost	$	$$$	$$$	$$	$$$$	$$$$$
Fabric treatments to improve performance	**ePTFE Membrane:** Laminated to collection surface-most efficient option, enables fabric to handle system upsets reviewed in paper at more consistent airflow/less cleaning frequency.					
	Micro-denier fibers/Tri-lobal fibers: Creates improved efficiency over standard fibers by increasing total fiber surface area. Limited improvement over ability to handle upset conditions reviewed.					
	PTFE Coating: Non-membrane surface coating used to improve dust cake release-sacrifices ability to maintain consistent airflow leading to increased cleaning frequency/high differential pressure.					
	Singe: Removes some of the fabric surface area, creating an improved ability of the fabric to release dust cake. Limited improvement over ability to handle upset conditions reviewed.					

Dust-Cake/Emissions Management

Over time, a dust-cake develops on the surface of the filtration media as a result of the particulate in the gas stream. In a coal-fired boiler, for example, this dust would consist of fly ash and any materials used to treat the gas stream (lime, trona, powder-activated carbon, etc.) before it collects on the fabric filter. This dust-cake is controlled by the baghouse cleaning system. The dust-cake performs two critical functions in the baghouse:

1. Filtration efficiency: The fabric filter acts as a support structure for a dust-cake that actually creates and controls efficiency. The fabric itself is not as efficient as the dust cake that is created on its surface, and the fabric alone cannot allow the system to meet environmental regulations. This dust-cake also provides some protection against the incoming gas stream, keeping the fabric from being directly subjected to the incoming dust load.

2. Gas-stream contact with dust-cake: In a coal-fired boiler that uses scrubber technology or activated-carbon injection technology before the baghouse, the dust-cake on the filter is providing some of the contact time between the gas stream and the materials injected into the gas stream for pollution control.

Common Upsets Causing Fabric Filter Issues 2

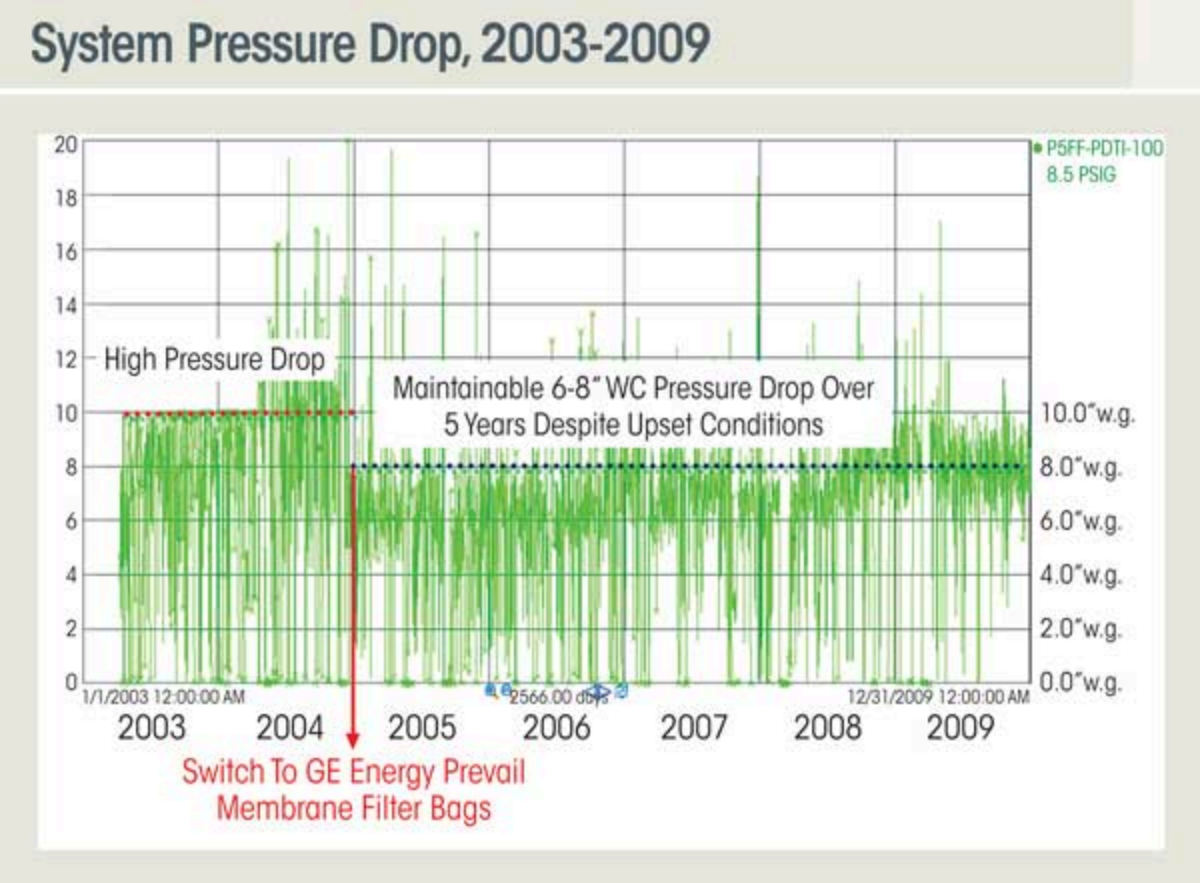
Upset Condition	Fabric Filter Effects
Tube leaks	High pressure drop from moisture carry-over, leading to constant cleaning
Material handling system failure	High hopper levels leading to high pressure drop from re-entrainment and filter abrasion/failure-also potential for heat excursion from hopper fires
Cleaning system failure	High pressure drop
Dew point excursions from pre-fabric filter equipment failure	High pressure drop from moisture condensation and chemical degradation of fabric/premature corrosion of support cages in pulse-jet-style units
SCR system upsets leading to high ammonia slip	High pressure drop from sticky dust created by ammonia levels, leading to constant cleaning
Fire suppression system failure	High pressure drop from moisture carry-over, leading to constant cleaning

The key to controlling this dust-cake is monitoring the pressure drop and controlling the cleaning to maintain the dust-cake.

Over-cleaning filter bags is one of the main causes of premature bag failure. First of all, the filter has the ability to withstand a certain number of cleaning cycles over the course of its life. If we clean a filter every five minutes, it may last two years. If we clean it every 10 minutes, it may last four years. The cleaning energy will slowly degrade the filter much like cleaning fabric in a washing machine will degrade clothing over time. The less we clean, the longer the fabric should last. The other problem with over-cleaning is it does not allow a dust-cake to properly develop, leading to either dust penetrating into the depth of the fabric and becoming permanently lodged there (blinding) or the dust passing completely through the fabric and ending up as emissions (bleed-through). Most people intuitively believe that the more they clean the filters, the lower the pressure drop and the lower the potential for emissions, but the opposite is true: it is the dust-cake that provides the efficiency and protects the fabric from premature blinding and/or bleed-thru.

In a utility baghouse, with gas stream treatment equipment upstream of the baghouse, the dust-cake has another purpose: create more contact time between the gas stream and the dust to help scrub the gas stream. This is an important variable to note. When trying to improve the filter's ability to release dust-cake, we often consider other fabric finishes. This raises the question about degrading the scrubbing results with filters that can potentially

operate at a lower overall pressure drop. Can we improve dust-cake release to the point where it adversely affects the scrubbing characteristics of the dust-cake? Real-world results show that the fabric finish does not necessarily affect the filter's ability to create the dust-cake needed to accomplish scrubbing goals. Dust-cake management, regardless of the fabric finish used, continues to be the important factor when operating a power plant baghouse.



Effects on Dust-Cake Management of Gas Stream Treatment

The air pollution control equipment used in today's coal-fired utility plants will almost always consist of more than just a fabric filter. Various different gas stream treatment technologies are used either before or after the fabric filter to treat the gas stream before it leaves the stack. Not only does this equipment have the potential to affect the performance of the fabric filter, the fabric filter can also affect this equipment.

To maintain a lower pressure drop for a longer period of time with the lowest cleaning frequency possible, end users have chosen different fabric types and fabric finishes. The gas stream treatment equipment used in conjunction with fabric filters can create conditions that make it more challenging for the cleaning system to maintain pressure drop. There are several instances where the fabric style or finish has been successfully changed in order to

improve a system's ability to maintain pressure drop in the correct range with the lowest cleaning frequency possible. The most successful example in recent years has been the treatment of the base fabric with an expanded polytetrafluoroethylene (ePTFE) membrane. In brief, the membrane creates a very slick and highly efficient surface that allows the dust-cake to be maintained with less cleaning energy. This helps the system not only handle a sticky, difficult-to-clean dust-cake, it decreases cleaning frequency (leading to longer filter life). The gas stream treatment options listed below all have an effect on the dust-cake that the fabric filter handles. Several of the case studies discussed below will show results with standard filtration media and results after switching to the ePTFE membrane option.

While ePTFE filters enable the fabric filter to run at a lower pressure drop regardless of the changes in gas stream, the real-world results show that they do not adversely affect the scrubbing results from the potential decrease in contact between the gas stream and the dust-cake.

Scrubbers

Scrubbers are used for flue gas desulfurization (FGD) and acid gas control. There are several different technologies used.

- Spray dry FGD-typically upstream of the fabric filter
- Wet dry FGD-typically downstream of the fabric filter
- Circulating dry scrubber
- Dry sorbent injection

Potential fabric filter effects:

- Increase in grain loading
- Potential for moisture introduction into fly ash, leading to high pressure-drop/increased cleaning requirements
- Potential for decreased inlet temperature, increasing the risk of the gas stream dropping below the acid dew point before or inside of the fabric filter
- When scrubber is downstream of fabric filter, inefficient operation can lead to increased cleaning requirements for downstream technology

Selective Catalytic Reduction (SCR)

SCRs are used to convert nitrogen oxides (NOx) with the aid of a catalyst into diatomic nitrogen (N2) and water. Typically ammonia is added into the flue gas stream and is absorbed onto a catalyst.

Potential fabric-filter effects:

Sticky dust created by ammonium bisulfate that leads to higher pressure-drop/increased cleaning frequency

Electrostatic Precipitators (ESPs)

ESPs remove particulate from the flue gas by using electrical forces. The dirty gas stream is passed through an electrical field set up between electrodes of opposite polarity. In the utility industry, where ESPs were originally installed as the primary Air Pollution Control device, they sometimes are left in service after the addition of a fabric filter downstream from the ESP.

Potential fabric filter effects:

- Lower grain loading — a good thing — leads to potentially lower cleaning frequency
- Potential for applying fabric filter at a higher A/C ratio based on lower grain loading
- Can change the particle size distribution going to the fabric filter, removing the larger particulate and allowing mostly the finer particulate to pass through. This can create a more challenging dust-cake for the baghouse

Carbon Injection

One method to help control mercury emissions is the injection of activated carbon into the flue gas to adsorb mercury before it exits the stack. This is typically done upstream of the fabric filter.

Potential fabric filter effects:

- Increased grain loading
- Fire potential
- Inability to sell fly ash from baghouse

Real-World Upset Conditions Affecting Fabric Filters

The fabric filter has several jobs to perform in a coal-fired boiler application. It needs to maintain pressure drop while meeting all environmental regulations in conjunction with the other pieces of environmental equipment in the system. On top of that, upset conditions in the real world can present challenges to the fabric filter. If the fabric filter can’t handle the upsets, the result could lead to the plant not being able to run at the required load demand or being forced to shut down because of an inability to meet environmental regulations. The other issue is if the upset conditions require continuous cleaning for prolonged periods of time, leading to premature bag failures and shorter bag life than the budget anticipates.

Case Study “A”

Problem: This power plant struggled with differential pressure levels with the original set of bags, which were made of a PPS base fabric with a Teflon surface coating. This included scrubber system upsets, ammonia slip over 10 ppm, fire suppression system upset, and pulsing system failure all leading to pressure-drop increases that were difficult to control even when pulsing at maximum psi levels and rapid pulse settings.

Additional Info: Case Study A	3
Cleaning style	Pulse-jet
APC train summary	SCR, spray dryer, fabric filter
MW	565 MW
Fuel	PRB
Average pressure drop at full load	7 inches wc
Fabric	Original: PPS with Teflon coating.
	Three-year life with dp struggles.
	Upgrade: PPS with ePTFE membrane. Six-year life at steady dp.
Average opacity	1 percent

Solution: GE Energy Preveil eTPFE membranes on PPS filters

Result: After three years, the original filters were replaced with GE Energy Preveil ePTFE on PPS filters. The system ran for more than five years at below 7 inches of pressure drop while again experiencing all of the upset conditions listed above. There was no change in the system’s scrubbing ability with the switch to membrane and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

Case Study “B”

Problem: This location struggled with particulate bleed-through and blinding with the original set of PPS filters, leading to opacity and high pressure drop.

Solution: GE Energy Preveil ePTFE membranes on PPS filters.

Additional info: Case Study B	4
Cleaning style	Pulse-jet
APC train summary	Electrostatic precipitator-dry scrubber-baghouse
MW	250 MW
Fabric	Original: PPS. Two-year life with dp and opacity struggles.
	Upgrade: PPS with ePTFE membrane. Two years to date with steady dp and no opacity issues.
Average opacity	Two percent

Results: After three years, the original PPS filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters. The plant has operated for two years with the new style filters without any bleed-through or blinding, and the pressure drop and opacity issues have been eliminated. There was no change in the system's scrubbing ability with the switch to membrane, and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

Case Study "C"

Problem: While this reverse-air style unit achieves more than a nine-year life with the standard woven fiberglass filters, the challenge had been the high pressure drop levels over 9 inches and the annual expense of using a vac truck to vacuum out the clean air plenum. Every six months a crew would have to isolate each compartment and vacuum off the tube sheet because of the bleed-through of the fine particulate created in this system.

Additional info: Case Study C	5
Cleaning style	Reverse-air
APC train summary	Fabric filter, wet scrubber
MW	245
Fuel	Low-sulfur coal
Average pressure drop at full load	4 inches wc
Fabric	Original: woven glass, acid-resistant finish. Struggled to maintain 9-inch pressure drop. Sifting of ash through fabric led to quarterly project of vacuuming ash out of clean air plenum. Bags changed after eight years. Current: same base fabric with ePTFE membrane-after five years of operation, pressure drop maintained at 4 inches with cleaning typically triggered by three-hour timer versus upper pressure drop setting of 5 inches. Have not yet vacuumed clean air plenum since the installation of the membrane.
Average opacity	2 to 3 percent

Solution: GE Energy Preveil ePTFE membrane-treated woven fiberglass filters

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane-treated woven fiberglass filters five years ago.

The pressure drop average dropped from 9 to 4.5 inches, and the expense of vacuuming off the tube sheet has been eliminated. The cleaning frequency has also been cut in half.

Case Study “D”

Problem: This unit struggled for the first two years with pressure drop over 9 inches. Offline cleaning methods were used to try to recover with limited success.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional info: Case Study B	6
Cleaning style	Pulse-jet
APC train summary	Dry scrubber-baghouse
MW	120
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS struggled with pressure drop over 9 inches, changed filters after three years.
	Current: PPS with ePTFE membrane, on year three with pressure drop averaging 6 inches with less cleaning frequency.
Average opacity	2 percent

Results: The original filters were replaced with ePTFE membrane on PPS filters. The pressure drop has averaged 6 inches after two years of operation. The current system is limited with regards to pulsing pressure and volume, so pulsing frequency and pressure are unchanged. There is no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage.

Case Study "E"

Problem: This system struggled with 9-inch pressure-drop levels caused by a scrubber control issue that led to low inlet temperatures. Ammonia slip levels also caused a stickier dust-cake.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional Info: Case Study E	7
Cleaning style	Pulse-jet
APC train summary	SCR, dry scrubber, activated- carbon injection, baghouse
MW	790 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS/P84 blend. High pressure drop struggles over 9 inches caused by ammonia bisulphate formation and low inlet temperatures. Changed filters at three years.
	Current: PPS with ePTFE membrane. Pressure drop averaging 6 inches after two years.
Average opacity	1 percent

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters and, after two years, the pressure drop has been averaging 6 inches. The cleaning energy and frequency has been decreased. A year after the membrane filters were installed, the pulsing system had an upset condition allowing a very heavy dust-cake to develop on the filters. After the problem was solved with the pulsing system, the filters immediately recovered to normal pressure drop levels.

Case Study “F”

Problem: This system has always operated in the 9-inch pressure-drop range with continuous cleaning using standard woven fiberglass. The sizing of the unit is relatively aggressive.

Solution: GE Energy Preveil ePTFE membranes on woven fiberglass filters

Additional info: Case Study F	8
Cleaning style	Reverse-air
APC train summary	Dry scrubber-baghouse
MW	450 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	7 inches wc
Fabric	Original: woven fiberglass with acid-resistant finish. Nine-inch pressure drop with continuous cleaning and a four-year life.
	Current: same base fabric with ePTFE membrane. Maintains 9-inch pressure drop with continuous cleaning and a six-year life.
Average opacity	2 percent

Results: After installing GE Energy Preveil ePTFE membrane on woven fiberglass filters, the unit still operates at 9-inch pressure drop, but the cleaning frequency has been decreased and the bag life has gone from four to six years. There was no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage.

Case Study "G"

Problem: This reverse-air unit had challenges with efficiency, which led to ash buildup in the wet scrubber that required expensive pressure washing of the scrubber on a semi-annual basis.

Additional info: Case Study G	9
Cleaning style	Reverse-air
APC train summary	Baghouse-wet scrubber
MW	300 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6.5 inches wc
Fabric	Original: woven fiberglass with acid-resistant finish.
	Current: same base fabric with ePTFE membrane treatment.
Average opacity	2 percent

Solution: GE Energy Preveil ePTFE membrane-style

Results: Three years after installing GE Energy Preveil ePTFE membrane-style filters, the plant has not yet had to go through the wet-scrubber cleaning process.

Case Study “H”

Problem: This system struggled with 9-inch pressure-drop levels and opacity spikes above 5 percent with the original PPS-style filters.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional info: Case Study G	10
Cleaning style	Pulse-jet
APC train summary	SNCR, CFD, baghouse
MW	500 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS struggled with 9-inch pressure drop and opacity spikes. Filters changed after 3.5 years.
	Current: PPS with ePTFE membranes, averaging 6-inch pressure drop and below2-percent opacity after 1.5 years.
Average opacity	Less than 2 percent

Results: After 3.5 years, GE Energy Preveil ePTFE membranes were installed on PPS filters. After 1.5 years since the GE filters were installed, the system has been averaging 6-inch pressure-drop and 2 percent or lower opacity levels, and the opacity spikes have been eliminated. There has been no change in the system's scrubbing ability with the switch to the membrane and no increase in lime usage.

Conclusion

Fabric filters utilized on coal-fired boilers face real-world environments that make their primary goals of managing pressure-drop, efficiency and a percentage of the systems scrubbing performance a challenge. Dust-cake management is critical in ensuring these goals are met. Multiple factors can have an impact on a system's dust-cake:

1. Low inlet temperatures
2. High moisture levels
3. Challenging dust-cake created when using scrubbers/SCRs/activated carbon injection
4. Longer-than-normal filter bags requiring aggressive cleaning to maintain pressure drop
5. Changes in ash volume and gas stream chemistry

Managing the dust cake requires controlling the filter differential pressure and is critical in ensuring:

1. Required particulate removal efficiency
2. Plant load requirements

3. Necessary scrubbing by dust-cake on filter media
4. Minimized energy cost for operating fabric filter

10. Maximized filter life with minimized maintenance costs

Filter media technology exists that improves the ability of the fabric filter to operate under real-world conditions. The use of ePTFE membrane laminated filters improves the performance of the fabric filter by allowing it to operate at a lower pressure drop and recover from common upset conditions.

Standard Fabrics Used in Utility Coal-Fired Boiler Applications
Environmental and EmissionsPE Volume 116 Issue 8

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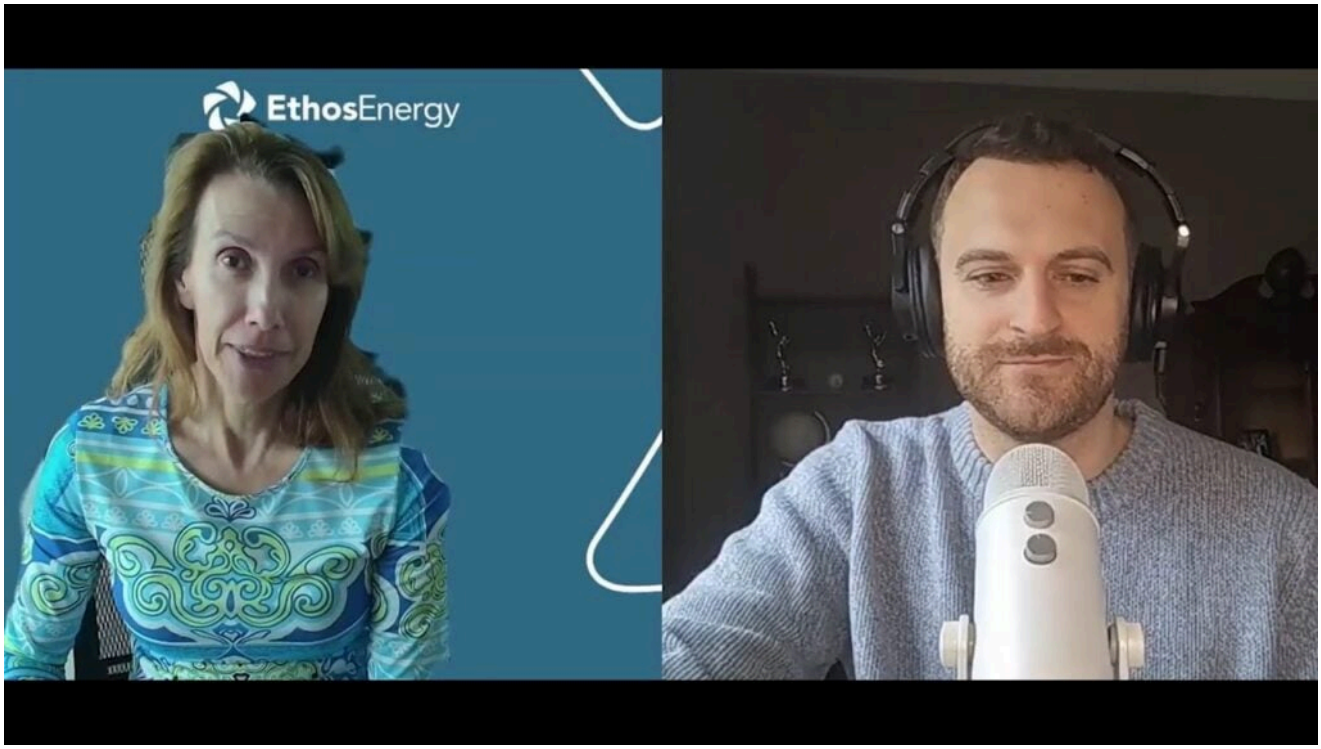

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-77:
Power Engineering Wet-Limestone Scrubbing Article

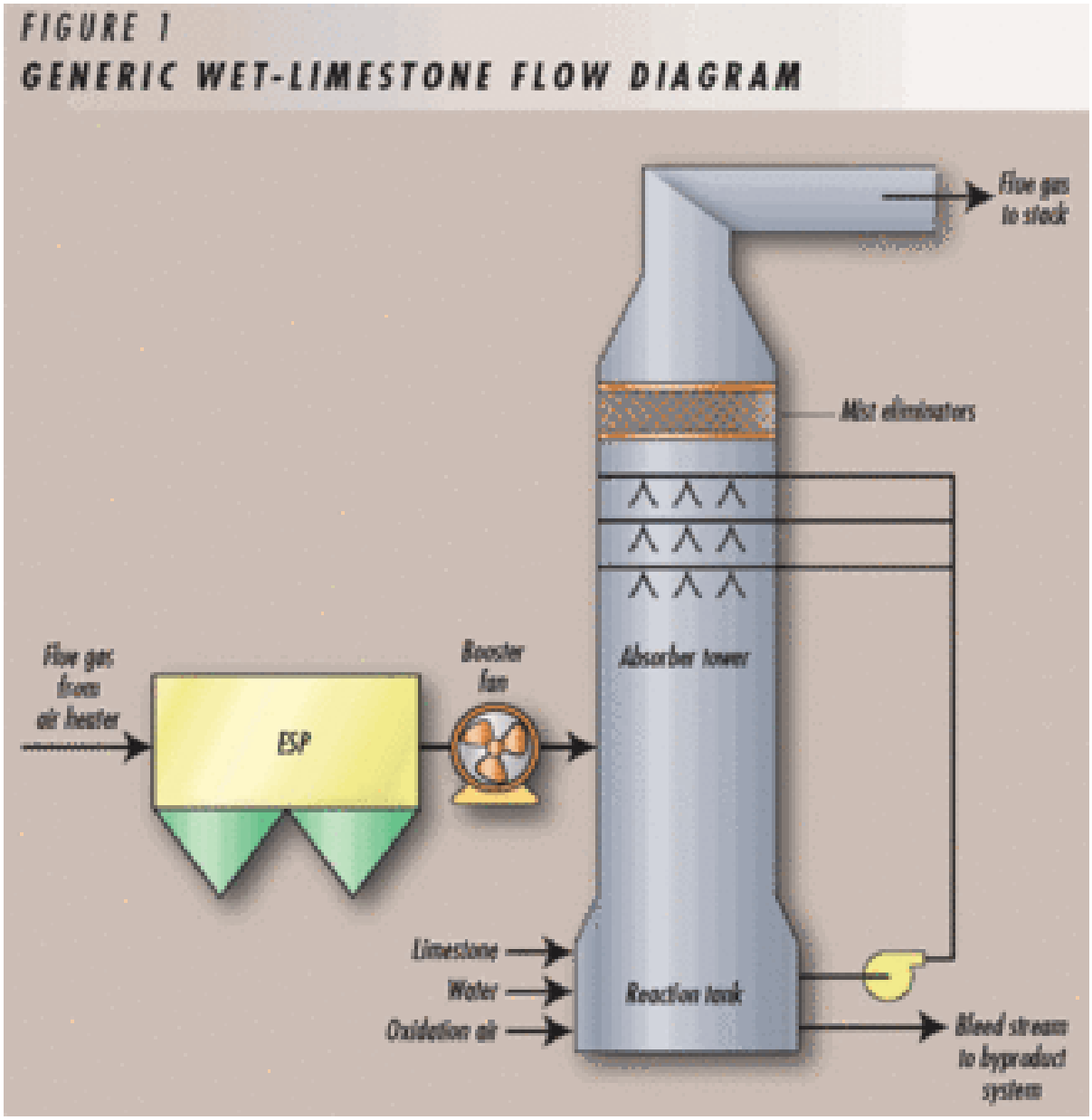
Wet-Limestone Scrubbing Fundamentals

www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/

August 1, 2006

By Brad Buecker, Contributing Editor

Stricter environmental regulations are forcing many utilities to install flue gas desulfurization (FGD) systems to control sulfur dioxide (SO_2) emissions below levels that can be attained by burning Powder River Basin (PRB) coal alone. The choice for many applications is wet-limestone scrubbing, a proven technology. Startup of the new scrubbers, combined with the many workforce retirements that are coming or have already occurred, will force many new personnel to learn FGD details. Properly controlling chemistry in these systems is vital for issues such as scale control, good reagent utilization and corrosion prevention. This article examines important concepts of wet-limestone scrubbing.



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A generic wet-limestone flow diagram is outlined in Figure 1. (The diagram also applies for systems using hydrated lime-Ca(OH2)-as the reagent, where equipment and vessel sizes are smaller.) Wet-limestone scrubbing is a classic example of an acid-base chemistry reaction applied on a large industrial scale. Simply stated, an alkaline limestone slurry reacts with acidic sulfur dioxide. As flue gas passes through the scrubber and is contacted by the limestone slurry sprays, sulfur dioxide absorbs into the liquid. Theoretical chemists argue that sulfur dioxide forms only a hydrated compound, where individual SO2 molecules are surrounded by water. However, when SO2 is introduced to water, a pH depression occurs, where the following equilibrium reactions are representative:

SO 2 + H 2O â† â†’ H 2SO 3 â† â†’ H + + HSO 3– â† â†’ H + + SO 3 -2
Limestone, whose primary components are calcium carbonate (CaCO3) with lesser amounts of magnesium carbonate (MgCO3), when introduced to water will raise the pH according to the following mechanism.

CaCO 3 + H 2O â† â†’ Ca +2 + CO 3 -2 + H 2O â† â†’ Ca +2 + HCO 3– + OH –
However, CaCO3 is only very slightly soluble in water, so this reaction is minor in and of itself. In the presence of acid, calcium carbonate reacts much more vigorously. It is the acid generated by absorption of SO2 into the liquid that drives the limestone dissolution process.

CaCO 3 + 2H + â†’ Ca +2 + H 2O + CO 2 â†‘
Equations 1, 2 and 3 when combined illustrate the primary scrubbing mechanism.

CaCO 3 + 2H + + SO 3 -2 â†’ Ca +2 + SO 3 -2 + H 2O + CO 2 â†‘
In the absence of any other factors, calcium and sulfite ions will precipitate as a hemihydrate, where water is actually included in the crystal lattice of the scrubber byproduct.

Ca +2 + SO 3 -2 + ½H 2O â†’ CaSO 3 – ½H 2O â†“
However, oxygen in the flue gas has a major impact on chemistry and in particular on byproduct formation. Aqueous bisulfite and sulfite ions react with oxygen to produce sulfate ions (SO4-2).

2SO 3 -2 + O 2 â†’ 2SO 4 -2
Approximately the first 15 mole percent of the sulfate ions co-precipitate with sulfite to form calcium sulfite-sulfate hemihydrate [(CaSO3 – CaSO4) – ½H2O]. Any sulfate above the 15 percent mole ratio precipitates with calcium as gypsum.

Ca +2 + SO 4 -2 + 2H 2O â†’ CaSO 4 – 2H 2O â†“
Calcium sulfite-sulfate hemihydrate is a soft, difficult-to-dewater material that previously has had little practical value as a chemical commodity (although interest is beginning to develop in agricultural benefits of the material). For this reason, many scrubbers are equipped with forced-air oxidation systems to introduce additional oxygen to the scrubber slurry. A properly designed oxidation system will convert all of the liquid sulfite and bisulfite ions to sulfate ions. Sulfate, of course, precipitates with calcium as gypsum, which typically forms a cake-like material when subjected to vacuum filtration. In many cases 85 to 90 percent of the free moisture can be removed by this relatively simple mechanical process. Gypsum is the primary ingredient of wallboard. A number of FGD systems throughout the world produce wallboard-grade byproduct. (To read more about combustion by product markets, see the July 2006 issue of *Power Engineering*.)

Improvements

Problems that plagued first- and second-generation wet-limestone scrubbers included poor SO2 removal, scale formation in the scrubber vessels and poor utilization of the limestone reagent. Spray nozzle efficiency, scrubber vessel configuration, limestone reactivity and particle size are all factors that influence these processes.

Adequate mixing of the flue gas and slurry is critical. Early scrubber towers usually were equipped with internal packing or trays to enhance gas-liquid contact. While the theoretical concept behind these mixing devices was valid, the material would often become plugged with scale, necessitating periodic cleaning, replacement or laborious control methods.1 In some early designs, the packing consisted of plastic balls, which often would “cement” together and cause a degradation in scrubber performance. Spraying technology has greatly improved in the last few years and open spray towers are now becoming popular.2 Spray nozzle design is critical in these systems, as droplet size must be optimized to provide the best contact. The slurry spray pattern also must be such that channeling of the flue gas does not occur. (An excellent article on spray nozzle types may be found in reference 3.) A still-common technique is to introduce the flue gas in a tangential pattern to the scrubber tower. This imparts a centripetal motion to the gas and forces it to swirl around the tower as it passes upwards. The swirling action improves slurry-gas mixing and increases gas residence time in the vessel.

Limestone reactivity is another key factor. In general, limestones with 94 percent or greater calcium carbonate content provide suitable alkalinity for reaction. Impurities in the stone may cause significant operating difficulties. Magnesium, a common substitute for calcium, can be either helpful or harmful depending upon its chemical makeup within the stone. If the magnesium exists as homogenous magnesium carbonate (MgCO3), it can enhance SO2 removal by providing extra alkalinity to the scrubbing solution. However, magnesium often co-exists with calcium in a crystal matrix known as dolomite (CaCO3 – MgCO3). Dolomite is rather un-reactive and stones containing a significant dolomite content may require excess feed to achieve the required SO2 removal. Limestones typically also contain inert materials, including siliceous compounds such as quartz. These have different densities than the scrubber byproducts and may negatively affect slurry separation device performance. Iron in limestone can form oxides that plug vacuum filter cloths. Iron can also influence gypsum scale formation on scrubber vessel internals, although this is usually not a problem in forced-oxidation systems.

Limestone reactivity is greatly influenced by particle size. A typical method of preparing limestone slurry is to grind the raw limestone with water in a ball mill. This produces a suspended solution of fine limestone particles (slurry), which is then pumped to the reaction vessel. Smaller particle size increases the total surface area of the limestone reactant. Grind size is determined by passing a slurry sample through progressively smaller sieves. A typical specification for grind size in first-generation scrubbers was 70 percent passage through a

200-mesh screen. However, scrubber designers, operators and chemists came to realize that this size was too coarse to promote good utilization. Nowadays, 90 percent or greater passage through a 325-mesh screen is more desirable.

Even with a well-ground, high-purity limestone, utilization may fall short of expected levels. A recent approach is the use of additives to enhance performance. One of the most popular of these is adipic acid (HOOCCH2CH2CH2CH2COOH), which goes by the common name of dibasic acid (DBA). DBA functions by assisting limestone dissolution, which in turn increases sulfur dioxide removal kinetics. Supplemental DBA feed represents a practical approach for enhancing the SO2-removal performance of existing scrubbers.

Improvements have also been made in scrubber vessel construction material. Chlorine in coal converts to hydrogen chloride (HCl) during combustion. HCl is an acid that reacts with limestone to produce calcium and magnesium chloride (CaCl2 and MgCl2), both of which are soluble salts. Chloride concentrations may reach several thousand milligrams per liter. Many first- and second-generation designs incorporated stainless steels in system components. These materials proved unstable when exposed to high chloride concentrations, as chlorides penetrate the protective oxide layer on stainless steels and initiate pitting.

Various inorganic and organic linings have been tested over the years. These often failed due to poor application or simply the stressful nature of the scrubber environment. More exotic materials are not always the answer. Even titanium will fail in the presence of porous slurry deposits, which allow chloride to concentrate at the metal substrate. These conditions are prevalent at the wet-dry interface where flue gas first contacts the slurry sprays. A retrofit technique for some scrubber components, such as scrubber vessel outlet ducts, is overlay (commonly termed wallpapering) of the base metal with a corrosion-resistant material. The most common choices have been the nickel-based alloys C-276 and C-22.

Byproduct Disposal

An issue of continuing importance is byproduct disposal. At plants equipped with forced-air oxidation systems and filter drying systems to produce high grade gypsum, land requirements and costs for byproduct disposal are greatly reduced when plant manufacturers can sell the product to wallboard manufacturers. Other options include gypsum production with landfill of the byproduct, or no forced oxidation with disposal of the byproduct slurry in retention ponds. Some utilities own enough land so that the retention ponds can serve as evaporation ponds, eliminating liquid discharge as an issue. Disposal requirements will undoubtedly become more important due to water conservation issues. Plant personnel are facing regulations that require minimized or zero liquid discharges. No longer can a scrubber be planned without giving thought to liquid discharge issues.

One potential drawback of wet-limestone systems is that they can emit very fine particulates and aerosols. Health and regulatory officials are becoming increasingly concerned about the effects of fine particulates on human well-being. Regulations are becoming increasingly strict with regard to particulate discharge.

Other drawbacks of wet-limestone scrubbing are large up-front capital costs, large equipment size and substantial predictive and corrective maintenance requirements. Substituting hydrated lime as the reagent reduces equipment size and costs, but increases reagent costs and material handling issues. Thus, limestone is more popular as a reagent for wet system handling equipment. This eliminates the need for expensive and maintenance-intensive dewatering and sludge disposal equipment. Also, the drying process does not expose the scrubber materials to chlorides as in wet systems. This relaxes requirements for materials of construction, which in turn lowers capital and building costs.

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Brad Buecker is an air quality control specialist at a large Midwestern power plant. He has previous experience as a chemical cleaning services engineer, a water and wastewater system supervisor and a consulting chemist for an engineering firm. He also served as a results engineer, flue gas desulfurization (FGD) engineer, and analytical chemist for City Water, Light & Power, Springfield, Illinois. Buecker has written more than 70 articles on steam generation, water treatment and FGD chemistry, and is the author of three books on steam generation topics published by PennWell Publishing. He is a member of the ACS, AIChE, ASME, and NACE.

