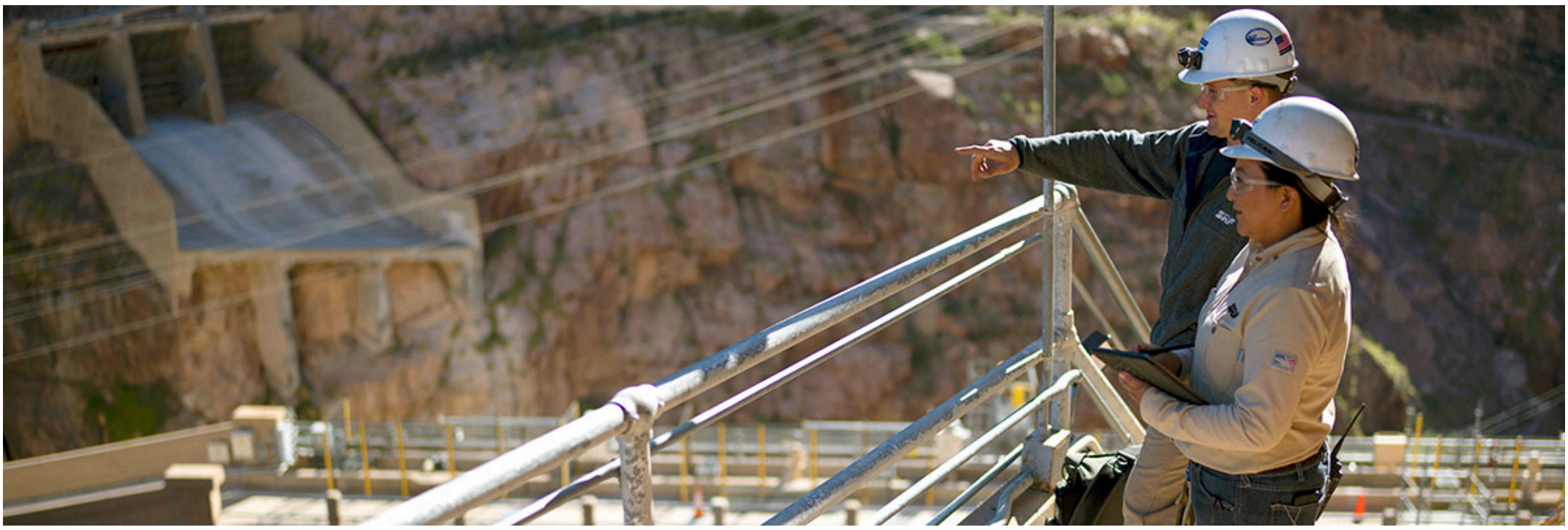
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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	)

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

Exhibit 2-60:
SRP Power Generation Sources



SRP power generation sources

SRP is strengthening and preparing the grid for a future that's powered by renewable energy while maintaining the reliability we need to keep your family safe.

On this page:

Explore SRP power sources

Sustainability at SRP

Technology and innovation

On related pages:

Santan Generating Station reports & action plans

Coolidge Generating Station reports & action plans

Feedback

Explore SRP power sources

SRP operates and participates in a number of major power plants and generating facilities in Arizona and around the Southwest. As we add more renewable energy sources to our energy mix, we're strategically using traditional energy sources like natural gas and coal to reliably strengthen our power grid, especially during the hot summer months when energy needs are at their highest.

Explore our diverse energy mix by source or location on the map below.

Filter by Technology

Coronado

Apache County, AZ

Operating Year: 1979

Conventional Steam Coal

Craig (CO)

Moffat County, CO

Operating Year: 1980

Conventional Steam Coal

Davis

Mohave County, AZ

Operating Year: 1951

Conventional Hydropower

Desert Basin

Casa Grande, AZ

Operating Year: 2001

Natural Gas

Dorman Battery

Chandler, AZ

Operating Year: 2018

Battery

Dry Lake Wind

Navajo County, AZ

Operating Year: 2009

Onshore Wind Turbine

East Line Solar

Coolidge, AZ

Operating Year: 2020

Solar Photovoltaic



Craig (CO): Conventional Steam Coal

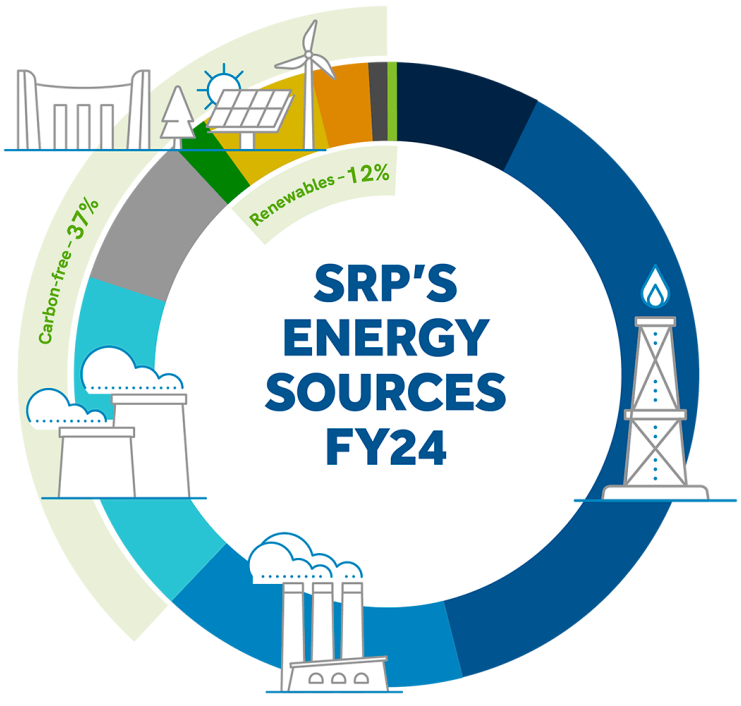
Operated by Tri-State Generation and Transmission, SRP owns a share of this three-unit station (29% of Unit 1 and 29% of Unit 2) located in northwestern Colorado. SRP is committed to reducing our carbon emissions, and we are starting to decommission certain coal-fired plants. The plan includes decommissioning Craig Unit 1 in 2025 and Unit 2 in 2028.

