DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS
(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

5 CCR 1001-9

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

Outline of Regulation

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 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.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

PART A Applicability and General Provisions

I. Applicability

I.A.

I.A.1. The provisions of this regulation shall apply as follows:

I.A.1.a. All provisions of this regulation apply to the Denver 1-hour ozone attainment/maintenance area, to any nonattainment area for the 1-hour ozone standard, and to the 8-hour Ozone Control Area.

I.A.1.b. (State Only) All provisions of this regulation apply to any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Section I.A.1.c. Colorado's ozone nonattainment or attainment maintenance area maps and chronologies of attainment status are identified in Appendix A of this regulation.

I.A.1.c. The provisions of Part B, Sections III., IV.B.1. and 2., V.C., and Part D, Sections II., III., IV., and V. apply statewide. The provisions of Part D, Sections II., III., and any other sections marked by (State Only) are not federally enforceable, unless otherwise identified.

I.A.2. REPEALED

I.A.3. REPEALED

I.B. Sources

I.B.1. New Sources

I.B.1.a. New sources, defined as any sources which either (1) submit a complete permit application on or after October 30, 1989, or (2) if no permit is required, commence operation on or after October 30, 1989, must comply with the provisions of this regulation upon commencement of operation.

I.B.1.b. (State Only) New sources are any sources which commenced construction on or after the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989. New sources shall comply with the requirements of this regulation by whichever date comes later:

I.B.1.b.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.1.b.(ii) (State Only) February 1, 2009, if they are located in an 8-Hour Ozone Control Area and outside of the 1-hour ozone nonattainment or attainment maintenance area; or

I.B.1.b.(iii) (State Only) Upon commencement of operation, if located within an ozone nonattainment or attainment maintenance area.

I.B.1.c. This Section I.B.1. does not apply to oil and gas operations subject to Part D, Section I., stationary and portable engines subject to Part E, Section I.A. through C., or natural gas actuated pneumatic controllers subject to Part D, Section III.

I.B.2. Existing Sources

I.B.2.a. Existing sources are (1) those sources for which a complete permit application was submitted prior to October 30, 1989, or (2) those sources, which commenced operation prior to October 30, 1989.

I.B.2.b. (State Only) Existing sources are those sources which commenced construction prior to the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989.

I.B.2.c. Existing sources shall not be required to comply with requirements of this regulation until on and after October 30, 1991. All existing sources shall comply with the requirements set forth in Exhibit A until October 30, 1991.

I.B.2.d. (State Only) Existing sources shall be required to comply with requirements of this regulation by whichever date comes later:

I.B.2.d.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.2.d.(ii) (State Only) February 1, 2009, if they are located in an 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area; or

I.B.2.d.(iii) (State Only) the date on which the area is first designated as being in nonattainment for ozone, if located within that ozone nonattainment or attainment maintenance area.

I.B.2.e. On and after October 30, 1991, all existing sources shall comply with the requirements of this regulation, and Exhibit A shall no longer be applicable.

I.B.2.f. Repealed.

I.B.2.g. Repealed.

I.B.2.h. This Section I.B.2. does not apply to oil and gas operations subject to Part D, Section I., or stationary and portable engines subject to Part E, Section I.A. through C.

I.C. Once a source subject to this regulation exceeds an applicable threshold limit, the requirements of this regulation are irrevocably effective unless the source obtains a federally enforceable permit limiting emissions to levels below the threshold limit by restricting production capacity or hours of operation.

I.D. The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II. General Provisions

II.A. Definitions

II.A.1. "8-Hour Ozone Control Area" means the Counties of Adams, Arapahoe, Boulder (includes part of Rocky Mountain National Park), Douglas, and Jefferson; the Cities and Counties of Denver and Broomfield; and the following portions of the Counties of Larimer and Weld:

II.A.1.a. For Larimer County (includes part of Rocky Mountain National Park), that portion of the county that lies south of a line described as follows: Beginning at a point on Larimer County's eastern boundary and Weld County's western boundary intersected by 40 degrees, 42 minutes, and 47.1 seconds north latitude, proceed west to a point defined by the intersection of 40 degrees, 42 minutes, 47.1 seconds north latitude and 105 degrees, 29 minutes, and 40.0 seconds west longitude, thence proceed south on 105 degrees, 29 minutes, 40.0 seconds west longitude to the intersection with 40 degrees, 33 minutes and 17.4 seconds north latitude, thence proceed west on 40 degrees, 33 minutes, 17.4 seconds north latitude until this line intersects Larimer County's western boundary and Grand County's eastern boundary.

II.A.1.b. For Weld County, that portion of the county that lies south of a line described as follows: Beginning at a point on Weld County's eastern boundary and Logan County's western boundary intersected by 40 degrees, 42 minutes, 47.1 seconds north latitude, proceed west on 40 degrees, 42 minutes, 47.1 seconds north latitude until this line intersects Weld County's western boundary and Larimer County's eastern boundary.

II.A.2. "Denver 1-Hour Ozone Attainment/Maintenance Area" means the Counties of Jefferson and Douglas, the Cities and Counties of Denver and Broomfield, Boulder County (excluding Rocky Mountain National Park), Adams County west of Kiowa Creek, and Arapahoe County west of Kiowa Creek.

II.A.3. "Capture System" means the equipment used to contain, capture, or transport a pollutant to a control device.

II.A.4. "Capture System Efficiency (vapor gathering system efficiency)" means the percent by weight of VOC emitted by an operation subject to this regulation, which is captured by the capture system and sent to the control device; i.e., (mass flow of VOC captured)/(mass flow of VOC emitted by the operation) x 100%.

II.A.5. "Carbon Adsorption System" means a device containing adsorbent material, an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.

II.A.6. "Condenser" means any heat transfer device used to liquefy vapors by removing their latent heats of vaporization. Such devices include, but are not limited to, shell and tube, coil, surface, or contact condensers.

II.A.7. "Control Device" means a carbon adsorber, refrigeration system, condenser, flare, firebox or other device, which will reduce the concentration of VOC in a gas stream by adsorption, combustion, condensation, or other means of removal.

II.A.8. "Control Device Efficiency" means the percent removal by weight of VOC by a control device; i.e., (mass flow of VOC into control device - mass flow of VOC out of control device)/(mass flow of VOC into control device) x 100%.