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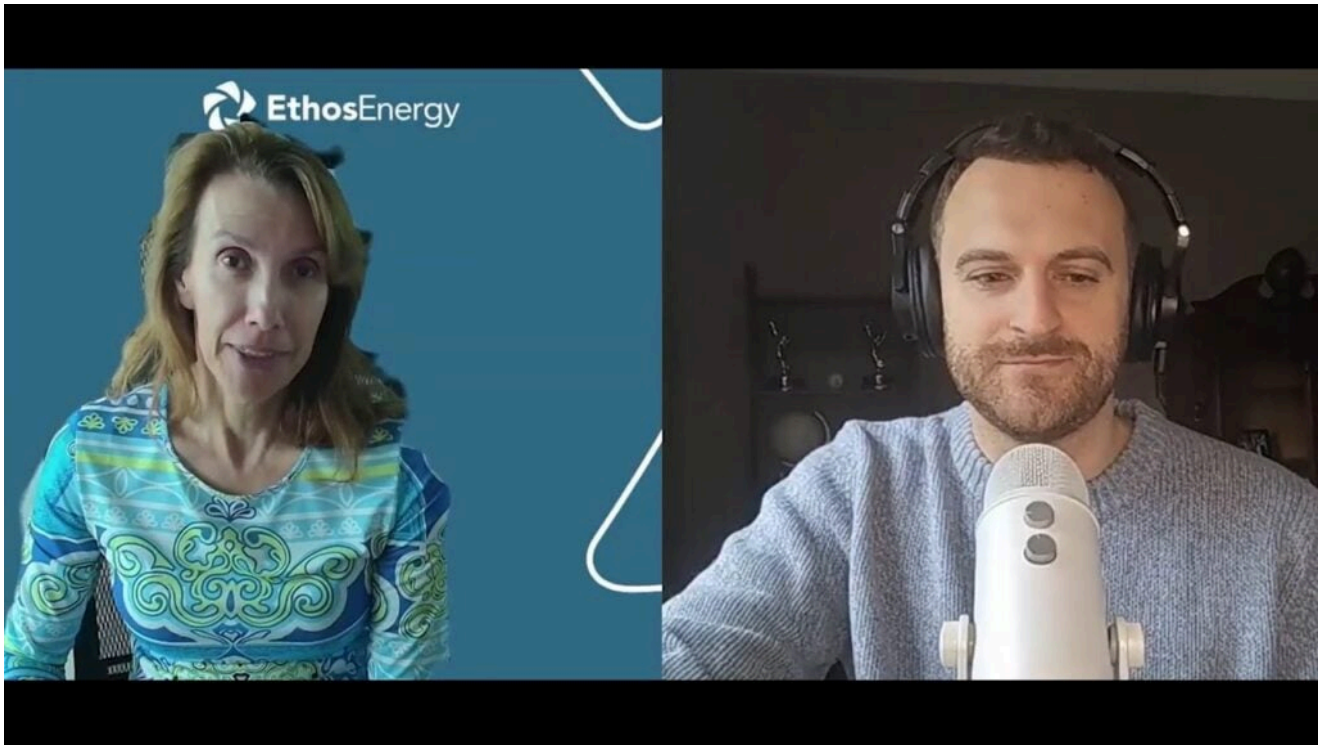

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

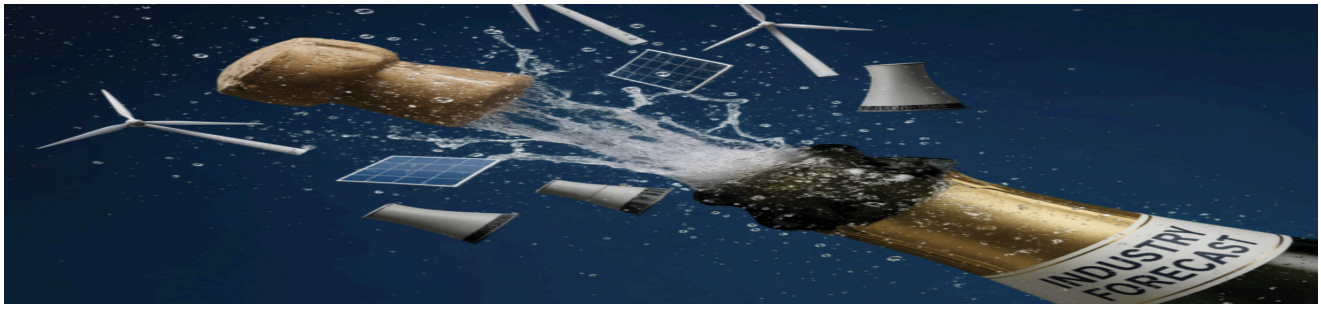
Filed April 28, 2026

Exhibit 2-78:
Power Magazine Pulverizers Article

To optimize performance, begin at the pulverizers

www.powermag.com/to-optimize-performance-begin-at-the-pulverizers/

POWER February 15, 2007



Optimizing combustion in pulverized coal (PC)-fired boilers today is more important today than ever. It is well known that the average American PC plant is over 30 years old and that over its lifetime NO_x and SO_2 emissions limits have been steadily ratcheted down (see box). Today, operators no longer wonder whether permissible levels will continue to fall but, rather, when and by how much.

Change is in the air

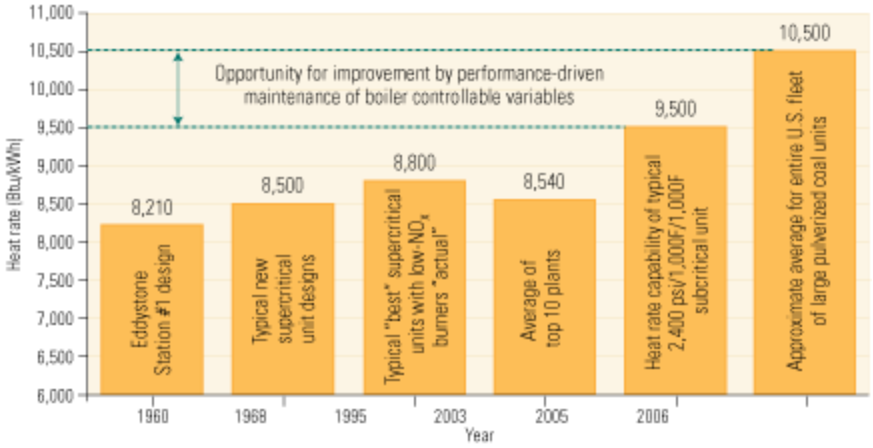
Tighter pollution control has been a common thread in the major evolutionary development of coal-fired generation over the past 30 years:

- Low-NO_x burners, overfire air systems, and other "furnace solutions" have enabled major reductions in NO_x emissions, from 0.5 to 1.5 lb/million Btu to less than 0.15 lb/million Btu.
- Many boilers designed to fire eastern and midwestern bituminous coals have been adapted to burn lower-sulfur Powder River Basin coal at reduced production costs.
- Pulverizers designed for coals with a Hardgrove Grindability Index (HGI) of 50 to 60 are today working with coals that have an HGI in the low 40s.
- Additions of electrostatic precipitator fields and back-end retrofits of baghouses, selective catalytic and noncatalytic reduction systems, and scrubbers have become commonplace.
- Distributed control systems and advanced electronic hardware and software have modernized and optimized boiler operations.
- Public and regulatory pressures are leaning toward mandatory CO_2 emissions caps.

The newest fork in coal-fired generation's path forward is determining how to capture plant emissions of carbon dioxide (CO_2) when—not if—the gas is regulated as a pollutant. Some advocate widespread installations of unproven integrated gasification combined cycle (IGCC) technology ASAP, to prepare it as a long-term solution. Others say building fleets of

super-efficient supercritical and ultrasupercritical-pressure and -temperature plants would be a timelier, more prudent, and more cost-effective alternative. But while regulators, Congress, and the courts wrestle with the question of what to do about greenhouse gases, one thing remains clear: CO_2 emissions could be lowered considerably by raising the efficiency of the existing U.S. fleet of 1,100+ coal plants.

Today's average U.S. PC-fired plant operates at a heat rate of about 10,500 Btu/kWh. Yet a subcritical (2,400 psi/1,000F/1,000F) unit is capable of operating at least 10% more efficiently, at a heat rate of 9,500 Btu/kWh (Figure 1). There are many proven ways to improve a boiler's performance by continuously optimizing its controllable variables (see box). This article explores opportunities for raising a unit's efficiency by improving the performance of its pulverizers.



1. Room for improvement. The heat rate of most older coal-fired steam plants could be lowered by improving their combustion air and fuel systems. Source: Storm Technologies

Storm Technology's experience has demonstrated that, of the 20 key O&M controllable variables with the greatest impact on unit heat rate (see box), most involve the furnace's "burner belt." Essentially (and most often), in a plant operating at its lowest possible heat rate, the combustion airflows, pulverizers, fuel line balancing, burners, and air heaters will all be optimized.

20 boiler variables that can be controlled by O&M practices to improve unit heat rate

1. Flyash loss-on-ignition (LOI), or unburned carbon in ash.

2. Bottom ash carbon content.

3. Boiler and ductwork air in-leakage.

4. Primary airflow. (Measure and control more precisely, to reduced tempering airflows.)

5. Pulverizer air in-leakage on suction-fired mills. (Reduce it.)

6. Pulverizer throat size and geometry. (When optimized, reduces coal rejects and complements operation at lower primary airflows, which reduces tempering airflow and total airflow bypassing the secondary air heater.)

7. Secondary airflow. (When measured and controlled more closely, it enables more precise control of furnace stoichiometry—essential to low-NO_x operation.)

8. Peak upper furnace exhaust gas temperatures. (When too high, they foster "popcorn ash" carryover into the selective catalytic reduction system and air preheater, excessive spray water flows, and boiler slagging and fouling.)

9. Desuperheating spray water flow to the superheater. (Reduce the level.)

10. Desuperheating spray water flow to the reheater. (Reduce the level.)

11. Air heater leakage. (Reduce it; the level for Ljungstrom regenerative air heaters should and can be less than 9%.)

12. Superheater outlet steam temperature.

13. Reheater outlet steam temperature.

14. Air heater exit gas temperature. (Correct it to a "no leakage" basis and optimize it.)

15. Burner "inputs" tuning. (For lowest possible excess oxygen at the boiler outlet and satisfactory NO_x and LOI levels.)

16. Boiler exit (economizer exit) gas temperatures ideally between 650F and 750F, with zero air in-leakage (no dilution).

17. Cycle losses due to valve leak-through. (For spray water valves, reheater drains to the condenser and superheater, reheater drains and vents, and—especially—any low-point drains to the condenser or hotwell.)

18. Sootblowing frequency. (Optimized for maximum cleaning effect and minimal impact on heat rate.)

19. Steam purity. (Turbine deposits negatively impact unit heat rate and capacity.)

20. Auxiliary power consumption. (Minimize it by optimizing fan clearances, duct leakage, fuel and primary air system performance.)

Despite all the changes in regulations, equipment, fuels, and combustion controls over the past few decades, one thing has not changed in evaluating pulverizer performance: You need to get the inputs right! Table 1 breaks down the potential heat rate improvements

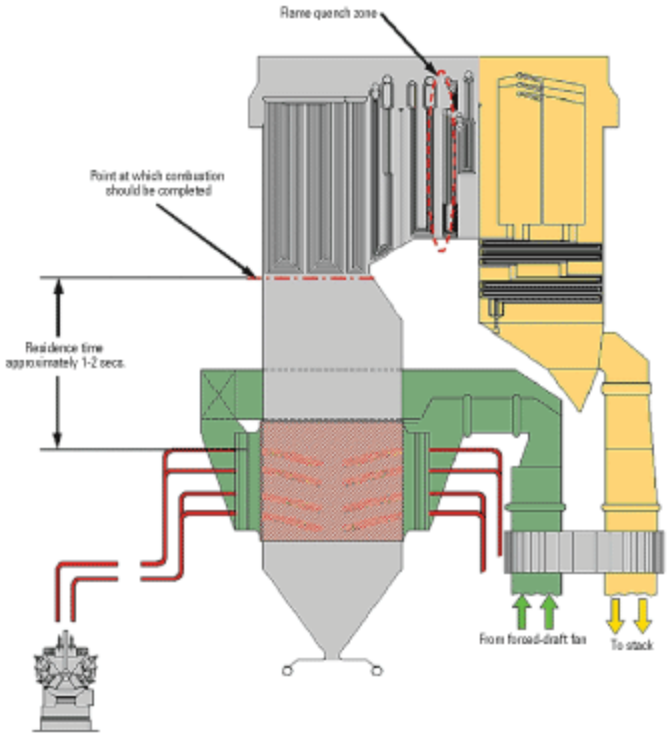
achievable from giving your pulverizer and related systems a good tune-up.

Controllable O&M variable	Heat rate improvement potential (Btu/kWh)
Air in-leakage (reduce)	200
Primary airflow (optimize)	50
Pulverizer performance, fuel line balance (optimize)	100
Air heater leakage (reduce)	80
Coal "pyrites" rejects (reduce)	40
LOI (minimize)	80
Desuperheating spray water flows (minimize)	50
Total	**600**

Table 1. Pulverizer improvements are significant and easy to accomplish. Source: Storm Technologies

Reversal of fortune

Before moving on to some prescriptions for pulverizer optimization, consider the internal configuration of a typical, 1970s-vintage 600-MW PC-fired boiler (Figure 2). The top of the burner belt is about 55 feet below the nose arch, or furnace exit. For optimal production and environmental performance, combustion must be 99% complete by the time its products are passing over the superheater and reheater surfaces. The flue gases are moving swiftly; the residence time in the furnace of the primary air/coal mixture that entered the furnace at the top burner level is less than 2 seconds. Usually, residence time from the top burners to the nose arch is more like 1 second. Remembering the shortness of this interval is important when it is essential to minimize NO_x emissions and when firing fuels with high levels of iron and sodium in their ash.



2. Burned to a crisp. In a typical "thirty-something" pulverized coal-fired boiler, 99+% of combustion should be complete by the time the products of the process reach the convection surfaces. Source: Storm Technologies

Common in-furnace NO_x-reduction solutions include using low-NO_x burners and overfire air (OFA) systems to intentionally stage or slow down combustion. Realizing that delayed combustion is fundamental to the design of all low-NO_x burners and OFA systems helps in understanding why it is so important to optimize pulverizer performance. For example, the ash-softening temperature of a bituminous coal whose ash is high in iron content may be as much as 300 degrees F lower in a reducing (0% oxygen) atmosphere than in an oxidizing environment.

Storm Technologies has found that when coal with high sulfur and high iron content is fired with non-optimized inputs, excessive slagging occurs in the furnace due to the combination of coal chemistry and secondary combustion. The key point to be made here is that the effect of chemistry kicks in when the ash becomes "sticky" or molten, and that happens at a lower temperature with fuel ash high in iron content.

Low-NO_x combustion deliberately consumes some of the furnace residence time for staging combustion and, as a result, contributes to more zones in the upper furnace being in an oxygen-deficient state. Consequently, more slagging occurs and more sootblowing is needed to remove the slag, which reduces heat transfer. Because increased sootblowing increases tube erosion and shortens tube life, suboptimal combustion contributes to reduced plant reliability and availability.

Double down

Suboptimal combustion also takes its toll on unit heat rate:

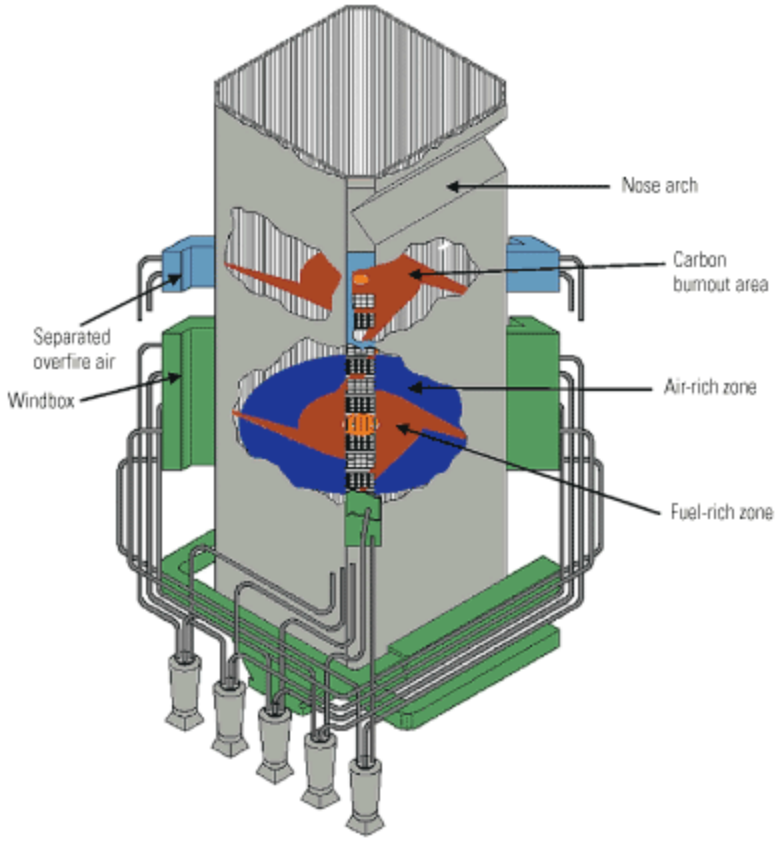
- Each extra sootblowing cycle imposes an overhead cost on steam cycle efficiency.
- The carryover of cinders into the air heater increases draft losses and fan auxiliary power consumption. The increased air heater differential will then increase air in-leakage due to the fouling.
- In units retrofitted with low-NO_x burners or an OFA system, combustion may be actively occurring higher in the furnace, creating secondary combustion. This elevated center of combustion will decrease waterwall heat absorption, elevating the peak furnace exit gas temperature (FEGT). High FEGTs lower combustion efficiency and raise unit heat rate.

Given the extremely short furnace residence times and the staging or slowing of combustion to reduce NO_x formation at the source, it is clear that combustion efficiency must be maximized in the burner belt. Unnecessarily high FEGTs can overheat superheater and reheater metals and cause higher-than-optimal desuperheating spray water flows (imposing a sizable heat rate penalty). Optimizing burner belt performance requires more precise measurement of key boiler performance variables and tighter control of the fuel:air ratio.

Focus on firing

By now, you're probably asking,"What does low–heat rate, low-NO_x boiler performance have to do with pulverizer operation?" Plenty, as it turns out. Several significant factors involved in optimizing combustion with low-NO_x burners are equally applicable to corner-fired and wall-fired boilers.

Let's first consider corner-fired boilers, which are considered inherently forgiving of less-than-optimal combustion tuning. This tolerance seems to derive from the fact that in corner-fired boilers (Figure 3), the entire furnace volume can be considered a single burner into which fuel and air are injected from the corners, creating a burning mass in the center. The burning mass serves to reduce peak temperatures. Meanwhile, tangential injections from the corners impart "swirl" to the fuel and combustion air at all burners; that creates a more homogeneous mix of the products of combustion for fuel-rich and fuel-lean burners. The tangential admission of the fuel and air also slightly increases the residence time of a coal particle, from its introduction into the furnace until its conversion to a burning carbon char particle that is quenched to below 1,400F in the convection pass.

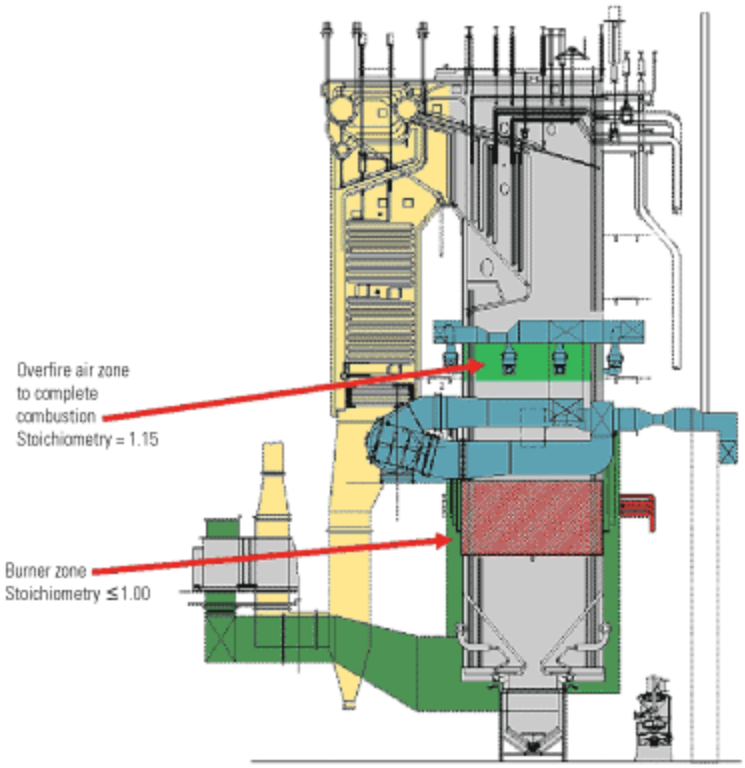


3. Stand in the corner. Corner-fired boilers utilize more of the total furnace for combustion and tend to have lower NO_x emissions. Source: Storm Technologies

The "burning mass" principle also reduces the intensity of combustion in the burner belt, lowering "natural" NO_x levels in the process. Before low-NO_x burner technology was perfected, corner-fired boilers inherently produced less NO_x than wall-fired boilers. Modern, low-NO_x designs stage combustion not only vertically, but horizontally as well.

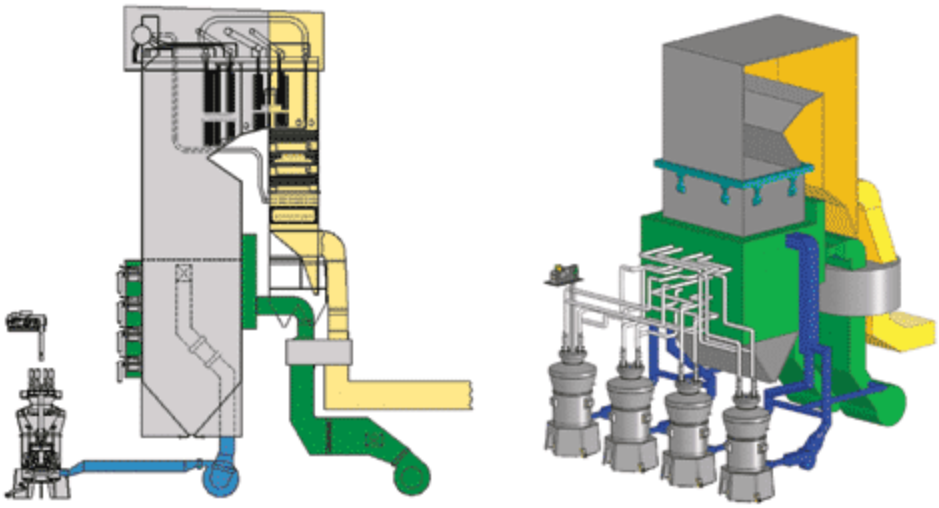
Learn from experience

Another proven way to reduce NO_x emissions without imposing a heat rate penalty is to apply high-momentum OFA through opposed nozzles in the upper furnace. Figure 4 shows the configuration of such a system, as installed both at AES Corp.'s 126-MW Westover Plant in Johnson City, N.Y. (see *POWER*, October 2006) and Savannah Electric's McIntosh Plant.



4. Over and above. NO_x emissions can be reduced by applying high-momentum overfire air through opposed nozzles in the upper furnace. Source: Storm Technologies

In Storm Technologies' experience, wall-fired boilers require fine-tuning of the fuel and air inputs to the burner belt to optimize plant performance, response, and heat rate. A good example is McIntosh Unit 1, a 1975-vintage, 175-MW unit with 16 front wall-mounted burners (Figure 5, left). The furnace division panel separated the eight burners on the right side of the boiler from the eight burners on the left. The 16 burners are arranged in four levels of four across. A fan-boosted OFA system was retrofitted to the unit (Figure 5, right) with excellent results (Table 2). For McIntosh Unit 1, the overall project included optimization of its pulverizers, burners, combustion airflow paths (primary, secondary, and OFA), and improvements to the management and control functions of the systems.



5. You're fired. McIntosh Plant Unit 1 before (L) and after (R) retrofit of a fan-boosted overfire air system. Source: Storm Technologies

Variable	Pre-retrofit	Post-retrofit
Coal fineness (percentage of <HGI coal particles passing 200-mesh screen)	50%–60%	75%–80%
Clean airflow balance (distribution imbalances)	5%–17%	<2%
Fuel flow balance (distribution imbalances)	±20%	±10%
Air-fuel ratio (lb air/lb fuel)	>2.0	~1.8
Flyash loss-on-ignition with Eastern bituminous coals	16%–22%	<10%
Flyash loss-on-ignition with low-rank Venezuelan coals	Not available	<15%
Furnace exit gas temperature (average FEGT/maximum FEGT)	~2,250F/2,400F	<2,200F/2,300F
NO_x (lb/mmBtu)	0.78–1.0	~0.28/0.36 (with 3 or 4 mills operating)

Table 2. Results of retrofitting a fan-boosted overfire air system to Unit 1 of Savannah Electric's McIntosh Plant. Source: Storm Technologies

This wall-fired unit—which has an unforgiving furnace arrangement (furnace division panels and wall-mounted burners) and a relatively short residence time (1 second from the top burners to the nose arch)—validates the potential of using the tenets of combustion optimization found in Table 1. It has test-burned a wide range of coals from South America, Central Appalachia, and the Powder River Basin with good results.

Those results include improved reliability, which must be quantified and factored into the savings equation. Optimized combustion has reduced slagging and fouling. Improved fuel fineness, fuel distribution, and combustion air distribution also have contributed to greater unit availability.

One less well-documented advantage of greater fuel fineness (75% of coal particles pass a 200-mesh screen, and none pass one of 50 mesh) is reduced waterwall wastage. This type of corrosion becomes more severe on boilers operating at supercritical pressure and firing fuels with high sulfur and iron content. Even boilers running at 1,600 to 1,800 psi can have their useful life shortened considerably if their waterwalls are exposed to highly aggressive fireside corrodents of sulfur and iron in a reducing environment.

Future shock

In fact, the industry can expect fireside wastage to become more prevalent as more 30+-year-old plants install SO_2 scrubbers and then are converted to be capable of firing higher-sulfur coals. Why? The reason is because most low-sulfur compliance coals also have low iron content in their ash. These coals are "forgiving" from the perspective of contributing to aggressive fireside corrosion of water walls and slagging. Once a plant owner has spent the money on a scrubber, he will be tempted to buy a higher-sulfur fuel (with higher iron content in its ash) for economic reasons—primarily escalating Western coal rail costs and improved Eastern coal cost-competitiveness. This "reverse fuel switch" trend is likely to foster more slagging, fouling, and aggressive furnace tube corrosion.

Fortunately, there are options available to prevent increases in slagging and fouling that result from a reverse fuel switch. One for minimizing fireside wastage is to optimize pulverizer performance to fuel fineness that’s acceptable in all fuel lines at all times. Storm Technologies’ standard minimum recommended fineness is greater than 75% of particles passing through a 200-mesh screen and none through a 50-mesh screen. Lowering superheater and reheater metal temperatures, to reduce slagging and fouling in the convection passes, is another step than can be taken to improve unit reliability and burner belt combustion.

Finally, operating a unit at its maximum efficiency and capacity should be an overriding economic objective. Optimizing pulverizer performance and burner belt inputs can help reach that goal. So can diagnostic performance testing of fuel lines, combustion airflows, and key upper furnace combustion parameters. When fuel line fineness declines, and reducing environments are found in the furnace, corrective action should be taken immediately.

Cleaner coal-burner

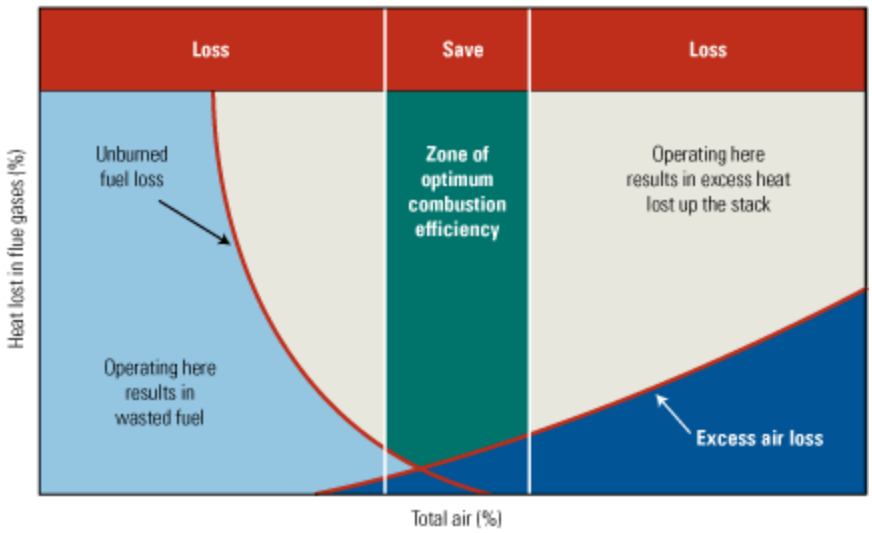
To sum up, there are three significant ways in which optimizing pulverizer performance can contribute to a reduction in a coal-fired boiler’s NO_x emissions.

One. Release of fuel-bound nitrogen in the burner’s devolatilization zone is enhanced by making coal particles smaller, in effect increasing the overall fuel surface area. Low-NO_x burners are most effective when they’re fed coal that has been finely ground. Poor fineness

traps fuel-bound nitrogen within the carbon char particles, beyond the reach of even the best low-NO_x burners.

Two. Fuel balance usually improves with better fuel fineness. A powdery mixture of fine coal particles passing through a pulverizer, classifier, and coal riffles (if the unit is so equipped) will flow more uniformly when it is more finely ground. Such fuels actually flow more like a gas when entrained at the proper ratio in the primary air stream. Fine coal particles mixed in the transport air become more uniformly distributed than coarsely ground coal particles at a similar air/fuel ratio.

Three. A more homogeneous mixture of coal and air entering the burners will naturally reduce required excess air levels. By reducing the total airflow and reducing the excess air, thermal NO_x production is reduced. The better the mixing of the combustion products in the available residence time, the less "extra air" that has to be added to create oxidizing zones in portions of the furnace that are fuel-rich (Figure 6). When these "peaks and valleys" of free oxygen and high temperatures are made more uniform, then it becomes possible to reduce the total excess air that has to be added to make up for imprecise fuel and air inputs into the burner belt.



6. Walk the line. Economic plant operation requires operation in the narrow zone of optimum combustion efficiency. Source: Storm Technologies

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-79:
Riley Power Low NOx Burner Performance Article

TECHNICAL PUBLICATION

Advanced Erosion Protection Technology Provides Sustained Low NO_x Burner Performance

by:
Douglas Goebel
Engineer, We Energies

Michael Saari
Sr. Mechanical Engineer, We Energies

K. Scott Trunkett
Market Manager, Conforma Clad Inc.

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Presented at:

Electric Power, March 30-April 1, 2004
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&
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ABSTRACT

Electric power generators are experiencing the most complex confluence of market pressures in the history of the industry. Environmental regulations are stricter than ever, forcing producers to make substantial capital investments in emissions conformance, while the pressures of deregulation are making available maintenance dollars ever more scarce. The threat of non-conformance penalties weighs heavily against the pressures of Wall Street, and the decisions between capital expenditures, potential fines, and everyday equipment maintenance becomes a precarious balancing act.

The current high-cost of LNG combined with transmission bottlenecks places low NO_x coal-fired megawatts at a premium, particularly in those regions where generating capacity closely matches demand. This increased value of low NO_x megawatts puts further pressure on personnel to maintain peak performance of their NO_x management systems.

After an electric power generator invests in NO_x reduction technologies to achieve conformance, it is faced with maintaining the equipment to ensure that NO_x rates remain within specified tolerance. Pulverized coal traveling at high velocities through coal burners and burner tips typically produces significant component erosion, causing owners to repeatedly replace parts and even entire burner assemblies. During the period between repairs, changes in burner geometry caused by excessive erosion can impact combustion characteristics, resulting in upward trending NO_x emissions.

The most advanced Low NO_x burner technologies utilize a unique tungsten carbide cladding applied through an infiltration brazing process to protect components against erosion wear, substantially increasing burner life while maintaining combustion characteristics for sustained low NO_x performance. This paper will discuss the exhaustive laboratory analyses used to find the best wear solution for this extreme application, how it is applied, and the performance results of these burners in actual operation after more than two years of service.

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CONFLUENCE OF MARKET PRESSURES IN POWER GENERATION

Power production facilities are under ever-increasing pressure to reduce production costs to compete in a market environment that is more complex today than it's ever been in the past. Failure to effectively reduce production and maintenance costs to a competitive level means reduced profits for each MW-hr sold, and may result in reduced dispatch load—a double jeopardy in a market plagued by over capacity.

The situation is exacerbated by the need for production facilities to balance costs against compliance with a growing number of stringent air quality restrictions for NO_x, SO_x, particulates, and now mercury. These challenges often manifest themselves in a conflicting effort to reduce day-to-day operating costs while optimizing the return on capital investments.

POWER GENERATION AS A BUSINESS

Deregulation and the 1990 Clean Air Act Amendments have often created significant constraints to the operation and maintenance of generation facilities. Before The Clean Air Act Amendments, power producers were relatively unconstrained in the fuels, technologies, and production strategies they employed to meet the market demand. Their primary objective was to provide a reliable source of quality power. Whatever equipment was in place per original design could be used without a great deal of concern for the quality or type of fuel being burned. Original equipment design took into account the planned fuel formulation, and auxiliary equipment was selected primarily based upon these original specifications. Equipment deterioration was accepted as a normal cost of operation, and was dealt with through frequent and relatively long maintenance outages.

Today's competitive market conditions, combined with strict emissions standards, have created entirely new challenges that generate potential conflicts between fuel formulations, equipment configurations, and maintenance programs. Capital expenditures for new advanced Low NO_x burning systems, while designed to support environmental compliance, can lead to unexpected system maintenance challenges, such as rapid component wear. The time deviation between major plant outages for maintenance has increased from one (1) year to as much as four (4) years.

Asset managers are now faced with ever-rising capital investment costs combined with the often-unexpected increase in maintenance costs required to ensure unit availability and acceptable performance. The competitive power generation environment and Wall Street pressures to increase short-term profits further complicate these demands. The combination of these pressures, relatively new to the industry, often drives the use of short-term solution approaches in order to minimize the initial cost of implementation. These factors, all too often, mean that maintenance teams end up chasing ongoing performance and reliability problems with an ever-decreasing staff. While initial capital investment may have been reduced, the ongoing cost of maintaining availability and performance can create a drag on cash flow and reduce the overall return on investment.

RETHINKING INVESTMENTS IN COMPLIANCE

Selection, installation, and implementation of emissions reduction systems frequently involve a large contingent, including plant personnel, corporate engineers and asset teams, numerous contractors and subcontractors, and even subs to the subcontractors. Throughout this complex web of influences, each party has a vested interest in showing the greatest return for the lowest cost. Only a few suppliers, those who have confidence in the value of their innovative and value-added technologies, will be willing to risk losing a project, which might be perceived to be an initially more costly installation. Because of the complexity of the evaluation process, only the savviest of asset owners are able to effec-

tively cut through the smoke and mirrors of promises to recognize the longer term return possible through more advanced, albeit more costly, technologies.

Large power generating assets certainly cost a great deal of money to operate; but they cost even more when, due to degradation of performance and reduced reliability, they are forced into a premature maintenance outage or have to operate at sub-par performance. Higher costs are driven by the incremental replacement power costs. Oftentimes, the payoff for installing lower-cost components is an increased risk of downtime and frequency of maintenance. By thinking about the importance of long-term performance, savvy asset owners are able to parlay smart investments into quantifiable returns. Therefore, it is important to plan capital projects so as to reduce the need for periodic and unnecessary maintenance. The selection of "Best Available Control Technology" will, in many cases, increase initial installation costs only nominally. Savvy asset owners will seek out and explicitly specify such technologies, thus protecting their overall investment against the ill-advised cost-cutting measures employed by many contractors and their subcontractors.

BALANCING ENVIRONMENTAL STEWARDSHIP AGAINST WALL STREET EXPECTATIONS

The war against pollution is mounting, with an ever-increasing list of forbidden effluent constituents, including particulates, SO_2, NO_x, and mercury. NO_x, one of the industry's oldest and most familiar foes, has been challenging boiler designers for the greater part of three decades. Advanced design burner configurations have become one of the industry standard approaches to NO_x abatement, and burner designers are continually developing new ways to achieve and maintain lower levels of NO_x output.

Burner designers are faced with several challenges in the war against NO_x:

- Designing within the parameters of the existing system not originally sized or configured for Low NO_x operation
- Varying coal specifications from the customer which cover wider and wider ranges of fuel properties
- Mill system performance and limitations
- The high heat release rates of some wall-fired cell configurations
- Retrofitting of cell configurations for NO_x reduction without required spacing modifications and pressure part reconfiguration
- Non-homogenous coal flow typically resulting in sub-optimal burner performance
- Coal flow imbalances between pipes requiring additional flexibility of the burner design to compensate for adjusting the airflow to be consistent with coal flow imbalances
- The requirement for burner parts to last up to four (4) years between major outages
- The continuing struggle between decreasing NO_x emissions and maintaining some reasonable level of UBC in the flyash
- The often employed "solution" of highly turbulent mixing resulting in hotter initial burn temperatures and harder to control NO_x

Current state-of-the-industry wall-fired Low NO_x burner designs combine sophisticated mixing and stabilization designs with Best Available Control Technology in wear protection.

Riley Power Inc's (RPI) CCV® burner technology employs a venturi coal nozzle to provide more controllable fuel mixture combined with a low swirl coal spreader to provide good mixing without excessive turbulence. Integral air diverters and stabilizer rings improve flame attachment and reduce NO_x emissions. This combination of sophisticated design component geometries, utilizing an infiltration brazed tungsten carbide protective cladding, ensures that homogenous non-turbulent coal mixing and controlled burn rate is maintained over extended periods of operation. With Best Available Burner Technology, NO_x levels will not only test low at initial startup, but can be expected to remain low throughout the majority of burner life between major outages. This extended performance is achieved by significant reduction in erosion-driven changes in component geometry. The net result is more prolonged compliance with NO_x emissions with reduced risk of both planned and unplanned downtime and an increase in overall unit productivity and reliability.

PERFORMANCE AND LONGEVITY CONSIDERATIONS

The advanced CCV® burner technology has evolved significantly since its initial inception in the early 1980s. Using increasing computing power over the years to perform complex computational fluid dynamic (CFD) analyses and full-scale test facilities, the burner has reached its current advanced state of performance. On a unit firing bituminous fuel with burners only and no overfire air, the NO_x level obtained is 0.36 lb/MMBTU. This can be achieved with a simple "plug-in" retrofit requiring no pressure part replacement, over fired air (OFA), or burner respacing. Burner turndown ratio of 2.5:1 is still maintained. Similar retrofits on units burning sub-bituminous coal achieve NO_x emissions as low as 0.15 lb/MMBTU or less.