Esri Community Maps Contributors, © OpenStreetMap, Microsoft, Esri, TomTom, Garmin, SafeGraph,… Powered by Esri

Feedback

Sustainability at SRP

As part of our commitment to achieve net zero carbon by 2050, we are expanding our mix of clean, renewable energy sources.



We are committed to net-zero carbon emissions by 2050.

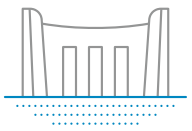
MARKET – 8%
NATURAL GAS – 38%
COAL – 16%
NUCLEAR – 18%
CUSTOMER PROGRAMS – 8%
HYDRO – 2%
SOLAR – 5%
GEOTHERMAL – 3%
WIND – 1%
BIOMASS – <1%

The pie chart shows how the power needs of SRP's retail customers were met during fiscal year 2024 (May 1, 2023–April 30, 2024). This chart represents generation output from all generating facilities operational in FY24. Generation data is pending third-party verification by The Climate Registry.

SRP is committed to cutting carbon emissions intensity by 65% by 2035 and reaching net zero by 2050. Learn more about sustainability at SRP.

Renewables

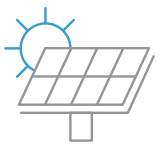
At SRP, we're steadily expanding our energy portfolio to include more power from carbon-free sources.



Hydropower

SRP manages eight dams on the Salt River and Verde River watersheds that provide more than 230 megawatts (MW) of hydropower.

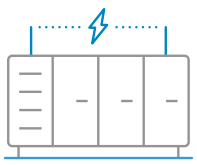
Learn more



Solar

SRP is harnessing the power of America's sunniest city to support a variety of solar solutions for homes and businesses.

Learn more



Battery storage

SRP uses large-scale battery storage projects to store renewable energy for when it is most needed to support grid reliability.

Feedback

Learn more



Other renewables

SRP is investing in additional carbon-free resources like wind, geothermal and biomass.

Learn more

SRP generation resources comply with local, state and federal air quality regulations which are protective of human health and the environment. Learn more about our environmental policies and programs.

Technology and innovation

We're continually working to provide reliable, affordable and sustainable power today and for Arizona's future. Check out the stories below to learn how we're innovating today to ensure Arizona continues thriving tomorrow.



Powering the grid with solar

Learn more

Feedback



Powering carbon neutrality with new energy storage technology

Learn more

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[Sustainability at SRP]

The future of our water and power resources depends on the actions we take today. See how we're working toward a sustainable future.

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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]

[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

[redacted]

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	)

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

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






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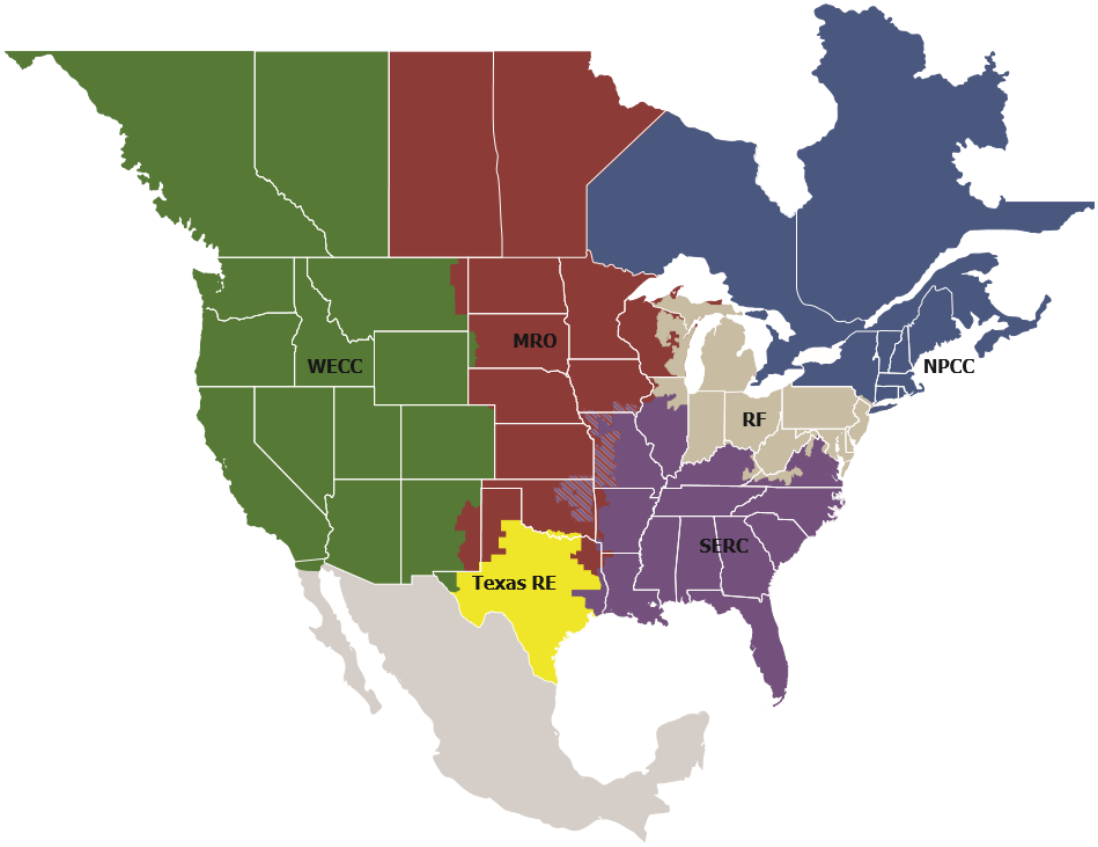
Preface

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**).