II.A.9. "Gasoline" means a petroleum distillate having a Reid vapor pressure between 208 and 1040 torr (4-20 psi), which is used as fuel for internal combustion engines.

II.A.10. "Highly Volatile Organic Compound" is defined as a Volatile Organic Compound or mixture of such compounds with a true vapor pressure in excess of 570 torr (11 psia) at 20 C.

II.A.11. “Organic Material” means a chemical compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.

II.A.12. (State Only) “Ozone Nonattainment Area” means any area designated as not in attainment with the ozone National Ambient Air Quality Standard as determined by the Environmental Protection Agency.

II.A.13. “Petroleum Refinery” means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

II.A.14. “Reid Vapor Pressure” means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquefied petroleum gases as determined by the American Society for Testing and Materials, Part 17, 1973, D-323-72 (Reapproved 1977).

II.A.15. “True Vapor Pressure” means the equilibrium partial pressure exerted by petroleum (or other) liquid. This may be determined by the methods described in American Petroleum Institute Bulletin 2517, “Evaporation Loss from Floating Roof Tanks,” 1962.

II.A.16. “Vapor Recovery System” means a system that prevents release to the atmosphere of organic compounds emitted during the operation of any transfer, storage, or processing equipment.

II.A.17. "Volatile Organic Compound (VOC)" means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60 (September 14, 1989). A reference method, an equivalent method, or an alternative method, however, may also measure nonreactive organic compounds. In such cases, an owner or operator may exclude the compounds listed in Section II.B. when determining compliance with a standard if the amount of such compounds is accurately quantified, and such exclusion is approved by the Division. As a precondition to excluding such compounds as VOC, or at any time thereafter, the Division may require an owner or operator to provide monitoring or testing methods and results demonstrating, to the satisfaction of the Division, the amount of negligible-reactive compounds in the source's emissions.

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation. However, the hydrocarbon threshold in Part D, Section I.L. and natural gas emissions standards in Part D, Sections III.C.1. and III.C.2. are used as indicators for the volatile organic compound emission reduction measures in Part D, Sections I.L., III.C.1., and III.C.2., and are enforceable provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Part D.

II.C. General Emission Limitation

II.C.1. Existing Sources (State Only: Located in any Ozone Nonattainment Area or Attainment Maintenance Area)

II.C.1.a. All existing sources shall comply with the requirements set forth in this regulation.

II.C.1.a.(i) Existing sources of VOC which are not subject to specific emission limitations set forth in this regulation, and which have the potential to emit 100 tons per year or more of VOC, shall utilize Reasonably Available Control Technology (RACT).

II.C.1.a.(ii) The potential to emit of such sources shall be based on design capacity or maximum production rate, whichever is greater, 8760 hours/year operation, and before add-on controls.

II.C.1.a.(iii) Owners or operators of such sources with potential emissions of 100 tons per year or more, but with actual emissions less than 100 tons per year may obtain a federally enforceable permit limiting emissions to actual rates by restricting production capacity or hours of operation, thus avoiding RACT requirements.

The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II.C.1.a.(iv) Such sources with potential emissions of 100 tons per year or more but with actual emissions of less than 50 tons per year, on a rolling 12-month total, may avoid RACT and permit requirements if the following requirements are met:

II.C.1.a.(iv)(A) The owner or operator shall submit revised Air Pollutant Emission Notices (APENs) by April 1 of each year, which demonstrate that the 50 tons per year threshold has not been exceeded.

II.C.1.a.(iv)(B) The owner or operator shall maintain records on site which include monthly VOC use and monthly VOC emissions. The records shall include calculation of total emissions for each rolling 12-month period. The records shall be made available to the Division for inspection upon request.

II.C.1.a.(v) (State Only) Existing sources that are modified – undergo any physical change, or changed in the method of operation of a stationary source which increase VOC or NOx emissions – on or after March 30, 2008, shall utilize RACT control technologies pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. upon recommencing operation.

II.C.1.b. Provided however, that no existing source of VOC emissions employing emission controls on or within the six-month period preceding the effective date of this regulation may reduce its level of control of VOC emissions below that level of control actually achieved, even though such source may otherwise be subject to less stringent control requirements, except that no existing source shall be required to control emissions to an extent greater than that level of control which RACT would achieve.

II.C.1.c. (State Only) Existing sources with potential emissions equal to or greater than 100 tons per year of volatile organic compound emissions shall submit a permit modification application that includes a revised APEN (or APENs) and a RACT analysis, to the Division, as follows:

II.C.1.c.(i) (State Only) By October 30, 1991 if located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area; or

II.C.1.c.(ii) (State Only) By April 30, 2009 or within one year after the date on which the area is first designated as being in nonattainment for ozone, whichever comes later, if they are located in the 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area.

II.C.1.d. (State Only) Existing sources shall utilize RACT pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. by whichever date comes later:

II.C.1.d.(i) (State Only) October 30, 1991, if they are located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area;

II.C.1.d.(ii) (State Only) November 21, 2011, if they are located in the 8-hour Ozone Control Area, and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area;

IIC.1.d.(iii) (State Only) Three years after the date on which the area is first designated as being in nonattainment for ozone; or

II.C.1.d.(iv) (State Only) Two years after Division determination of case-by-case RACT pursuant to this Section II.C.1. The Division shall be deemed to have approved the RACT analysis for purposes of this Section II.C.1.d.(iv) if it does not object after eighteen months from having received a complete permit application.

II.C.2. New Sources

All new sources shall utilize controls representing RACT, pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D., upon commencement of operation.

II.D. Alternative Control Plans and Test Methods

II.D.1. Sources subject to specific requirements of this regulation shall submit for approval as a revision to the State Implementation Plan:

II.D.1.a. Any alternative emission control plan or compliance method other than control options specifically allowed in the applicable regulation. Such alternative control plans shall provide control equal to or greater than the emission control or reduction required by the regulation, unless the source contends that the control level required by the regulation does not represent RACT for their specific source.

II.D.1.b. Any alternative test method or procedure not specifically allowed in the applicable regulation.

II.D.2. No alternative submitted pursuant to this Section II.D. is effective until the alternative is approved as a revision to the State Implementation Plan.