In order to protect components against erosion degradation and maintain long-term performance, burner designers performed comprehensive laboratory evaluation of multiple wear protection materials, many of which were industry-accepted, to identify and specify the Best Available Control Technology for the application.

Burner designers tested the following erosion protective materials:

- STOODY 101HC
- SA1750 CR
- Conforma Clad WC219
- Stellite 31
- A560 Grade 50Cr-50Ni
- A532-82 Type II Class C
- A532-82 Type I Class A
- Silicon Carbide
- Stellite 6

Figure 1 - Test Fixture with Sample

Testing utilized an ASTM standard G73 method utilizing Black Beauty Coal Slag as the erodent material (See Figure 1). As a result of this testing, burner designers selected Conforma Clad infiltration brazed WC219 tungsten carbide cladding as the Best Available Control Technology for protecting burner components against erosion deterioration to ensure long-term performance (See Figure 2). Conforma Clad's proprietary cloth application technique makes it highly unique in that it can be easily applied to very complex geometry components, forms a true metallurgical bond with the base component, has an extremely uniform thickness and density, and is not subject to spalling, with the ability to withstand continuous operation at temperatures in excess of 1900 º F. The method of application produces an impervious cladding layer with no interconnected porosity or check cracking, and carbon dilution at the bond line is virtually zero. This, combined with its non-magnetic characteristic, allows for precision in situ measurement of remaining thickness and life-extrapolation in support of predictive maintenance programs.

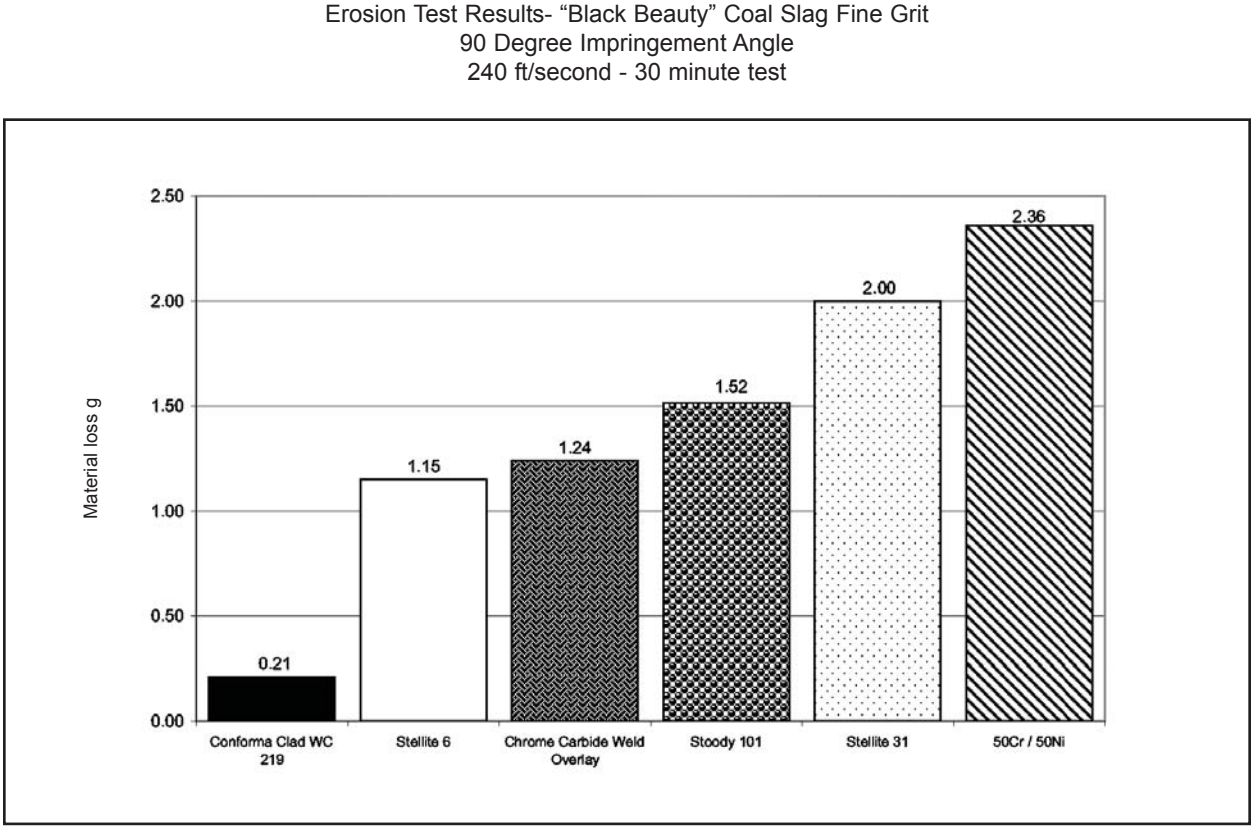

Figure 2 - Erosion Comparison Results

CASE STUDY I

In 1994 RPI retrofitted all four boilers at We Energies, Valley Power Plant, with *first* generation low NO_X burners. The pre-retrofit NO_X levels were 1.02 lb/MMBTU. After the installation of the burners, NO_X levels were reduced to 0.41 lb/MMBTU. An integral component of the RPI design is the low swirl coal spreaders found in the coal nozzle of the burner. The spreader is designed to enhance the combustion by controlling the flame length and minimizing both NO_X and Unburned Carbon (UBC).

New low swirl coal spreaders were installed into the existing CCV® low NO_X burners at We Energies Valley Station, Unit 2, Boiler 3 in February of 2003 as part of the normal maintenance schedule. Several of the materials tested in the laboratory were supplied for a direct comparison. They were installed in burners fed by the same mill. Three (3) low swirl coal spreaders were supplied for installation; one of Riloy 74 clad with Conforma Clad infiltration brazed tungsten carbide, and two of cast silicon carbide.

RPI, working in partnership with We Energies, chose Valley Power Plant as a test site due to the burner velocities and fuel properties, which contribute to high erosion rates. Typical coal/primary airflow velocity through burners at full load is approximately 87 ft/sec. The pulverized coal fired at this station is blended with approximately 9% petroleum coke and the ultimate analysis is shown below:

Carbon:	61.29 - 69.31 %	Sulfur:	0.74 - 0.98 %
Hydrogen:	4.18 - 4.82 %	Ash:	4.19 - 15.37 %
Nitrogen:	1.36 - 1.51 %	Moisture	8.14 - 10.51%
Oxygen:	8.92 - 9.31 %	Hard Grove	46 HGI

Valley Station stopped receiving pet coke April 2003

Due to relatively high nozzle velocity, combined with the high silica and alumina content in the coal, this burner application is considered to be a moderately high erosive environment. This is evident from the wear that can be seen on the burner components that were not protected with tungsten carbide cladding (See Figures 3 and 4).

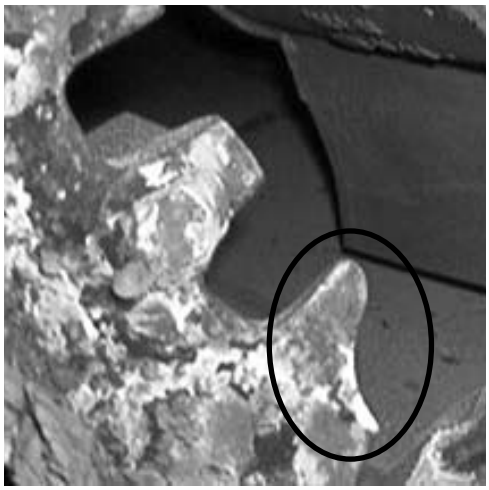

Figure 3 - Unit # 2, Boiler # 3 unprotected burner component showing typical wear after 22 months of service

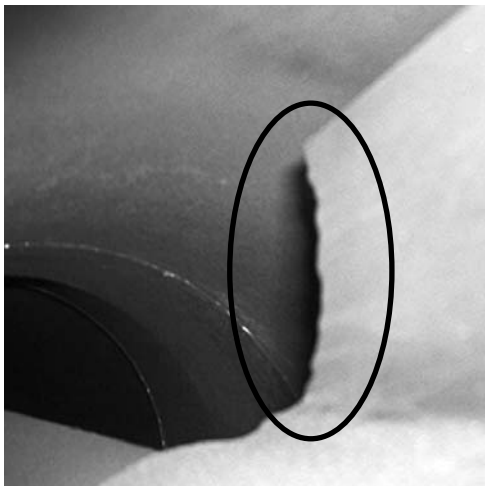

Figure 4 - Stellite Weld Overlay on the leading edge shows approximately 1 1/2" off vane leading edge after nine months of service

As part of development and evaluation of the selected tungsten carbide erosion protection, burner designers chose to install a single component (coal spreader, See Figure 5) protected with the chosen material as a test to confirm performance in operation. This prototype burner test piece was protected with 0.040" thickness of Conforma Clad WC219 applied directly to the leading edge of the spreader base material using a proprietary infiltration brazing process. The prototype coal spreader was installed in Unit 2, Boiler 3, D1 burner location on February of 2003 along with the balance of coal spreaders being supplied with stellite weld overlay on the leading edges. After approximately 9 months of continuous service, the prototype test piece was inspected on October 20, 2003.

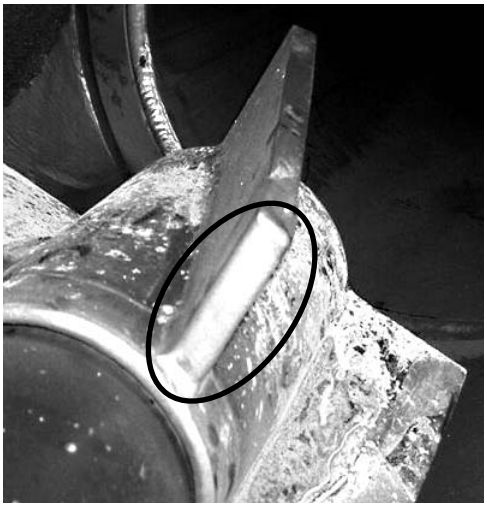

Figure 5 - Conforma Clad infiltration brazed tungsten carbide spreader shows no visable wear

Prior to the installation of the test spreader and new coal spreaders in the remaining burners, recorded NO_X emissions from the CEMS for the third quarter of 2002 show a sustained NO_X performance of 0.423 lb/MMBTU at full load. The NO_X emissions recorded from the CEMS for fourth quarter of 2002 after the equipment component changes showed an average of 0.413 lb/MMBTU at full load.

Results for Case Study I

The stellite protected coal spreader shown in Figure 4 has approximately 1-1/2" of the coal spreader vane missing. The prototype test piece, protected with tungsten carbide cladding was visually inspected and showed no visible signs of erosion (See Figure 5). Due to the non-magnetic nature of the cladding protection, it was possible to measure actual remaining cladding thickness using an Elcometer eddy current thickness gauge. Measurements showed that the maximum extent of erosion was 0.007", or less than 20% of the total protective layer thickness (See Table 1). From these results the predicted life of the coal spreader protected by the tungsten carbide coating is estimated at approximately 5 years.

Table 1
Cladding Thickness Measurements

	BASE	MIDDLE	TIP	
LEADING EDGE				
VANE 1	.042"	.036"	.039"	
VANE 2	.040"	.033"	.043"	
VANE 3	.038"	.036"	.039"	
VANE 4	.039"	.037"	.040"	
BODY	1	2	3	4
LOCATION	.038"	.039"	.037"	.036"

CASE STUDY II

A second installation of Conforma Clad was applied to the new coal flow distributor elements installed at We Energies, Presque Isle Power Plant. In 2001 PIPP installed RPI's low NO_x CCV® second generation Dual Air Zone Burners. In conjunction with this installation, modifications were made to the coal mill system to improve the coal pipe-to-pipe balance to improve the overall unit performance. The coal flow distributor installed by RPI was designed for installation in the coal stream exiting the mill. This location has the potential to experience severe erosion due to sliding and impact abrasion.

Conforma Clad Inc. agreed to test their tungsten carbide material on this application due to the unique location of the device and the wear characteristics of the fuel.

Fuel Composition:		Ash Composition:	
Carbon:	73.8 - 74.2 %	Silicon Dioxide:	56%
Hydrogen:	5.0 - 5.1 %	Aluminum Oxide:	25%
Nitrogen:	1.6 %	Iron Oxide:	5%
Oxygen:	8.8 - 9.1 %	Sulfur Trioxide:	2%
Sulfur:	0.82 - 0.85 %	Calcium Oxide:	4%
Ash:	9.1 - 9.9 %	Other:	8%

Results for Case Study II

The coal flow distributors were installed in Unit #6 pulverizers in December of 2002. The coal flow distributors for Unit #5 were installed in February of 2003. Although the two units have slightly different operating times, a good comparison can be made between the unprotected flow elements in Unit #6, which were inspected in September of 2003, and the Unit #5 elements which were inspected in October of 2003.

Figure 6 - No protective cladding on the flow element

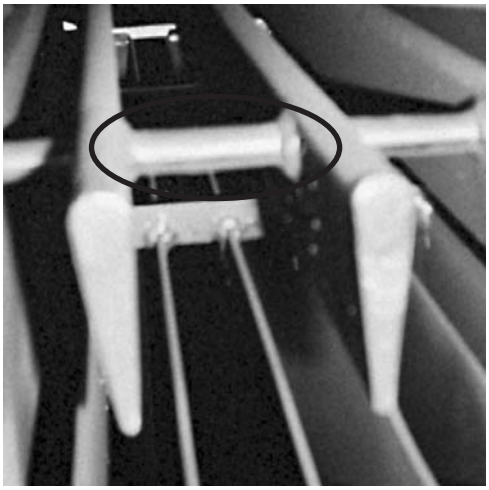

Figure 7 - Leading edge protected with Conforma Clad infiltration brazed tungsten carbide

Figure 6 shows the unprotected element installed in the Unit #6 D pulverizer. These elements are made from a heat-treated alloy with a hardness of 300+ Brinell. Figure 7 shows the same element design clad with tungsten carbide supplied by Conforma Clad.

Initial base cladding thickness was 0.040". With braze scale (Un-melted Chrome), the resulting total cladding thickness was approximately 0.045 - 0.050". From the thickness measurements shown in Table 2, it can be seen that the braze layer, which has a hardness of approximately 57Rc and is relatively erosion resistant, had not yet been penetrated.

Table 2
Cladding Thickness Measurements

	Inboard						Outboard
Location on Vane	1	2	3	4	5	6	7
Left	0.047	0.048	0.049	0.048	0.050	0.048	0.050
Left Center	0.048	0.048	0.047	0.046	0.046	0.046	0.048
Right Center	0.046	0.047	0.046	0.046	0.046	0.047	0.048
Right	0.049	0.051	0.047	0.051	0.049	0.049	0.049

CONCLUSION

Plant maintenance teams are experiencing ever-increasing pressures to reduce the cost of maintaining critical low NO_x burner equipment, and are expected to use innovative methods to maintain emissions compliance while extending the operating period between unit shutdowns. Technologies are available that have proven their ability, in both the laboratory and in the field, to provide substantial protection against some of the most common causes of aggressive equipment wear present in coal-fired power plants, including those present in Low NO_x burner systems.

Innovative burner designers can take advantage of sophisticated protection technologies to extend run time between repairs and component replacement to ensure that their systems provide peak performance not only at startup, but for several years thereafter. Asset managers can realize greater returns on their capital investments with only a nominal increase in initial installation cost through their awareness of proven Best Available Control Technologies.

The data contained herein is solely for your information and is not offered,
or to be construed, as a warranty or contractual responsibility

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-80:
Neundorfer Fabric *Filter Design*

Lesson 5

Fabric Filter Design Review

Goal

To familiarize you with the factors to be considered when reviewing baghouse design plans for air pollution control programs.

Objectives

At the end of this lesson, you will be able to do the following:

1. List and explain at least six factors important in good baghouse design
2. Estimate the cloth area needed for a given gas process flow rate
3. Calculate the number of bags required in a baghouse for a given process flow rate
4. Calculate the gross air-to-cloth ratio, the net air-to-cloth ratio, and the net,net air-to-cloth ratio for a baghouse design

Introduction

The design of an industrial baghouse involves consideration of many factors including space restriction, cleaning method, fabric construction, fiber, air-to-cloth ratio; and many construction details such as inlet location, hopper design, and dust discharge devices. Air pollution control agency personnel who review baghouse design plans should consider these factors during the review process.

A given process might often dictate a specified type of baghouse for particulate emission control. The manufacturer's previous experience with a particular industry is sometimes the key factor. For example, a pulse-jet baghouse with its higher filter rates would take up less space and would be easier to maintain than a shaker or reverse-air baghouse. But if the baghouse was to be used in a high temperature application (500°F or 260°C), a reverse-air cleaning baghouse with woven fiberglass bags might be chosen. This would prevent the need of exhaust gas cooling for the use of Nomex felt bags (on the pulse-jet unit), which are more expensive than fiberglass bags. All design factors must be weighed carefully in choosing the most appropriate baghouse design.

Review of Design Criteria

The first step in reviewing design criteria is determining the flow rate of the gas being filtered by the baghouse, which is measured in cubic meters (cubic feet) per minute. The gas volume

to be treated is set by the process exhaust, but the filtration velocity or air-to-cloth ratio is determined by the baghouse vendor's design. The air-to-cloth ratio that is finally chosen depends on specific design features including fabric type, fibers used for the fabric, bag cleaning mechanism, and the total number of compartments, to mention a few. Figure 5-1 depicts a number of these design features. A thorough review of baghouse design plans should consider the following factors.

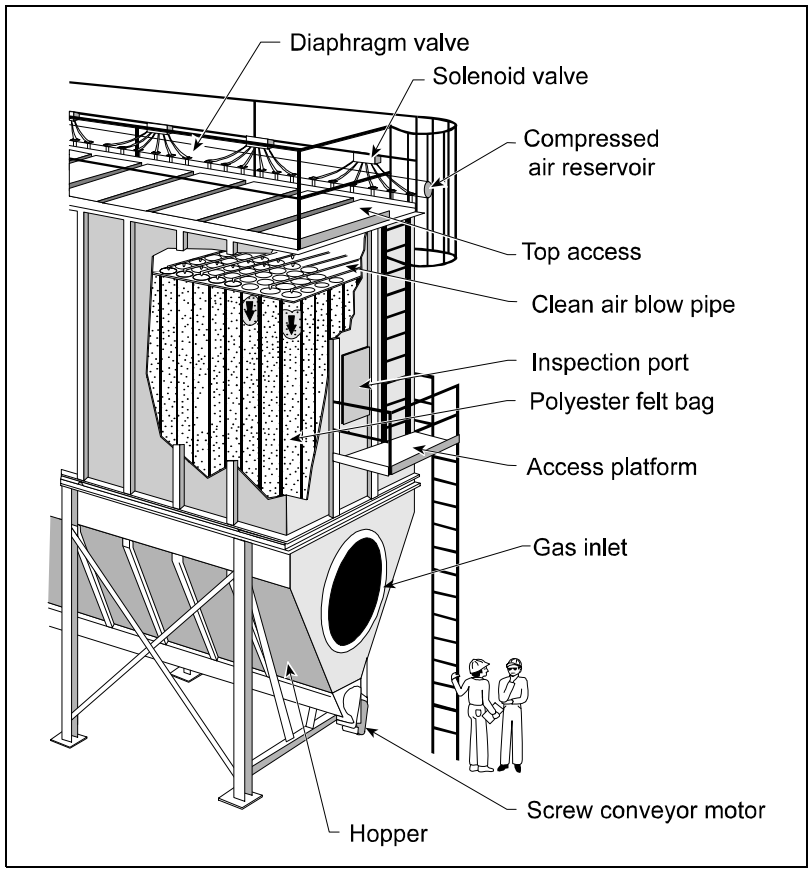

Figure 5-1. Design considerations for a pulse-jet baghouse

Physical and chemical properties of the dust are extremely important for selecting the fabric that will be used. These include size, type, shape, and density of dust; average and maximum concentrations; chemical and physical properties such as abrasiveness, explosiveness, electrostatic charge, and agglomerating tendencies. For example, abrasive dusts will deteriorate fabrics such as cotton or glass very quickly. If the dust has an electrostatic charge, the fabric choice must be compatible to provide maximum particle collection yet still be able to be cleaned without damaging the bags.

Predicting the gas flow rate is essential for good baghouse design. The average and maximum flow rate, temperature, moisture content, chemical properties such as dew point, corrosiveness, and combustibility should be identified prior to the final design. If the baghouse is going to be installed on an existing source, a stack test could be performed by the industrial facility to determine the process gas stream properties. If the baghouse is being installed on a new source, data from a similar plant or operation may be used, but the baghouse should be designed conservatively (large amount of bags, additional compartments, etc.). Sometimes,

heavy dust concentrations are handled by using a baghouse in conjunction with a cyclone precleaner, instead of building a larger baghouse. Once the gas stream properties are known, the designers will be able to determine if the baghouse will require extras such as shell insulation, special bag treatments, or corrosion-proof coatings on structural components.

Fabric construction design features are then chosen. The design engineers must determine the following: woven or felt filters, filter thickness, fiber size, fiber density, filter treatments such as napping, resin and heat setting, and special coatings. Once dust and gas stream properties have been determined, filter choice and special treatment of the filter can be properly made. For example, if the process exhaust from a coal-fired boiler is 400°F (204°C), with a fairly high sulfur oxide concentration, the best choice might be to go with woven glass bags that are coated with silicon graphite or other lubricating material such as Teflon.

Along with choosing the filter type the designer must select the appropriate **fiber type**. Fibers typically used include cotton, nylon, fiberglass, Teflon, Nomex, Ryton, etc. The design should include a fiber choice dictated by any gas stream properties that would limit the life of the bag. (See Lesson 4 for typical fabrics and fibers used for bags.) For more information about fabric construction, see McKenna and Turner (1989).

Proper air-to-cloth (A/C) ratio is the key parameter for proper design. As stated previously, reverse-air fabric filters have the lowest A/C ratios, then shakers, and pulse-jet baghouses have the highest. For more information about air-to-cloth ratios, see McKenna and Turner (1989).

Once the bag material is selected, the **bag cleaning methods** must be properly matched with the chosen bags. The cost of the bag, filter construction, and the normal operating pressure drop across the baghouse help dictate which cleaning method is most appropriate. For example, if felted Nomex bags are chosen for gas stream conditions that are high in temperature and somewhat alkaline (see Table 4-1), pulse-jet cleaning would most likely be used.

The **ratio of filtering time to cleaning time** is the measure of the percent of time the filters are performing. This general, “rule-of-thumb” ratio should be at least 10:1 or greater (McKenna and Furlong 1992). For example, if the bags need shaking for 2 minutes every 15 minutes they are on-line, the baghouse should be enlarged to handle this heavy dust concentration from the process. If bags are cleaned too frequently, their life will be greatly reduced.

Cleaning and filtering stress is very important to minimize bag failures. The amount of flexing and creasing to the fabric must be matched with the cleaning mechanism and the A/C ratio; reverse-air is the gentlest, shaking and pulse-jet place the most vigorous stress on the fabric. For example, it would probably not be advisable to use woven glass bags on a shaker baghouse. These bags would normally not last very long due to the great stress on them during the cleaning cycle. However, fiberglass bags are used on reverse-air baghouses that use shake-and-deflate cleaning. Also, some heavy woven glass bags (16 to 20 oz) are used on pulse-jet units (which also have high cleaning stress).

Bag spacing is very important for good operation and ease of maintenance. Bag spacing affects the velocity at which the flue gas moves through the baghouse compartment. If bags are spaced too close together, the gas velocity would be high because there is very little area between the bags for the gas stream to pass through. Settling of dust particles during bag cleaning would become difficult at high velocities. Therefore, it is preferable to space bags far

enough apart to minimize this potential problem but not so far apart as to increase the size of the baghouse shell and associated costs.

For pulse-jet baghouses, bag spacing is important to prevent bag abrasion. Bag-to-bag abrasion can occur at the bottom of the bags because the bags are attached to the tube sheet only at their tops which allows them to hang freely. Slight bows in the bag support cages or a slight warping in the tube sheet can cause bag-to-bag contact at the bottom of the bags.

Finally, access for bag inspection and replacement is important. For example, in a reverse-air unit, sufficient space between bags should be used so that maintenance personnel can check each bag visually for holes. The bag can either be replaced or a cap can be placed on the tube sheet opening to seal off the bag until it is later changed. The bag layout should allow the bag maintenance technician to reach all the bags from the walkway. One measure of bag accessibility is called bag reach and is the maximum number of rows from the nearest walkway. There is no single value for bag reach, but typical units have a value of 3 or 4.

The **compartment design** should allow for proper cleaning of bags. The design should include an extra compartment to allow for reserve capacity and inspection and maintenance of broken bags. Shaker and reverse-air cleaning baghouses that are used in continuous operation require an extra compartment for cleaning bags while the other compartments are still on-line filtering. Compartmentalized pulse-jet units are frequently being used on municipal solid waste and hazardous waste incinerators for controlling particulate and acid gas emissions.

The design of **baghouse dampers** (also called baghouse valves) is important. Reverse-air baghouses use inlet and outlet dampers for gas filtering and bag cleaning sequences. As described in Lesson 2, during the filtering mode, the compartment's outlet gas damper and inlet dampers are both open. During the cleaning sequence, the outlet damper is closed to block the flow of gas through the compartment. The reverse-air damper is then opened to allow the air for bag cleaning to enter the compartment.

Dampers are occasionally installed in by-pass ducts. By-pass ducts, which allow the gas stream to by-pass the baghouse completely, are a means of preventing significant damage to the bags and/or baghouse. Dampers in by-pass ducts are opened when the pressure drop across the baghouse or the gas temperature becomes too high. However, many state regulatory agencies have outlawed the use of baghouse by-pass ducts and dampers to prevent the release of unabated particulate emissions into the atmosphere.

Space and cost requirements are also considered in the design. Baghouses require a good deal of installation space; initial costs, and operating and maintenance costs can be high. Bag replacement per year can average between 25 and 50% of the original number installed, particularly if the unit is operated continuously and required to meet emission limits less than 0.010 gr/dscf. This can be very expensive if the bags are made of Teflon which are approximately $100 for a 5-inch, 9-foot long bag, or Gore-tex which are approximately $140 for a 6-inch, 12-foot long bag.

The **emission regulations in terms of grain-loading and opacity requirements** will ultimately play an important role in the final design decisions. Baghouses usually have a collection efficiency of greater than 99%. Many emission regulations (and permit limits) require that industrial facilities meet opacity limits of less than 10% for six minutes, thus requiring the baghouse to operate continuously at optimum performance.

Typical Air-To-Cloth Ratios

During a permit review for baghouse installations, the reviewer should check the A/C ratio. Typical A/C ratios for shakers, reverse-air, and pulse-jet baghouses are listed in Table 3-1, Lesson 3.

Baghouses should be operated within a reasonable design A/C ratio range. For example, assume a permit application was submitted indicating the use of a reverse-air cleaning baghouse using woven fiberglass bags for reducing particulate emissions from a small foundry furnace. If the information supplied indicated that the baghouse would operate with an A/C ratio of 6 $(cm^3/sec)/cm^2$ [12 $(ft^3/min)/ft^2$] of fabric material, you should question this information. Reverse-air units should be operated with a much lower A/C ratio, typically 1 $(cm^3/sec)/cm^2$ [2 $(ft^3/min)/ft^2$] or lower. The fabric would probably not be able to withstand the stress from such high filtering rates and could cause premature bag deterioration. Too high an A/C ratio results in excessive pressure drops, reduced collection efficiency, blinding, and rapid wear. In this case a better design might include reducing the A/C ratio within the acceptable range by adding more bags. Another alternative would be to use a pulse-jet baghouse with the original design A/C ratio of 6 $(cm^3/ sec)/cm^2$ [12 $(ft^3/min)/ft^2$] and use felted bags made of Nomex fibers. However, Nomex is not very resistant to acid attack and should not be used where a high concentration of SO_2 or acids are in the exhaust gas. Either alternative would be more acceptable to the original permit submission.

Typical air-to-cloth ratios for baghouses used in industrial processes are listed in Tables 5-1 and 5-2. Use these values as a guide only. Actual design values may need to be reduced if the dust loading is high or the particle size is small. When compartmental baghouses are used, the design A/C ratio must be based upon having enough filter cloth available for filtering while one or two compartments are off-stream for cleaning.

Table 5-1. Typical A/C ratios [$(ft^3/min)/ft^2$] for selected industries[1]

Industry	Fabric filter air-to-cloth ratio		
	Reverse air	Pulse jet	Mechanical shaker
Basic oxygen furnaces	1.5-2	6-8	2.5-3
Brick manufacturing	1.5-2	9-10	2.5-3.2
Castable refractories	1.5-2	8-10	2.5-3
Clay refractories	1.5-2	8-10	2.5-3.2
Coal-fired boilers	1-1.5	3-5	-
Conical incinerators	-	-	-
Cotton ginning	-	-	-
Detergent manufacturing	1.2-1.5	5-6	2-2.5
Electric arc furnaces	1.5-2	6-8	2.5-3
Feed mills	-	10-15	3.5-5
Ferroalloy plants	2	9	2
Glass manufacturing	1.5	-	-
Grey iron foundries	1.5-2	7-8	2.5-3
Iron and steel (sintering)	1.5-2	7-8	2.5-3
Kraft recovery furnaces	-	-	-

Continued on next page

Table 5-1. ***(continued)***
Typical A/C ratios [$(ft^3/min)/ft^2$] for selected industries[1]

Industry	Fabric filter air-to-cloth ratio		
	Reverse air	Pulse jet	Mechanical shaker
Lime kilns	1.5-2	8-9	2.5-3
Municipal and medical waste incinerators	1-2	2.5-4	-
Petroleum catalytic cracking	-	-	-
Phosphate fertilizer	1.8-2	8-9	3-3.5
Phosphate rock crushing	-	5-10	3-3.5
Polyvinyl chloride production	-	7	-
Portland cement	1.2-1.5	7-10	2-3
Pulp and paper (fluidized bed reactor)	-	-	-
Secondary aluminum smelters	-	6-8	2
Secondary copper smelters	-	6-8	-
Sewage sludge incinerators	-	-	-
Surface coatings spray booth	-	-	-

1. High efficiency: a sufficiently low grain loading to expect a clear stack.
Source: EPA 1976, revised 1992.

Table 5-2. Typical A/C ratios for fabric filters used for control of particulate emissions from industrial boilers.

Size of boiler (10^3 lb steam per hour)	Temperature (°F)	Air-to-cloth ratio [$(ft^3/min)/ft^2$]	Cleaning mechanism	Fabric material
260 (3 boilers)	400°	4.4:1	On- or off-line pulse-jet or reverse-air	Glass with 10% Teflon coating (24 oz/yd^2)
170 (5 boilers)	500°	4.5:1	Reverse-air with pulse-jet assist	Glass with 10% Teflon coating
140 (2 boilers)	360°	2:1	Reverse-air	No. 0004 Fiberglas with silicone-graphite Teflon finish
250	338°	2.3:1	Shake and deflate	Woven Fiberglas with silicone graphite finish
200 (3 boilers)	300°	3.6:1	Shake and deflate	Woven Fiberglas with silicone-graphite finish
400 (2 boilers)	Stoker, 285° to 300°; pulverized coal, 350°	2.5:1	Reverse-air	Glass with Teflon finish
75	150°	2.8:1	Reverse-air	Fiberglas with Teflon coating
50	350°	3:1	On-line pulse-jet	Glass with Teflon finish
270 (2 boilers)	330°	3.7:1	On-line pulse-jet	Teflon felt (23 oz)
450 (4 boilers)	330°	3.7:1	On-line pulse-jet	Teflon felt (23 oz)
380	NA	2:1	Reverse-air vibrator assist	Glass with 10% Teflon coating
645	NA	2:1	Reverse-air vibrator assist	Glass with 10% Teflon coating
1440 (3 boilers)	360°	3.4:1	Shake and deflate	Woven Fiberglas with silicone-graphite finish

Source: EPA 1979.

Simple Cloth Size Check

Baghouse sizing is done by the manufacturer. This example will show you how to verify the manufacture's measurements by doing a simple cloth size check. Given the process gas exhaust rate and the filtration velocity, you can estimate the amount of cloth required by the baghouse. Once you know the total amount of cloth required and the dimensions of a bag, you can calculate the number of bags in the baghouse.

Problem

Calculate the number of bags required for an 8-compartment pulse-jet baghouse with the following process information and bag dimensions.

Q,	process gas exhaust rate	100,000 ft^3/min
A/C,	gross air-to-cloth ratio	4 (ft^3/min)/ft^2
Bag dimensions:		
	bag diameter	6 in.
	bag height	12 ft

Solution

1. **Calculate the total gross cloth area**. Use equation 3-6 (in Lesson 3):

$$v_f = \frac{Q}{A_c} \text{ or } A_c = \frac{Q}{v_f}$$

Where: A_c = cloth area, ft^2
Q = process exhaust rate, ft^3/min
v_f = filtration velocity, ft/min

$$A_c = \frac{100{,}000 \text{ ft}^3 / \text{min}}{4 \text{ ft} / \text{min}}$$
$$= 25{,}000 \text{ ft}^2$$

2. **Determine the amount of fabric required per bag**. Use the formula:

$$A_b = \pi dh$$

Where: A_b = area of bag, ft^2
π = 3.14

Given: d = 0.5 ft, bag diameter
h = 12 ft, bag height

$$A_b = 3.14 \times 0.5 \text{ ft} \times 12 \text{ ft}$$
$$= 18.84 \text{ ft}^2 \text{ required per bag}$$

3. **Calculate the number of bags required in the baghouse**.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

From step 1: $A_c = 25{,}000\ ft^2$

From step 2: $A_b = 18.84\ ft^2$

$$\text{Number of bags} = \frac{25{,}000\ ft^2}{18.84\ ft^2}$$
$$= 1{,}326.96 \text{ bags}$$
$$\text{or } 1{,}328 \text{ bags}$$

So there will be an even number of bags in each of the 8 compartments, round the value 1326.96 up to the next highest multiple of 8 (i.e. 1,328). Thus, there will be 166 bags (1,328/8) in each compartment.

4. **Calculate the net air-to-cloth ratio**. As you recall from Lesson 3, the net air-to-cloth ratio is the A/C ratio when one compartment is taken off-line for bag cleaning or maintenance. Use the formula:

$$(A/C)_{net} = \frac{Q}{A_c\left(\frac{\text{total \# of compartments} - 1}{\text{total \# of compartments}}\right)}$$

Given: $Q = 100{,}000\ ft^3/min$, process exhaust gas rate
The total number of compartments is 8.

From step 1: $A_c = 25{,}000\ ft^2$, total cloth area

$$(A/C)_{net} = \frac{100{,}000\ ft^3/min}{25{,}000\ ft^2(7/8)}$$
$$= 4.57\ (ft^3/min)/ft^2$$

Or, you can simply divide the gross air-to-cloth ratio by 7/8.

$$(A/C)_{net} = \frac{4\ (ft^3/min)/ft^2}{7/8}$$
$$= 4.57\ (ft^3/min)/ft^2$$

5. **Calculate the net, net air-to-cloth ratio** (when two compartments are off-line).

$$(A/C)_{net,\,net} = \frac{(A/C)_{gross}}{\dfrac{[(\text{total \# of compartments}) - 2]}{\text{total \# of compartments}}}$$

$$(A/C)_{net,\,net} = \frac{4\,(ft^3/min)/ft^2}{6/8}$$

$$= 5.33\,(ft^3/min)/ft^2$$

Review Exercise

1. From the baghouses listed below, which would take up less space because of high filter rates?

   a. Shaker
   b. Pulse-jet
   c. Reverse-air

2. True or False? Gas and dust stream properties influence filter choice.

3. An appropriate “rule of thumb” ratio of filtering time to cleaning time should be at least:

   a. 3:1
   b. 1.5:1
   c. 5:1
   d. 10:1

4. True or False? An air-to-cloth ratio that is too high results in reduced pressure drops.

5. Nomex is not very resistant to:

   a. HCl
   b. CO_2
   c. SO_2
   d. Lead
   e. a and c, only

6. Calculate the area of a bag (A_b) given a bag diameter of 15 inches and a bag height of 20 feet.

   a. 942 ft^2
   b. 70.5 $in.^2$
   c. 78.5 ft^2
   d. 25 ft^2

7. If the cloth area (A_c) is known to be 4,050 ft^2, how many bags would be used in a baghouse with the bag area (A_b) given above?

   a. 52 bags
   b. 519 bags
   c. 120 bags
   d. 10 bags

8. A baghouse has 8 compartments and a gross air-to-cloth ratio of 2.0 $(ft^3/min)/ft^2$. What is the net air-to-cloth ratio?

   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.66 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

9. For the baghouse information given in question 8 above, what is the net, net air-to-cloth ratio?

   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.67 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

Review Answers

1. **b. Pulse-jet**
   Due to their high filter rates, pulse-jet baghouses take up less space than shaker and reverse-air baghouses.

2. **True**
   Gas and dust stream properties influence filter choice.

3. **d. 10:1**
   An appropriate “rule of thumb” ratio of filtering time to cleaning time should be at least 10:1. If the ratio is much lower, the bags would be cleaned too frequently and may wear out too quickly.

4. **False**
   An air-to-cloth ratio that is too high results in *higher* pressure drops.

5. **e. a and c, only**
   Nomex is not very resistant to HCl and SO_2 (acid gases).