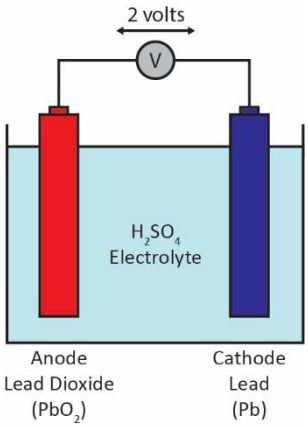


Figure I.1: Schematic of a Battery

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.

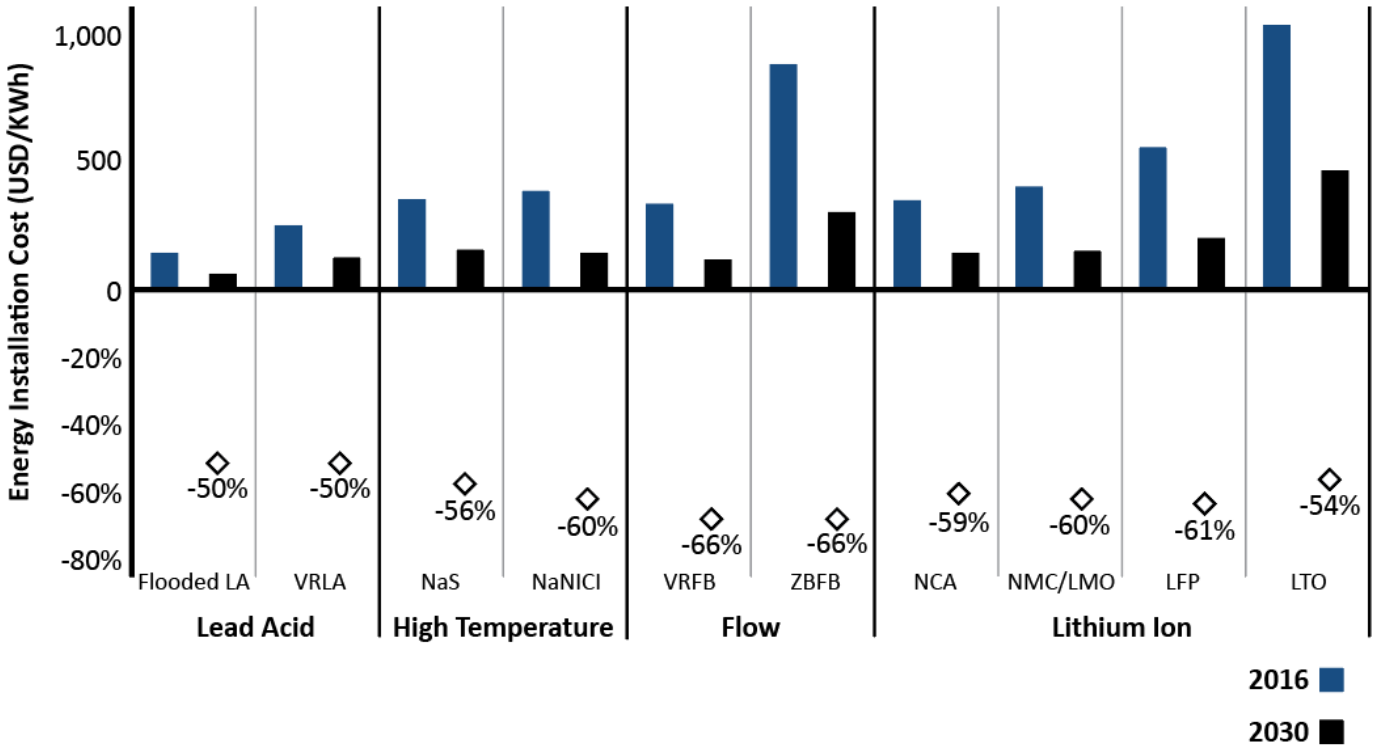


Figure I.2: Energy Installation Costs Central Estimate for Battery Technologies, 2016–2030
(The diamond represents the decrease in installation cost when comparing 2016 to 2030 data)