II.E. REPEALED

II.F. Provisions for Specific Processes

II.F.1. The Gates Rubber Company Provision – REPEALED

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

1978 Denver 1-hour Ozone Nonattainment Area designation first becomes effective in 7-county Denver Metropolitan Area

10/11/01 Denver 1-hour Ozone Attainment Maintenance Area designation replaces non-attainment designation and becomes effective in 7-county Denver Metropolitan Area

9/2/05 1-hour Ozone National Ambient Air Quality Standard is Revoked in Colorado except for the Denver 1-hour Ozone Attainment Maintenance Area.

Denver Metropolitan Area and North Front Range

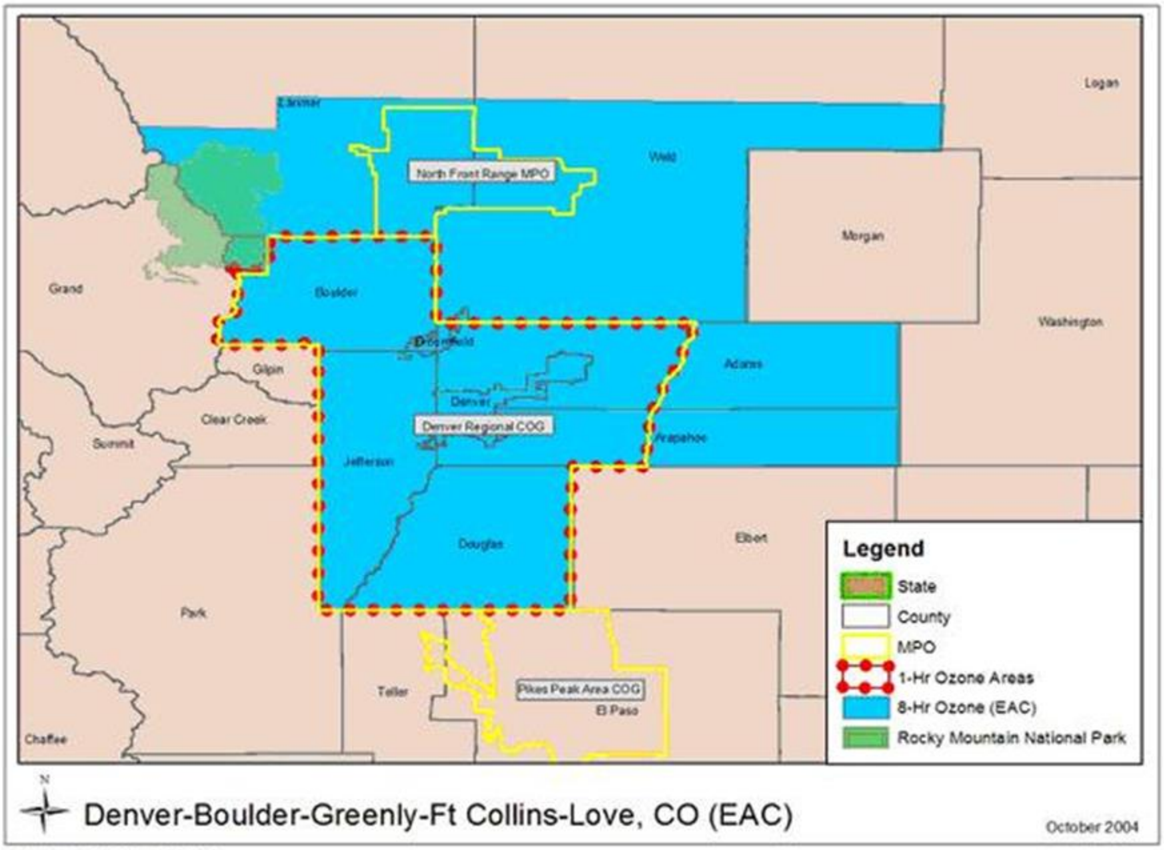
10/11/01 1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area

4/15/04 EPA designates the Denver Metro Area/North Front Range region as an 8-hour ozone non-attainment area, designation deferred due to the implementation of the Early Action Compact

11/20/07 Denver 8-hour ozone non-attainment designation becomes effective in 9 county Denver Metropolitan Area

II. Maps

Denver Metropolitan Area and North Front Range



Prepared by FHWA - HEPN-40

PART B Storage, Transfer, and Disposal of Volatile Organic Compounds and Petroleum Liquids and Petroleum Processing and Refining

I. General Requirements for Storage and Transfer of Volatile Organic Compounds

I.A. Maintenance and Operation of Storage Tanks and Related Equipment

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing and monitoring shall be conducted as in Part B, Section VI.C.3.

I.B. Transfer (excluding Petroleum Liquids)

Except as otherwise provided in this regulation, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

I.C. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of Section I.B.

II. Storage of Highly Volatile Organic Compounds

II.A. Highly volatile organic compounds shall be stored:

II.A.1. In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air; or

II.A.2. With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility.

II.B. Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, vapor loss means a VOC concentration exceeding 10,000 ppm and testing and monitoring procedures shall be conducted as in Part B, Section VI.C.3.

III. Disposal of Volatile Organic Compounds

III.A. No person shall dispose of volatile organic compounds by evaporation or spillage unless RACT is utilized.

III.B. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

IV. Storage and Transfer of Petroleum Liquid

IV.A. General Requirements

IV.A.1. No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

IV.A.2. Definitions

For the purpose of this section, the following definitions apply:

IV.A.2.a. Repealed.

IV.A.2.b. "Crude Oil" means a naturally occurring mixture which consists of hydrocarbons, sulfur, nitrogen or oxygen derivatives of hydrocarbons, and which is a liquid at standard conditions.

IV.A.2.c. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

IV.A.2.d. "EFR Tank" means a storage vessel having an external floating roof.

IV.A.2.e. "External Floating Roof" means a storage vessel cover in an open top tank consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

IV.A.2.f.“Liquid-Mounted Seal" means a primary seal mounted in continuous contact with the contained liquid and which occupies an annular space between the inner tank wall and the perimeter of the floating roof.

IV.A.2.g. "Petroleum Liquid" means crude oil, condensate and any finished or intermediate product manufactured or extracted in a petroleum refinery.

IV.A.2.h. "Shoe Seal" means a primary seal employing a metallic band (called a shoe) which is held against the vertical inner-wall of the tank, concentric with the perimeter of the floating roof.