6. **c. 78.5 ft^2**

   Solution:

   1. Calculate the area of a bag (A_b).

$$A_b = \pi dh$$

Given: $\pi = 3.14$
d = 15 in., diameter of bag
h = 20 ft, height of bag

$$A_b = 3.14 \times 15 \text{ in.} \times \frac{1 \text{ ft}}{12 \text{ in.}} \times 20 \text{ ft}$$
$$= 78.5 \text{ ft}^2$$

7. **a. 52 bags**

Solution:

1. Calculate the number of bags.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

Given: $A_c = 4{,}050\ ft^2$, the total cloth area
$A_b = 78.5\ ft^2$, the area of a bag

$$\text{Number of bags} = \frac{4{,}050\ ft^2}{78.5\ ft^2} = 52 \text{ bags}$$

8. **b. 2.29 $(ft^3/min)/ft^2$**

Solution:

1. Calculate the net air-to-cloth ratio using the following equation:

$$(A/C)_{net} = \frac{(A/C)_{gross}}{\frac{[(\text{total \# of compartments}) - 1]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross} = 2.0\ (ft^3/min)/ft^2$
The total # of compartments is 8.

$$(A/C)_{net} = \frac{2\ (ft^3/min)/ft^2}{7/8} = 2.29\ (ft^3/min)/ft^2$$

9. **c. 2.67 (ft^3/min)/ft^2**

Solution:

1. Calculate the net, net air-to-cloth ratio using the following equation:

$$(A/C)_{net,\ net} = \frac{(A/C)_{gross}}{\frac{[(\text{total \# of compartments}) - 2]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross} = 2.0\ (ft^3/min)/ft^2$

The total # of compartments is 8.

$$(A/C)_{net,\ net} = \frac{2\ (ft^3/min)/ft^2}{6/8}$$

$$= 2.67\ (ft^3/min)/ft^2$$

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-81:
Norman Kapala 2021 Consumers IRP Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.

Case No. U-21090

Volume 7

PUBLIC RECORD

_____/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
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IAN F. BURGESS, ESQ.
Consumers Energy Company
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Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

Q. What is your formal education experience?

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation

activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) Revised	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) Revised	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

Exhibit A-55 (NJK-6) Revised	Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants;
Exhibit A-56 (NJK-7)	Summary of Projected Generation Operations Separation Activity Capital Expenditures;
Exhibit A-57 (NJK-8) Revised	Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032;
Exhibit A-58 (NJK-9)	Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032;
Exhibit A-59 (NJK-10)	Generating Unit Random Outage Rates; and
Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-50 (NJK-1) Revised.

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
  - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
  - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
  - Low Pressure Turbine Overhaul ($3,500,000);
  - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
  - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
  - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
  - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
  - Replace CO-O2 Monitors ($1,044,600);
  - Mill Complete Overhauls ($1,235,000);
  - Reheater Sootblower ($1,250,000);
  - Sootblowing Air Upgrade ($1,200,000);
  - Replace Lake Michigan Intake Screens ($1,339,000);
  - Cell Construction and Permitting ($5,482,830); and
  - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
  - SCR Reactor Catalyst Management ($1,866,200);
  - Complete Mill Overhauls ($1,264,800);
  - Replace CO-O2 Monitors ($967,400);
  - Design and Install New Large Particle Ash Screen ($1,485,100);
  - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

- Distributed Control System and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and

- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - SCR Reactor Catalyst Management ($1,959,510);
  - Turbine Drain Modifications ($2,535,000);
  - Superheat Terminal Drain Replacement ($3,023,100);
  - Replace Boiler Sidewall Panels ($2,425,000);
  - Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - Secondary Air Heater basket & seal replacement ($1,562,000);
  - Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~Dry Ash Landfill Closure ($1,635,230);~~
  - Cell Construction and Permitting ($5,482,830); and
  - ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
  - GSU Replacement ($6,485,045);
  - SCR Reactor Catalyst Management ($3,000,000);
  - AQCS Equipment repair/replacement ($1,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
  - Cell Construction and Permitting ($2,000,000); and
  - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

- Catalyst Management ($1,120,000); and
- Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~Replace Air and Flue Gas Expansion Joints ($2,000,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

- Fuel Handling and Infrastructure Replacements ($1,000,000);
- AQCS Equipment repair/replacement ($1,000,000); and
- Two projects totaling $1,500,000 with no individual project which exceeds $500,000;

- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
  - ~~Cell Construction and Permitting ($3,500,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
  - SCR Reactor Catalyst Management ($2,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment repair/replacement ($2,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation

capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
  - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
  - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
  - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000); and
  - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
  - Campbell 3 Turbine Overhaul ($7,931,350);
  - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
  - Campbell 3 Periodic Outage Maintenance ($933,100); and
  - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
  - Campbell 3 Turbine Overhaul ($12,000,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
  - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);

- Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
- Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;

- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

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Generation Operations - Capital - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

Line No.	Year	(a) Karn 1/2 Total	(b) Karn 3/4 Total	(c) Campbell 1 Total	(d) Campbell 2 Total	(e) Campbell 3 Total
1	2020	7,176	8,679	10,025	9,268	12,860
2	2021	2,859	4,172	3,493	13,512	19,576
3	2022	2,135	15,416	7,300	5,257	17,125
4	2023	1,124	10,072	7,215	9,472	20,478
5	2024		9,775	9,753	11,252	33,396
6	2025		10,134	2,550	7,800	14,512
7	2026		9,900	3,300	4,420	4,400
8	2027		8,950	4,050	6,845	5,900
9	2028		2,000	3,500	7,394	4,400
10	2029		2,000	3,879	2,500	11,750
11	2030		1,000	2,564	1,050	11,150
12	2031		500	250	250	2,400
13	2032					2,750
14	2033					11,750
15	2034					5,400
16	2035					10,150
17	2036					4,650
18	2037					2,400
19	2038					550
20	2039					
21	Total	$ 13,294	$ 82,598	$ 57,878	$ 79,020	$ 195,597

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Karn 3&4 Early Retirement Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Retire Karn 3&4 5/31/2023					**Retire Karn 3 & 4 5/31/2025**			
Line No.	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Cas	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Cas	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
1	2020	5,500	-	(3,179)	-	2020	8,679	-	-	-
2	2021	750	-	(3,422)	-	2021	6,012	-	1,840	(667)
3	2022	500	-	(14,916)	(13,675)	2022	2,370	-	(13,046)	(7,204)
4	2023	200	-	(9,872)	(1,790)	2023	1,850	-	(8,222)	(1,290)
5	2024	-	-	(9,775)	-	2024	500	-	(9,275)	-
6	2025	-	-	(10,134)	-	2025	200	-	(9,934)	-
7	2026	-	-	(9,900)	-	2026	-	-	(9,900)	-
8	2027	-	-	(8,950)	-	2027	-	-	(8,950)	-
9	2028	-	-	(2,000)	-	2028	-	-	(2,000)	-
10	2029	-	-	(2,000)	-	2029	-	-	(2,000)	-
11	2030	-	-	(1,000)	-	2030	-	-	(1,000)	-
12	2031	-	-	(500)	-	2031	-	-	(500)	-
13	Total	$ 6,950	$ -	$ (75,648)	$ (15,465)	Total	$ 19,611	$ -	$ (62,987)	$ (9,161)

Note:
1. Cost of removal has not been included.

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Generation Operations - Capital - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Retire Campbell 3 5/31/2025				**Retire Campbell 3 5/31/2032**		
Line No.	Year	Campbell 3 Total	Campbell 3 Variance to Base Cas	Campbell Unit 3 Separation Variance to Base Case	Year	Campbell 3 Total	Campbell 3 Variance to Base Cas	Campbell Unit 3 Separation Variance to Base Case
1	2020	12,860	0	-	2020	12,860	0	-
2	2021	18,397	(1,179)	-	2021	19,576	-	-
3	2022	12,885	(4,240)	-	2022	17,125	-	-
4	2023	8,705	(11,773)	-	2023	20,478	-	-
5	2024	6,044	(27,352)	-	2024	33,396	-	-
6	2025	400	(14,112)	-	2025	14,512	-	-
7	2026	-	(4,400)	-	2026	4,400	-	-
8	2027	-	(5,900)	-	2027	5,900	-	-
9	2028	-	(4,400)	(6,780)	2028	4,400	-	(6,780)
10	2029	-	(11,750)	(14,341)	2029	8,750	(3,000)	(14,341)
11	2030	-	(11,150)	(28,683)	2030	11,150	-	(28,683)
12	2031	-	(2,400)	(14,341)	2031	2,400	-	(14,341)
13	2032	-	(2,750)	-	2032	2,750	-	-
14	2033	-	(11,750)	-	2033	-	(11,750)	-
15	2034	-	(5,400)	-	2034	-	(5,400)	-
16	2035	-	(10,150)	-	2035	-	(10,150)	-
17	2036	-	(4,650)	-	2036	-	(4,650)	-
18	2037	-	(2,400)	-	2037	-	(2,400)	-
19	2038	-	(550)	-	2038	-	(550)	-
20	2039	-	-	-	2039	-	-	-
21	Total	$ 59,291	$ (136,306)	$ (64,146)	Total	$ 157,697	$ (37,900)	$ (64,146)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 1 Early Retirement Cases

Retire Campbell 1 5/31/2024

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
		(a)	(b)	(c)	(d)	(e)
1	2020	9,644	9,268	(381)	-
2	2021	3,293	13,541	(200)	29
3	2022	1,050	5,257	(6,250)	-
4	2023	800	9,696	(6,415)	224
5	2024	250	11,252	(9,503)	-
6	2025	-	7,800	(2,550)	-
7	2026	-	4,420	(3,300)	-
8	2027	-	6,845	(4,050)	-
9	2028	-	7,394	(3,500)	-
10	2029	-	2,500	(3,879)	-
11	2030	-	1,050	(2,564)	-
12	2031	-	250	(250)	-
13	Total	$ 15,037	$ 79,273	$ (42,840)	$ 253

Retire Campbell 1 5/31/2025

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
	(f)	(g)	(h)	(i)	(j)
2020	9,989	9,268	(36)	-
2021	3,293	13,512	(200)	-
2022	3,810	5,257	(3,490)	-
2023	3,784	9,472	(3,431)	-
2024	800	11,252	(8,953)	-
2025	250	7,800	(2,300)	-
2026	-	4,420	(3,300)	-
2027	-	6,845	(4,050)	-
2028	-	7,394	(3,500)	-
2029	-	2,500	(3,879)	-
2030	-	1,050	(2,564)	-
2031	-	250	(250)	-
Total	$ 21,926	$ 79,020	$ (35,951)	$ -

Retire Campbell 1 5/31/2026

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
		(a)	(b)	(c)	(d)	(e)
14	2020	9,989	9,268	(36)	-
15	2021	3,293	13,512	(200)	-
16	2022	3,810	5,257	(3,490)	-
17	2023	4,073	9,472	(3,141)	-
18	2024	1,616	11,252	(8,137)	-
19	2025	800	7,800	(1,750)	-
20	2026	250	4,420	(3,050)	-
21	2027	-	6,845	(4,050)	-
22	2028	-	7,394	(3,500)	-
23	2029	-	2,500	(3,879)	-
24	2030	-	1,050	(2,564)	-
25	2031	-	250	(250)	-
26	Total	$ 23,831	$ 79,020	$ (34,046)	$ -

Retire Campbell 1 5/31/2028

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
	(f)	(g)	(h)	(i)	(j)
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	7,800	-	-
2026	2,050	4,420	(1,250)	-
2027	800	6,845	(3,250)	-
2028	250	7,394	(3,250)	-
2029	-	2,500	(3,879)	-
2030	-	1,050	(2,564)	-
2031	-	250	(250)	-
Total	$ 43,436	$ 79,020	$ (14,442)	$ -

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 2 Early Retirement Cases

Retire Campbell 2 5/31/2024

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	10,025	8,861	-	(407)
2	2021	3,530	11,739	37	(1,773)
3	2022	7,300	1,300	-	(3,957)
4	2023	7,500	800	285	(8,672)
5	2024	9,753	250	-	(11,002)
6	2025	2,550	-	-	(7,800)
7	2026	3,300	-	-	(4,420)
8	2027	4,050	-	-	(6,845)
9	2028	3,500	-	-	(7,394)
10	2029	3,879	-	-	(2,500)
11	2030	2,564	-	-	(1,050)
12	2031	250	-	-	(250)
13	Total	$ 58,200	$ 22,950	$ 322	$ (56,070)

Retire Campbell 2 5/31/2025

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,219	-	(49)
2021	3,493	13,271	-	(241)
2022	7,300	5,107	-	(150)
2023	7,215	3,800	-	(5,672)
2024	9,753	800	-	(10,452)
2025	2,550	250	-	(7,550)
2026	3,300	-	-	(4,420)
2027	4,050	-	-	(6,845)
2028	3,500	-	-	(7,394)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	$ 57,878	$ 32,446	$ -	$ (46,573)

Retire Campbell 2 5/31/2026

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	10,025	9,219	-	(49)
15	2021	3,493	13,271	-	(241)
16	2022	7,300	5,107	-	(150)
17	2023	7,215	3,800	-	(5,672)
18	2024	9,753	1,300	-	(9,952)
19	2025	2,550	800	-	(7,000)
20	2026	3,300	250	-	(4,170)
21	2027	4,050	-	-	(6,845)
22	2028	3,500	-	-	(7,394)
23	2029	3,879	-	-	(2,500)
24	2030	2,564	-	-	(1,050)
25	2031	250	-	-	(250)
26	Total	$ 57,878	$ 33,746	$ -	$ (45,273)

Retire Campbell 2 5/31/2028

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	4,800	-	(3,000)
2026	3,300	3,170	-	(1,250)
2027	4,050	3,706	-	(3,139)
2028	3,500	250	-	(7,144)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	$ 57,878	$ 60,687	$ -	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2024				**Retire Campbell 1&2 5/31/2025**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	8,861	(381)	(407)	2020	9,989	9,219	(36)	(49)
2	2021	3,293	11,739	(200)	(1,773)	2021	3,293	13,271	(200)	(241)
3	2022	1,050	1,300	(6,250)	(3,957)	2022	3,810	5,107	(3,490)	(150)
4	2023	800	800	(6,415)	(8,672)	2023	3,784	3,800	(3,431)	(5,672)
5	2024	250	250	(9,503)	(11,002)	2024	800	800	(8,953)	(10,452)
6	2025	-	-	(2,550)	(7,800)	2025	250	250	(2,300)	(7,550)
7	2026	-	-	(3,300)	(4,420)	2026	-	-	(3,300)	(4,420)
8	2027	-	-	(4,050)	(6,845)	2027	-	-	(4,050)	(6,845)
9	2028	-	-	(3,500)	(7,394)	2028	-	-	(3,500)	(7,394)
10	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
11	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
12	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
13	Total	$ 15,037	$ 22,950	$ (42,840)	$ (56,070)	Total	$ 21,926	$ 32,446	$ (35,951)	$ (46,573)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2026				**Retire Campbell 1&2 5/31/2028**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,219	(36)	(49)	2020	10,025	9,268	-	-
15	2021	3,293	13,271	(200)	(241)	2021	3,493	13,512	-	-
16	2022	3,810	5,107	(3,490)	(150)	2022	7,300	5,257	-	-
17	2023	4,073	3,800	(3,141)	(5,672)	2023	7,215	9,472	-	-
18	2024	1,616	1,300	(8,137)	(9,952)	2024	9,753	11,252	-	-
19	2025	800	800	(1,750)	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	250	250	(3,050)	(4,170)	2026	2,050	3,170	(1,250)	(1,250)
21	2027	-	-	(4,050)	(6,845)	2027	800	3,706	(3,250)	(3,139)
22	2028	-	-	(3,500)	(7,394)	2028	250	250	(3,250)	(7,144)
23	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
24	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
25	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
26	Total	$ 23,831	$ 33,746	$ (34,046)	$ (45,273)	Total	$ 43,436	$ 60,687	$ (14,442)	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-82:
2011 BART

Best Available Retrofit Technology (BART) Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2

I. Source Description

Owner/Operator: Tri-State Generation & Transmission Association, Inc.
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100222
Boiler Type: Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Error! Reference source not found. below 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	4,417	4,417

Rating, MMBtu/Hr for coal		
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% PM – 99.6% PM_{10} – 99.4%	NO_x – 29.5%/54.7% SO_2 – 79.5% PM – 99.9% PM_{10} – 99.5%

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first NO_x number compares the additional reduction achieved by the ultra-low NO_x burners vs. the original low-NO_x burners and the second NO_x number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For PM/PM_{10}-, uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and 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, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "TriState BART Submittals".

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	5,190	0.278	5,372	0.271
SO_2	970	0.052	982	0.050
PM_{10}	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. 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 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	Colowyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

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

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

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0

[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

Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

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

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

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

	SO_2 limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

[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.

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 TriState, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. TriState 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, TriState submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

TriState 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, TriState determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO_2 by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:
1. DBA has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.
3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

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

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

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

Therefore, TriState and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit	0.081	0.052

1		
Craig Unit 2	0.093	0.079

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98th percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD).

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

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							

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

Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

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

Table 8: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

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

Step 6: Select BART Control

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

B. Filterable Particulate Matter (PM_{10})

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

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

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

TriState 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

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: TriState 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 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 Units 1 and 2. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

Neural network system combustion controls: TriState 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. 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 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. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although TriState asserts that the units cannot achieve below 0.08 lb/MMBtu. See "TriState BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not

been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

TriState 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: 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

[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
[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

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: TriState stated in the May 14, 2010 submittal that based on the boiler configuration, TriState could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on TriState'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. TriState 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. 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: TriState 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. TriState did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission

[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.

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, The Division may evaluate tighter emission limits in future RH planning periods if SCR is determined to be BART for either Craig Unit 1 or 2. At this time, the Division accepts Tri-State's estimates of 0.08 lb/MMBtu on a 30-day rolling average. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted TriState's estimate to 0.07 lb/MMBtu based on the reasoning above.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		TriState Estimate	Division Estimate	TriState Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners/Ultra-low NO_x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – 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	~15%	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

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

[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.

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.[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.

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.[12] 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.[13] The TriState-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

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.
[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."
[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

capital costs and capacity factor. [15,16] It should be noted that TriState 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. TriState 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 TriState. The costs for these two items are higher than other Colorado facility estimates. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts TriState'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 TriState is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. TriState'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

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

SNCR	15	4,412	0.236	0.27
SCR	74.9	1,305	0.070	0.08

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	0.07

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	3,893	$25,036,709	$6,432	$6,708

Table 15: Craig Unit 2NO_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	$6,299	$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

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

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98^{th} percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than

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

one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD control).

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

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	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		207	57	150	123	12	111
	2	0.07							

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1	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	0.07	2.75	0.98	26%	$25,652,365
Combo	1	0.07	1.17	2.56	69%	$19,537,034
	2	0.07				

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 Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART is SNCR controls at the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

For SNCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan.

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

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

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

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NO_x emission rate equates to a 14% control and a NO_x reduction of 727 tons per year, which is slightly less than the 15% control and a NO_x reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NO_x reduction of 3,975 tons per year, which is much greater than the 15% control and a NO_x reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
The total NO_x emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NO_x emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig

Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-83:
2025 EIA Form 923

State	Facility Nai	Facility ID	Unit ID	Associated Year	Operating T	Sum of the	Gross Loac	Steam Loa	SO2 Mass (	SO2 Rate (l	CO2 Mass	CO2 Rate (	NOx Mass (	NOx Rate (l	Heat Input	Primary Fu	Secondary	Unit Type	SO2 Contr	NOx Contr	PM Control	Hg Control	Program Code
CO	Craig	6021	C1	2020	8511	8490.94	2517304		560.023	0.0431	2726442	0.105	3097.992	0.2329	25995872	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2021	8123	8119.01	2563445		573.766	0.0439	2751844	0.105	3095.465	0.2316	26238031	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2022	8413	8393.53	2797335		742.279	0.0518	2917219	0.1049	3492.321	0.2465	27814864	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2023	8083	8072.47	2015029		526.926	0.0474	2210610	0.105	2518.031	0.2337	21077513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2024	8541	8536.69	1824100		335.429	0.0325	2058659	0.105	2211.571	0.2218	19628748	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2020	7993	7961.83	2300379		517.033	0.0404	2562694	0.105	763.524	0.0618	24434513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2021	8635	8628.91	2822038		476.124	0.0301	3177713	0.105	1014.748	0.0667	30298549	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2022	8427	8420.82	2629692		645.904	0.0451	2948921	0.105	987.563	0.0698	28117158	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2023	5582	5573.88	1245370		282.48	0.0381	1457229	0.105	401.375	0.0562	13894277	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2024	8405	8400.47	1801957		302.703	0.0271	2209975	0.105	625.283	0.0587	21071487	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2020	7811	7789.23	2821877		1644.329	0.1077	3145100	0.105	3152.793	0.2047	29987627	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2021	7426	7415.67	2579840		1307.602	0.1058	2635046	0.1049	2731.044	0.2108	25124446	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2022	7708	7697.91	2783361		1714.714	0.1259	2837603	0.105	2973.326	0.2122	27055733	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2023	7624	7611.42	1981366		1195.702	0.117	2135790	0.105	2131.88	0.2023	20364134	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2024	6146	6137.68	1441766		666.086	0.0852	1610839	0.105	1495.032	0.1898	15358887	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-84:
2024 EIA Form 923

U.S. Department of Energy, The Energy Information Administration (EIA)
EIA-923 Monthly Generating Unit Net Generation Time Series File, 2024 Final Data
Sources: EIA-923 and EIA-860 Reports

Plant Id	Combustion Heat And Power Plant	Plant Name	Operator Name	Operator Id	Plant State	Census Region	NERC Region	NAICS Code	Sector Number	Sector Name	Generator Id	Reported Prime Mover	Respondent Frequency	Net Generation (MWh)													
														Net Generation January	Net Generation February	Net Generation March	Net Generation April	Net Generation May	Net Generation June	Net Generation July	Net Generation August	Net Generation September	Net Generation October	Net Generation November	Net Generation December	Net Generation Year To Date	Balancing Authority Code	YEAR
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	194.852	164.236	159.884	86.688	100.346	129.110	144.745	137.814	121.411	121.223	94.922	140.473	1,503.93	WACM	2024
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	185.996	134.270	159.552	129.604	118.365	129.458	141.851	137.824	126.164	122.724	80.365	132.87	1,618.91	WACM	2024
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	226.238	165.044	46.248	0	63.346	124.830	173.748	164.116	122.393	41.794	90.473	81.046	1,300.97	WACM	2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-85:
Colorado Commission Decision No. C23-0437

Decision No. C23-0437

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20A-0528E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN.

PHASE II COMMISSION DECISION APPROVING A COST-EFFECTIVE RESOURCE PLAN AND ADDRESSING TRI-STATE'S 2023 ELECTRIC RESOURCE PLAN FILING

Mailed Date: June 30 ,2023
Adopted Date: May 10, 2023

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I. BY THE COMMISSION

A. Statement

1. On February 13, 2023, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed a report regarding the evaluation of bids and selection of a preferred resource portfolio for its 2020 Electric Resource Plan (ERP). The ERP Implementation Report or 150-Day Report was filed in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth at 4 Code of Colorado Regulations (CCR) 723-3-3600 *et seq*., and specifically Rule 3605.

2. By this Phase II Decision, we approve Tri-State's Revised Preferred Plan (RPP) as a cost-effective resource plan. The plan primarily includes the acquisition of a 200 MW wind resource through a power purchase agreement. The acquisition of the wind resource during this

resource acquisition period (RAP) will enable Tri-State to make incremental progress toward achieving 2030 and interim-year emissions reduction targets.

3. This Phase II Decision further addresses technical and policy considerations for Tri-State's next ERP. For instance, we address the emissions and economic modeling of the retirement of Tri-State's Craig Unit 3 and additional information Tri-State should submit in its forthcoming 2023 ERP filing, to ensure as robust a record as possible given economic and other uncertainties and lessons learned in this Proceeding.

4. Furthermore, based on the record in this 2020 ERP proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Revised Preferred Plan portfolio includes a renewable resource that can be acquired at a reasonable cost and rate impact and with appropriate consideration to Best Value Employment Metrics; issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

B. Background

1. Electric Resource Planning for Tri-State

5. This Application addresses the first ERP filed by Tri-State before the Commission in response to legislative changes made by Senate Bill 19-236. SB 19-236 directed the Commission to promulgate ERP rules for wholesale electric cooperatives, and in so doing, to consider whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

[1] *See* § 40-2-134, C.R.S.

6. The Commission adopted amendments to the ERP Rules at 4 Code of Colorado Regulations (CCR) 723-3-3600, *et seq* of the Rules Regulating Electric Utilities[2] which set forth a process in Rule 3605 under which the Commission would review Tri-State's ERP in a manner that reflected the time-tested Phase I and Phase II process applied to investor-owned utilities, with an additional pre-filing assessment of existing resources which provided an opportunity for education of the parties and the Commission as to Tri-State's system and operations.[3]

7. In accordance with Rule 3605, Tri-State assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas emissions, in Phase I of the ERP proceeding. Tri-State is also directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

8. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan. We describe these briefly here.

9. Pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

[3] *See generally* Proceeding 20M-0218E.

10. Additionally, the Commission determines whether the utility has provided Best Value Employment Metrics (BVEM) in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. BVEM includes information the utility must request from bidders through the RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

11. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of the revenue requirement for utility portfolios, with and without the net present value of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

12. While recognizing these statutory obligations, we also note that Tri-State's inaugural ERP filed pursuant to Rule 3605 is being decided during a time of significant uncertainty for the wholesale cooperative. This includes supply chain challenges[4]; the prospect of additional member departures that have been announced since the Phase I decision became final[5]; planned, but not yet confirmed, entry into an organized wholesale market[6]; and the potential for new opportunities for financial mechanisms under the Inflation Reduction Act (IRA).[7] Public comments, including those from representatives served by Tri-State's member cooperatives,[8] urge

[4] Tri-State ERP Implementation Report at 5.
[5] Conservation Coalition Comments at 18.
[6] Colorado Energy Office Comments at 4.
[7] COSSA/SEIA Comments at 6-7.
[8] *See*, *e.g.*, Public Comment of John Clark, Mayor of Town of Ridgway (April 10, 2023).

the Commission to consider these factors carefully. Moreover, the Commission recently approved postponing Tri-State's filing of its 2023 ERP from June 1, 2023, to no later than December 1, 2023.[9] All of these complex factors weigh into the Commission's decision, as set forth below.

2. Procedural History

13. On December 1, 2020, Tri-State filed its 2020 ERP in two volumes along with Direct Testimony of six witnesses and other attachments. Tri-State's application was subsequently supplemented in response to Decision No. C20-0820[10] and Staff's Notice of Deficiency.[11]

14. Tri-State previously announced its Responsible Energy Plan in January 2020, which included actions to reduce carbon dioxide emissions from resources owned and operated by Tri-State in Colorado by 90 percent by 2030, as compared to 2005 levels, including through planned retirements of the coal units located at Craig.[12] While Tri-State did not file its 2020 ERP as a Clean Energy Plan,[13] the ERP nonetheless reflects increases in renewable energy, decreases in carbon dioxide emissions, and coal unit retirements while also delaying investments in new gas-fired generation.

15. On February 2, 2021, Natural Resources Defense Council, Sierra Club, and Western Colorado Alliance (collectively, the Conservation Coalition) filed a Proposed Motion Requesting that the Commission Instruct Tri-State to Revise its Application (CC Motion). The Commission set a deadline for response to the CC Motion by Decision No. C21-0139-I, issued March 10, 2021.

[9] Proceeding No. 23V-0050E, Decision No. C23-0107, issued February 16, 2023.

[10] Proceeding No. 20M-0218E, Decision No. C20-0820, issued November 25, 2020.

[11] Staff's Notice of Deficiency was filed on January 25, 2021, and Tri-State's supplemental direct testimony and attachments were filed on February 12, 2021.

[12] Hearing Exhibit (HE) 101, Direct Testimony and Attachments of Brad Nebergall, at Att. BN-1.

[13] Settlement Agreement at ¶ 2.2.

16. Also pursuant to Decision No. C21-0139-I, the following parties to this Proceeding are intervenors as of right: the Office of the Utility Consumer Advocate (UCA), the Colorado Energy Office (CEO), and Trial Staff of the Commission (Staff). Permissive intervenors include the Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively, Wyoming Cooperatives); Poudre Valley Rural Electric Association, Inc. (Poudre Valley), Empire Electric Association, Inc. (Empire), Highline Electric Association (Highline), K.C. Electric Association (K.C.), Morgan County Rural Electric Association (Morgan County), Mountain View Electric Association, Inc. (Mountain View), Southeast Colorado Power Association (Southeast), and Y-W Electric Association, Inc. (Y-W) (collectively, Joint Cooperative Movants); Colorado Solar and Storage Association and Solar Energy Industries Association (COSSA/SEIA); the Conservation Coalition; Colorado Independent Energy Association (CIEA); Southwest Energy Efficiency Project (SWEEP); Interwest Energy Alliance (Interwest); Western Resource Advocates (WRA); International Brotherhood of Electrical Workers, Local No. 111 (IBEW Local 111); and Vote Solar. Delta-Montrose Electric Association was granted intervener status for a limited purpose.[14]

17. In responses to the CC Motion, parties proposed various alternative scenarios that we found could enhance the record of this Proceeding, and Tri-State set forth an alternative proposal in which additional scenarios could be modeled subject to modifications to the procedural schedule. Decision No. C21-0263-I, issued April 30, 2021, directed Tri-State to confer with parties

[14] A Motion to Intervene Out of Time filed by the Office of Just Transition was denied by Recommended Decision No. R21-0682-I, issued November 1, 2021.

and to submit a consensus proposal for a procedural schedule that would accommodate the modeling of up to five additional scenarios.

18. On June 8, 2021, the Commission issued Decision No. C21-0334-I. The Application was deemed complete for purposes of § 40-6-109.5, C.R.S., and referred to an Administrative Law Judge (ALJ).

19. Tri-State submitted Supplemental Direct Testimony reflecting additional scenario modeling on September 28, 2021.

20. Answer Testimony was filed by CEO, CIEA, Conservation Coalition, Interwest, Staff, SWEEP, UCA, and WRA on November 23, 2021.

21. Cross-Answer Testimony was filed by CEO, Conservation Coalition, Interwest, SWEEP, and WRA on January 4, 2022.

22. On January 4, 2022, Tri-State filed Rebuttal Testimony of four witnesses. Attached to the rebuttal testimony of Lisa K. Tiffin, Tri-State submitted as Highly Confidential Attachment LKT-4, a Verification Workbook (Verification Workbook) produced consistent with the March 2021 Clean Energy Plan Guidance (CEP Guidance) developed by the Colorado Department of Public Health and Environment's (CDPHE) Air Pollution Control Division (APCD).

23. On January 14, 2022, CDPHE filed its Motion for Limited Participation. The Motion was granted by Decision No. R22-0109-I, issued on February 23, 2022.

24. On January 18, 2022, Tri-State filed a Joint Motion to Approve Unopposed Comprehensive Settlement Agreement (Joint Motion). The Settling Parties[15] stated that they had

[15] All parties except Vote Solar and Delta-Montrose Electric Association, which took no position.

reached a comprehensive settlement (Settlement Agreement). The Settlement Agreement not only resolved certain modeling inputs and assumptions and set forth additional process for Phase II, but also established commitments to greenhouse gas emissions reductions, including interim reductions in years prior to 2030 that expressly survive the conclusion of this Proceeding. Furthermore, the Settlement Agreement also set forth commitments for its next ERP, including enhanced assumptions around demand-side management and beneficial electrification, and a commitment to host multiple stakeholder meetings around topics like scenario selection.

25. By Decision No. R22-0097-I, issued February 16, 2022, the ALJ issued clarifying questions regarding the Settlement Agreement. On March 2, 2022, Tri-State filed its Consensus Response to Interim Decision No. R22-0097-I (Consensus Response). The answers provided by the parties in the Consensus Response addressed all questions of the ALJ and the Joint Motion was approved by Recommended Decision No. R22-0191, issued March 28, 2022. No exceptions were filed, and it subsequently became the final decision of the Commission, thus initiating the Phase II process.

C. Tri-State's ERP Implementation Report and the RPP

26. Tri-State submitted its ERP Implementation Report pursuant to Rule 3605(h)(I) and the terms of the Settlement Agreement on February 13, 2023, or 150 days after bids were due. Tri-State requests the Commission find its RPP to be a cost-effective resource plan and approve it through this Phase II decision.

27. Pursuant to the Settlement Agreement as approved by the Commission, Tri-State presents a RAP of 2022 through 2030, and focuses only on acquisition of resources in 2025 and 2026. Tri-State received 274 eligible bid proposals and applied a screening process considering

completeness, economics, transmission interconnection, and non-price factors. Eleven bids were advanced to portfolio modeling.

28. Tri-State modeled five scenarios or portfolios: the RPP, which is Tri-State's preferred portfolio and would lead it to acquire a 200 MW wind power purchase agreement in 2025; Early GHG Reduction (EGHG), which expedites interim greenhouse gas emissions (GHG) targets by one year and acquires an additional 200 MW solar PPA in 2026; Reduced Load (RL), reflective of the departure of United Power; Wind Back-Up (Wind BKUP), in the event the primary bid fails; and Early Craig Retirement (EC3), which retires Craig Unit 3 at the end of 2026. Tri-State provided certain analyses related to the net present value revenue requirement, the impact of the Social Cost of Carbon (SCC) and the Social Cost of Methane (SCM), transmission interconnection, and reliability, for each portfolio. Tri-State also applied gas price and extreme weather event (EWE) sensitivities to each portfolio.

29. Tri-State recommends the Commission approve its selection of the RPP and the backup wind bid from the Wind BKUP portfolio should the primary bid fail, and affirm a December 31, 2029 retirement date for Craig Unit 3.[16] First, Tri-State states that it is in a capacity-long position until 2030 and resources acquired through Phase II are focused on incremental progress toward 2030 and interim-year emissions reduction targets rather than needed for resource adequacy or reliability. Second, Tri-State states that it must be cautious about acquiring new resources while the certainty and timing of member exists is still being reviewed in various regulatory proceedings. Finally, Tri-State argues that the RPP is the least-cost portfolio for Tri-State members. Tri-State states that 14 percent of end-use customers served by Tri-State members live below the federal poverty line and up to half of residential end-use customers suffer

[16] Response Comments by Tri-State at p. 39-40.

from some form of energy burden. Tri-State argues that maintaining a 2029 retirement date for Craig Unit 3 is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-scale dispatchable technologies are in place for reliability and resource adequacy, and to provide certainty to the Craig community and plant staff.

30. While Tri-State did not file a Clean Energy Plan,[17] Recommended Decision No. R22-0109-I, issued February 23, 2022, established the path by which the APCD of CDPHE would verify Tri-State's portfolios in Phases I and II. The APCD submitted Verification Workbooks for Tri-State's Phase II portfolios on March 22, 2023.[18] APCD's filing (1) verifies that CEP guidance and the Verification Workbook have been used properly to calculate emissions reductions requirements, including updates to expected member load requirements; (2) verifies that 2005 baseline emissions used are supported by historical data and reflect changes to the utility's customer base; and (3) verifies the projected emissions for calendar year 2030 produced by each portfolio. APCD finds that all portfolios achieve 81 to 83 percent emissions reductions by 2030 and Tri-State achieves a safe harbor from future Air Quality Control Commission regulations.

31. Additionally, Tri-State explains that it developed, in consultation with stakeholders, a set of robust reliability criteria and tested an extreme weather event (EWE) sensitivity on portfolios to ensure future resource additions can meet the necessary reliability and resource adequacy needs of member cooperatives.[19]

32. With its ERP Implementation Report, Tri-State included numerous attachments in response to provisions of the Settlement Agreement approved in Phase I, including documentation

[17] Settlement Agreement at ¶ 2.2.

[18] Decision No. C23-0198, issued March 22, 2023, granted an extension for the submission of the Verification Workbooks.

[19] ERP Implementation Report at 17 and Attachment E.

of updated modeling assumptions (Attachment B), bids advanced to modeling (Attachment C), maps of bids as compared to disproportionately impacted communities (Attachment G), and heat maps related to topics like emissions and renewable resource curtailment (Attachment H).[20]

D. Overview of Party Comments

33. The following parties timely filed comments on the ERP Implementation Report on March 30, 2023: CEO, the Conservation Coalition,[21] COSSA/SEIA, Interwest, Staff, the UCA, and WRA. Tri-State submitted its response to parties' comments on April 14, 2023. We have carefully considered all of these filings and summarize the principle themes of the parties' advocacy below.

1. CEO

34. CEO does not recommend that the Commission adopt a specific portfolio. However, it observes that the EGHG portfolio achieves earlier, and greater, cumulative emissions than the Revised Preferred Portfolio—and while the capital cost is $111 million higher, the EGHG portfolio is actually $576 million less when the SCC is applied. CEO further acknowledges the uncertainty of Tri-State's member load and the prospect of new federal funding opportunities, but observes that investments in additional renewable resources during this resource acquisition period may reduce cumulative GHG emissions over time. Finally, while supporting a retirement date of no earlier than summer 2027 for Craig Unit 3—and expressing concerns that the Craig community has been planning around the previously announced 2029 retirement date—CEO notes that

[20] While many of Tri-State's attachments are marked as confidential or highly confidential, per Rule 3605(h)(III), Tri-State shall file a proposal addressing the public release of bid information after the completion of Phase II.

[21] This time, comprised of the Natural Resources Defense Council and the Sierra Club.

additional renewable acquisitions may result in lower dispatch of the Craig unit when Tri-State joins an organized market.

2. COSSA/SEIA

35. COSSA/SEIA do not opine on the selection of a portfolio for Tri-State, and focus their comments on proposals to improve the competitive bid process in the 2023 ERP, both generally and due to new opportunities for generation asset ownership given the Inflation Reduction Act (IRA).