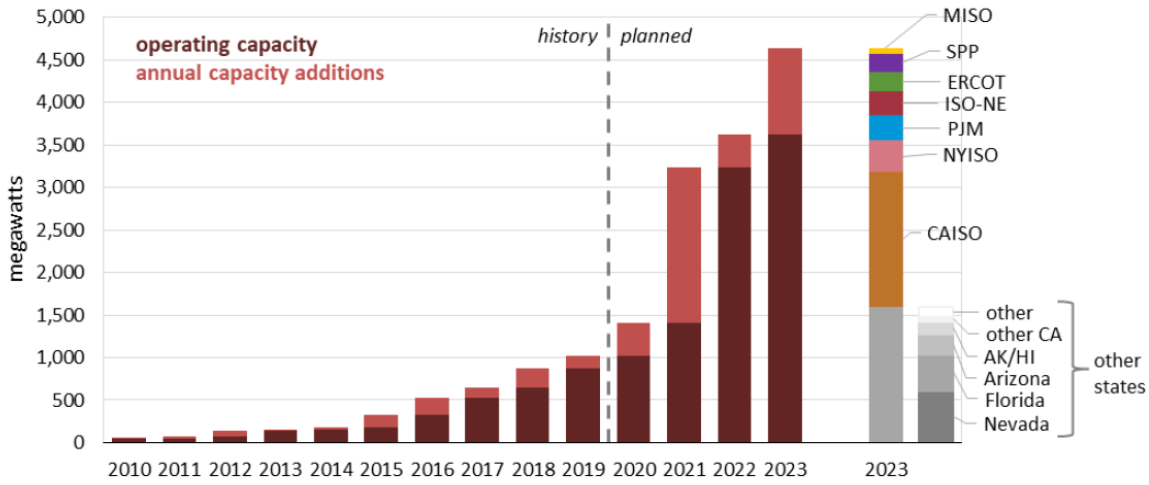


Figure I.3: United States BPS-Connected Battery Energy Storage Power Capacity (July 2020)[4]

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**.

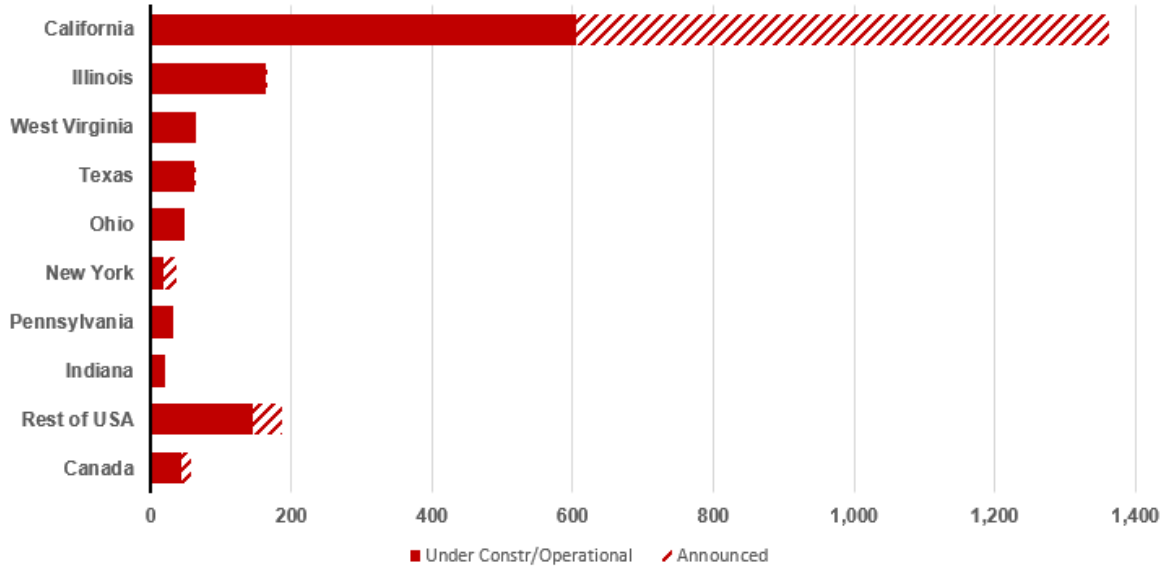


Figure I.4: United States Operating Utility-Scale Battery Storage by State[6]

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.

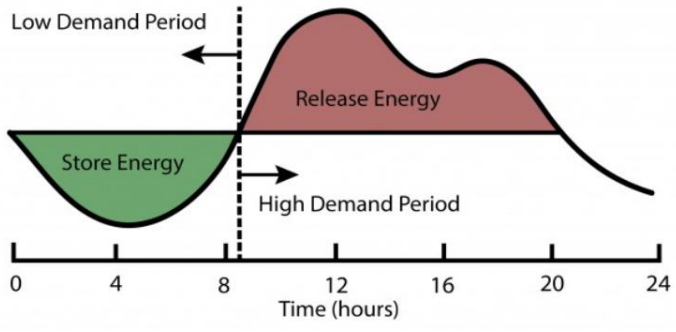


Figure I.5: Daily Energy Storage and Load Leveling[7]

[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.