IV.A.2.i. "Vapor Balance System" means a combination of pipes or hoses that create a closed system between the vapor spaces of an unloading tank and a receiving tank such that vapors displaced from the receiving tank are transferred to the tank being unloaded.

IV.A.2.j. “Vapor Collection System” means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

IV.A.2.k. "Vapor-Mounted Seal" means a primary seal mounted so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the liquid surface, the floating roof, and the tank wall (thus excluding shoe seals).

IV.A.2.l. "Waxy, Heavy Pour Crude Oil" means a crude oil with a pour point of 10°C (50°F) or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils."

IV.B. Storage of Petroleum Liquid

IV.B.1. Exemptions

IV.B.1.a. Tanks or other containers used to store the following liquids are exempt from the provisions of Sections IV.B.2. and IV.B.3.:

IV.B.1.a.(i) Diesel Fuels 1-D, 2-D, and 4-D as defined in ASTM D975-78.

IV.B.1.a.(ii) Fuel Oils #1, #2, #3, #4, and #5, as defined in ASTM D396-78.

IV.B.1.a.(iii) Gas Turbine Fuels 1-GT through 4-GT as defined in ASTM D2880-78.

IV.B.1.b. The following underground storage facilities are exempt from Section IV.B.2.:

IV.B.1.b.(i) Underground tanks if the annual sum total of the volume of liquid removed from the tank plus the sum of the volume of liquid added to it does not exceed twice the operational volume of the tank (i.e., a maximum of one turnover per year is allowed).

IV.B.1.b.(ii) Subsurface caverns or porous rock reservoirs.

IV.B.1.b.(iii) Horizontal underground tanks storing JP-4 Jet Fuel.

IV.B.2. Storage of petroleum liquid in tanks greater than 151,412 liters (40,000 gallons)

IV.B.2.a. Storage of petroleum liquid in fixed-roof tanks.

IV.B.2.a.(i) The owner or operator of a fixed-roof tank used for storage of petroleum liquids which have a true vapor pressure greater than 33.6 torr (0.65 psia) at 20°C (or, alternatively, a Reid vapor pressure greater than 1.30 pounds - (67.2 torr) but not greater than 570 torr (11.0 psia) at 20°C, and which are stored in any tank or other container of more than 151,412 liters (40,000 gallons) shall ensure that the tank at all times meets the following conditions:

IV.B.2.a.(i)(A) The tank has been equipped with a pontoon-type, or double-deck type, floating roof or an internal floating cover which rests on the surface of the liquid contents and which is equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and tank walls; or

IV.B.2.a.(i)(B) The tank has been equipped with a vapor gathering system capable of collecting the petroleum liquid vapors discharged, together with a vapor recovery or disposal system capable of processing such vapors so as to prevent their emission into the atmosphere.

IV.B.2.a.(i)(C) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections III.A.3.a., b., c., and e., and III.A.8.a. and b.

IV.B.2.a.(i)(D) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.B.2.a.(i)(E) The owner or operator shall maintain records for at least two years of the type, average monthly storage temperature, and true vapor pressure of all petroleum liquids stored in tanks not equipped with an internal floating roof or cover or other control pursuant to Regulation Number 7, Sections IV.B.2.a.(i)(A) or IV.B.2.a.(i)(B) or Part A, Section II.D.

IV.B.2.a.(ii) No owner or operator of a fixed-roof tank equipped with an internal floating roof or cover shall permit the use of such tank unless:

IV.B.2.a.(ii)(A) The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; and

IV.B.2.a.(ii)(B) All openings, except stub drains, are equipped with covers, lids, or seals such that:

IV.B.2.a.(ii)(B)(1) The cover, lid, or seal is in the closed position at all times except when in actual use;

IV.B.2.a.(ii)(B)(2) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports; and

IV.B.2.a.(ii)(B)(3) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

IV.B.2.a.(iii) The operator of a fixed-roof tank equipped with an internal floating roof shall:

IV.B.2.a.(iii)(A) Perform a routine inspection through the tank roof hatches at least once every six months;

IV.B.2.a.(iii)(A)(1) During the routine inspection, the operator shall measure for detectable vapor loss inside the hatch. Detectable vapor loss means a VOC concentration exceeding 10,000 ppm, using a portable hydrocarbon analyzer.

IV.B.2.a.(iii)(B) Perform a complete inspection of the cover and seal whenever the tank is out of service, whenever the routine inspection required in Section IV.B.2.a.(iii)(A) reveals detectable vapor loss, and at least once every ten years, and shall notify the Division in writing before such an inspection.

IV.B.2.a.(iii)(C) Ensure during inspections that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; that the cover is floating uniformly on or above the liquid surface; that there are no visible defects in the surface of the cover or liquid accumulated on the cover; and that the seal is uniformly in place around the circumference of the cover between the cover and the tank wall. If these items are not met, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this section cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Division in writing. Such a request must document that alternative storage capacity is unavailable and specify a schedule of actions the owner or operator will take that will assure that the items will be repaired or the vessel will be emptied as soon as possible;

IV.B.2.a.(iii)(D) Maintain records for at least two years of the results of all inspections.

IV.B.2.b. Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity for solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacturer for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less.

IV.B.2.c. Seals on External Floating Roof Tanks

IV.B.2.c.(i) General Provisions

IV.B.2.c.(i)(A) Applicability

This section applies to all petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons) that are located in ozone nonattainment areas.

IV.B.2.c.(i)(B) Exemptions

IV.B.2.c.(i)(B)(1) Total Exemption

The following categories of EFR tanks are exempt from the requirement of Section IV.B.2.c., except for the applicable recordkeeping requirements of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(1)(a) EFR tanks which store any material whose true vapor pressure as stored never exceeds 67 torr (1.3 psia).

IV.B.2.c.(i)(B)(1)(b) Tanks less than 1,600,000 liters (10,000 barrels) which are used to store crude oil and condensate prior to custody transfer.