3. Conservation Coalition

36. Conservation Coalition recommends the Commission reject Tri-State's request to approve its RPP because of significant deficiencies in modeling related to the EWE sensitivity and its implications for the retirement of Craig Unit 3. Significantly, as we discuss further below, Conservation Coalition recommends the Commission decline to approve Tri-State's proposal to retire Craig Unit 3 by the end of 2029, and instead address the appropriate retirement date in the 2023 ERP. Conservation Coalition alleges significant defects in the Phase II modeling, including the construction and application of the EWE sensitivity, which Conservation Coalition argues includes reliability criteria and assumptions that have not been fully vetted, lack a basis in reality, and contravene common industry practices.

37. Conservation Coalition also recommends the Commission defer a decision on Craig Unit 3 to more fully consider federal funding options and because of emerging information about potential additional member departures, including not only United Power but also Northwest Rural Public Power District (NRPPD) and Mountain Parks. Even the RL portfolio overstates Tri-State's load, Conservation Coalition states. However, Conservation Coalition does not oppose the

Commission approving Tri-State's acquisition of the 200 MW wind project, arguing that energy from the new project will displace more expensive and polluting energy.

4. Interwest

38. Interwest recommends the Commission approve the EGHG portfolio rather than the RPP, as the latter is no longer the least-cost portfolio when the SCC and SCM are appropriately considered. Given recent gas price swings, Interwest also believes the EGHG portfolio has the greater price risk mitigation benefits. It specifically supports the 200 MW wind acquisition in eastern Wyoming and recommends the 200 MW solar acquisition in eastern Colorado also be acquired under the EGHG portfolio as it would contribute complementary operating characteristics and diverse locations.

5. Staff

39. Staff supports the RPP, or alternatively, the EGHG portfolio. Given modeling issues related to the EWE sensitivity and a range of uncertainties, Staff considers these to be the most realistic scenarios. While acknowledging the portfolios are similar in many ways, such as their system-wide GHG emissions and bids selected during the RAP, Staff explains that the RPP portfolio is less expensive than the EGHG portfolio based on NPVRR, but more expensive when SCC and SCM are considered.

40. Staff also raises concerns regarding the mechanics of Tri-State's Phase II modeling. There were significant variations between Phase I and Phase II which Tri-State did not explain, according to Staff. Staff also points out unexplained annual cost differences between portfolios that create questions as to the validity of Tri-State's selection of the RPP on cost grounds. Moreover, while stating its belief that Tri-State complied with the terms of the Settlement

Agreement around sensitivity modeling approaches, Staff critiques the limited information that Tri-State presents regarding the initial portfolio for each scenario, and suggests that repeated failures may indicate that the EWE sensitivity was not effectively constructed. In particular, Staff notes how annual planning reserve margins exceed 30 percent in all years beginning in 2025, despite a 15 percent minimum requirement.

41. However, Staff generally supports Tri-State moving forward with the acquisition of 200 MW of wind PPA to support compliance with GHG reduction requirements at a reasonable cost and given uncertainties Tri-State currently is operating under—including member load, future wholesale market participation, IRA tax credits and other funding opportunities, and the expectation of enhanced transmission capacity being available by 2028.

6. UCA

42. UCA supports Tri-State's proposal to select a 200 MW wind project given it is long on capacity and is experiencing uncertainty related to member load, supply chain issues, and federal incentives. UCA also raises that the 2023 ERP is fast approaching.

7. WRA

43. WRA argues that the Commission should refrain from approving any portfolio in its entirety in Phase II, as all portfolios were manually adjusted to meet the EWE sensitivity, and Tri-State did not present the original portfolios under base case conditions. WRA suggests this is problematic because the Commission cannot compare base case portfolios with the adjusted extreme weather portfolios to understand which incremental capacity additions are driven by the sensitivity, which is relevant to the decision regarding the Craig Unit 3 retirement date.

44. Ultimately, however, WRA recommends the Commission approve Tri-State's proposed acquisition of a 200 MW wind project in 2026. WRA asserts that despite flaws in the modeling, the portfolios indicate that deeper GHG emissions reductions are more cost-effective. Specifically, for the EGHG and EC3 portfolios, which have lower system-wide and cumulative emissions, the cost of incremental additional emissions reductions is well below the SCC. WRA thus recommends that Tri-State acquire an additional 200 MW solar resource in 2026.

E. Tri-State's Response to Party Comments

45. Tri-State points out that only 7 parties to the Settlement filed comments, with 21 parties filing no comments. While filed comments disagree regarding portfolio selection, they are largely supportive of Tri-State's proposal to acquire 200 MW of wind. Tri-State argues that parties' critiques are largely cherry-picking rather than holistically considering modeling outcomes, and it continues to support the RPP scenario as incorporating the most reasonable modeling assumptions. Tri-State also emphasizes that it is the first Colorado utility to incorporate binding interim-year and 2030 commitments for emissions reduction which it is meeting through the RPP. Moreover, Tri-State notes that an ERP is modeled using the best available information at any given point in time—future uncertainty in its load forecast does not warrant special action by the Commission, nor do modeling critiques warrant deferring a decision regarding the modeling of Craig Unit 3. Tri-State believes the best way to address uncertainty is to adopt the RPP, which reflects a reasonable path forward given current circumstances.

46. Tri-State further argues that it deserves the opportunity to fully prepare and present its 2023 resource plan as established by Rule 3605, and that the Commission should not take action on its 2023 ERP at this time. Tri-State raises concerns that not all parties have addressed the same issues; that the Commission does not have a full and comprehensive record on which to address

matters pertaining to the 2023 ERP; and accordingly, it would give a small subset of parties a disproportionate voice to make findings here. Finally, Tri-State argues that various items are already established for its 2023 ERP through the Settlement Agreement, and that it has been engaged in stakeholder discussions on that filing since January 2023, making additional Commission intervention unnecessary and potentially devaluing its collaborative stakeholder efforts. Ultimately, Tri-State asks the Commission to reject requests by parties to provide additional direction for its 2023 ERP.

F. Discussion, Findings, and Conclusions

1. Cost Effective Resource Plan

47. In consideration of the comments of all parties and given the broader perspective of the issues raised throughout this Proceeding, we approve Tri-State's selection of the RPP as the cost-effective resource plan. Acquiring 200 MW of wind through a power purchase agreement represents a no-regrets path forward, at a reasonable cost and rate impact to Tri-State members and with carbon emissions reduction benefits, given the uncertainties Tri-State has faced during this ERP. We further find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource, and that the RPP supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of greenhouse gas emissions by 2030.

48. While an additional solar acquisition consistent with the EGHG portfolio could potentially also be cost-effective as compared to continuing to utilize coal generating units which, as we describe below, have significant direct expenses, we agree with Tri-State that such an action

is premature at this time as the process and timeline of member departures remains complicated and uncertain.

49. However, while approving Tri-State's RPP overall, we are not prepared to endorse Tri-State's decision to retain the December 31, 2029, retirement date for Craig Unit 3 as final based on the record in this Proceeding. As explained in more detail below, parties have made a reasonable showing that an earlier retirement of Craig Unit 3 might be preferrable for emission reductions and economic purposes upon further analysis in Tri-State's next ERP. Retirement before 2029 may also be shown to be feasible for Tri-State with respect to reliability and resource adequacy with more refined modeling and analysis. For example, we have concerns regarding the treatment of the EWE sensitivity in the Phase II modeling process in this ERP. At the same time, however, we recognize that the coal plant retirement timing decision also involves a host of other factors including providing adequate and timely host community assistance, on-site construction management issues, the cost and benefits of potential replacement power, load uncertainty, and the future value of capacity in evolving regional market structures. Accordingly, we choose to tread cautiously in this area at the current time and direct further modeling and presentation of information in Tri-State's 2023 ERP, as described below.

2. Best Value Employment Metrics

50. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine in accordance with § 40-2-129, whether the utility has obtained and provided best value employment metrics (BVEM) and taken certain other steps.[22] BVEM include the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor;

[22] The Commission has not yet initiated a rulemaking regarding BVEM, although it has committed to do so in response to a legislative audit in July 2022.

long-term career opportunities; and industry-standard wages, health care, and pension benefits. Tri-State's bid evaluation process treated BVEM as a qualitative or non-price factor within the "community stewardship" category, which was considered along with counterparty profile, project feasibility, and project capability.[23] Tri-State also presented a ranking approach for reviewing non-price factors and submitted the documentation provided for bids advanced to modeling in Highly Confidential Attachment F to its ERP Implementation Report.

51. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders. IBEW Local #111 is a party to this proceeding and did not provide comments on the sufficiency of the materials in the ERP Implementation Report. Upon review of the materials and the bid process, particularly Highly Confidential Attachment F, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, Tri-State has provided BVEM and objective standards for how it evaluated BVEM as between bids. As Tri-State has not proposed to construct or expand a generating facility, it has not proposed any PLAs.

3. Modeling, Bid Evaluation, and Plan Development

a. Extreme Weather

52. Parties raise various concerns about the content and application of the EWE sensitivity in the 2020 ERP and recommend modifications to the 2023 ERP.

53. Conservation Coalition argues that Tri-State's target reliability criteria are uncommon and lack support; the assumptions of the EWE lack support and are not reflective of historical experience; and the EWE sensitivity modeling led to implausible outcomes, including excessively high planning reserve margins. Moreover, Conservation Coalition states that Tri-State

[23] Tri-State 150-Day Report, pp. 12-13.

modified each modeling run to meet the EWE and did not present "base" portfolios, in contrast with typical resource planning practices. In its next ERP, Conservation Coalition argues that the Commission should direct Tri-State to make significant changes to EWE modeling, including implementing a detailed, four-step probabilistic assessment or at minimum, presenting portfolios with and without the sensitivity applied, and incorporating more realistic and better-documented assumptions.

54. Both Staff and WRA note that this issue is appropriately addressed in Tri-State's upcoming ERP, and state that stakeholder discussions are already revisiting how to define the EWE to better reflect weather conditions, duration, renewable resource performance, and other factors.

55. Tri-State explains that the EWE sensitivity was incorporated in the Settlement Agreement and then more specifically described as part of its Consensus Response. Tri-State contends it communicated frequently with the parties, but no parties expressed concerns with or suggested alterations to reliability criteria before it initiated modeling. Moreover, Tri-State alleges that Conservation Coalition misrepresents how it presented the portfolios, indicating that the sensitivity analysis was applied only to the dispatch and not to capacity expansion itself. Tri-State further rejects requests from parties that direct it to modify its EWE sensitivity modeling in specific ways in its next ERP, arguing that the Commission has an incomplete record here and that stakeholder discussions are ongoing leading up to the 2023 ERP.

56. Broadly, we have been pleased with the work that parties have done to develop a robust record for this Proceeding and to come together through the Settlement Agreement and other activities. We do not believe that disagreements around the EWE sensitivity undermine what has been achieved through this ERP process. However, discussion around this issue reveals the need for more transparent and detailed information around the treatment of sensitivities and

reliability indicators to be presented with sufficient timeliness to enable robust evaluation by the parties and by the Commission. While we decline to adopt the specific remedies the Conservation Coalition recommends with regard to EWE modeling, we direct Tri-State to present in the direct case of its 2023 ERP thorough descriptions of and justifications for all assumptions used in its modeling of an EWE, including its impact on load, its duration, its frequency, its geographic scope, the technology and operational options available to the model (e.g., market purchases both before and after joining an RTO), and any anticipated reduction in output from all generator types during the EWE. Tri-State should also discuss any probabilistic modeling applied in weather sensitivities or describe in its direct case the limitations it faces in doing so.[24]

57. We note that some parties have recommended that the parameters used in modeling an EWE should be based on historical events. While we agree that there must be some anchoring of EWE parameters to history, recent experience in Colorado suggests that history may not be fully predictive of future weather extremes given climate change, and an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs.

58. Finally, we agree with parties that one role of a sensitivity analysis is to present results with and without the sensitivity applied. Without a full understanding of the cost, environmental and reliability characteristics of each portfolio under the base case, neither the Commission nor the parties can understand the many tradeoffs involved in selecting an alternate portfolio that may exhibit superior characteristics in response to a sensitivity run. Accordingly, in its 2023 ERP, we direct Tri-State to present the modeling results of portfolios under sensitivity

[24] Tri-State Response Comments, p. 33.

conditions as additions to, not substitutions for, the results of portfolio performance under base case assumptions.

b. Load Reduction

59. Tri-State's portfolios include a base load profile, with the exception of the RL portfolio, which removes load attributable to United Power.

60. Parties, including Staff and WRA, acknowledge the uncertainty caused by the prospect of member cooperatives departing the Tri-State system.

61. Conservation Coalition specifically contends that the Commission should not make a decision on key issues in the 2023 ERP, such as the retirement date for Craig Unit 3, given the prospect of member departures. United Power and NRPPD filed non-conditional notices of withdrawal from Tri-State at the Federal Energy Regulatory Commission on April 29, 2022, and Mountain Parks announced an intent to exit in January 2023. Conservation Coalition states that these members represent at least 25 percent of Tri-State's load, meaning that even the RL scenario potentially overstates Tri-State's load. However, Conservation Coalition also acknowledges that the parties agreed upon certain load forecasts in the Phase I Settlement Agreement. Thus, it recommends that in the next ERP, Tri-State should use a load forecast for every scenario that removes all load from member cooperatives that have provided notice of intent to exit, or negotiated partial requirements contracts, as of May 1, 2023. It recommends further that the Company should be required to file a notification with the Commission for any load changes announced following that date.

62. Tri-State responds that an ERP is a decision made at a point in time, and that it is not possible to change every input at every time. Moreover, it argues that it would be inappropriate

to set specific requirements for the next ERP in this venue, with comments from a limited subset of parties and with an ongoing stakeholder process.

63. We find the uncertainty attached to Tri-State's load forecast to be a troubling aspect of this ERP that will extend into the next, which is fast approaching. For instance, notices of intent to withdraw from Tri-State are not guarantees that member cooperatives will depart the system and reduce Tri-State's resource obligations. Recognizing this uncertainty, we have approved Tri-State's acquisition of 200 MW of wind as a no-regrets opportunity. However, given the magnitude of load that may leave Tri-State's system, we are concerned that the load forecast be more robustly vetted in the next ERP. We request that Tri-State submit a load forecast that is indicative of anticipated member departures at the time of filing, and if this is not the baseline, Tri-State should address why not. Moreover, we direct Tri-State to propose a process to notify the Commission of material changes to the load forecast at any time such a change occurs before the due date for bids in any competitive solicitation proposed in the next ERP.

64. Furthermore, we note that the appropriate incorporation of distributed energy resources remains a work in progress for Tri-State, given its position as a wholesale cooperative. We recognize that pursuant to the Settlement Agreement, Tri-State submitted an informational filing regarding demand-side management and beneficial electrification.[25] We encourage Tri-State to further explore the potential benefits of strategically locating distributed energy storage within member cooperative territories, and to address their approach to this process as part of their description of their load forecast for the 2023 ERP.

[25] 2023/24 Colorado Demand-Side Management Plan (September 1, 2022).

c. Bid Evaluation Process

65. Staff and COSSA/SEIA raise concerns that out of 274 bids, only 11 were advanced through the screening process for modeling. In light of this, Staff suggests that Tri-State should provide better guidance to bidders in its next ERP. First, COSSA/SEIA recommends that Tri-State be required to provide more information to bidders on the thresholds, criteria, and outcomes of each bid evaluation step in the 2023 ERP. Bidders do not know what cost thresholds were used in the economic screen, for example, and which screens failed which bids. Second, COSSA/SEIA states that unlike investor-owned utilities, Tri-State is not required to notify bidders at day 45 whether their bids advanced to computer modeling and if not, why not. According to COSSA/SEIA, this process should be applied along with a dispute resolution process so that modeling errors can be corrected in a timely way. Third, COSSA/SEIA alleges that Tri-State only advanced 4 percent of bids whereas prior ERPs by Public Service Company of Colorado advanced 52 percent of bids in 2011 and 38 percent of bids in 2016. Because a smaller bid pool reduces flexibility, COSSA/SEIA urges the Commission to require that at least 25 percent of bids be advanced to modeling in the 2023 ERP. Finally, COSSA/SEIA contends that the IRA has changed the incentives for Tri-State to participate in its future competitive solicitations, because due to the "direct-pay" provisions of the IRA, it will now be able to monetize federal tax credits for renewable generators. This, COSSA/SEIA suggests, means that an independent evaluator is needed to oversee future ERPs.

66. Tri-State argues that comments provided by COSSA/SEIA are outside the scope of the Commission's decision in a Phase II proceeding, as they would impact Tri-State's next ERP. Tri-State states that it has already been engaged in discussions with parties regarding its Phase II process and lessons learned for evaluation of bids in the next ERP. Tri-State rejects the proposal

to advance a set number or percentage of bids to modeling because it may advance bids that are not viable given screening criteria, instead proposing to provide more guidance to bidders in future ERPs. Tri-State also opposes the request to provide additional insight at each bid screen to bidders given its limited resources. It does state that it is considering an independent evaluator, but it reserves the right to make that proposal based on discussion with stakeholders.

67. We share the concerns expressed by Staff and COSSA/SEIA regarding the limited bids advanced to modeling and the limited information that Tri-State has thus far provided about the factors that resulted in only four percent of bids being advanced to modeling. While we decline to require most of COSSA/SEIA's specific recommendations, we do agree that more information and transparency into the inner workings of the bid selection process is warranted. Accordingly, we ask Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided in the 45-day report. At minimum, this report should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail. Such information will enable parties and the Commission to better understand the criteria that are causing bids to fail and assess whether any adjustments are advisable for future solicitations. We further request that Tri-State either propose as part of its 2023 ERP the selection of an independent evaluator to review its bid selection and modeling process in Phase II of that proceeding, or explain why, in its view, an independent evaluator is unnecessary.

4. Coal Unit Retirements

a. Craig Unit 3

68. The retirement of Craig Unit 3 on December 31, 2029, is essential for Tri-State to achieve emission reduction targets by 2030,[26] the date by which significant reductions in emissions must be achieved pursuant to a Clean Energy Plan for a Colorado investor-owned electric utility.[27] In this Proceeding, the parties stress in their comments that additional emission reductions could be achieved if Craig Unit 3 is retired before 2030. The Commission further received dozens of public comments from individuals identifying themselves as being served by Tri-State member cooperatives that asked the Commission to require Tri-State increase its use of renewable resources and accelerate the retirement of coal-fired generating units like Craig Unit 3 to as early as 2025.

69. Tri-State identifies December 31, 2029, as the optimal retirement date for 448 MW Craig Unit 3 in the RPP. It claims that this date is essential to maintain sufficient dispatchable capacity until replacement capacity is in place to meet reliability and resource adequacy needs in 2030 and that the Phase II modeling has served to highlight the importance of this unit remaining online through 2029 under current system conditions. Additionally, Tri-State explains that this will create continuity for the City of Craig and Moffat County, which it is engaging through a third-party facilitated stakeholder process to explore community assistance opportunities.

70. CEO recommends clear and firm closure dates for all Craig units, with at least two but ideally three years or more between the submission of workforce and community assistance plans and a plant closure. According to CEO, Tri-State submitted its workforce transition plan to the Office of Just Transition and is expected to submit an informational community assistance plan

[26] *See*, *e.g.*, ERP Implementation Report at Attachment D-1.
[27] § 40-2-125.5(3)(a)(I), C.R.S.

in the summer of 2024. CEO states that workers, the City of Craig, Moffat County, and Tri-State have been planning around a 2029 retirement date for Craig Unit 3. If the Commission leaves open modifying a date in Tri-State's 2023 ERP, CEO recommends the Commission at minimum specify the earliest and latest possible retirement dates for Craig Unit 3, and suggests the window of summer 2027 through December 31, 2029.

71. Conservation Coalition urges the Commission to delay a decision on the Craig Unit 3 retirement date to Phase I of the 2023 ERP, as setting a date in this Proceeding is not justified by the current modeling, including flawed load forecasts and sensitivities. However, Conservation Coalition argues that if the Commission decides to set the unit's retirement date in this Proceeding, it should be set no later than January 1, 2027. Conservation Coalition asserts that the member departures will make Craig Unit 3 financially and environmentally expensive surplus capacity as soon as the end of 2025. Furthermore, full consideration of the SCC and SCM makes the retirement of Craig Unit 3 by 2027 the lowest-cost option, and a more realistic version of the EWE scenario suggests that early retirement is preferable.[28]

72. Staff states that it does not oppose including a firm retirement date for Craig Unit 3 here, but also suggests that it may be appropriate to consider earlier alternatives and the Commission's decision-making may benefit from additional modeling. Staff states its agreement that Community Assistance and Workforce Transition Plans should be established at least two years before the actual retirement date and thus indicates that Craig Unit 3 should be retired no earlier than January 1, 2027.

[28] ERP Implementation Report, Attachment I at 3.

73. WRA finds the modeling of the EWE faulty to the point that it recommends that the Commission refrain from approving a retirement date for Craig Unit 3 until it has more robust and useful modeling results. WRA refers to ongoing discussions with Tri-State which are likely to lead to better data on which to base a retirement date decision in the 2023 ERP proceeding.

74. Tri-State disagrees with parties' characterizations of the modeling results. Tri-State contends that the model's selection of December 31, 2029, as the optimal retirement date for Craig Unit 3 across all portfolios despite its ability to select any time between 2026 and 2029 (except where an earlier retirement was forced) affirms its long-standing plans for retirement. Tri-State argues that Conservation Coalition inflates the importance of the EWE to support its dissatisfaction with the resulting retirement date; that achieving reliability metrics was a more significant factor in portfolio selection; and that Craig Unit 3 is necessary until additional firm replacement capacity is available. In response to parties suggesting that the retirement date be modeled in the 2023 ERP, Tri-State argues that such a delay would do a disservice to those affected by the closure and would achieve, at most, a date that is one or two years earlier than currently planned. It argues that this would make little sense since the unit is already retiring well in advance of its useful life and the RPP will achieve necessary emission reductions. Tri-State further points to administrative complexities in staging retirements at Craig Station.

75. We recognize that this Proceeding is being conducted at a time of significant uncertainty for Tri-State, and that there are factors extending beyond the scope considered here that influence Tri-State's judgement about when to retire Craig Unit 3. We are thus reluctant to substitute our judgement for that of the utility in this case. At the same time, we find that the modeling flaws identified by the Conservation Coalition, Staff, and others are significant, and render the record in this Proceeding inconclusive with regards to the optimal retirement date for

Craig Unit 3. We see our role as ensuring that this process provides sufficiently accurate and actionable information to support the retirement decision, even if factors external to the ERP process may play a significant role in that decision.

76. Selecting an optimal date to retire a fossil generating unit includes a complex constellation of financial, contractual, construction, and other decisions. In this instance, there are also the considerations of a fair transition for the Craig community, including at least two and ideally more than three years for plant closure.[29] In addition, while parties have proposed dates as early as 2027 for retirement, and there is some evidence suggesting that earlier retirement could produce economic benefits for Tri-State's member-customers, we are concerned about a variety of factors that may impact the costs of replacement power, ranging from supply chains to inflation. While we would have preferred to establish a specific date for retirement in this Decision, we cannot in good conscience do so given critiques of the modeling process and these uncertainties.

77. Because we find that the record in this Proceeding does not clearly support December 31, 2029, or any other date, as the optimal retirement date for Craig Unit 3, we will not affirm a retirement date for that unit in this Proceeding.[30] Instead, we will direct Tri-State to evaluate alternate retirement dates for Craig Unit 3 in its 2023 ERP filing. We further request that Tri-State continue to work with interested parties to refine modeling assumptions and practices in an attempt to forge as great a degree of consensus as possible, by using its model to analyze the benefits and costs associated with various retirement dates for Craig Unit 3, including identifying economically optimal retirement dates as part of the direct case it will file in its 2023 ERP. We

[29] HE 1103, Cross-Answer Testimony of Wade Buchanan Rev. 1 (January 4, 2022) at p. 6:12-18.

[30] We note here that Commissioner Plant's preference during deliberations was to select a date certain for Craig 3 retirement within this proceeding to provide certainty to the Craig community, to allow sufficient time for the development of a community transition plan in advance of the plant's closure, and to ensure sufficient time for the community to apply for community assistance grants funded by the Inflation Reduction Act.

anticipate that this additional modeling will provide important analyses and information that can be balanced against other considerations as part of the process of developing a reasonable and appropriate retirement date.

b. Springerville Unit 3

78. Conservation Coalition argues that Springerville Unit 3, which, unlike Craig Unit 3, is located in Arizona and not Colorado, is Tri-State's most expensive generating unit and that the Commission should therefore reject Tri-State's proposal to continue its operation until 2040. Conservation Coalition states that Tri-State chose this year because its contract with the Salt River Project (SRP) expires in 2036, and that Tri-State erred in failing to model its retirement on economic grounds.

79. Conservation Coalition argues both that supplemental modeling in Phase I showed that Springerville Unit 3 was uneconomic as early as 2022, despite potential contract penalties, and that Tri-State's primary responsibility should be to its members rather than to SRP. Conservation Coalition thus recommends the Commission direct that Tri-State allow Springerville Unit 3 to economically retire in any year in every scenario modeled in Phase I of its 2023 ERP, and that all such modeling should incorporate the Company's best estimate of costs associated with early retirement. In the alternative, it asks the Commission to instruct Tri-State to model at least one portfolio that requires the model to retire Springerville Unit 3 during the RAP to enable comparisons across portfolios.

80. Tri-State states that Conservation Coalition has failed to provide any factual support for its contention that an early retirement for Springerville Unit 3 would save Tri-State customers money or that the unit would be surplus capacity following the announced load departures. Tri-State also criticizes Conservation Coalition for failing to identify the additional financial costs

(which include financing and equity partner penalties) to Tri-State members of an early retirement, which it claims are correctly reflected in all portfolio modeling. It notes further that even in the RL portfolio, Springerville Unit 3 is forecast to operate through January 1, 2040. Finally, referring to paragraph 3.11.14 of the Settlement Agreement, Tri-State notes that it has already agreed through the Settlement Agreement to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in the next ERP.

81. We agree with the parties that address Springerville Unit 3 in their comments that the facility is expensive for Tri-State to continue to operate, and that its early retirement should be modeled as part of the 2023 ERP. However, as Tri-State indicates, it has already committed to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in its next ERP based on discussions with stakeholders.[31] Given the Settlement Agreement, we find it would be procedurally unfair to direct the specific actions requested by Conservation Coalition. However, we acknowledge the concerns raised by Conservation Coalition regarding the expense of Springerville Unit 3 and expect that Tri-State's next ERP will accurately reflect the costs associated with early retirement in its modeling.

5. Treatment of Federal Funding

82. Parties raised two primary issues related to federal funding in Tri-State's 2023 ERP. The first relates to the modeling of IRA tax credits. The second relates to the treatment of federal funding, including whether Tri-State should be encouraged to pursue it and if so, how it should be modeled in future cases.

[31] Settlement Agreement at ¶ 3.11.14.

83. As to the first issue, Staff states that since the IRA was passed in August 2022, significant tax credits and other funding opportunities now exist which apply specifically to not-for-profit entities like Tri-State. These credits may result in cost-effective bids in the next ERP solicitation. More specifically, Conservation Coalition notes IRA provisions that maintain certain tax credits until the later of either 2032 or the year in which annual GHG emissions from electricity production fall below 25 percent of their 2022 level, and recommends that the Commission instruct Tri-State to assume in its modeling that those tax credits continue for the duration of the analysis period it uses in its next ERP—presumably, at least 2040. Tri-State responds that it made best efforts to incorporate the impact of IRA tax credits into Phase II modeling, despite the tight timeframe, and it continues to evaluate IRA-related assumptions for the 2023 ERP.

84. As to the second issue, CEO states that Tri-State submitted to Senators Bennet and Hickenlooper and Representative Perlmutter a proposal for funding to study the feasibility of a Craig Energy Center to test and demonstrate clean and low-emission technologies. CEO recommends the Commission encourage Tri-State to pursue community assistance opportunities for the City of Craig and Moffat County, as identified in the stakeholder engagement process, and to pursue federal funding for just transition. Similarly, Conservation Coalition recommends that the Commission direct Tri-State to incorporate at least one portfolio in its next ERP regarding U.S. Department of Agriculture Section 22004 funding, as well as detailed information on applications, timelines, collaboration, and other federal funding opportunities for which it may be eligible.

85. Tri-State states that it appreciates and shares CEO's concerns regarding a just transition for affected communities but argues that CEO's recommendations have limited relevance to Phase II and that it is participating in the development of a facilitated Community Assistance Plan, in partnership with the Office of Just Transition, the City of Craig, Moffat County,

CEO, and UCA. Tri-State states that it already submitted a Workforce Transition Plan for Craig Station to OJT in December 2022 and has voluntarily provided information to the Commission regarding federal funding pursuits in Proceeding No. 23M-0053ALL. Ultimately, it argues that it need not be persuaded to seek funding and urges the Commission to reject parties' requests. Moreover, it notes that modeling federal funding opportunities in the next ERP may not be appropriate, as not all funding opportunities are generation-related, they require complex financial analysis, and Commission oversight may impede efforts to rapidly secure funding.

86. We agree with Staff and Conservation Coalition that the treatment of tax credits under the IRA is an emerging and potentially significant area, and ask Tri-State to specifically address related modeling assumptions in its next ERP. Beyond that, while the funding mechanisms and incentives established in the Infrastructure and Jobs Act and the IRA are anticipated to create significant opportunities for Tri-State and its members, we agree that it has strong incentives to pursue such funding on behalf of its members. Nevertheless, we do encourage Tri-State to pursue all relevant funding to support community transition and the broader clean energy transition, and direct Tri-State to provide a narrative description of all federal funding it has or intends to pursue as part of its direct case for the 2023 ERP.

6. Requests Not Explicitly Addressed

87. Various other concerns and suggestions were raised by parties in addition to the issues explicitly addressed in this Decision—including for example, procedural issues related to the next ERP. While we support and encourage continuous improvement towards transparency, we find that it is not necessary to address each of these items, many of which are premature. Any request not addressed in this Decision is denied.

7. Waiver of Rule 3605(h)(II)(A)

88. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the utility's ERP Implementation Report. While the Commission has completed its deliberations, it finds that additional time is necessary for the circulation of this Decision prior to issuance given the Commission's significant caseload at this time.

II. ORDER

A. It Is Ordered That:

1. The Commission approves as a cost-effective resource plan the Revised Preferred Plan presented by Tri-State Generation and Transmission Association (Tri-State) in its ERP Implementation Report filed on February 13, 2023, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600 *et seq*., consistent with the discussion above.

2. In its next Electric Resource Plan (ERP) filing, Tri-State shall incorporate modifications to its modeling and present in its direct case certain information, consistent with the discussion above.

3. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

4. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

5. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING May 10, 2023.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-86:
Tri-State 150-Day Implementation Report

Colorado PUC E-Filings System

Tri-State Generation and Transmission Association, Inc.

2020 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 20A-0528E)

Notice of confidentiality. A portion of this document has been filed under seal.
Confidential information has been redacted from page 13.
Highly confidential information has been redacted from pages 24, 36, 47, 57-58, and 68.

February 13, 2023

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's Phase II ERP Implementation Report. The report complies with Colorado Public Utilities Commission (CoPUC) Rule 3605(h) and Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (Settlement Agreement) filed with the CoPUC on January 18, 2022, concluding Phase I of Tri-State's 2020 Electric Resource Plan (ERP).

Tri-State's preferred cost-effective resource portfolio is the Revised Preferred Plan. The Revised Preferred Plan adds 200 MW of new wind in 2026, maintains the previously announced Craig 3 retirement at the end of 2029, and results in a generation portfolio that meets and slightly exceeds both the interim and 2030 GHG emissions reduction targets[1] for Tri-State's Colorado wholesale sales. The Revised Preferred Plan is also the least-cost portfolio for Tri-State Members.[2] Tri-State supports this portfolio, which reflects its Members' strategic directives to ensure reliable, affordable, and responsible service. Importantly, the Revised Preferred Plan portfolio will enable continued progress under Tri-State's Responsible Energy Plan, under which Tri-State is forecasting that by 2030 it will eliminate 100% of the CO_2 emissions from Tri-State-owned coal generation in Colorado and that 70% of the electricity used by its Members will come from clean sources.

Tri-State has selected the Revised Preferred Plan as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Relevant economic and operational contexts are also important. During 2022 and continuing into 2023, many industries have faced significant inflationary and supply chain pressures, which create a difficult environment for resource procurements. Additionally, utilities face reliability challenges in retiring baseload power that will be replaced solely with intermittent resources—in some cases leading to unforeseen delays in baseload resource retirements.[3] Tri-State's aggressive, yet incremental, approach to its generation portfolio transition aims to avoid these pitfalls and continue to deliver the system reliability expected by its Members. This approach is even more important given extreme weather

[1] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[2] Lowest PVRR, exclusive of SCoC and SCoM.

[3] *For example:* Ameren (Missouri) 1.1 GW plant, three years; Omaha Public Power District (Nebraska), 645 MW, three years; NiSource/NIPSCO (Indiana) 877 MW plant, two years; Alliant Energy (Wisconsin) 400 MW plant, 2.5 years and 1.1. GW plant, 18 months; WEC Energy Group Inc. (Wisconsin) 1.1 GW plant, 18 months; PNM San Juan (New Mexico) 847 MW plant, three months.

events that add resource adequacy pressure.[4, 5] Uncertainty around Tri-State's future load requirements, given certain Members' announced plans to exit Tri-State, affirms the benefits of a tempered approach to resource acquisition and generation changes in this Phase II process. The benefits of the Revised Preferred Plan over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled five portfolios for Phase II of the 2020 ERP: 1) the Revised Preferred Plan, 2) Early Greenhouse Gas Reduction (EGHG), 3) Reduced Load (RL), 4) Wind Back-up Bid (Wind BKUP), and 5) Early Craig 3 Retirement (EC3). The Revised Preferred Plan portfolio, and Wind BKUP, reflect input assumptions that Tri-State believes to be the most accurate, and reflective of its system operations and Members' needs. The EGHG and EC3 portfolios reflect stakeholder-driven modeling assumptions that narrowly seek to drive prescribed outcomes for Tri-State's generation portfolio. The RL portfolio provides potential indication of system changes that could result from a Member exit.

Tri-State remains in a capacity-long position until 2030.[6] Therefore, resources acquired through Phase II of the 2020 ERP are not necessary for ensuring ongoing resource adequacy and reliability. All else being equal, the addition of 200 MW of new wind in 2026 in the Revised Preferred Plan portfolio will only add to Tri-State's forecasted 597 MW-long capacity position in 2026. Procurements in this resource acquisition period (RAP) will support Tri-State in making incremental progress toward achievement of its 2030 and interim-year emissions reduction targets,[7] and will provide value to its Members through the addition of a low-cost renewable resource to the generation portfolio.

The Revised Preferred Plan also makes sense in light of certain Tri-State Members' notices that they intend to exit the cooperative and no longer purchase wholesale power from Tri-State. Until the relevant regulatory proceedings are concluded, it is possible that those exits (and the corresponding reductions in future capacity needs) may not occur or the timing of the exists may change; therefore, Tri-State must be cautious about pursuing new resources based on a load forecast that includes these Members.

Further, affirming the already announced retirement date for Craig 3 (December 31, 2029) is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-

[4] Colorado Public Utilities Commission, "Resource Adequacy Planning and Analysis: Investigation of Potential Best Practice RA Approaches to Account for Increasing Penetrations for Renewable Energy Resources, Climate Change, and Extreme Weather," November 30, 2022. Available: https://drive.google.com/file/d/10PkMMJFMaTmFwOOjWfVvSk-d5575d6HU/view?usp=share_link.

[5] Western Electricity Coordinating Council (WECC), "2022 Western Assessment of Resource Adequacy," November 1, 2022. Available: https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

[6] See Table 2, Loads and Resources, submitted in the 2022 ERP Annual Progress Report filed December 1, 2022 in Proceeding No. 20A-0528E.

[7] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

scale dispatchable technologies are in place to meet reliability and resource adequacy needs in 2030. The modeling conducted in Phase II has served to further highlight the importance of this unit remaining online through 2029 under current system conditions. Furthermore, maintaining continuity in the previously announced plans for the plant will provide needed certainty and assurance to the Craig community and the plant staff who are commendably working to ensure safe and reliable plant operations continuously through the period leading up to the plant's closure. In partnership with state and local leaders, Tri-State is launching a third-party facilitated stakeholder engagement process in 2023 to explore community assistance opportunities for the City of Craig and Moffat County, in preparation for plant closure. The previously announced plant retirement date allows sufficient time for that process to conclude, for Tri-State to evaluate the opportunities presented and make subsequent determinations related to community support in light of overall business conditions and Member expectations, and offer necessary lead-time for related planning efforts in advance of plant closure.

The EC3 portfolio results, by contrast, demonstrate the significant risks presented by aggressive pursuit of plant retirement without regard to operational, financial, and reliability realities. Notably, under the forced retirement window of the EC3 portfolio, the model delayed retirement of Craig 3 until the last possible date (January 1, 2027), while all other portfolios (none of which included a forced retirement window for Craig 3) selected to retain the December 31, 2029 announced retirement date for Craig 3. As a result of the EC3 portfolio's forced early retirement of Craig 3 (in addition to the constraint common to all portfolios that allows no new gas generation before 2030), the EC3 portfolio also diverged from the other portfolios in the amount of new resources forecasted to be brought online during the RAP. The EC3 portfolio results in the addition of an unrealistic and costly amount of new hybrid renewable-storage resources to meet reliability metrics. Further, the availability of such resources from experienced bidders at the size and locations needed, at a competitive cost, is uncertain and likely to come with significant curtailment costs and a need for additional third-party transmission capacity reservations. Retirement of dispatchable coal resources cannot be replaced solely with semi-dispatchable 4-hour batteries and keep reliability, affordability, and responsibility in balance; other dispatchable technologies—new or emerging—will be required.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II Portfolio to support, and carefully compared all the portfolios against the EC3 portfolio, which resulted in the lowest greenhouse gas (GHG) emissions in 2030. This included review of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that the Revised Preferred Plan portfolio in Phase II is the best course of action at this time. While the Reduced Load portfolio meets the 80% GHG emissions reduction target in 2030 with the updated baseline, given the significantly lower load forecast, the model does not select any renewable additions in the RAP for this portfolio, resulting in a system mix in 2030 with less renewable resources and higher average rates of emissions and water usage per MWh when compared to other portfolios. While this scenario achieves the lowest present value of revenue requirements (PVRR), the low PVRR is driven by a possible reduction in Member load that is currently uncertain as explained above. Importantly, the Revised Preferred Plan portfolio is forecasted to not only meet, but slightly exceed, Tri-State's Settlement Agreement targets for emissions reductions in 2025, 2026, 2027, and 2030.[8] On balance with reliability

[8] See Table 11.

and affordability expectations of Tri-State Members, the risks associated with the assumptions and outcomes of other portfolios that model slightly higher emissions reductions or lower SCoC and SCoM do not outweigh these factors.