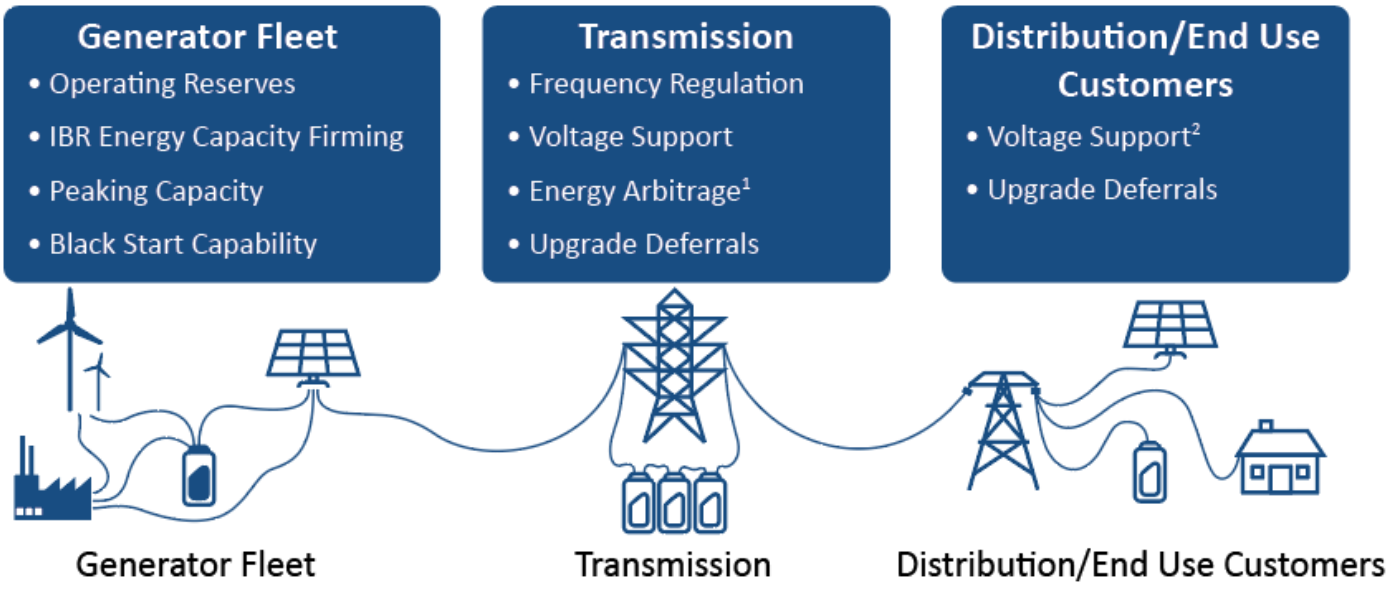
Safety

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.

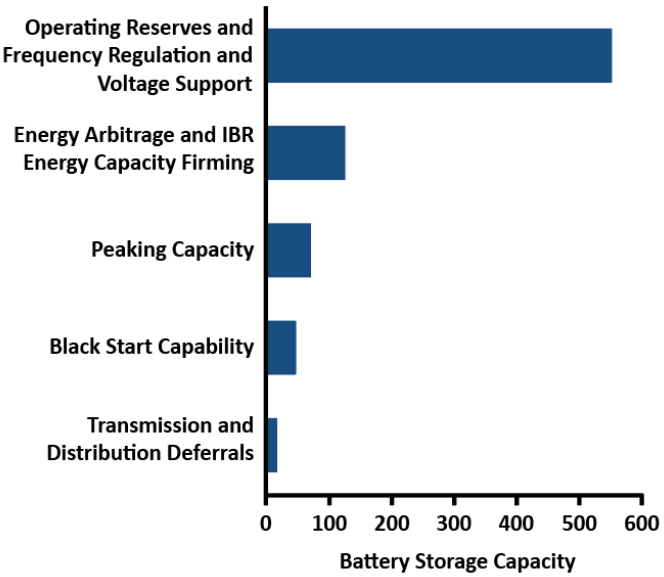


Figure 1.2: United States BPS-Connected Battery Energy Storage Capacity by Service[13]

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.