IV.B.2.c.(i)(B)(2) Limited Exemptions

The following are exempt from both secondary seal and secondary seal inspection requirements but shall meet the equipment/procedure provisions in Section IV.B.2.c.(ii)(A)(1), the semi-annual inspection provisions of Section IV.B.2.c.(ii)(B), and the record keeping provisions of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(2)(a) Those tanks storing petroleum liquid between 67 and 207 torr (1.3 to 4.0 psia) maximum true vapor pressure (as stored) which are of welded construction and which have one of the following primary seals:

IV.B.2.c.(i)(B)(2)(a)(I) metallic shoe seal

IV.B.2.c.(i)(B)(2)(a)(II) liquid mounted, resilient seal

IV.B.2.c.(i)(B)(2)(a)(III) liquid mounted, liquid filled seal

IV.B.2.c.(i)(B)(2)(b) Any tank storing waxy, heavy-pour crude oil.

IV.B.2.c.(ii) General Requirements

IV.B.2.c.(ii)(A) An operator of an EFR tank storing petroleum liquids with true vapor pressure (as stored) above 67 torr (1.3 psia) shall equip the tank as follows and observe the following procedures:

IV.B.2.c.(ii)(A)(1) Equipment

IV.B.2.c.(ii)(A)(1)(a) Drains: roof drains which are designed to empty directly into the stored product shall be provided with slotted-membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening.

IV.B.2.c.(ii)(A)(1)(b) Openings: except for automatic bleeder vents, rim space vents, and leg sleeves, all openings shall be equipped with:

IV.B.2.c.(ii)(A)(1)(b)(I) Projections into the tank which remain below the liquid surface at all times; and

IV.B.2.c.(ii)(A)(1)(b)(II) Covers, seals, or lids.

IV.B.2.c.(ii)(A)(2) Procedures

IV.B.2.c.(ii)(A)(2)(a) Covers, seals and lids shall be kept closed except when the openings are in actual use.

IV.B.2.c.(ii)(A)(2)(b) Automatic bleeder vents shall be kept closed at all times except when the roof is floated off or landed on roof leg supports.

IV.B.2.c.(ii)(A)(2)(c) Rim vents shall be set to open at the manufacturer's recommended setting or, alternatively, only when the roof is being floated off the leg supports.

IV.B.2.c.(ii)(B) Inspections

The operator of an EFR tank subject to this Section IV.B.2.c. shall:

IV.B.2.c.(ii)(B)(1) Perform routine inspections at least once every six months in order to ensure compliance with Section IV.B.2.c.(ii)(B)(2). The inspections shall include a visual inspection of the secondary seal gap if equipped with a secondary seal.

IV.B.2.c.(ii)(B)(2) Ensure that all seal closure devices meet the following requirements:

IV.B.2.c.(ii)(B)(2)(a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; and

IV.B.2.c.(ii)(B)(2)(b) The seal(s) are intact and uniformly in place around the circumference of the floating roof and the tank wall.

IV.B.2.c.(ii)(C) Records

IV.B.2.c.(ii)(C)(1) Operators shall:

IV.B.2.c.(ii)(C)(1)(a) Maintain records of the average monthly storage temperature, the Reid vapor pressure of the liquid and the type of liquid stored for all EFR tanks lacking secondary seals and receiving petroleum liquids with a true vapor pressure of 1.0 psi (7.0kPa) or greater; and

IV.B.2.c.(ii)(C)(1)(b) Maintain records of the results of the inspections required herein.

IV.B.2.c.(ii)(C)(2) Copies of all records specified by this Section IV.B.2.c.(ii)(C) shall be retained by the operator for a minimum of two years after the date on which the record was made.

IV.B.2.c.(iii) Secondary Seal Requirements

IV.B.2.c.(iii)(A) General

No owner or operator of an EFR tank (storing petroleum liquids) not specifically exempted in Section IV.B.2.c.(i)(B) shall store that petroleum liquid unless such vessel is equipped with a continuous secondary seal extending from the rim of the floating roof to the tank wall (i.e., a rim-mounted secondary seal).

IV.B.2.c.(iii)(B) Vapor-Mounted Seals

For EFR tanks required to have a secondary seal and which have a vapor-mounted primary seal:

IV.B.2.c.(iii)(B)(1) An annual inspection shall be made of the total gap area between the secondary seal and the wall of the tank in accordance with the method in IV.B.2.c.(iii)(B)(3).

IV.B.2.c.(iii)(B)(2) This total gap area shall not exceed 21.2 cm2/meter diameter (1.0 in2/ft. diameter).

IV.B.2.c.(iii)(B)(3) Method to determine gap area:

IV.B.2.c.(iii)(B)(3)(a) Physically measure the length and width of all gaps around the entire circumference of the secondary seal in each place where a 0.32 cm (1/8 in.) uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and the tank wall; and,

IV.B.2.c.(iii)(B)(3)(b) Sum the area of the individual gaps.

IV.B.3. Storage of petroleum liquid in tanks of or less than 151,412 liters (40,000 gallons) capacity

IV.B.3.a. Tanks or containers used to store liquids with true vapor pressure at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) at 20°C are exempt from the provisions of this Section IV.B.3.

IV.B.3.b. The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections IV.C.2. or IV.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and all vapors displaced from the storage tank are transferred to the delivery vessel being unloaded using a properly maintained, functioning, and leak-tight vapor collection system, as in accordance with applicable provisions of Appendix B and Section VII., if the tank:

IV.B.3.b.(i) Has a rated manufacturer's capacity of 2,082 liters (550 gallons) or more and was installed after November 7, 1973, (except for storage tanks below 550-gallon capacity used exclusively for agricultural use; however, these must have a submerged fill pipe), or

IV.B.3.b.(ii) Has a rated manufacturer's capacity of 7,571 liters (2,000 gallons) or more and was installed before November 7, 1973.

IV.B.3.c. Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix B.

IV.B.3.d. The owner or operator of storage tanks at a gasoline dispensing facility must install and operate one or more of the following

IV.B.3.d.(i) A vapor collection system designed and operated in accordance with a vapor-tight line from the storage tank to delivery vessel.

IV.B.3.d.(ii) A refrigerator-condensation system or equivalent designed to recover at least 90 percent by weight of the organic compounds in the displaced vapor.

IV.B.3.e. The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor collection system is installed and operated to ensure the system is leak-tight during gasoline transfer.

IV.B.3.f. The vapor collection system shall meet the specifications of Appendix B and applicable requirements of Section VII.