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The Revised Preferred Plan is the least-cost portfolio, having the lowest PVRR, exclusive of SCoC and SCoM. While the EC3 portfolio achieves the greatest percentage reduction in Colorado GHG emissions in 2030 among the portfolios,[9] it does so at the highest PVRR of the portfolios modeled. Similarly, the EGHG portfolio achieves the lowest[10] system-wide CO_2 emissions in 2030, but has a higher annual revenue requirement from 2024-2026 than the Revised Preferred Plan portfolio. This is due, in part, to the EGHG portfolio selecting two resource additions during the 2025-26 period. Tri-State is not in a position to pursue significant changes to its generation mix at a time when it is capacity-long, as that would not only greatly compromise its ability to meet the core reliability needs of its Members, but would also likely cause significant undue financial burdens for Member-consumers.[11] Not only does the Revised Preferred Plan meet essential reliability and affordability goals, but it is also the responsible choice, delivering an 81% GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[12] which aligns with Colorado policy.[13]

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*
>
> Phase II of Tri-State's 2020 ERP included a request for proposals (RFP) under which only emissions-free resources, located in any region of the Tri-State system, would be advanced to modeling. The Phase II portfolio analysis included, for the first time, modeling of new, aggressive energy efficiency targets agreed upon in the Settlement Agreement in Phase I of the 2020 ERP.

[9] RL portfolio excluded from comparison, due to dissimilar load modeled.
[10] RL portfolio excluded from comparison, due to dissimilar load modeled.
[11] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[12] See Attachment D-1.
[13] C.R.S. 25-7-105 (1)(e)(VIII)(I)

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The Revised Preferred Plan portfolio meets these rigorous standards, while providing sufficient time for continued planning toward a just transition for communities impacted by planned future coal plant closures. Approval of the Revised Preferred Plan portfolio also assures the continued economic prosperity of its Member systems, operating in Colorado and outside of Colorado, by not aggressively adding new resource procurements that are unnecessary at this time and would apply additional financial pressure to Members serving predominately rural communities.

The Revised Preferred Plan portfolio will advance the environmental objectives of the State of Colorado because it is forecast to achieve (and exceed) the Colorado GHG reduction targets agreed on in the Settlement Agreement. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided best value employment metrics (BVEM) provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section below, consistent with the RFP and as discussed with stakeholders on April 26, 2022.

Tri-State intends to enter into a power purchase agreement (PPA) for the applicable generation facility, therefore the resource developer will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The Revised Preferred Plan is the most cost-effective portfolio modeled, having the lowest PVRR. [14] The Revised Preferred Plan portfolio also complies with all applicable rules and regulations in the state of Colorado, most importantly by achieving an 80% reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

[14] Excluding the Reduced Load portfolio.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The Revised Preferred Plan has the lowest PVRR among the portfolios modeled.[15] Tri-State considered the SCoC in its review of the portfolio modeling results as described above in the Portfolio Analysis Summary section of the Executive Summary above and in the Environmental Analysis and the Financial Analysis sections of the Comparative Analysis discussion below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase II resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II and, in some cases, future ERPs. These stakeholder meetings occurred between April 2022 and January 2023, covering the following topics:

1. April 26, 2022: Phase II Meeting 1 – EnCompass Benchmarking and Bid Evaluation Criteria[16]
2. April 27, 2022: DSM Meeting 1 – Program Updates, Idea-Sharing, Potential Study Status[17]
3. May 24, 2022: Phase II Meeting 2 – Modeling Assumptions and Potential Studies Status[18]
4. April 10, 2022: Developer Perspectives Meeting 1[19]
5. June 13, 2022: Developer Perspectives Meeting 2[20]
6. June 14, 2022: DSM Meeting 2 – Program Best Practices, Energy Efficiency Targets[21]
7. June 14, 2022: Phase II RFP Status Update Meeting
8. August 1, 2022: DSM Meeting 3 – DSM Plan Overview[22]
9. August 16, 2022: Discussion of Emissions Rates[23]
10. August 23, 2022: Discussion of Phase II Bid Detail for Commission Staff and UCA[24]
11. September 7, 2022: Discussion #1 on Organized Markets[25]
12. September 29, 2022: Phase II Meeting 3 – Modeling Assumptions[26]

[15] Excluding the Reduced Load Portfolio.
[16] Settlement Agreement sections 3.5.3., 3.5.4., 3.5.5., and 3.5.6.
[17] Settlement Agreement sections 3.6.3. and 3.11.5.
[18] Settlement Agreement sections 3.3.2., 3.3.4., 3.6.3., 3.6.9., 3.6.10., 3.7., 3.9., and 3.10.
[19] Settlement Agreement section 3.8.
[20] Settlement Agreement section 3.8.
[21] Settlement Agreement section 3.11.5. and 3.11.9.
[22] Settlement Agreement section 3.11.5. and 3.11.9.
[23] Settlement Agreement section 3.11.4.
[24] Settlement Agreement section 3.7.11.
[25] Settlement Agreement section 3.14.1.
[26] Settlement Agreement sections 3.6.9., 3.6.10., 3.7., and 3.10.

13. October 27, 2022: Phase II Meeting on EWE Results for Revised Preferred Plan Portfolio[27]
14. November 9, 2022: Discussion #2 on Organized Markets[28]
15. November 15, 2022: Phase II Meeting on EWE Results for Early GHG Reduction Portfolio[29]
16. December 6, 2022: Phase II Meeting on EWE Results for Reduced Load Portfolio[30]
17. January 5, 2023: Phase II Meeting on EWE Results for Craig 3 Early Retirement Portfolio[31]
18. January 19, 2023: Phase II Meeting on EWE Approach for Reduced Load Portfolio and eGRID Rates for GHG Analysis[32]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics.

Tri-State maintains ongoing collaboration with interested stakeholders related to its next ERP, and in discussion of organized market-related matters.

Bid Evaluation

Tri-State's Phase II Request for Proposals (RFP) was issued on May 18, 2022. Tri-State's bid evaluation process was undertaken over a 30-day period following the close of the RFP on September 16, 2022. The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, had incomplete or missing bid forms or narratives, or did not include a redlined Form PPA. When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information for those bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar Wind	Standalone Battery Dispatchable Renewables[33]

[27] Excerpt from March 2, 2022 Consensus Response (filed in Proceeding 20A-0528E): "If the extreme weather sensitivities for certain portfolios evaluate poorly under this analysis, Tri-State intends to work with the parties to determine whether and to what extent it would be appropriate to make revisions to those portfolios…If the extreme weather sensitivity for any of Tri-State's portfolios fails to satisfy the minimum reliability criteria that Tri-State sets in EnCompass, Tri-State will…notify the parties as soon as practicable…"
[28] Settlement Agreement section 3.14.1.
[29] See FN 27.
[30] See FN 27.
[31] See FN 27.
[32] See FN 27.
[33] E.g., biogas, geothermal.

Wind Repowering Solar + Battery Wind + Battery	

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing (see Table 2 below) and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status, if applicable. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. This was a verification step and not one used for evaluation.

Projects not receiving favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Land use considerations • Bids in Moffat or Montrose Counties
Counterparty Profile	• Bidder's prior experience with project development • Financial viability of the bidder • Markup of PPA terms and conditions
Project Feasibility	• Certainty of outside funding sources • Compliance with all applicable local, state and federal laws, rules and orders • Ability to source materials • Project retirement/decommissioning plan
Project Capability	• Forecasting capability

	• Renewal and purchase options at end of PPA • Impact on scheduling to load

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 274 individual eligible bid proposals by the bid deadline, as identified in the 30-Day Report filed in Proceeding No. 20A-0528E on October 17, 2022. On October 28, 2022, Tri-State provided, via email, to Commission Staff and UCA a highly confidential list of bids advanced to modeling.[34] A total of 11 bids were advanced to modeling following the bid evaluation described above. On October 31, 2022, Tri-State notified bidders whether their projects had advanced to modeling. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS	MWh BESS
Solar	5	630		
Wind	2	[redacted]		
Solar + Battery	3	430	170	680
Standalone Battery	1		200	442

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The best value employment metrics (BVEM) information provided by bidders whose bids were advanced to modeling is provided in Attachment F. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Settlement Agreement sections 3.9.7. and 3.12.9. require that bids in the West End of Montrose County be identified and clearly described; however, no bids in the West End of Montrose County were received. Of note, [redacted]

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted communities, in **Highly Confidential Attachment G**.[35] The file contains three maps—one of all bids, one of bids advanced to modeling, and one of the bids selected in portfolio modeling.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

[34] Upon completion of Phase II, Tri-State will file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and will post on its website certain required information from all bids and utility proposals, as required by Commission Rule 3605(h)(III).
[35] Settlement Agreement section 3.9.4.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios[36]
WI-028-1-WYO-WNE	Wind	200	1, 2, 5
PV-030-1-ECO	Solar	200	2
WI-071-1-WYO-WNE	Wind	116	4
PC-PV-030-1-ECO	Solar	200	5
PC-ST-030-1-ECO	Battery	50	5

Phase II Portfolio Analysis

Tri-State modeled five portfolios, as identified in Section 3.7 of the Settlement Agreement and Attachment B-3:[37]

1. Revised Preferred Plan (RevPP)
2. Early GHG Reduction Portfolio (EGHG)
3. Reduced Load Portfolio (RL)
4. Wind Back-Up Bid Portfolio (Wind BKUP)
5. Craig 3 Early Retirement Portfolio (EC3)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Additionally, two sensitivity analyses were performed on each portfolio's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The modeling assumptions and results of the sensitivity analyses are provided in Attachment E.

Each section that follows presents data and analytical results from portfolio modeling, formatted in the following order:

- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

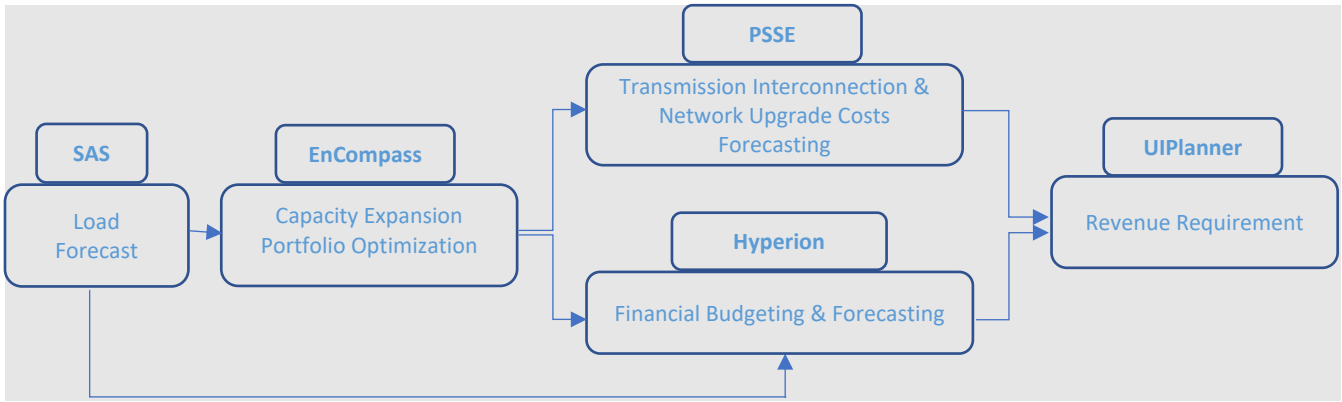
An overview of Tri-State's approach to each section of the portfolio analyses is provided below.

[36] All project bids selected in portfolio modeling had late 2025 or early 2026 commercial operation dates, resulting in the resources being "2026 resources" in alignment with section 3.4.4.1. of the Settlement Agreement, which states: "A "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction. Tri-State acknowledges that 2026 Bids include resources with commercial operations dates in December 2025."

[37] No unique assumptions for the Least-Cost Portfolio were identified in section 3.7.1.2. of the Settlement Agreement. Tri-State identified the need for clarification on the Least-Cost Portfolio expectations in the ERP stakeholder meeting held May 24, 2022; discussion during the meeting indicated there may not be a need for a Least-Cost Portfolio. Final modeling assumptions sent to ERP stakeholders on September 14, 2022 indicated "Unique assumptions for this portfolio are unknown at this time. The need for running this portfolio is uncertain if differing assumptions from the Revised Preferred Plan cannot be identified." A Least-Cost Portfolio was not run because no differing assumptions from the Revised Preferred Plan could be identified by Tri-State.

Error! Reference source not found. below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data through each system.

Figure 1: Modeling Software Tools



Use of the EnCompass modeling software for capacity expansion and portfolio optimization is new for Tri-State starting in 2022. In December 2022, Anchor Power (the EnCompass software vendor), provided modeling QA/QC for one portfolio run for Tri-State's Phase II. The QA/QC process was able to effectively reproduce the same modeling results, affirming the proper set-up and operation of EnCompass for Phase II.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B[38] and reflecting the Tri-State system topology, provided as Attachment B-4. Resource bids advanced to modeling as a result of the Request for Proposals (RFP) issued by Tri-State on May 18, 2022 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

Given that Phase I of the ERP extended longer than anticipated, concluding in early 2022, the RAP and Resource Planning Period (RPP) modeled for Phase II were both shortened by one year to 2022-2030 and 2022-2040, respectively.[39]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane. SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[40]

[38] See Attachments B, B-1, B-2, and B-3.
[39] At the time Phase II modeling was initiated, calendar year 2022 had not concluded, therefore all 2022 data included in this report is based on short-term forecasts rather than actuals.
[40] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

For each portfolio, Tri-State separately produced a verification workbook calculating forecasted carbon emissions reductions, provided in Attachment D.[41] Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Although 2020 eGRID rates were available, Tri-State used 2018 EPA eGRID rates for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. Although the grid is expected to become decarbonized over time, using 2018 eGRID rates rather than 2020 eGRID was a more conservative approach for modeling as there is ambiguity in emissions rates due to organized market formation and sourcing of Basin Western Interconnection contract. The carbon emission rate assumption for market purchases and sales and Basin Western Interconnection contract is 1,280 pounds per MWh through 2029 per 2018 eGRID rate (2020 eGRID rate is 1,144 pounds per MWh) and 450 pounds per MWh, per ACDP Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 1,240 pounds per MWh through 2029, which is the 2018 eGRID rate (2020 eGRID rate is 980 pounds per MWh) and 675 pounds per MWh, per APCD Workbook requirement starting in 2030. Tri-State reviewed this conservative approach to the market emission rates with stakeholders during a meeting held January 19, 2023.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[42] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades. Transmission facilities included in Tri-State's application to the CoPUC for certificates of public convenience and necessity" (CPCNs) for eastern Colorado transmission upgrades[43] were treated as "planned upgrades not yet in service" as of their anticipated installation dates for purposes of

[41] The emissions baseline in the verification workbooks differs slightly from Phase I of the ERP, reflecting the removal of load associated with Tri-State Members who have opted for Partial Requirements – MAX contracts. This adjustment aligns with Section 3.6.4. of the Settlement Agreement.

[42] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

[43] Filed February 18, 2022 in Proceeding No. 22A-0085E.

the analyses and, therefore, are not included in the values shown for "Expansion Plan CapEx + IDC: Transmission" but are included in the PVRR and annual revenue requirements.

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Any project bids received by Tri-State in response to the RFP that intend to interconnect to transmission facilities included in Tri-State's application for CPCNs, but with in-service dates prior to the proposed CPCN project in-service dates, were required to factor that into their bids.[44]

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).
    - Target (min) is 15%
- *Loss of Load Hours (LoLH)*[45]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)
        - 2022-2030 – annually cannot exceed 2.4 hours
        - 2031-2040 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[46]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.5 GWh annually

A detailed analysis of how load will be served from intermittent resources is also provided for portfolios that retired a dispatchable resource.

[44] Bidders can request in-service dates be accelerated under LGIP or LGIA procedures.
[45] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.
[46] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

1. Revised Preferred Plan

The Revised Preferred Plan portfolio and assumptions served as the base case portfolio for Phase II.[47] Assumptions unique to the Revised Preferred Plan portfolio are identified in Attachment B-3.

Portfolio 1 (Revised Preferred Plan) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 5: Expansion Plan (Revised Preferred Plan Portfolio)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	East Colorado	100	1	100
	Solar	West Colorado	100	4	400
	4 hr - Battery	West Colorado	100	1	100
	4 hr - Battery	West Colorado	25	1	25
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr - Battery	New Mexico	100	1	100
	4 hr - Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	8	800
	Wind	New Mexico	100	2	200
2034	4 hr - Battery	East Colorado	100	1	100
	Wind	East Colorado	100	1	100
2038	Solar	West Colorado	100	1	100
2039	4 hr - Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr - Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Revised Preferred Plan.

[47] Paragraph 78 of Decision No. R22-0191: "…Tri-State shall continue to present a base case portfolio consistent with its ERP, including base assumptions as updated by the Settlement Agreement."

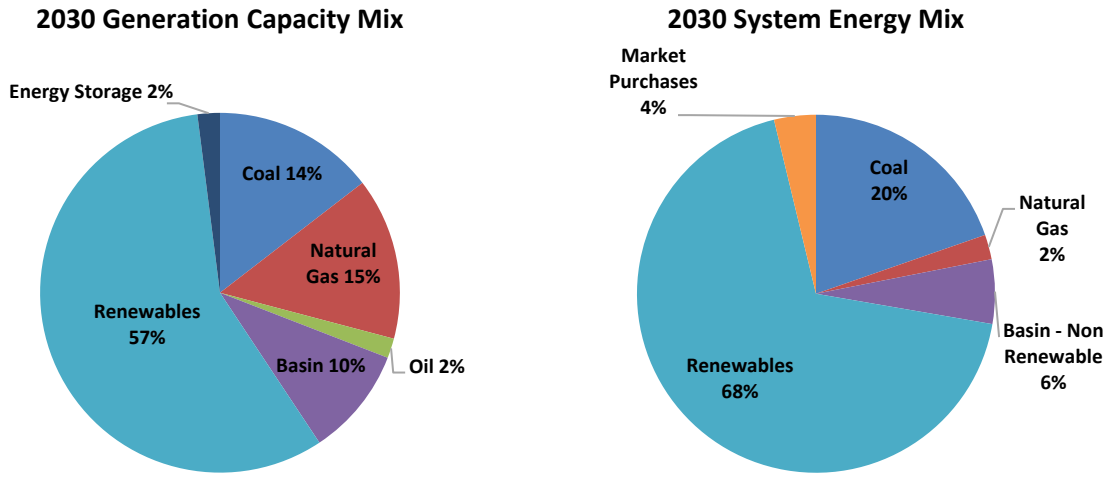
Unit retirements selected in the modeling are shown in the following table.[48]

Table 6: Modeled Retirements (Revised Preferred Plan Portfolio)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[49]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Resource Mix 2030 (Revised Preferred Plan Portfolio)[50, 51]



[48] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[49] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[50] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[51] System Energy Mix reflects sales to Members and non-Members.

Table 7: Projected Annual Capacity Factors for Thermal Resources (Revised Preferred Plan Portfolio)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	77%	50%	-	-	-	-	-
Craig 2	86%	84%	93%	32%	31%	7%	7%	-	-
Craig 3	73%	90%	79%	66%	63%	44%	31%	22%	-
LRS 2	51%	81%	70%	83%	70%	80%	79%	78%	63%
LRS 3	54%	70%	62%	47%	61%	51%	47%	39%	56%
SPV 3	72%	60%	56%	69%	71%	69%	62%	61%	54%
JM Shafer	16%	5%	5%	22%	19%	45%	38%	27%	12%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	1%	13%	8%	9%	8%	7%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193 MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 1 (Revised Preferred Plan) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 8: Environmental Impact - System Wide (Revised Preferred Plan Portfolio)[52]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[53]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,948	6,666	10,987	0.2547	429	5,396,587,708	30,624
2024[54]	12,080,369	6,028	9,842	0.2264	379	4,903,055,968	28,125
2025	11,391,567	5,617	9,142	0.2006	358	4,656,896,322	25,697
2026	10,800,773	5,607	8,388	0.1942	353	4,408,782,191	24,392
2027	10,170,496	5,042	7,774	0.1601	338	4,119,039,328	21,828
2028	9,216,480	4,537	6,947	0.1336	300	3,600,196,358	19,369
2029	8,372,919	4,107	6,171	0.1126	259	3,183,889,130	17,576
2030	5,998,477	3,599	5,041	0.0764	231	2,510,012,063	14,683
2031	5,804,891	3,646	5,167	0.0771	227	2,372,970,720	14,219
2032	4,844,978	3,137	4,359	0.0638	181	1,944,541,883	12,237
2033	3,236,139	2,163	2,772	0.0349	93	1,229,265,966	8,522
2034	3,250,950	2,205	2,872	0.0369	101	1,229,302,841	8,449

[52] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[53] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.

[54] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2035	3,420,743	2,270	2,932	0.0378	101	1,310,661,128	8,932
2036	3,179,535	2,257	3,028	0.0376	107	1,148,852,072	8,181
2037	2,783,449	2,235	3,246	0.0393	121	894,190,119	6,643
2038	2,617,181	2,137	3,083	0.0354	110	808,747,853	6,233
2039	2,719,064	2,215	3,200	0.0374	115	844,733,917	6,487
2040	2,976,408	2,385	3,487	0.0412	128	940,034,205	7,067
Total	**129,085,300**	**72,147**	**108,622**	**2.023**	**4,340**	**50,722,273,115**	**298,757**
Pounds/Gallons per MWh[55]	**829**	**0.46**	**0.70**	**0.00001**	**0.03**	**163**	**2.11**

Table 9: Social Cost of Carbon Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,805,608
2024	$1,051,155,113
2025	$1,029,231,387
2026	$1,013,023,741
2027	$988,068,664
2028	$927,233,404
2029	$872,130,962
2030	$646,742,348
2031	$648,111,840
2032	$560,035,451
2033	$387,189,697
2034	$402,524,463
2035	$438,221,341
2036	$421,347,919
2037	$381,487,319
2038	$370,913,081
2039	$398,395,931
2040	$450,782,578

[55] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Methane Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,466,457
2024	$71,863,757
2025	$68,813,076
2026	$68,416,552
2027	$63,962,740
2028	$59,264,169
2029	$56,122,398
2030	$48,901,831
2031	$49,537,142
2032	$44,563,390
2033	$32,422,468
2034	$33,565,315
2035	$37,031,220
2036	$35,376,889
2037	$29,949,676
2038	$29,279,882
2039	$31,743,858
2040	$36,003,537

Table 11: GHG Emissions Reduction Percentages, Targets and Forecast (Revised Preferred Plan Portfolio)

Year	Target[56]	Forecast
2025	26%	33%
2026	36%	43%
2027	46%	49%
2030	80%	81%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (Revised Preferred Plan) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

[56] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

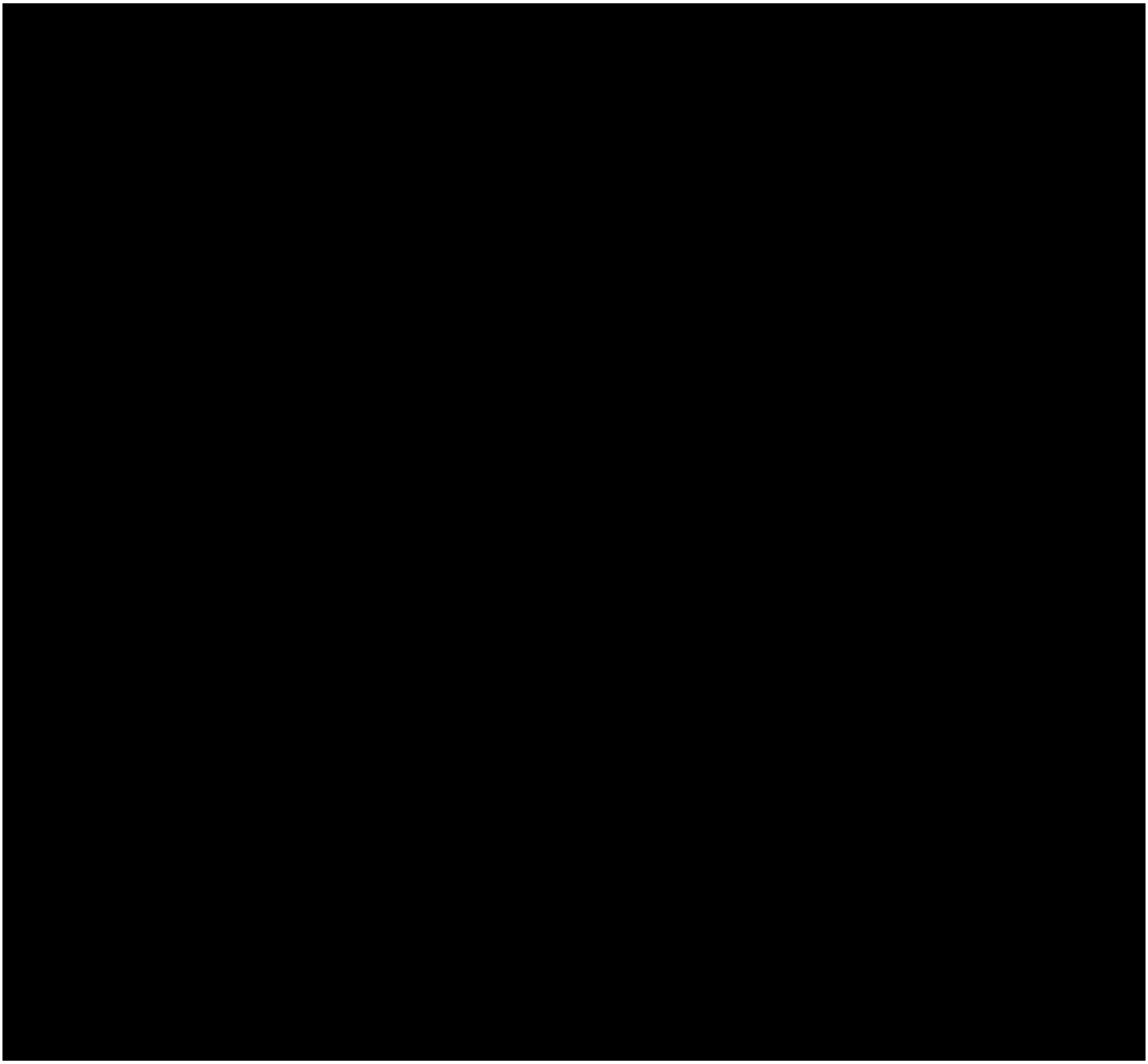
Table 12: Total Financial (Revised Preferred Plan Portfolio)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,465.6	$10,888.9	$771.0	$29,354.5	$30,125.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,481.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,761.8				

Table 13: Annual Financial (Nominal $) (Revised Preferred Plan Portfolio)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,171
2024	$1,137
2025	$1,114
2026	$1,195
2027	$1,264
2028	$1,345
2029	$1,398
2030	$1,479
2031	$1,569
2032	$1,578
2033	$1,604
2034	$1,624
2035	$1,638
2036	$1,648
2037	$1,652
2038	$1,671
2039	$1,707
2040	$1,725

Table 14: NPV by Resource (Revised Preferred Plan Portfolio)[57, 58]



[57] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[58] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[59] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[60] NPV using 2.5% discount rate
[61] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Revised Preferred Plan Portfolio dispatch, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3, we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Since solar resources do not typically have a production tax credit (PTC) penalty associated with curtailment, they are curtailed first. Total financial curtailment costs in 2030 exceed $4.5 million, as shown in Table 17 below, and reflect 90% of the curtailment costs over the RAP.

Table 15: Curtailed Intermittent Energy, Annual MWh (Revised Preferred Plan Portfolio)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	472	0	0	0	0	**472**
2026	0	1,086	0	0	0	0	**1,086**
2027	0	2,356	0	0	0	0	**2,356**
2028	75	2,914	6	0	3	0	**2,998**
2029	1,112	10,203	13	0	9	0	**11,338**
2030	31,183	38,850	10,065	91,325	3,108	0	**174,530**
RAP Total	**32,369**	**55,882**	**10,084**	**91,325**	**3,120**	**0**	**192,780**

Table 16: Seasonal Intermittent Resource Curtailments, Annual MWh (Revised Preferred Plan Portfolio)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	44	416	0	12
2026	284	756	0	46
2027	126	2,146	0	84
2028	286	2,692	19	0
2029	136	10,605	29	567
2030	17,435	130,461	8,916	17,717
RAP Total	**18,311**	**147,077**	**8,965**	**18,426**

The following table reflects PPA pricing, penalties, and taxes.

Table 17: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Revised Preferred Plan Portfolio)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$11,490
2026	$0	$26,572
2027	$0	$64,948
2028	$3,348	$75,517
2029	$46,512	$234,197
2030	$1,727,512	$2,933,914
RAP Total	**$1,777,373**	**$3,346,638**

Portfolio 1 (Revised Preferred Plan) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[62]

Table 18: Transmission Interconnection & Network Upgrade Expenses Real (2022) $ (Revised Preferred Plan Portfolio)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind (Build Transfer)		$2.21	
2029	100	Wind (Build Transfer)		$2.21	
2029	100	Wind (Build Transfer)		$2.21	
2030	100	Solar		$2.21	
2032	100	Wind		$7.30	
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	

[62] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2034	100	Wind		$3.11	
2039	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2030	25	Battery	$1.30	$2.21	
2030	100	Battery	$1.30	$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$3.11	
2030	100	Solar		$3.11	
2030	100	Solar		$3.11	
2031	100	Battery	$1.20	$1.22	
2038	100	Solar		$1.22	
2040	100	Battery	$1.40	$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$1.22	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$3.11	
2028	100	Wind (Build Transfer)		$3.11	$92.61
2028	100	Wind (Build Transfer)		$3.11	
2030	100	Wind (Build Transfer)		$3.11	
2032	100	Wind (Build Transfer)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (Build Transfer)		$2.21	$221.98
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 1 (Revised Preferred Plan) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 Revised Preferred Plan.

Table 19: Planning Reserve Margin, % Annual (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	39	36	33	33	30	29

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 Revised Preferred Plan.

Table 20: Loss of Load Probability, Hours (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 Revised Preferred Plan.

Table 21: Expected Unserved Energy, Annual MWh (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Revised Preferred Plan portfolio, dispatchable resource retirements selected by the model include the Craig units (on the previously announced dates) and Springerville 3 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources

including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) no later than 2030[63]. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

[63] Tri-State has provided more detailed information on its planned transition to organized markets in Proceeding No. 22R-0249E.

2. Early GHG Reduction Portfolio

Portfolio 2 (EGHG) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 22: Expansion Plan (EGHG)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[64]	Solar (PV-030-1-eco)	East Colorado	200	1	200
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2027	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Solar	West Colorado	100	2	200
	4 hr – Battery	West Colorado	100	1	100
	4 hr – Battery	West Colorado	25	1	25
	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	West Colorado	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr – Battery	New Mexico	100	1	100
	4 hr – Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	2	200
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	9	900
	Wind	New Mexico	100	1	100
2034	4 hr – Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr – Battery	East Colorado	100	2	200
	4 hr – Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EGHG portfolio.

[64] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

Unit retirements selected in the modeling are shown in the following table.[65]

Table 23: Modeled Retirements (EGHG)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[66]
Burlington 2	48[67]	Fuel Oil	1/1/2040[68]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 3: Projected Tri-State System Resource Mix 2030 (EGHG)[69, 70]

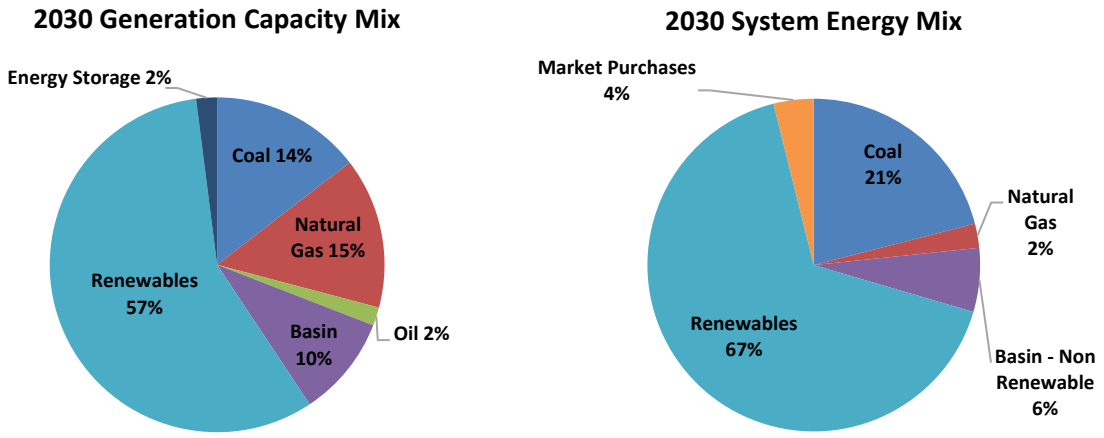


Table 24: Projected Annual Capacity Factors for Thermal Resources (EGHG)

Thermal Resource	2022	2023	2024[71]	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	29%	27%	-	-	-	-	-
Craig 2	86%	84%	16%	13%	15%	4%	2%	-	-
Craig 3	73%	90%	62%	57%	51%	33%	19%	2%	-
LRS 2	51%	81%	60%	81%	68%	79%	76%	71%	63%

[65] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.
[66] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[67] 48 MW is the summer capacity rating for Burlington; and 60 MW is the winter capacity rating for Burlington.
[68] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.
[69] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[70] System Energy Mix reflects sales to Members and non-Members.
[71] Redispatching of thermal resources occurs in 2024 to meet early GHG targets which results in higher gas capacity factors and lower coal capacity factors, for some units.

LRS 3	54%	70%	8%	44%	58%	45%	41%	33%	55%
SPV 3	72%	60%	75%	68%	70%	68%	60%	59%	53%
JM Shafer	16%	5%	47%	38%	24%	41%	35%	27%	11%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	1%	1%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	24%	16%	9%	10%	10%	10%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193 MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 2 (EGHG) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 25: Environmental Impact - System Wide (EGHG)[72]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[73]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,796	6,666	10,988	0.2547	429	5,397,427,780	30,623
2024[74]	10,279,291	4,645	7,683	0.1624	276	4,100,458,794	21,842
2025	10,723,153	5,255	8,472	0.1804	346	4,387,317,606	23,539
2026	10,052,408	5,177	7,717	0.1696	331	4,061,036,383	22,337
2027	9,372,178	4,584	7,015	0.1368	306	3,753,733,846	19,966
2028	8,364,046	4,043	6,139	0.1085	266	3,201,532,832	17,344
2029	7,124,089	3,352	4,940	0.0734	214	2,622,205,161	14,402
2030	5,980,029	3,586	5,025	0.0763	230	2,502,305,821	14,651
2031	5,793,816	3,645	5,153	0.0772	227	2,368,560,718	14,207
2032	4,659,379	3,025	4,184	0.0609	171	1,865,195,711	11,840
2033	3,090,588	2,074	2,622	0.0321	85	1,164,085,516	8,170
2034	3,226,343	2,191	2,849	0.0365	99	1,218,121,332	8,394
2035	3,398,074	2,256	2,911	0.0375	100	1,301,031,286	8,880
2036	3,175,388	2,256	3,026	0.0376	107	1,147,763,669	8,175
2037	2,776,086	2,229	3,238	0.0392	121	892,208,996	6,629
2038	2,679,619	2,175	3,152	0.0364	113	834,043,345	6,380
2039	2,714,332	2,217	3,202	0.0369	113	834,920,669	6,489
2040	3,072,119	2,450	3,593	0.0431	132	978,026,373	7,299

[72] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[73] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[74] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

Total	**122,701,666**	**68,117**	**102,090**	**1.822**	**4,076**	**47,850,489,178**	**280,663**
Pounds/Gallons per MWh[75]	**788**	**0.44**	**0.66**	**0.00001**	**0.03**	**154**	**1.99**

Table 26: Social Cost of Carbon Nominal Dollars – System Wide (EGHG)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,792,852
2024	$894,437,039
2025	$968,839,997
2026	$942,833,247
2027	$910,511,639
2028	$841,473,441
2029	$742,051,590
2030	$644,753,394
2031	$646,875,423
2032	$538,581,904
2033	$369,775,162
2034	$399,477,693
2035	$435,317,328
2036	$420,798,368
2037	$380,478,089
2038	$379,761,900
2039	$397,702,562
2040	$465,278,167

[75] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 27: Social Cost of Methane Nominal Dollars – System Wide (EGHG)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,463,270
2024	$55,808,422
2025	$63,036,195
2026	$62,653,055
2027	$58,508,215
2028	$53,066,829
2029	$45,988,403
2030	$48,797,547
2031	$49,493,536
2032	$43,119,191
2033	$31,084,266
2034	$33,344,708
2035	$36,816,129
2036	$35,352,502
2037	$29,886,926
2038	$29,973,889
2039	$31,753,639
2040	$37,186,436

Table 28: GHG Emissions Reduction Percentages, Targets and Forecast (EGHG)

Year[76]	Target[77]	Early GHG Targets[78]	Forecast
2024	N/A	26%	26%
2025	26%	36%	41%
2026	36%	46%	52%
2027	46%	N/A	61%
2029	N/A	80%	85%

See Appendix D for detailed GHG emissions calculations for the portfolio through 2030. For this portfolio, Tri-State completed an additional annual emissions calculation (for 2024), given the portfolio parameters—to advance the emission reduction targets by one year, to achieve at least a 26% reduction in 2024.