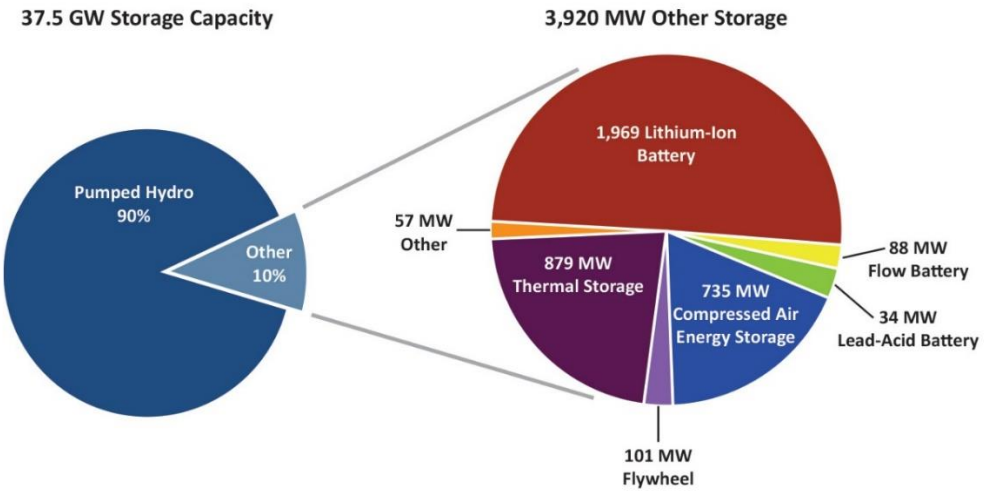
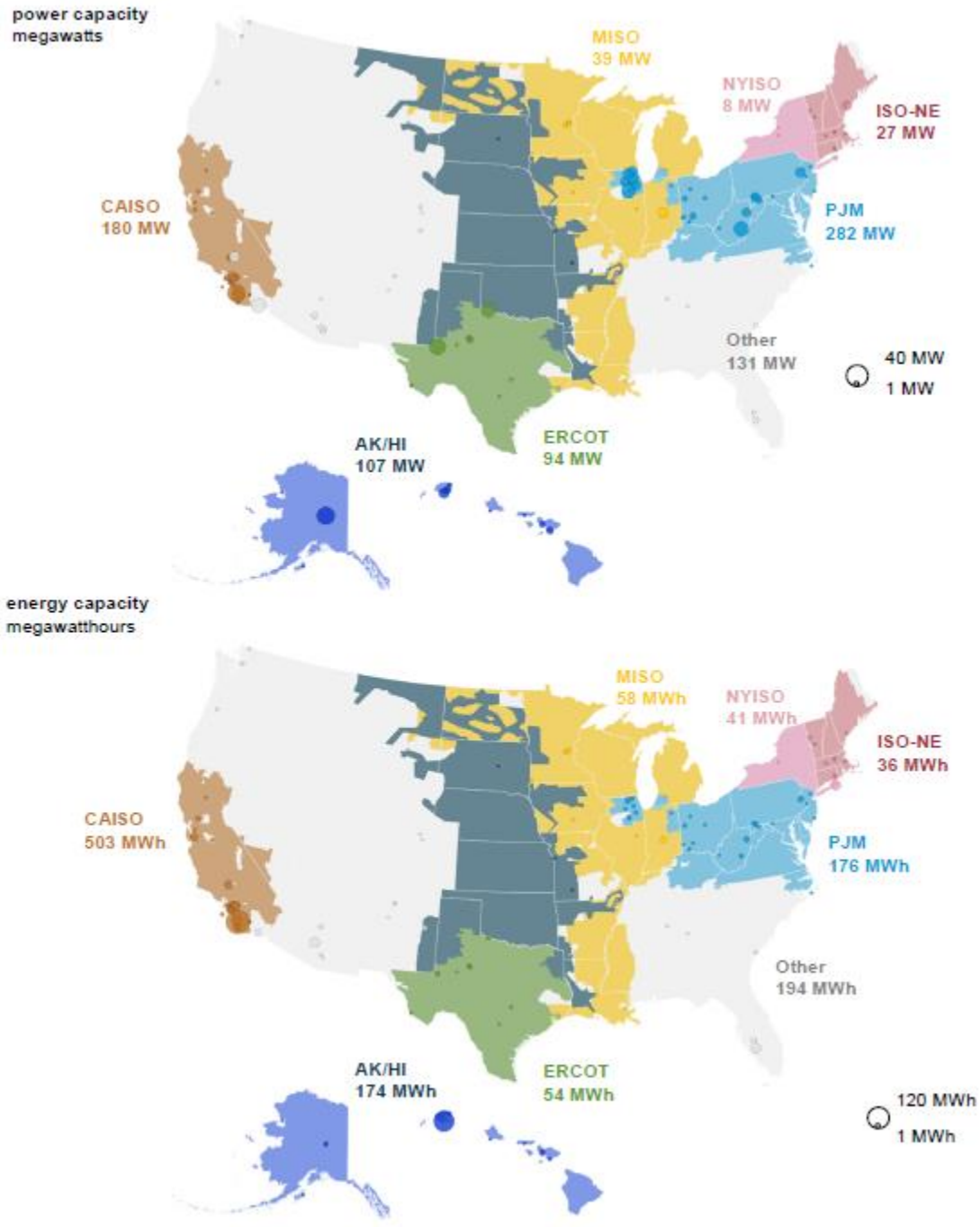


Figure 1.3: Electric Storage Capacity in the United States and Canada, by Type of Storage Technology[14]

[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	)