IV.B.3.g. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.B.3.h. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C. Transfer of Petroleum Liquid

IV.C.1. Exemptions

Transfer operations involving petroleum liquid with true vapor pressures at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) shall be exempt from the provisions of this Section IV.C.

IV.C.2. Loading Facilities Classified as Terminals

IV.C.2.a. A terminal is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of more than 76,000 liters of gasoline (20,000 gallons), which is loaded directly into transport vehicles. A rolling, 30-day average of throughput shall be used to determine the applicability of this Section IV.C.2.

IV.C.2.b. The owner or operator of a terminal subject to this section shall equip the terminal with proper loading equipment and shall follow the loading procedures listed:

IV.C.2.b.(i) Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles.

IV.C.2.b.(ii) Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use.

IV.C.2.b.(iii) Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.2.b.(iv) Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment.

IV.C.2.b.(v) Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles.

IV.C.2.b.(vi) Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices.

IV.C.2.b.(vii) Maintain and operate final recovery and disposal equipment or control devices so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division.

IV.C.2.b.(viii) Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight test certification as required in Section IV.D.

IV.C.2.b.(ix) Follow all control procedures to prevent leaks as specified in Section VII.

IV.C.2.c. Control devices shall meet the applicable requirements, including recordkeeping of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

IV.C.2.d. The applicable methods of 40 CFR 60. 503 (September 14, 1989), or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C.2.e. The method set forth in Appendix A of "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" October 1977, EPA-450/2-77-026 shall be used to test emission points other than control devices.

IV.C.3. Loading Facilities Classified as Bulk Plants

IV.C.3.a. A bulk plant is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of 76,000 liters of gasoline (20,000 gallons) or less, which is loaded directly into transport trucks. (As used herein, "bulk plant" does not include service stations nor separate operations within petroleum liquid distribution facilities which pump only into fuel tanks fueling motor vehicles. Both such operations are regulated by Section IV.B.3.). A rolling 30-day average of throughput shall be used to determine the applicability of this regulation.

IV.C.3.b. The owner or operator of a bulk storage plant subject to this section shall install a vapor balance system to return vapors to the incoming transport trucks during the filling of tanks controlled under Section IV.B.3. The vapor balance system must be designed and operated in accord with the provisions of Appendix C.)

IV.C.3.c. The owner or operator of a bulk plant which serves storage tanks which are required to collect and recover vapor as prescribed in Section IV.B.3. shall:

IV.C.3.c.(i) Install and operate vapor collection and return equipment on any transport vehicles used to deliver to controlled tanks, and

IV.C.3.c.(ii) Install and operate vapor collection and return equipment at loading facilities to collect vapors during loading of tank compartments of outbound transport trucks and return these vapors to the bulk plant storage tanks, using a vapor balance system.

IV.C.3.c.(iii) Assure that transport trucks and loading facilities conform to the applicable provisions of Sections IV.C.2. and IV.C.4.

IV.C.3.d. The owner or operator of a bulk plant which serves only storage tanks exempted from the provisions of Section IV.B.3.b. by reason of their small size or location in an attainment area shall load outbound transport trucks using equipment that provides for top loading of the petroleum liquid into the vehicle tank compartments through an extended fill tube which reaches within 15.24 cm (6 in.) of the bottom of the tank compartment.

IV.C.3.e. The owner or operator of a bulk plant subject to this section shall ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.

IV.C.3.f. The owner or operator of a bulk plant subject to this section shall follow all procedures to prevent leaks as specified in Section VII.

IV.C.4. Transport Vehicles

IV.C.4.a. Rail cars shall be loaded only at facilities which allow for the following:

IV.C.4.a.(i) A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank.

IV.C.4.a.(ii) Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car.

IV.C.4.a.(iii) A vapor-tight seal around the tank car hatch and the loading equipment.

IV.C.4.b. The owner or operator of petroleum transport trucks which serve locations required to be equipped with vapor recovery equipment shall load only at facilities capable of disposing of collected vapors. The owner or operator shall assure that such vehicles possess the proper equipment and that work practices are followed so that:

IV.C.4.b.(i) Dry-break loading and unloading nozzles are used and are compatible with those required at loading facilities.

IV.C.4.b.(ii) Vapor recovery hoses are connected at all times during unloading or loading of petroleum distillate.

IV.C.4.b.(iii) Transport trailers and vehicle tanks are operated and maintained to prevent detectable hydrocarbon vapor loss during loading, transport and delivery.

IV.C.4.b.(iv) Compartment dome lids are closed and locked during transfers of petroleum liquid. Such lids may be opened for the purpose of certifying the accuracy of a delivery only prior to and after such delivery.

IV.C.4.b.(v) Hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loading or unloading.

IV.D. Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks

IV.D.1. General Provisions

IV.D.1.a. Applicability

This section is applicable to all gasoline transport trucks equipped for gasoline vapor collection which receive or dispense gasoline at terminals, bulk plants, or gasoline dispensing facilities located in the nonattainment areas.

IV.D.1.b. Definitions

For the purpose of this section, the following definitions apply:

IV.D.1.b.(i) "Gasoline Transport Truck" means a tank truck or tank trailer equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants, or gasoline terminals.

IV.D.1.b.(ii) "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into a vessel being unloaded or into a vapor holding tank.

IV.D.2. Provisions for Specific Processes

IV.D.2.a. No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section IV.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck:

IV.D.2.a.(i) Is tested annually according to the test procedure in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). Testing must be completed prior to the onset of the summer ozone season (test October through April). In addition, a visual inspection, as detailed in Section IV.D.3.b. must be performed at least once every six months.

IV.D.2.a.(i)(A) The test must be conducted using a time period (t) for the pressure and vacuum tests of 5 minutes.

IV.D.2.a.(i)(B) The initial pressure (P_i) for the pressure test must be 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(C) The initial vacuum (V_i) for the vacuum test must be 150 mm H_2O (6 in. H_2O), gauge.

IV.D.2.a.(i)(D) The maximum allowable pressure and vacuum changes must not exceed the values in Table 1.

IV.D.2.a.(i)(E) After completing the tests under Sections IV.D.2.a.(i)(A) through (D), the tank's internal vapor valve must be pressure tested.

IV.D.2.a.(i)(E)(1) Use the procedures in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000) to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge.

IV.D.2.a.(i)(E)(2) Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

IV.D.2.a.(i)(E)(3) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line.