Portfolio 2 (EGHG) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

[76] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[77] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[78] GHG targets were modeled as accelerated for this portfolio from the years 2025, 2026, 2027 and 2030 to the years 2024, 2025, 2026, and 2029, per the Settlement Agreement.

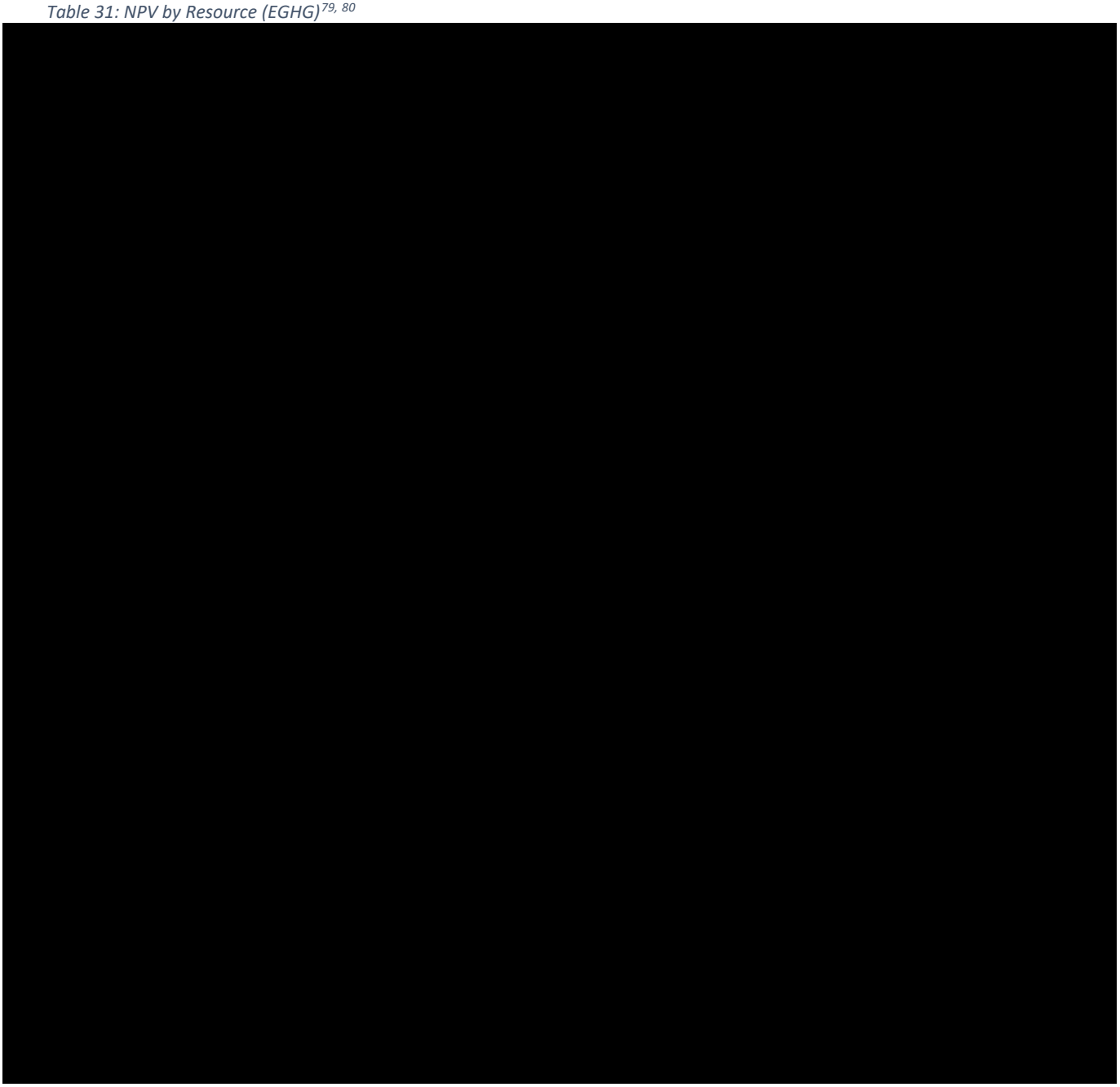
Table 29: Total Financial (EGHG)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,576.8	$10,358.1	$726.1	$28,934.9	$29,661.0
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,681.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,757.0				

Table 30: Annual Financial (Nominal $) (EGHG)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,171
2024	$1,194
2025	$1,172
2026	$1,200
2027	$1,219
2028	$1,379
2029	$1,373
2030	$1,482
2031	$1,597
2032	$1,577
2033	$1,617
2034	$1,626
2035	$1,640
2036	$1,652
2037	$1,654
2038	$1,671
2039	$1,702
2040	$1,733

Table 31: NPV by Resource (EGHG)[79, 80]



[79] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[80] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[81] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[82] NPV using 2.5% discount rate
[83] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Early GHG Portfolio dispatch, through 2028. In 2029, with the addition of 500 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 (at the end of 2029) we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs for wind and solar resources in 2030 exceed $4 million, as shown in Table 34 below, and reflect 59% of the curtailment costs over the RAP.

Table 32: Curtailed Intermittent Energy, Annual MWh (EGHG)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	941	0	0	0	76	**1,017**
2026	0	5,455	0	0	0	2,988	**8,443**
2027	0	6,024	0	0	0	2,916	**8,941**
2028	137	11,468	3,122	0	1,050	4,460	**20,236**
2029	4,453	25,000	7,103	20,842	2,286	24,359	**84,043**
2030	16,217	38,903	9,433	56,561	3,295	49,427	**173,838**
RAP Total	**20,807**	**87,791**	**19,658**	**77,404**	**6,631**	**84,226**	**296,517**

Table 33: Seasonal Renewable Curtailments, Annual MWh (EGHG)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	126	742	42	107
2026	1,426	5,949	348	719
2027	275	7,591	692	382
2028	1,224	18,514	154	345
2029	1,465	75,944	2,034	4,600
2030	15,505	132,550	8,594	17,189
RAP Total	**20,020**	**241,290**	**11,865**	**23,342**

The following table reflects PPA pricing, penalties, and taxes.

Table 34: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EGHG)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$27,779
2026	$0	$199,281
2027	$0	$213,979
2028	$148,076	$360,001
2029	$503,076	$1,595,780
2030	$1,100,907	$3,221,973
RAP Total	**$1,752,059**	**$5,618,793**

Portfolio 2 (EGHG) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[84]

Table 35: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EGHG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	200	Solar		$7.30	
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2032	100	Wind		$7.30	
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	

[84] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2040	100	Battery	$1.30	$2.21	
2040	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2029	100	Solar		$2.21	
2029	100	Solar		$2.21	
2029	100	Battery	$1.30	$2.21	
2029	25	Battery	$1.30	$2.21	
2030	193	Gas	$1.40	$3.11	
2030	100	Solar		$1.22	
2031	100	Battery	$1.20	$1.22	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Battery	$1.40	$3.11	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$3.11	
2028	100	Wind (BT)		$3.11	$92.61
2028	100	Wind (BT)		$3.11	
2030	100	Wind (BT)		$3.11	
2032	100	Wind (BT)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 2 (EGHG) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington Unit 2 are also provided. The model did not choose to retire Burlington Unit 1 during the resource planning period.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 EGHG.

Table 36: Planning Reserve Margin, % Annual (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	40	37	35	36	38	29

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 EGHG.

Table 37: Loss of Load Probability, Hours (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 EGHG.

Table 38: Expected Unserved Energy, Annual MWh (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2029, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2029 and 2030: 125 MW of standalone batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 300 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Early GHG portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates) and Springerville 3 and Burlington Unit 2 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new semi-dispatchable and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of Springerville 3 and Burlington Unit 2 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized

market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

Burlington Units Analysis

While allowed to retire beginning January 1, 2025, Burlington Unit 1 is not retired during the modeling period, while the model selected a retirement date of January 1, 2040, for Burlington Unit 2. Both Burlington units continue to be available for emergency and contingency power supply, as well as base power supply, when financially feasible throughout 2023-2039 and Burlington Unit 1 remains available through the entire resource planning period.

3. Reduced Load Portfolio

Portfolio 3 (RL) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 39: Expansion Plan (RL)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2030	Gas Combustion Turbine	West Colorado	193	1	193
2031	4hr – Battery	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
2032	Solar	West Colorado	100	1	100
	4hr -Battery	West Colorado	100	1	100
	Wind (Build Transfer)	New Mexico	100	2	200
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	5	500
	Wind	New Mexico	100	1	100
	Wind	Wyoming/Nebraska	100	4	400
2040	Solar	West Colorado	100	4	400

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- Applicable Colorado energy efficiency targets reflected in base assumptions, but reduced to reflect a reduction in Tri-State Colorado Utility Member load assumed for this portfolio;[85] and
- No additional EE was selected in the expansion plan of the Reduced Load portfolio.

Unit retirements selected in the modeling are shown in the following table.[86]

Table 40: Modeled Retirements (RL)

Location	MW	Technology	Date
Burlington 1	48	Fuel Oil	1/1/2025[87]
Burlington 2	48	Fuel Oil	1/1/2025[88]
Craig 3	448	Coal	12/31/2029

[85] Section 3.11.9. of the Settlement Agreement set energy efficiency targets as a percentage of Tri-State Colorado Utility Member system load.

[86] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[87] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 1 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

[88] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

Springerville 3	419	Coal	1/1/2040[89]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Resource Mix 2030 (RL)[90, 91]

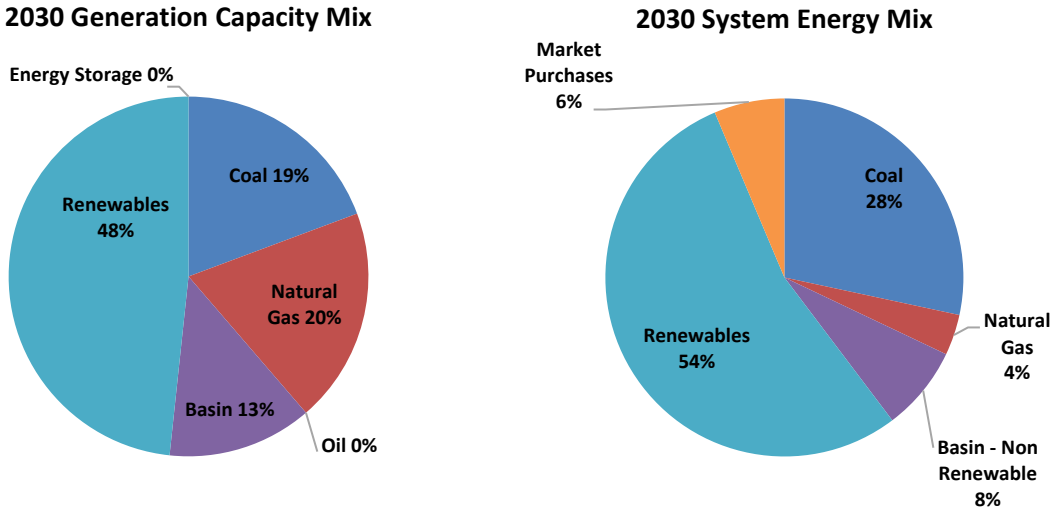


Table 41: Projected Annual Capacity Factors for Thermal Resources (RL)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	66%	40%	0%	0%	0%	0%	0%
Craig 2	86%	84%	93%	22%	29%	22%	5%	0%	0%
Craig 3	73%	90%	65%	59%	54%	41%	32%	19%	0%
LRS 2	51%	81%	67%	82%	69%	81%	80%	80%	69%
LRS 3	54%	70%	57%	45%	60%	50%	43%	39%	62%
SPV3	72%	60%	55%	68%	71%	69%	62%	61%	58%
JM Shafer	16%	5%	1%	3%	6%	7%	12%	19%	11%
Rifle	2%	0%	0%	0%	0%	0%	0%	0%	0%
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	0%	9%	6%	7%	7%	7%	6%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193MW CT West Colorado	0%	0%	0%	0%	0%	0%	0%	0%	14%

[89] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[90] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[91] System Energy Mix reflects sales to Members and non-Members.

Portfolio 3 (RL) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 42: Environmental Impact - System Wide (RL)[92]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[93]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,237,222	6,666	10,987	0.2546	429	5,395,640,098	30,622
2024[94]	11,087,650	5,496	8,824	0.1979	340	4,435,807,793	25,674
2025	10,471,242	5,327	8,371	0.1868	320	4,245,183,485	24,111
2026	10,059,770	5,293	7,726	0.1773	323	4,070,649,444	23,008
2027	9,512,743	4,900	7,207	0.1555	300	3,807,554,346	21,420
2028	8,678,490	4,439	6,592	0.1341	270	3,380,086,130	19,011
2029	8,080,886	4,006	5,940	0.1080	248	3,074,530,232	17,182
2030	6,569,383	3,892	5,507	0.0837	256	2,732,011,124	15,689
2031	5,978,207	3,703	5,293	0.0783	230	2,444,079,811	14,508
2032	5,228,723	3,358	4,756	0.0718	202	2,125,729,386	13,077
2033	3,853,089	2,491	3,351	0.0468	125	1,529,484,312	9,927
2034	3,805,926	2,509	3,397	0.0474	129	1,494,548,076	9,747
2035	4,578,489	2,958	4,080	0.0602	167	1,844,389,990	11,556
2036	4,309,312	2,905	4,123	0.0592	168	1,677,848,014	10,723
2037	3,849,101	2,901	4,333	0.0608	190	1,383,322,184	9,164
2038	3,847,021	2,896	4,333	0.0603	189	1,380,118,535	9,145
2039	3,575,346	2,751	4,065	0.0553	171	1,246,981,270	8,545
2040	4,016,764	3,026	4,541	0.0625	195	1,426,369,693	9,549
Total	**133,723,296**	**75,810**	**113,609**	**2.123**	**4,662**	**52,914,847,262**	**312,150**
Pounds/Gallons per MWh[95]	**1,094**	**0.62**	**0.93**	**0.00002**	**0.04**	**217**	**2.82**

[92] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[93] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[94] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 43: Social Cost of Carbon Nominal Dollars – System Wide (RL)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,828,536
2024	$964,775,149
2025	$946,079,762
2026	$943,523,752
2027	$924,167,590
2028	$873,108,319
2029	$841,712,469
2030	$708,296,238
2031	$667,462,468
2032	$604,392,898
2033	$461,005,102
2034	$471,240,142
2035	$586,536,829
2036	$571,064,587
2037	$527,540,797
2038	$545,208,802
2039	$523,857,975
2040	$608,346,446

Table 44: Social Cost of Methane Nominal Dollars – System Wide (RL)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,460,847
2024	$65,600,846
2025	$64,566,479
2026	$64,535,270
2027	$62,769,154
2028	$58,168,873
2029	$54,862,573
2030	$52,255,251
2031	$50,542,323
2032	$47,623,283
2033	$37,768,152
2034	$38,721,686
2035	$47,907,089
2036	$46,368,896
2037	$41,311,304
2038	$42,962,556
2039	$41,811,227
2040	$48,646,347

Table 45: GHG Emissions Reduction Percentages, Targets and Forecast (RL)

Year[96]	Target[97]	Forecast
2025	26%	58%
2026	36%	64%
2027	46%	67%
2030	80%	83%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (RL) – Financial Analysis[98]

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 46: Total Financial (RL)

$, Millions	Portfolio PVRR (2022 WACC 4.18%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$15,719.4	$11,349.6	$814.7	$27,069.0	$27,883.7
Expansion Plan CapEx + IDC: Generation (Nominal $)	$603.3				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$544.2				

Table 47: Annual Financial (Nominal $) (RL)

Year	Total Annual Revenue Requirement ($, Millions)
2022	$1,176
2023	$1,171
2024	$991
2025	$904
2026	$1,000
2027	$1,066
2028	$1,133

[96] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[97] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[98] Of note, no contract termination payment (CTP) or other items specific to potential Member withdrawal were included in the analysis, as those details were not available at the time of modeling.

2029	$1,185
2030	$1,207
2031	$1,260
2032	$1,324
2033	$1,352
2034	$1,345
2035	$1,342
2036	$1,353
2037	$1,366
2038	$1,375
2039	$1,409
2040	$1,410

Table 48: NPV by Resource (RL)[99, 100]

[99] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[100] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[101] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[102] NPV using 2.5% discount rate
[103] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Reduced Load Portfolio dispatch during the RAP. The majority of curtailments during the RAP are during spring from existing solar.

Table 49: Curtailed Intermittent Energy, Annual MWh (RL)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	48	1,125	0	0	0	0	1,174
2026	34	1,241	0	0	0	0	1,275
2027	0	973	0	0	0	0	973
2028	0	1,359	0	0	0	0	1,359
2029	0	2,197	0	0	0	0	2,197
2030	0	627	0	0	0	0	627
RAP Total	**82**	**7,523**	0	0	0	0	**7,605**

Table 50: Seasonal Renewable Curtailments, Annual MWh (RL)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	121	460	186	406
2026	479	586	30	180
2027	86	843	0	44
2028	180	1,180	0	0
2029	32	2,157	0	8
2030	0	436	6	184
RAP Total	**898**	**5,662**	**223**	**822**

The following table reflects PPA pricing, penalties, and taxes.

Table 51: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (RL)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0

2025	$2,603	$25,576
2026	$1,671	$30,680
2027	$0	$23,600
2028	$0	$34,157
2029	$0	$66,264
2030	$0	$14,903
RAP Total	**$4,274**	**$195,181**

Portfolio 3 (RL) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[104]

Table 52: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (RL)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2032	100	Wind		$2.11	
2032	100	Wind		$2.11	
2033	100	Wind		$7.30	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2032	100	Solar		$2.11	
2032	100	Battery	$1.30	$2.21	
2040	100	Solar		$2.21	
2040	100	Solar		$2.21	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
Wyoming (WYO) Transmission Area					
2031	100	Wind (BT)		$3.11	$92.61
2033	100	Wind		$3.11	

[104] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	$26.00
2033	100	Wind		$3.11	
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2032	100	Wind (BT)		$2.21	
2033	100	Wind		$2.21	

Portfolio 3 (RL) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington units are also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 RL.

Table 53: Planning Reserve Margin, % Annual (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	56	80	73	70	69	61	47

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 RL.

Table 54: Loss of Load Probability, Hours (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 RL.

Table 55: Expected Unserved Energy, Annual MWh (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, and 100 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Reduced Load portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates), Burlington Units 1 & 2 in 2025, and Springerville 3 in 2040. Throughout the planning period, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During the 2025-2029 period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2031 and 2032. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

Burlington Units Analysis

In this analysis, the Burlington units were allowed to retire starting in 2025, and the model selected the retirement of both units on January 1, 2025 given the modeled load reduction starting in mid-2024. Because PRMs are relatively high starting in 2025 and continuing throughout the RAP, and no LoLH or EUE is observed during the planning period, early retirement of the Burlington units in this scenario does not impact reliability, particularly given that these units are primarily operated as contingency reserves. However, the Burlington resources provide fuel diversity to mitigate the impact of extreme operating conditions, and the challenges of fuel supply issues are not evaluated through the extreme weather event sensitivity modeling. The contingency reserve benefits, along with potential market value of the Burlington units following entrance into an RTO, indicate further evaluation of the Burlington resources is necessary to assess the true ongoing viability of the resources.

4. Wind Back-up Bid Portfolio

Portfolio 4 (Wind BKUP) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below. This portfolio was modeled in recognition of the potential risk that Tri-State may not reach acceptable commercial terms will the bidder(s) included in the portfolio approved by the Commission. The bid selected by the model in this backup portfolio would be brought into PPA negotiations in the event negotiations with a primary bidder fail.

Table 56: Expansion Plan (Wind BKUP)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[105]	Wind (WI-071-1-wyo-wne)	Wyoming/Nebraska	116	1	116
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	East Colorado	100	1	100
	Solar	West Colorado	100	4	400
	4 hr - Battery	West Colorado	100	1	100
	4 hr - Battery	West Colorado	25	1	25
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr - Battery	New Mexico	100	1	100
	4 hr - Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	8	800
	Wind	New Mexico	100	2	200
2034	4 hr - Battery	East Colorado	100	1	100
	Wind	East Colorado	100	1	100
2038	Solar	West Colorado	100	1	100
2039	4 hr - Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr - Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Wind BKUP portfolio.

[105] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

Unit retirements selected in the modeling are shown in the following table.[106]

Table 57: Modeled Retirements (Wind BKUP)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[107]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Wind BKUP)[108, 109]

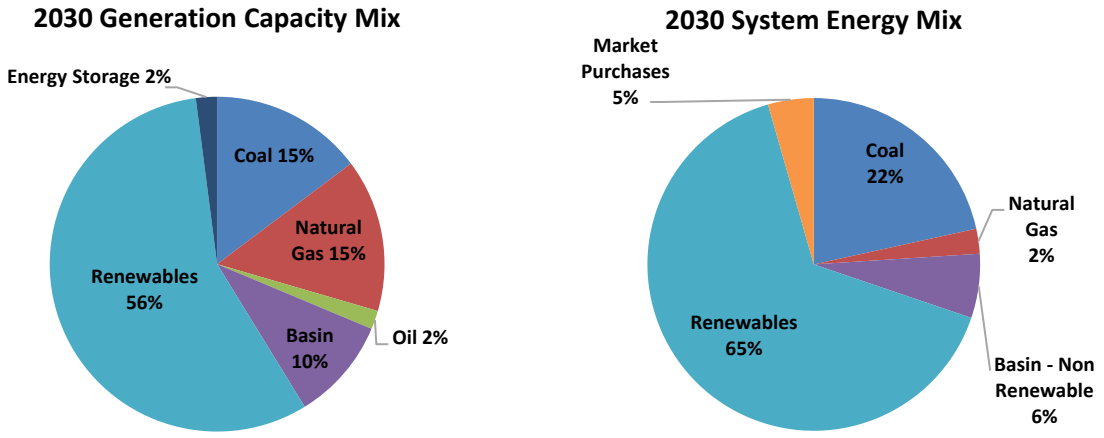


Table 58: Projected Annual Capacity Factors for Thermal Resources (Wind BKUP)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	77%	47%	-	-	-	-	-
Craig 2	86%	84%	93%	31%	25%	4%	4%	-	-
Craig 3	73%	90%	79%	66%	63%	43%	29%	19%	-
LRS 2	51%	81%	70%	83%	70%	79%	79%	79%	65%
LRS 3	54%	70%	62%	47%	61%	49%	45%	37%	56%
SPV3	72%	60%	56%	69%	71%	69%	62%	61%	55%
JM Shafer	16%	5%	5%	23%	24%	47%	44%	33%	11%

[106] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.
[107] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[108] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[109] System Energy Mix reflects sales to Members and non-Members.

Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	1%	13%	9%	11%	10%	8%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 4 (Wind BKUP) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 59: Environmental Impact - System Wide (Wind BKUP)[110]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[111]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,948	6,666	10,987	0.2547	429	5,396,587,708	30,624
2024[112]	12,080,369	6,028	9,842	0.2264	379	4,903,055,968	28,125
2025	11,390,382	5,633	9,138	0.2014	359	4,659,951,422	25,685
2026	10,820,886	5,609	8,431	0.1939	357	4,421,916,594	24,292
2027	10,179,424	5,003	7,752	0.1573	336	4,083,536,507	21,605
2028	9,224,221	4,478	6,930	0.1298	302	3,594,374,130	19,119
2029	8,378,388	4,038	6,131	0.1080	260	3,177,557,763	17,327
2030	6,121,079	3,665	5,147	0.0779	235	2,560,364,406	14,940
2031	5,857,912	3,679	5,222	0.0774	227	2,384,942,758	14,347
2032	5,023,844	3,261	4,547	0.0668	191	2,014,872,575	12,664
2033	3,347,732	2,229	2,883	0.0370	99	1,279,455,811	8,787
2034	3,345,868	2,265	2,968	0.0386	106	1,270,854,847	8,678
2035	3,535,464	2,343	3,049	0.0400	108	1,360,768,954	9,203
2036	3,258,394	2,309	3,110	0.0390	111	1,181,698,711	8,365
2037	2,889,591	2,302	3,359	0.0413	127	939,510,395	6,894
2038	2,721,615	2,205	3,194	0.0373	116	853,187,711	6,488
2039	2,810,342	2,276	3,297	0.0391	120	882,408,611	6,709
2040	3,094,990	2,463	3,612	0.0434	135	990,367,615	7,348
Total	**130,301,381**	**72,743**	**109,784**	**2.032**	**4,405**	**51,175,925,825**	**300,692**
Pounds/Gallons per MWh[113]	**837**	**0.47**	**0.71**	**0.00001**	**0.03**	**164**	**2.13**

[110] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[111] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[112] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[113] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 60: Social Cost of Carbon Nominal Dollars – System Wide (Wind BKUP)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,805,608
2024	$1,051,155,113
2025	$1,029,124,333
2026	$1,014,910,237
2027	$988,936,015
2028	$928,012,132
2029	$872,700,561
2030	$659,961,101
2031	$654,031,611
2032	$580,710,726
2033	$400,541,322
2034	$414,276,946
2035	$452,917,981
2036	$431,798,180
2037	$396,034,584
2038	$385,713,731
2039	$411,769,874
2040	$468,741,984

Table 61: Social Cost of Methane Nominal Dollars – System Wide (Wind BKUP)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,466,457
2024	$71,863,757
2025	$68,782,366
2026	$68,134,628
2027	$63,310,329
2028	$58,499,634
2029	$55,326,786
2030	$49,759,438
2031	$49,981,293
2032	$46,120,928
2033	$33,432,041
2034	$34,472,523
2035	$38,151,526
2036	$36,171,194
2037	$31,078,571
2038	$30,480,425
2039	$32,827,839
2040	$37,433,762

Table 62: GHG Emissions Reduction Percentages, Targets and Forecast (Wind BKUP)

Year[114]	Target[115]	Forecast
2025	26%	33%
2026	36%	41%
2027	46%	48%
2030	80%	81%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (Wind BKUP) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 63: Total Financial (Wind BKUP)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,501.8	$10,998.7	$777.0	$29,500.5	$30,277.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,481.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,754.8				

Table 64: Annual Financial (Nominal $) (Wind BKUP)

Year	Total Annual Revenue Requirement ($, Millions)
2022	$ 1,176
2023	$ 1,171
2024	$ 1,137
2025	$ 1,114
2026	$ 1,204
2027	$ 1,276
2028	$ 1,352
2029	$ 1,406

[114] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[115] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

2030	$	1,482
2031	$	1,573
2032	$	1,579
2033	$	1,602
2034	$	1,622
2035	$	1,637
2036	$	1,650
2037	$	1,653
2038	$	1,672
2039	$	1,711
2040	$	1,727

Table 65: NPV by Resource (Wind BKUP)[116, 117]

[116] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[117] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[118] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[119] NPV using 2.5% discount rate
[120] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Wind BKUP portfolio, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs in 2030 exceed $3.8 million, as shown in Table 68 below, and reflect 90% of the curtailment costs over the RAP.

Table 66: Curtailed Intermittent Energy, Annual MWh (Wind BKUP)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	218	0	0	0	0	218
2026	3	1,212	0	0	0	0	1,215
2027	0	2,605	0	0	0	0	2,605
2028	0	2,257	0	0	0	0	2,257
2029	1,121	8,510	0	0	0	0	9,631
2030	24,754	32,848	4,885	83,797	663	0	146,948
RAP Total	**25,878**	**47,651**	**4885**	**83,797**	**663**	**0**	**162,876**

Table 67: Seasonal Renewable Curtailments, Annual MWh (Wind BKUP)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	183	3	32
2026	197	973	0	45
2027	81	2,385	49	91
2028	186	2,071	0	0
2029	147	9,117	110	257
2030	10,331	115,961	8,085	12,571
RAP Total	**10,943**	**130,689**	**8,247**	**12,997**

The following table reflects PPA pricing, penalties, and taxes.

Table 68: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Wind BKUP)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$5,769
2026	$142	$34,621
2027	$0	$76,523
2028	$0	$56,558
2029	$46,309	$205,880
2030	$1,196,647	$2,639,204
RAP Total	**$1,243,097**	**$3,018,556**

Portfolio 4 (Wind BKUP) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[121]

Table 69: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (Wind BKUP)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind (BT)		$2.21	

[121] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2030	100	Solar		$2.21	
2032	100	Wind		$2.21	
2032	100	Wind		$2.21	
2033	100	Wind		$7.30	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2034	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2039	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Battery	$1.30	$2.21	
2030	25	Battery	$1.20	$1.22	
2031	100	Battery	$1.40	$3.11	
2038	100	Solar		$3.11	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Battery	$1.40	$3.11	
Wyoming (WYO) Transmission Area					
2025	116	Wind		$1.22	
2028	100	Wind (BT)		$3.11	$92.61
2028	100	Wind (BT)		$3.11	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2030	100	Wind (BT)		$3.11	
2032	100	Wind (BT)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 4 (Wind BKUP) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 Wind BKUP.

Table 70: Planning Reserve Margin, % Annual (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	40	35	32	33	29	28

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 Wind BKUP.

Table 71: Loss of Load Probability, Hours (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	1

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 Wind BKUP.

Table 72: Expected Unserved Energy, Annual MWh (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	6

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the minimum PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

As described in Attachment B-3, unit retirements were not altered from the Revised Preferred Plan portfolio for the Wind BKUP portfolio. See Dispatchable Retirements discussion above for the Revised Preferred Plan portfolio.

5. Craig 3 Early Retirement Portfolio

Portfolio 5 (EC3) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 73: Expansion Plan (EC3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[122]	Solar (PC-PV-030-1-eco) / Battery (PC-ST-030-1-eco)	East Colorado	200	1	200
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2027	Solar/Battery Hybrid*	West Colorado	100	6	600
	4 hr - Battery	East Colorado	100	3	300
	4 hr - Battery	East Colorado	25	2	50
2028	Solar/Battery Hybrid*	West Colorado	100	2	200
	Wind (Build Transfer)	East Colorado	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Solar/Battery Hybrid*	West Colorado	100	5	500
	Wind (Build Transfer)	East Colorado	100	3	300
	Wind/Battery Hybrid*	East Colorado	100	1	100
	Wind/Battery Hybrid*	Wyoming/Nebraska	100	1	100
2030	Wind (Build Transfer)	East Colorado	100	1	100
2031	4 hr - Battery	West Colorado	100	2	200
2032	Wind	New Mexico	100	3	300
2033	Wind	East Colorado	100	9	900
	Wind	Wyoming/Nebraska	100	1	100

*Generic hybrids include 25 MW/100 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EC3 portfolio.

Unit retirements selected in the modeling are shown in the following table.[123]

[122] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

[123] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

Table 74: Modeled Retirements (EC3)

Location	MW	Technology	Date
Craig 3	448	Coal	1/1/2027
Springerville 3	419	Coal	1/1/2037[124]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Resource Mix 2030 (EC3)[125, 126]

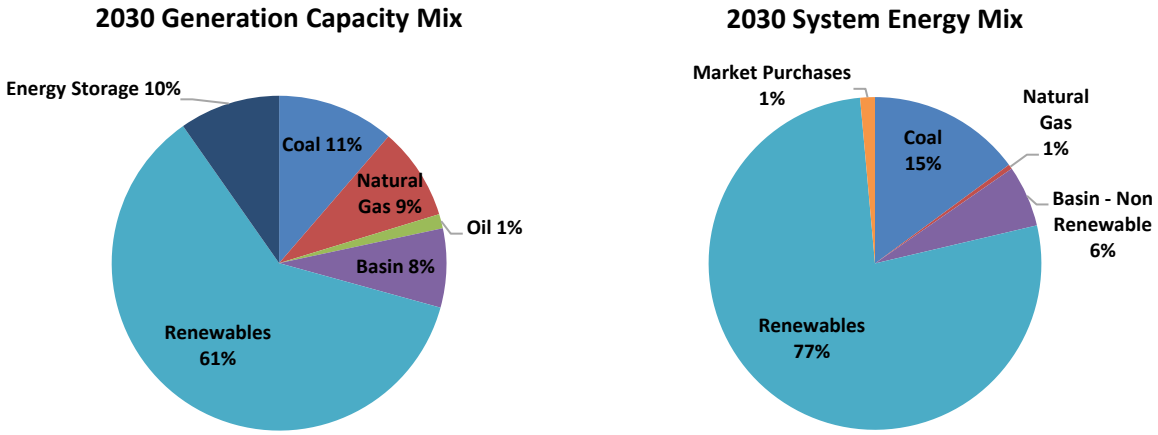


Table 75: Projected Annual Capacity Factors for Thermal Resources (EC3)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	78%	43%	-	-	-	-	-
Craig 2	86%	84%	93%	37%	36%	77%	60%	-	-
Craig 3	73%	90%	77%	66%	60%	-	-	-	-
LRS 2	51%	81%	71%	83%	70%	84%	75%	60%	48%
LRS 3	54%	70%	63%	48%	67%	79%	67%	49%	36%
SPV 3	72%	60%	56%	69%	70%	66%	55%	48%	43%
JM Shafer	16%	5%	4%	21%	10%	24%	14%	6%	4%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	1%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	1%	0%	0%	0%
Pyramid	8%	10%	1%	13%	6%	5%	3%	1%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%

[124] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[125] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[126] System Energy Mix reflects sales to Members and non-Members.

Portfolio 5 (EC3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 76: Environmental Impact - System Wide (EC3)[127]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[128]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,238,415	6,668	10,992	0.2549	429	5,398,945,303	30,634
2024[129]	12,078,302	6,016	9,828	0.2243	380	4,896,272,045	28,072
2025	11,387,401	5,636	9,088	0.2009	359	4,655,093,155	25,717
2026	10,720,411	5,650	8,326	0.1930	354	4,350,217,713	24,493
2027	9,404,897	4,519	6,539	0.1073	334	3,671,346,512	20,078
2028	8,013,305	3,988	5,683	0.0918	277	3,008,538,322	17,088
2029	6,239,451	3,241	4,447	0.0694	199	2,226,785,161	13,284
2030	4,402,419	2,762	3,710	0.0550	154	1,821,237,967	11,301
2031	4,230,638	2,738	3,743	0.0548	152	1,707,278,207	10,816
2032	3,541,268	2,356	3,149	0.0433	117	1,380,520,926	9,427
2033	2,371,859	1,629	1,961	0.0209	50	859,245,830	6,673
2034	2,434,623	1,704	2,109	0.0235	60	877,015,375	6,702
2035	2,634,155	1,799	2,217	0.0257	65	973,336,940	7,266
2036	2,536,532	1,863	2,434	0.0290	81	892,590,633	6,868
2037	2,097,369	1,755	2,481	0.0284	85	643,660,709	5,008
2038	2,168,986	1,812	2,554	0.0299	90	673,512,067	5,174
2039	2,274,365	1,888	2,665	0.0319	97	716,853,102	5,426
2040	2,752,770	2,202	3,195	0.0399	121	901,905,039	6,564
Total	**115,511,098**	**64,519**	**95,303**	**1.747**	**3,813**	**44,874,868,345**	**270,085**
Pounds/Gallons per MWh[130]	**742**	**0.41**	**0.61**	**0.00001**	**0.02**	**144**	**1.91**

Table 77: Social Cost of Carbon Nominal Dollars – System Wide (EC3)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,928,295
2024	$1,050,975,226
2025	$1,028,854,964
2026	$1,005,486,454
2027	$913,690,373

[127] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[128] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[129] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[130] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

2028	$806,186,716
2029	$649,906,908
2030	$474,658,928
2031	$472,347,719
2032	$409,338,399
2033	$283,782,481
2034	$301,448,912
2035	$337,453,880
2036	$336,137,939
2037	$287,456,177
2038	$307,393,820
2039	$333,238,841
2040	$416,912,104

Table 78: Social Cost of Methane Nominal Dollars – System Wide (EC3)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,491,110
2024	$71,728,358
2025	$68,866,647
2026	$68,698,619
2027	$58,836,508
2028	$52,285,011
2029	$42,417,929
2030	$37,640,895
2031	$37,680,362
2032	$34,330,170
2033	$25,389,611
2034	$26,624,745
2035	$30,123,995
2036	$29,697,905
2037	$22,576,585
2038	$24,306,819
2039	$26,551,725
2040	$33,441,978

Table 79: GHG Emissions Reduction Percentages, Targets and Forecast (EC3)

Year[131]	Target[132]	Forecast
2025	26%	34%
2026	36%	45%
2027	46%	58%
2030	80%	82%

[131] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[132] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (EC3) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 80: Total Financial (EC3)

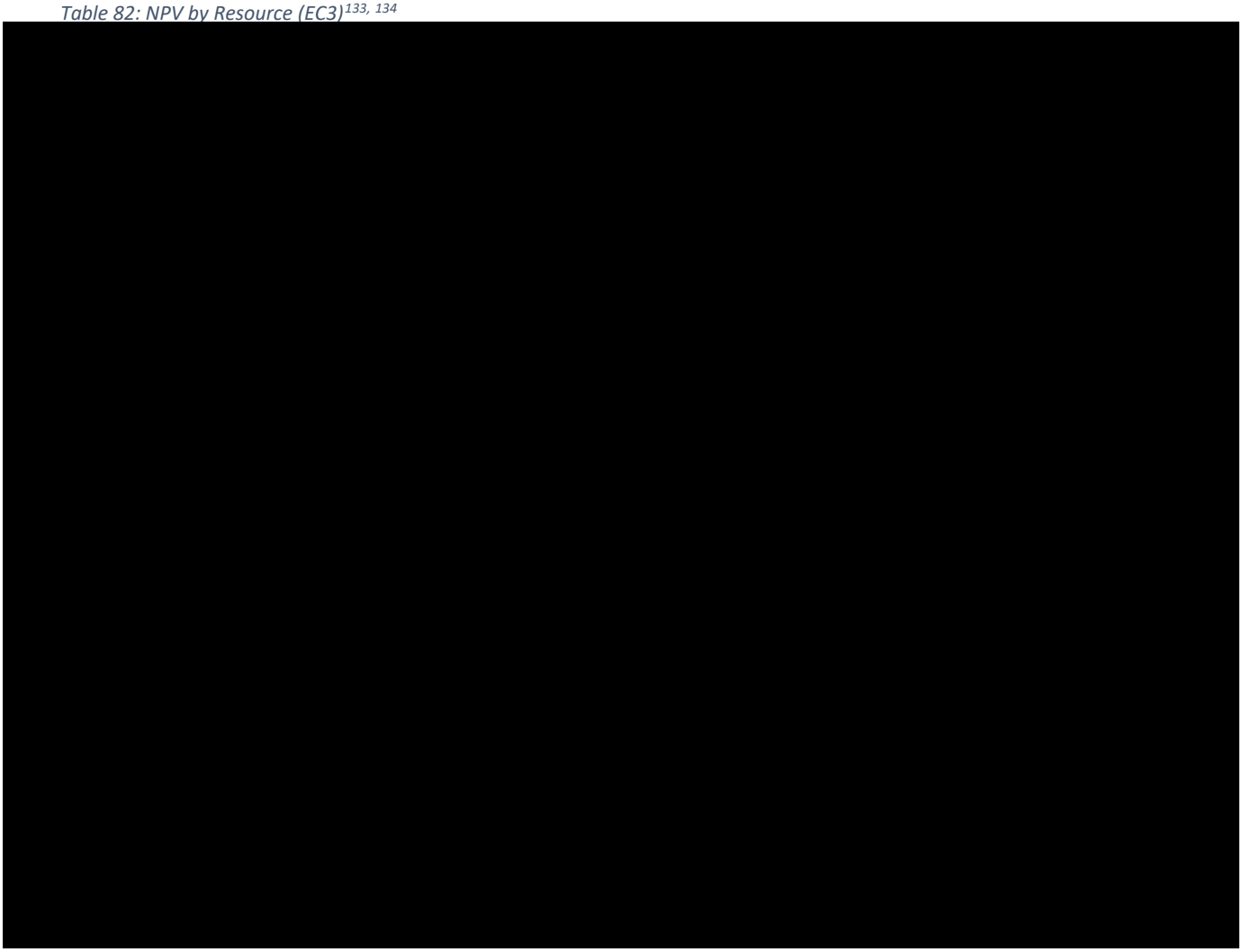
$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,879.0	$9,695.1	$691.3	$28,574.2	$29,265.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,379.3				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,677.7				

Table 81: Annual Financial (Nominal $) (EC3)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,186
2024	$1,155
2025	$1,153
2026	$1,264
2027	$1,453
2028	$1,523
2029	$1,432
2030	$,1481
2031	$1,582
2032	$1,606
2033	$1,645
2034	$1,663
2035	$1,669
2036	$1,665
2037	$1,604
2038	$1,620

2039	$1,654
2040	$1,626

Table 82: NPV by Resource (EC3)[133, 134]



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

[133] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[134] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[135] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[136] NPV using 2.5% discount rate
[137] NPV using 2.5% discount rate

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the EC3 dispatch, through 2026. In 2027 through 2030, with the addition of 700 MW of intermittent resources, 1,500 MW of intermittent resources paired with battery storage (hybrids), 350 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – most significantly impacting solar and occurring in the spring season. By 2029, the total financial curtailment cost exceeds $29 million and reflect approximately 40% of the curtailment costs over the RAP. Total financial curtailment costs in 2030 exceed $34 million, as shown in Table 85 below, and reflect 47% of the curtailment costs over the RAP.