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

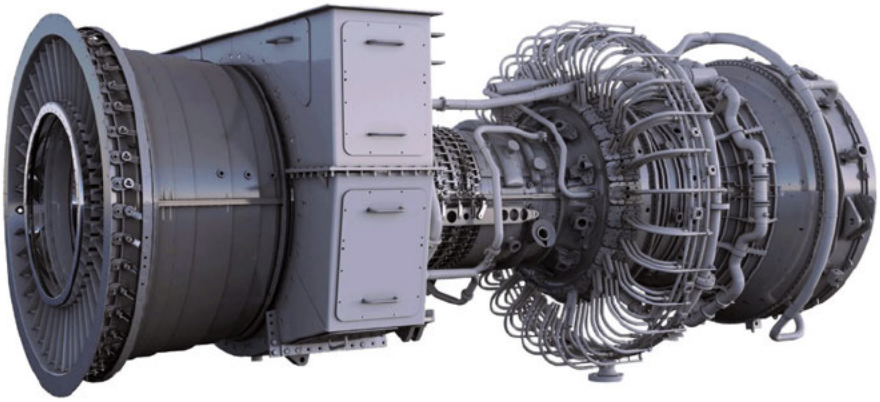
Exhibit 2-63:
GE LM6000 Information

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

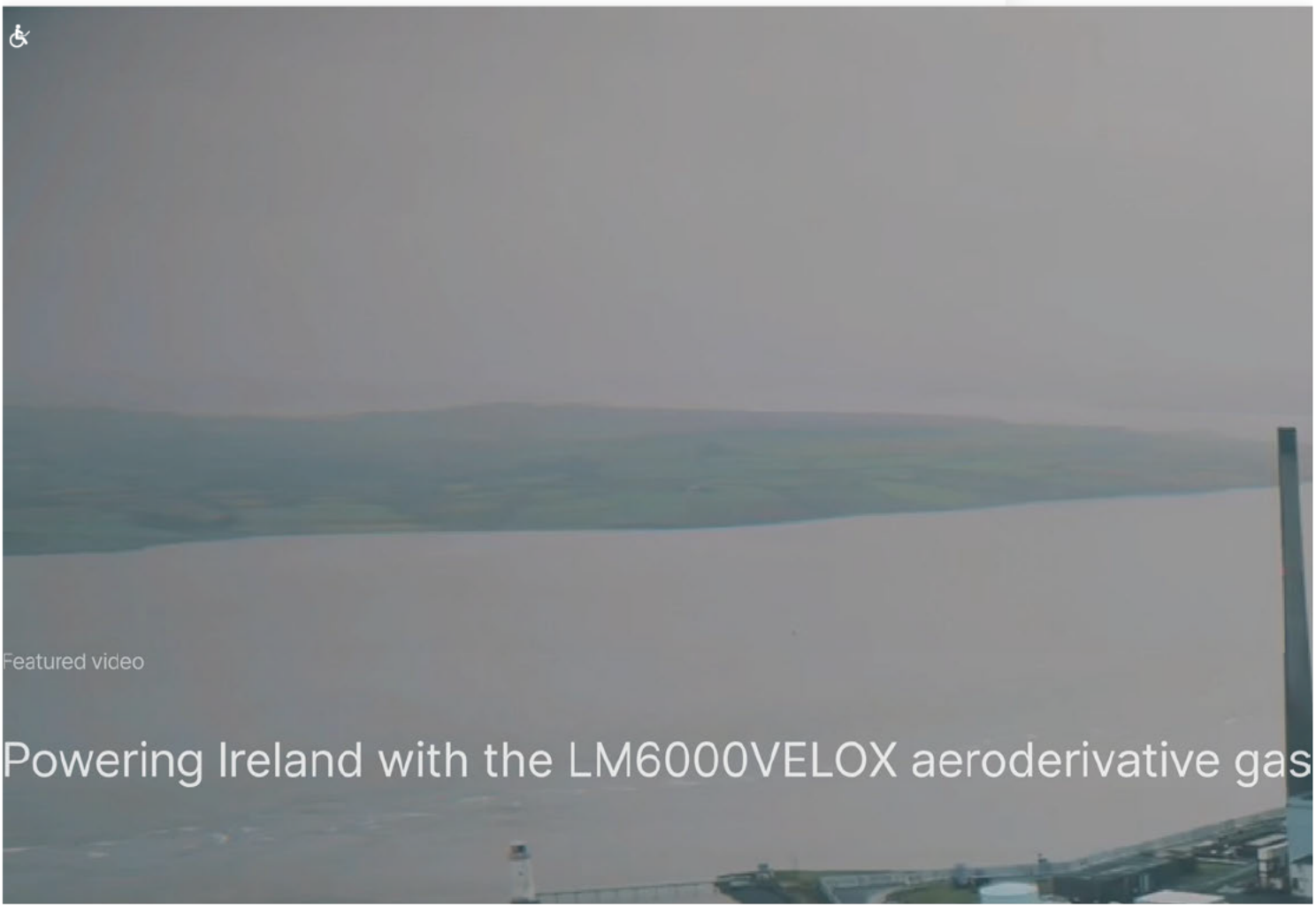
Highlight

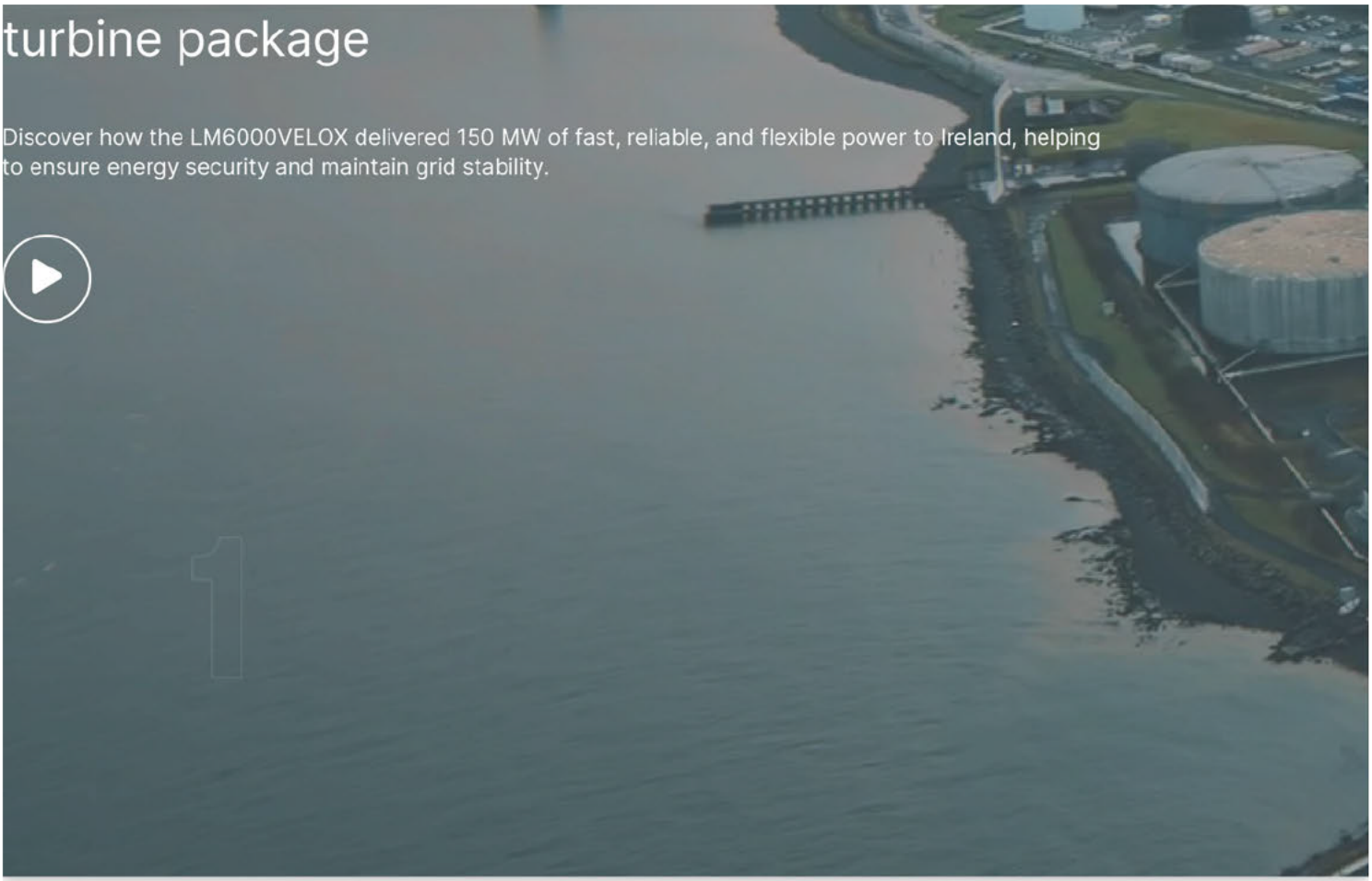
Do you know about the Mark* VIe capabilities?