IV.D.2.a.(i)(E)(4) After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change in 5 minutes, mm H2O (in. H2O)	Allowable pressure change in 5 minutes at any time, mm H2O (in. H2O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

IV.D.2.a.(ii) Passes a retest within twenty (20) days if it does not meet the criteria of Section IV.D.2.a.(i).

IV.D.2.b. Monitoring

IV.D.2.b.(i) The Division may, at any time, monitor a gasoline tank truck vapor collection system to confirm continued compliance with Section IV.D.2.a.

IV.D.2.b.(ii) Within fifteen (15) days after an exceedance is detected a tank shall pass a pressure/vacuum test per EPA Method 27 (40 CFR Part 60, Appendix A-8 (October 17, 2000)).

IV.D.3. Testing and Monitoring

IV.D.3.a. The owner or operator of a gasoline transport truck shall at their own expense, demonstrate compliance with Section IV.D.2, by methods of EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). All tests shall be made by, or under the direction of, a person qualified by training and/or experience in the field of air pollution testing or gasoline transport truck maintenance.

IV.D.3.b. The owner or operator of a gasoline transport truck must conduct a visual inspection of the gasoline transport truck at least once every six months. The entire tank, including domes, dome vents, cargo tank, piping, hose connections, hoses and delivery elbows, must be inspected for wear, damage, or misadjustment that could be a potential leak source. Inspect all rubber fittings except those in piping which are not accessible. Any part found to be defective must be adjusted, repaired, or replaced as necessary.

IV.D.4. Recordkeeping and Reporting

IV.D.4.a. The owner or operator of a gasoline transport truck subject to this Section IV.D. shall maintain records of all certification testing and repairs. The records shall identify the gasoline transport truck, the date of the test or repairs and, if applicable, the type of repair and the date of retest. The written record shall include entries of any pre-test repairs, adjustments, or modifications. These shall also include the part name, number, and vendor name of any part removed and of any part installed. The records shall be maintained in legible, readily available form for at least two (2) years after the date the testing or repair was completed and shall be made available to the Division for inspection upon request.

IV.D.4.b. The records of certification tests required by Section IV.D.2.a. must, as a minimum, contain all of the following entries:

IV.D.4.b.(i) The gasoline transport truck owner’s name and address;

IV.D.4.b.(ii) The gasoline transport truck/tank identification number;

IV.D.4.b.(iii) The nature of repair work and when performed in relation to vapor tightness testing.

IV.D.4.b.(iv) The following data for each test:

IV.D.4.b.(iv)(A) Test pressure.

IV.D.4.b.(iv)(B) Pressure or vacuum change, mm of water.

IV.D.4.b.(iv)(C) Time period of test.

IV.D.4.b.(iv)(D) Number of leaks found with instrument.

IV.D.4.b.(iv)(E) Leak definition.

IV.D.4.b.(v) The size of each of the compartments within the tank and whether such compartment was manifolded or was tested separately during pressure and vacuum tests.

IV.D.4.b.(vi) At the top of each report page shall be the company name and the date and location of the test results recorded on that page; and

IV.D.4.b.(vii) Name and title of the person conducting the test.

IV.D.4.b.(viii) For the vapor valve test required in Section IV.D.2.a.(ii)(A), the initial test pressure and time of reading.

IV.D.4.c. The records of the visual inspections required by Section IV.D.3.b.

IV.D.4.d. The owner or operator of a gasoline transport truck subject to this regulation must annually certify to the Division that the gasoline transport truck has been tested by the applicable method(s) referenced in Section IV.D.3. The certification must include:

IV.D.4.d.(i) The name and address of the company and the name and telephone number of responsible company representative over whose signature the certification is submitted; and,

IV.D.4.d.(ii) A copy of the information recorded to comply with Section IV.D.4.b.

IV.D.4.e. The records of certification tests must be kept with the tank or at the transport company office at all times and must be shown to Division personnel upon their request. Copies of all records and reports required by the provisions of this Section IV.D. must be made available to the Division upon oral or written request.

V. Crude Oil

V.A. General Exemptions

V.A.1. Storage tanks of 151,412 liters (40,000 gallons) or less used to store crude oil is exempt from the provisions of this section.

V.A.2. Storage tanks with capacities of less than 1,590 cubic meters (10,000 barrels) used to store crude oil and condensate prior to lease custody transfer are exempt from the provisions of this Regulation Number 7 other than Part D, Sections I. and II.

V.B. Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section IV.A.

V.C. Storage

Except as provided in Section V.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections IV.B.1.b. and IV.B.2.

VI. Petroleum Processing and Refining

VI.A. Wastewater (Oil/Water) Separators

VI.A.1. Definitions

VI.A.1.a. "Forebays" mean the primary sections of a wastewater separator.

VI.A.1.b. "Wastewater (oil/water) separator" means any device or piece of equipment which utilizes the difference in density between oil and water to remove oil and associated chemicals from water, or any device, such as a flocculation tank, clarifier, etc., which removes petroleum derived compounds from wastewater.

VI.A.2. The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall:

VI.A.2.a. Equip the forebays and separator sections of the wastewater separators with one or more of the following emission control devices, ensuring that such device is properly installed, in good working order and properly maintained:

VI.A.2.a.(i) A solid cover with all openings sealed and the liquid contents totally enclosed.

VI.A.2.a.(ii) A pontoon-type or double-deck type floating roof, or internal floating cover. The floating roof or cover must rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and the wall(s) of the compartment.

VI.A.2.a.(iii) A vapor recovery system consisting of a vapor gathering device capable of collecting the volatile organic compound vapors discharged and a vapor disposal device capable of processing such volatile organic vapors so as to prevent their emission into the atmosphere.

VI.A.2.a.(iii)(A) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.A.2.a.(iii)(B) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

VI.A.2.b. Equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized.

VI.B. Emissions from Petroleum Refineries

VI.B.1. Definitions

VI.B.1.a. "Firebox" means the chamber or compartment of a boiler or furnace in which materials are burned but does not mean the combustion chamber of an incinerator.

VI.B.1.b. "Turnaround" means the procedure of shutting a refinery unit down after a run to do necessary maintenance and repair work and then putting the unit back on stream.