Table 83: Curtailed Intermittent Energy, Annual MWh (EC3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	617	0	0	0	137	754
2026	0	3,056	0	0	0	1,152	4,208
2027	566	6,321	0	22,876	0	3,752	33,515
2028	11,215	20,800	533	188,169	97	17,772	238,585
2029	53,242	55,247	21,305	971,853	3,350	64,604	1,169,601
2030	113,889	92,920	67,778	979,905	2,733	103,345	1,360,570
RAP Total	**178,912**	**178,961**	**89,616**	**2,162,802**	**6,180**	**190,762**	**2,807,233**

Table 84: Seasonal Renewable Curtailments, Annual GWh (EC3)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	35	399	0	320
2026	436	2,716	211	844
2027	617	26,148	3,940	2,811
2028	7,335	153,679	53,276	24,295
2029	95,583	544,000	327,709	202,308
2030	163,229	622,166	334,726	240,449
RAP Total	**267,234**	**1,349,109**	**719,863**	**471,028**

The following table reflects PPA pricing, penalties, and taxes.

Table 85: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EC3)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$18,286

2026	$0	$96,989
2027	$24,255	$923,683
2028	$474,847	$6,389,605
2029	$3,151,858	$26,096,716
2030	$7,102,829	$27,121,912
RAP Total	**$10,753,789**	**$60,647,191**

Portfolio 5 (EC3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[138]

Transmission Available Transmission Capacity Adjustments – Portfolio 5 (EC3)

Given the extensive amount (2,950 MW during the RAP) of new resources modeled for the EC3 expansion plan, additional transmission capacity reservations were modeled to reflect the transmission that would be necessary from eastern Colorado into western Colorado (ECO > WCO) to accommodate the additions. Associated transmission capacity reservation costs are also reflected in the financial modeling. The specific additional third-party transmission purchase details are provided in Attachment B-3.

Table 86: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EC3)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	200	Solar + Battery		$7.30	
2027	100	Battery	1.3	$2.21	
2027	100	Battery	1.3	$2.21	
2027	100	Battery	1.3	$2.21	
2027	25	Battery	1.2	$1.22	
2027	25	Battery	1.2	$1.22	
2028	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind + Battery		$3.11	$836.22
2030	100	Wind - BT		$3.11	

[138] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
Western Colorado (WCO) Transmission Area					
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$2.21	
2027	100	Solar + Battery		$2.21	
2028	100	Solar + Battery		$9.98	
2028	100	Solar + Battery		$3.11	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$1.22	
2029	100	Solar + Battery		$1.22	
2031	100	Battery	1.3	$2.21	
2031	100	Battery	1.3	$2.21	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$9.98	
2028	100	Wind - BT		$9.98	$92.61
2028	100	Wind - BT		$3.11	
2029	100	Wind + Battery		$3.11	$26.00
2033	100	Wind		$3.11	
New Mexico (NM) Transmission Area)					
2032	100	Wind		$2.21	$221.98
2032	100	Wind		$2.21	
2032	100	Wind		$2.21	

Portfolio 5 (EC3) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 EC3.

Table 87: Planning Reserve Margin, % Annual (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	42	39	42	46	53	54

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 EC3.

Table 88: Loss of Load Probability, Hours (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 EC3.

Table 89: Expected Unserved Energy, Annual MWh (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires January 1, 2027.[139] To meet reliability metrics (see page 17) starting in 2027, the PRM is increased to 20%. The model selects the following semi-dispatchable resources in 2027-2030: 350 MW of stand-alone batteries in ECO and 375 MW of batteries for hybrid units (325 MW of batteries in WCO, 25 MW of batteries in ECO, and 25 MW of batteries in WYO). Reliability is met from 2031-2040 with the following battery storage additions: 200 MW in WCO. In order to enable the software model to meet transmission and build limits for the portfolio and Level II reliability criteria for the extreme weather sensitivity, 1,300 MW of solar/hybrid battery units were forced into WCO during the 2027-2029 timeframe. As modeled in this portfolio, by 2030, renewables are forecasted to make up 61% of generation capacity while storage makes up 10% of the generation capacity mix. The balance of the mix is made up of thermal and contract resources.

Dispatchable Retirements

This portfolio retires Craig 3 on January 1, 2027 and does not bring any dispatchable resources online for replacement capacity. A tremendous amount (nearly 3,000 MW during the RAP) of new renewable and semi-dispatchable resources were modeled to be required in order to meet reliability criteria, including during EWEs. This results in PRMs that are roughly 10-20% higher than the other portfolios[140] starting in 2027. The ability to procure and integrate this significant level of new resources into the system is questionable.

[139] Settlement Agreement section 3.7.4. identifies a retirement window of July 1, 2025 through December 31, 2026; however, software modeling requires January 1 retirement dates. This modeling limitation was discussed in a stakeholder meeting conveyed May 24, 2022.

[140] RL portfolio excluded from comparison, due to dissimilar load modeled.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolio is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

Figure 7: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Portfolio

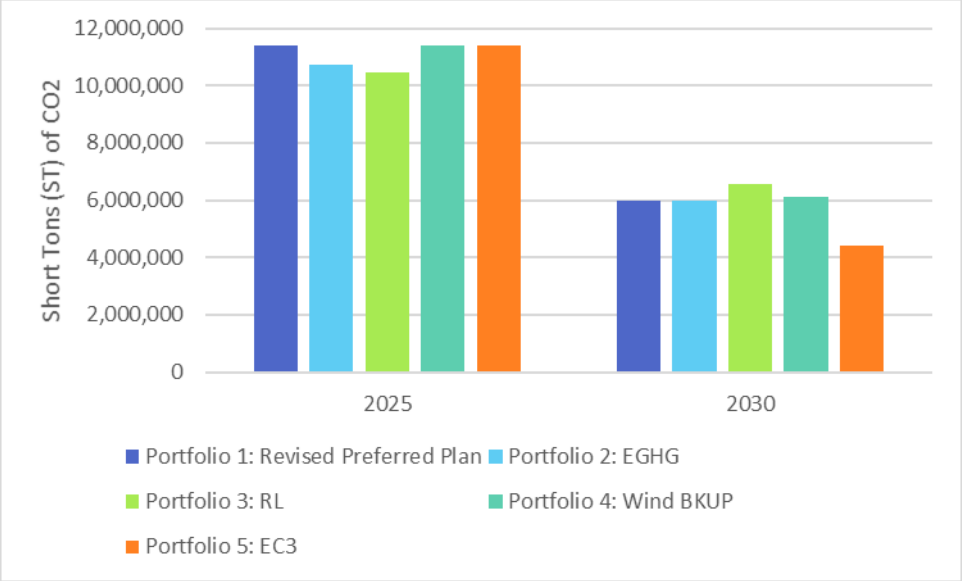
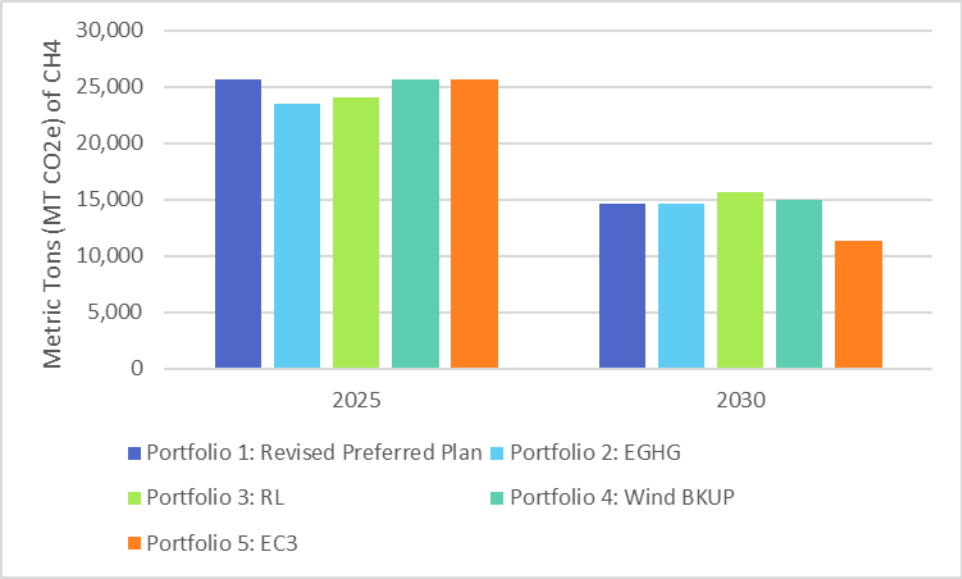


Figure 8: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Notably, Portfolio 2 (EGHG) results are driven by the underlying modeling assumption forcing achievement of the targets one year earlier than the other portfolios. Additionally, Portfolio 3 (RL)

demonstrates significant carbon reduction with no additional renewable resources in the RAP as a result of removing United Power's load (which has grown substantially since 2005) from both the baseline and forecast. While Portfolios 2 (EGHG) and 5 (EC3) have lower Colorado GHG emissions than the Revised Preferred Plan, those outcomes are the result of modeling input assumptions that raise concerns regarding their technical or financial feasibility. As shown in Table 92 below, the model selects a significant level of new resource acquisitions in the EC3 portfolio, which would create serious financial and reliability implications if this portfolio were to be implemented. Similarly, the EGHG portfolio brings forward an additional resource during this acquisition period which increases near-term annual revenue requirements for Tri-State Members. At this time of continued load uncertainty and utility system transitions, maintaining steady incremental progress toward Colorado's GHG reduction targets is best achieved by implementation of the Revised Preferred Plan. Tri-State supports the Revised Preferred Plan because it achieves the right balance of reliability, affordability, and responsibility expected by its Members.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 90: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Portfolio 1: Revised Preferred Plan	33%	43%	49%	81%
Portfolio 2: EGHG	41%	52%	61%	81%
Portfolio 3: RL	58%	64%	67%	83%
Portfolio 4: Wind BKUP	33%	41%	48%	81%
Portfolio 5: EC3	34%	45%	58%	82%

Figure 9: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets

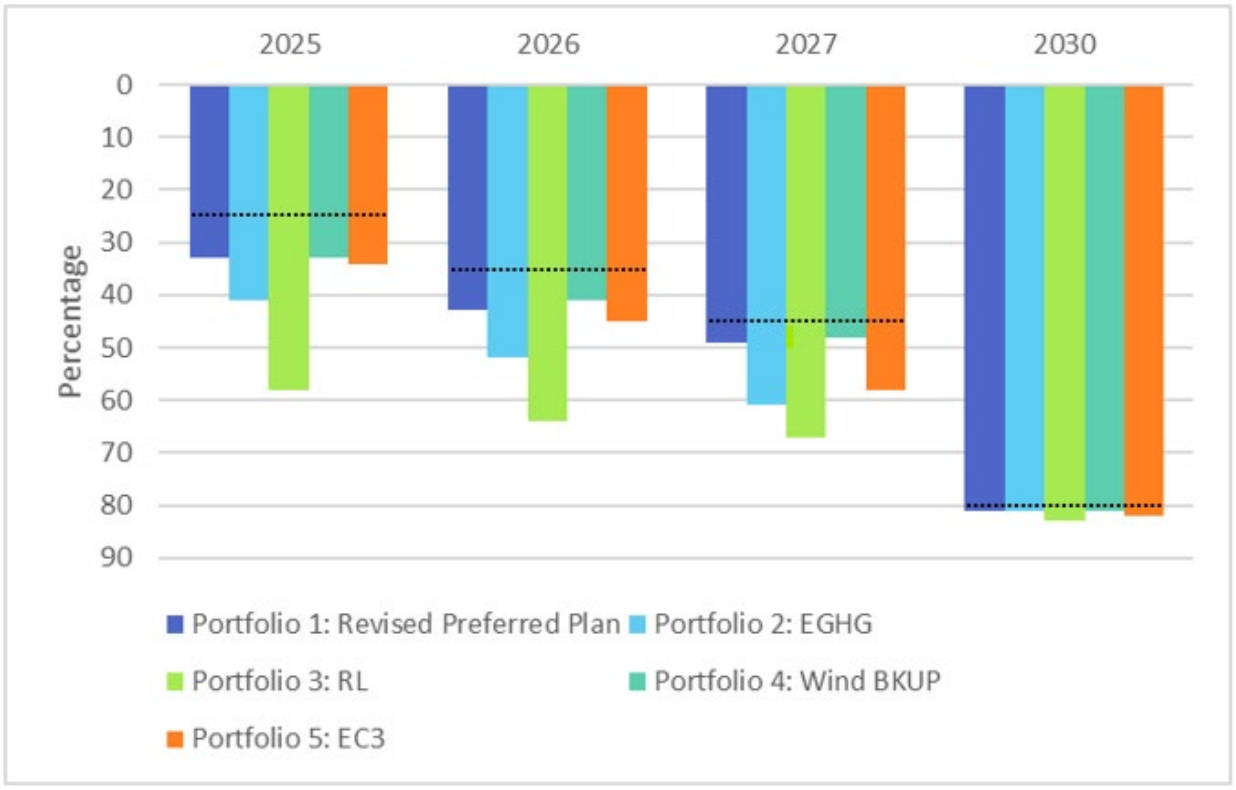


Figure 10: Comparison of Colorado CO2e

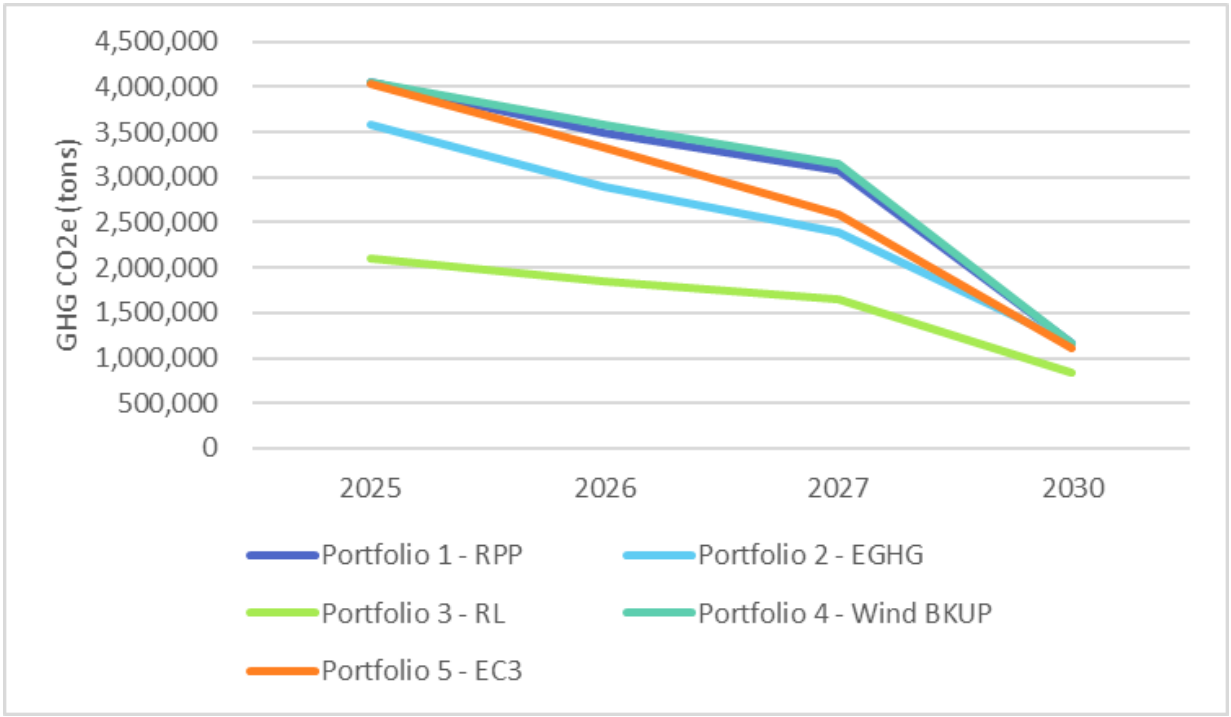


Figure 11: Comparison of SCoC

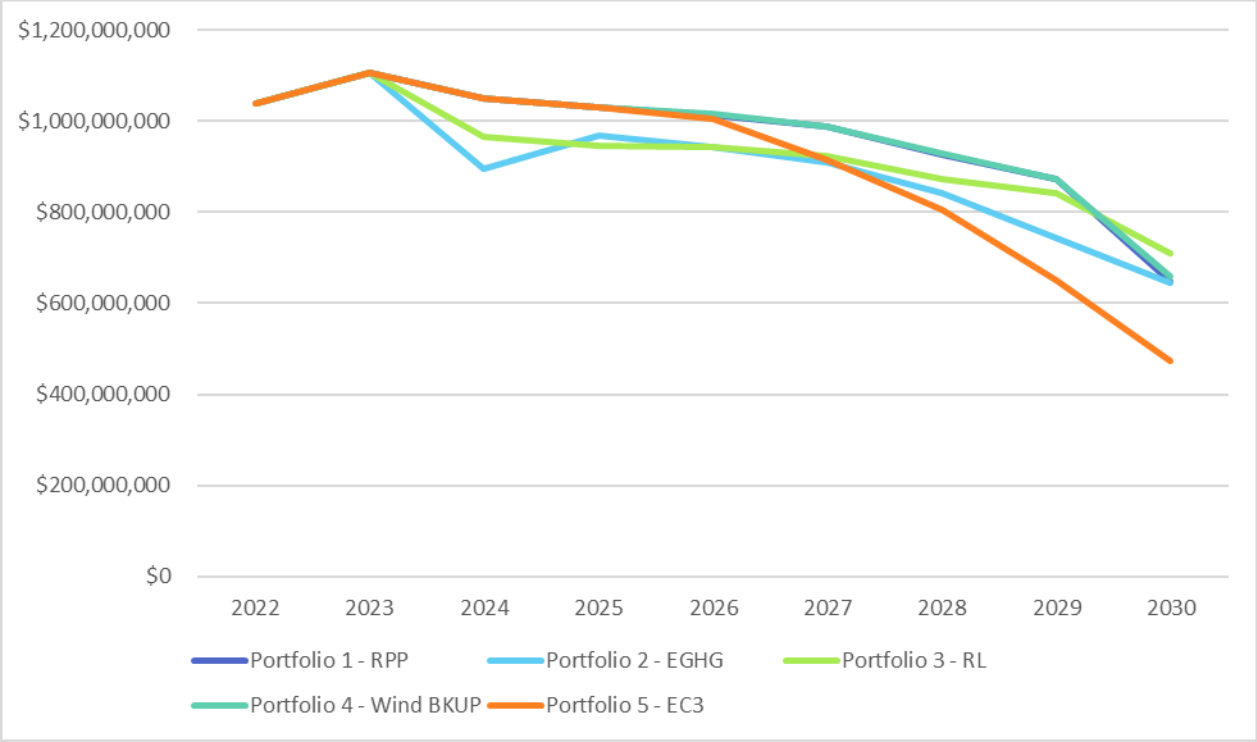
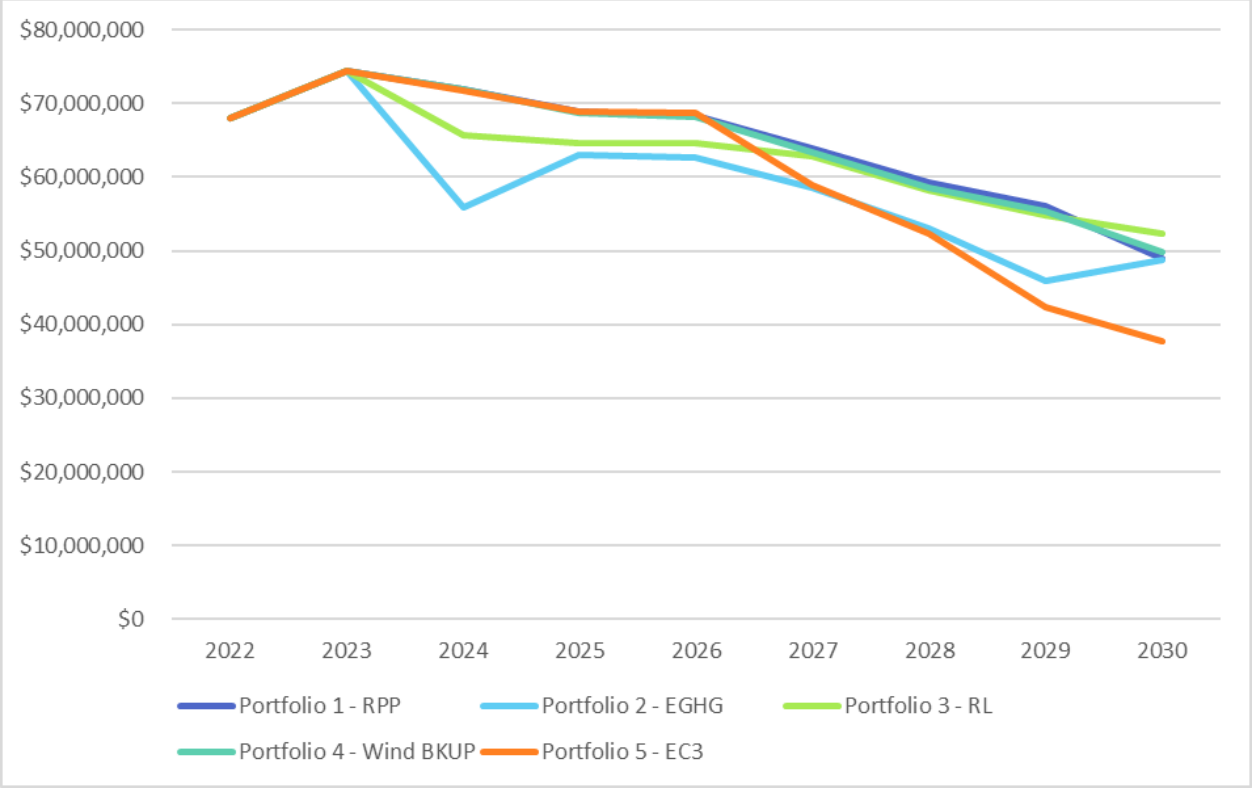


Figure 12: Comparison of SCoM



Financial Analysis

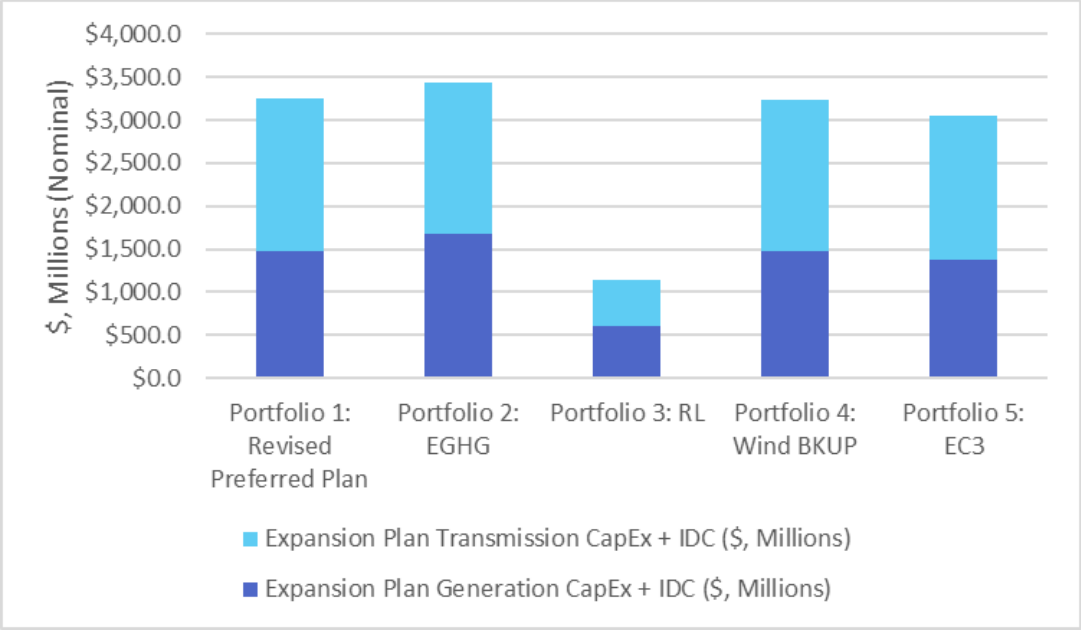
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 1 (Revised Preferred Plan) is the lowest cost plan on a PVRR basis with the exception of the Portfolio 3 (Reduced Load) which requires fewer new resource acquisitions. Although Portfolio 1 (Revised Preferred Plan) has a higher PVRR when SCoC and SCoM are included, as compared to Portfolios 2 (EGHG) and 5 (EC3), these plans have a higher annual revenue requirement in the RAP, unacceptably increasing costs to Tri-State Members in the near-term. Portfolio 1 (Revised Preferred Plan) reaches Colorado GHG reduction targets, including significant reductions in SCoC and SCoM, while maintaining reliability and affordability—which best serves Tri-State Members' priorities.

Table 91: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Portfolio 1: Revised Preferred Plan	$18,465.6	$30,125.5
Portfolio 2: EGHG	$18,576.8	$29,661.0
Portfolio 3: RL	$15,719.4	$27,883.7
Portfolio 4: Wind BKUP	$18,501.8	$30,277.5
Portfolio 5: EC3	$18,879.0	$29,265.5

The following figure compares capital expenditures and MW additions by portfolio.

Figure 13: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 92Table 95 below, the MW level and type of resource additions selected by the model were similar across Portfolios 1, 2, and 4. Portfolio 3 required few resource additions and significantly less transmission capital expenditure given the reduced load assumption. Portfolio 5 requires nearly

double the amount of resources to achieve the same levels of reliability over the RAP, than Portfolios 1, 2, and 4. Not only would Portfolio 5 result in undue near-term financial pressures for Tri-State Members, as discussed above, the technical feasibility of such resource additions is also questionable. The ability for Tri-State to acquire the forecasted amount of resources identified during the RAP for Portfolio 5 from experienced bidders at the size and locations needed, and, importantly, at a competitive and reasonable cost, is uncertain.

Table 92: Comparison of MW Additions by Portfolio, by Technology over the RAP

	Portfolio 1 – Revised Preferred Plan	Portfolio 2 – Early GHG	Portfolio 3 – RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
Wind	800	800	0	716	1,100
Solar	500	500	0	500	1,500
Battery Storage	125	125	0	125	350
Thermal	193	193	193	193	0
RAP Total	**1,618**	**1,618**	**193**	**1,534**	**2,950**

Table 93 below identifies the percentage of generation capacity and system energy that is renewable for each portfolio in 2030. Portfolio 1 (Revised Preferred Plan) yields the highest percentage of renewables in terms of generation capacity and system energy mix in 2030, except for Portfolio 5 (EC3) which is an outlier given the significant amount of resource additions it requires at a higher PVRR and with uncertainty in the technical and financial feasibility of such resource acquisitions, as described above, making it less comparable to the other portfolios.

Table 93: Comparison of Renewables' Contribution in 2030, by Portfolio

	2030 Generation Capacity Mix, % Renewables	2030 System Energy Mix, % Renewables
Portfolio 1: Revised Preferred Plan	57	68
Portfolio 2: EGHG	57	67
Portfolio 3: RL	48	54
Portfolio 4: Wind BKUP	56	65
Portfolio 5: EC3	61	77

Curtailments

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. The following table identifies the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. Significant curtailment costs in Portfolio 5 (EC3) represent the operational difficulty in integrating into the system a large amount of intermittent resources in a short timespan, while moving away from resources with dispatchable capability. The more measured approach to resource integration over time, taken in the other four portfolios, results in more reasonable curtailment impacts and supports greater affordability.

Table 94: Comparison of Wind PPA Curtailment Costs by Portfolio, Real (2022) $

	Portfolio 1 - Revised Preferred Plan	Portfolio 2 - Early GHG	Portfolio 3 - RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
2022	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0
2025	$0	$0	$2,603	$0	$0
2026	$0	$0	$1,671	$142	$0
2027	$0	$0	$0	$0	$24,255
2028	$3,348	$148,076	$0	$0	$474,847
2029	$46,512	$503,076	$0	$46,309	$3,151,858
2030	$1,727,512	$1,100,907	$0	$1,196,647	$7,102,829
RAP Total	**$1,777,373**	**$1,752,059**	**$4,274**	**$1,243,097**	**$10,753,789**

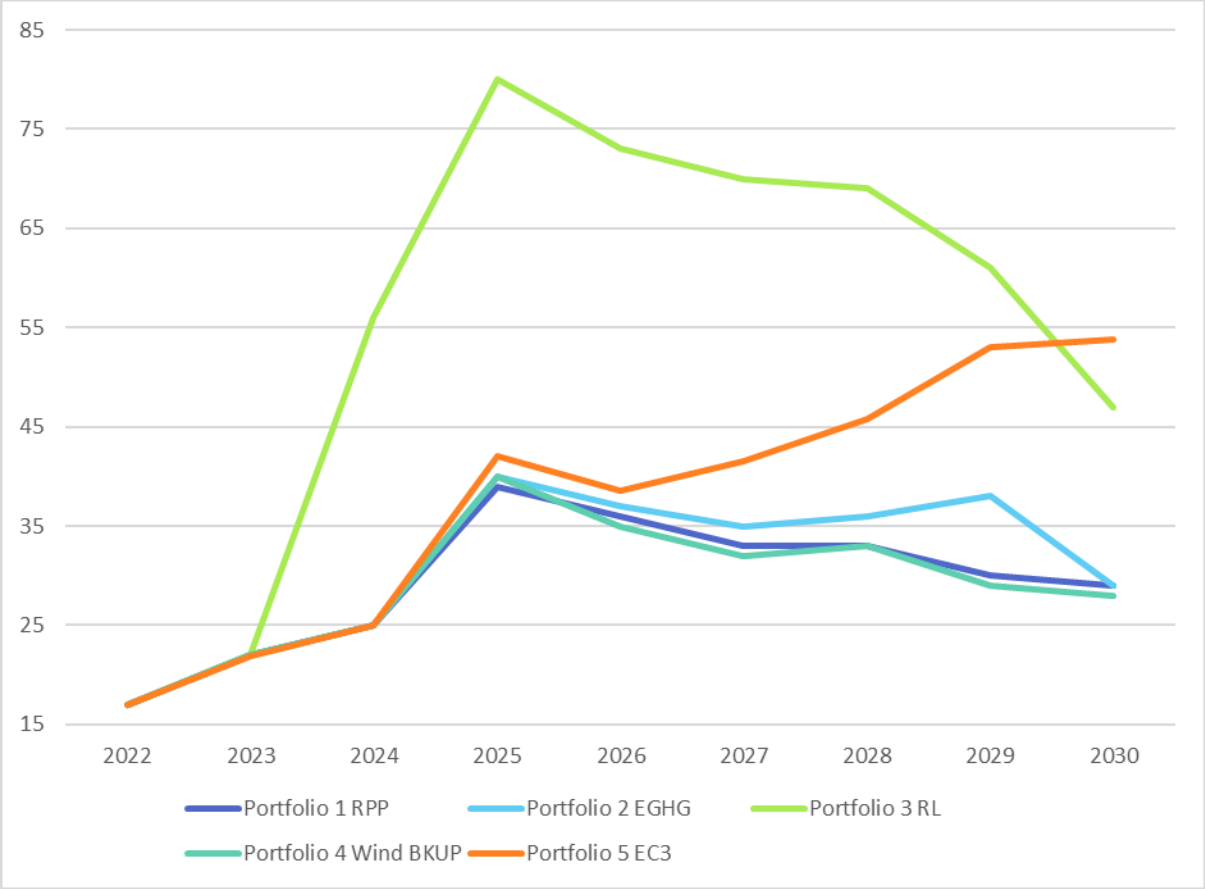
Table 95: Comparison of Solar PPA Curtailment Costs by Portfolio, Real (2022) $

	Portfolio 1 - Revised Preferred Plan	Portfolio 2 - Early GHG	Portfolio 3 - RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
2022	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0
2025	$11,490	$27,779	$25,576	$5,769	$18,286
2026	$26,572	$199,281	$30,680	$34,621	$96,989
2027	$64,948	$213,979	$23,600	$76,523	$923,683
2028	$75,517	$360,001	$34,157	$56,558	$6,389,605
2029	$234,197	$1,595,780	$66,264	$205,880	$26,096,716
2030	$2,933,914	$3,221,973	$14,903	$2,639,204	$27,121,912
RAP Total	**$3,346,638**	**$5,618,793**	**$195,181**	**$3,018,556**	**$60,647,191**

Reliability Analysis

PRMs were relatively consistent across three of the portfolios—Revised Preferred Plan, Early GHG, and Wind BKUP. The Reduced Load portfolio had considerably higher PRMs across the RAP than the other portfolios, given excess capacity becoming available due to a lower load requirement modeled. The EC3 portfolio also results in increasing PRMs after 2026 as a result of the large amount of intermittent resources modeled as new additions to the system during the RAP.

Figure 14: Comparison of PRMs During the RAP



Each of the portfolios were able to meet Level I and II reliability metrics. The Revised Preferred Plan is the portfolio that results in the greatest certainty in achieving reliability in the most cost-effective manner because it did not result from any forced modeling constraints that introduce risk.

The EC3 portfolio creates a forced early retirement of 448 MW of baseload generation and requires 950 MW of intermittent and semi-dispatchable resources to replace it in 2027, along with an additional 1,600 MW of intermittent resources to continue to maintain reliability from 2028 through 2030. The ability to swiftly integrate the extent of new resources suggested by EC3 modeling is uncertain, as described above. Further, in order to enable generation to reach load, additional third-party transmission capacity reservations had to be modeled for EC3 throughout the RPP, the use of which is not guaranteed to be available unless Tri-State could put a reservation in place before other interested parties. These factors associated with EC3 not only create financial burdens for Tri-State Members, but also result in resource adequacy concerns.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. We believe this analysis builds a clear record that supports approval of the Revised Preferred Plan portfolio. Tri-State requests the Commission find the Revised Preferred Plan portfolio to be a cost-effective resource plan and approve it in the Commission's Phase II Decision in this proceeding.

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