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

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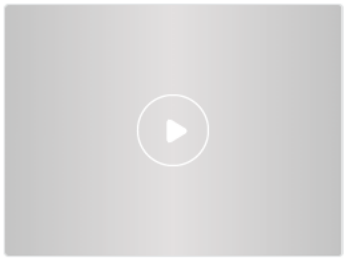
Featured videos



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.



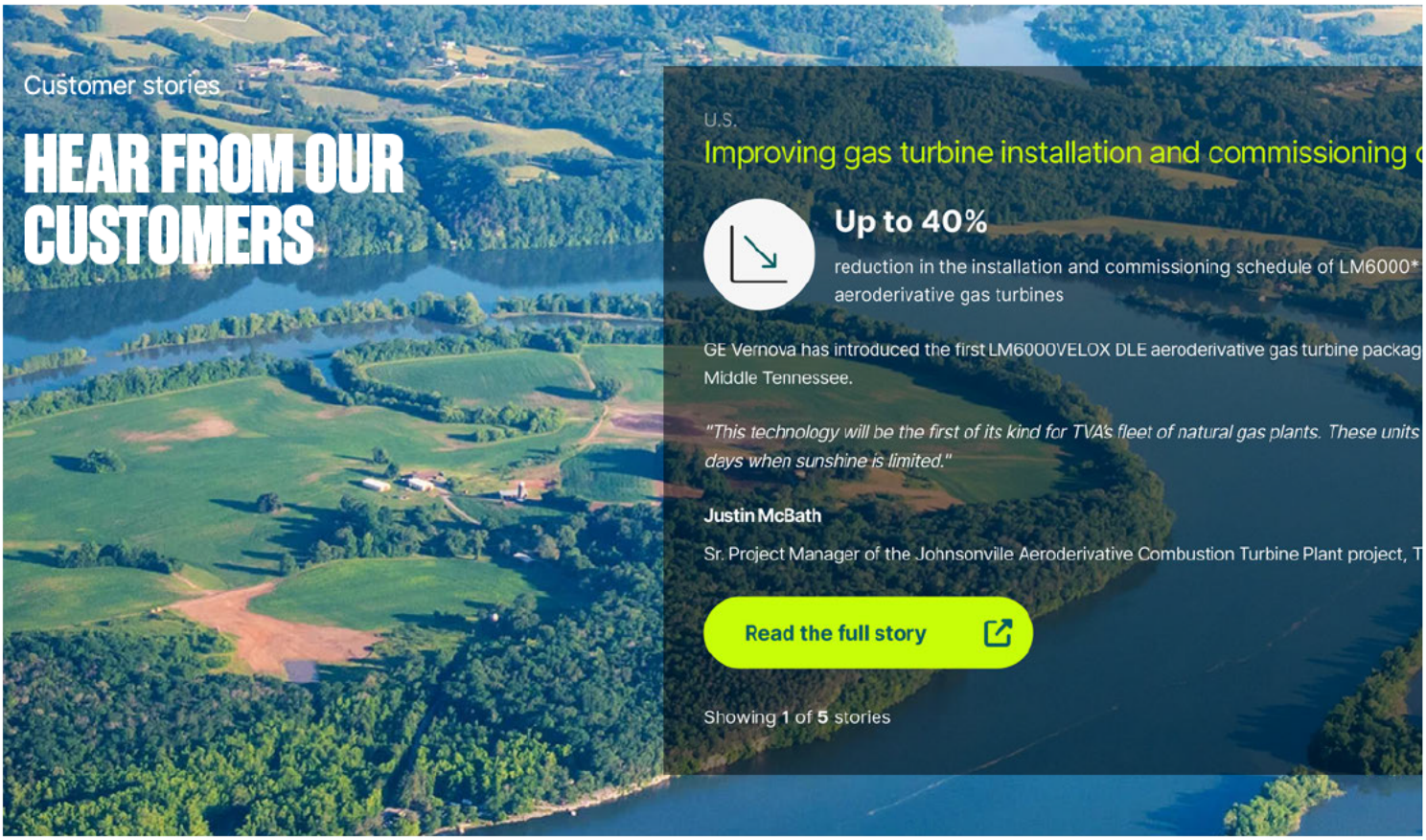
LM6000VELOX DLE package installation

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

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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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GE VERNOVA

Gas Power

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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	)

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

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

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

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	)

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

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	)

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

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	)

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

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.