VI.B.2. Process unit turnarounds

The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

VI.B.2.a. Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency;

VI.B.2.b. No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and

VI.B.2.c. Recordkeeping of the following items. Records shall be kept for at least two years and shall be made available to the Division for review upon request.

VI.B.2.c.(i) Every date that each process unit is shut down,

VI.B.2.c.(ii) The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere, and

VI.B.2.c.(iii) The approximate total quantity of volatile organic compounds emitted to the atmosphere.

VI.B.3. Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

VI.B.4. Vacuum-Producing Systems

VI.B.4.a. The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensible volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by:

VI.B.4.a.(i) Venting the noncondensible vapors to a flare or other combustion device, or,

VI.B.4.a.(ii) Compressing the vapors and adding them to the refinery fuel gas.

VI.B.5. All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access.

VI.B.6. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.B.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

VI.C. Petroleum Refinery Equipment Leaks

VI.C.1. Definitions

For the purpose of this section, the following definitions apply:

VI.C.1.a. "Accessible Component" means a component which can be reached, if necessary, by safe and proper use of portable ladders such as are acceptable to OSHA, as well as by built-in ladders and walkways. "Accessible" also includes components which can be reached by the safe use of an extension on the monitoring probe.

VI.C.1.b. "Component" means any piece of equipment, which has the potential to leak volatile organic compounds when tested in the manner described in Section VI.C.3. These sources include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open ended pipes. Excluded from these sources are valves which are not externally regulated.

VI.C.1.c. "Gaseous Service" means equipment which processes, transfers or contains a volatile organic compound or mixture of volatile organic compounds in the gaseous phase.

VI.C.1.d. "In Heavy VOC Liquid Service" means that the piece of equipment is not in gaseous service or in light VOC liquid service.

VI.C.1.e. "In Light Liquid VOC Service" Equipment is in light liquid service if the following conditions apply:

VI.C.1.e.(i) the true vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C. True vapor pressures may be obtained from standard reference texts or may be determined by ASTM D-2879.

VI.C.1.e.(ii) the total concentration of the pure components have a true vapor pressure greater than 0.3 kPa at 20°C, is equal to or greater than 20 percent by weight; and

VI.C.1.e.(iii) the fluid is a liquid at operating conditions.

VI.C.1.f. "Refinery Unit" means a set of components which are a part of a basic process operation, such as, distillation, hydrotreating, cracking, or reforming of hydrocarbons.

VI.C.1.g. "Water Draw" means a routinely used valve or system employing a valve which allows non-VOC material (usually water) to be separated from VOC.

VI.C.2. Provisions for Specific Processes

VI.C.2.a. The owner or operator of a petroleum refinery complex subject to this regulation shall:

VI.C.2.a.(i) Develop a monitoring program consistent with the provisions in Section VI.C.3.

VI.C.2.a.(ii) Conduct a monitoring program consistent with the provisions in Section VI.C.4.a.

VI.C.2.a.(iii) Record all leaking components which have a VOC concentration exceeding 10,000 ppm when tested according to Section VI.C.3., and place an identifying tag on each component consistent with the provisions in Section VI.C.4.a.(iii).

VI.C.2.a.(iv) Repair and retest leaking components, as defined in Section VI.C.2.a.(iii), as soon as possible, but no later than fifteen (15) days after the leak is found, excepting those specified in Sections VI.C.2.a.(v) and VI.C.2.a.(vi).

VI.C.2.a.(v) Identify all leaking components as defined in Section VI.C.2.a.(iii), which cannot be repaired until the unit is shut down for turnaround, and repair and retest as in Section VI.C.2.a.(iv) when the unit is back on stream.

VI.C.2.a.(vi) When a component leak cannot be fixed within fifteen (15) working days solely because parts are not available, the following shall be noted in an "awaiting parts log:"

VI.C.2.a.(vi)(A) component identification and tag number

VI.C.2.a.(vi)(B) date part was ordered

VI.C.2.a.(vi)(C) date part was received

VI.C.2.a.(vi)(D) date repair was made

VI.C.2.b. Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use.

VI.C.2.c. The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround provided:

VI.C.2.c.(i) The requirement does not exceed reasonable available control technology due to cost per ton of emissions reduction achieved by the early turnaround or other reasonable analysis.

VI.C.2.c.(ii) The Division provides the owner or operator of a petroleum refinery with written notification at least 180 days before requiring an early turnaround. The owner or operator will have 30 days from the date of the Division's notification to contest the requirement by submitting a demonstration that the requirement is beyond reasonable available control technology. If no demonstration is made, it will be assumed the requirement is reasonable. If a demonstration is submitted by the owner or operator, the Division will either approve the demonstration or disapprove the demonstration with a justification regarding the disapproval within 30 days of the date the demonstration is submitted to the Division.

VI.C.2.c.(iii) The requirement is not contested by the owner or operator. Should the requirement be contested, the requirement for early unit turnaround will be delayed until 180 days after the demonstration discussed in Section VI.C.2.c.(ii) is disapproved by the Division.

VI.C.2.d. Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly.

VI.C.3. Testing and Monitoring Procedures

Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60 (September 14, 1989). The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound.

VI.C.4. Monitoring, Recordkeeping, Reporting

VI.C.4.a. Monitoring

VI.C.4.a.(i) The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions:

VI.C.4.a.(i)(A) Monitor yearly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(A)(1) Pump seals; and

VI.C.4.a.(i)(A)(2) Piping valves in light liquid VOC service; and

VI.C.4.a.(i)(A)(3) Process drains; and

VI.C.4.a.(i)(A)(4) Heat-exchanger body flanges; and

VI.C.4.a.(i)(A)(5) Other accessible flanges in VOC service.

VI.C.4.a.(i)(A)(6) Components in heavy liquid VOC service are exempt from requirements of this Section VI.C.4.a.(i)(A).

VI.C.4.a.(i)(B) Monitor quarterly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(B)(1) Compressor seals; and

VI.C.4.a.(i)(B)(2) Piping valves in gaseous service; and

VI.C.4.a.(i)(B)(3) Pressure relief valves in gaseous service.

VI.C.4.a.(i)(C) Monitor at least weekly by visual methods all pump seals.

VI.C.4.a.(i)(D) Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking.

VI.C.4.a.(i)(E) Components in heavy liquid VOC service shall be monitored by the method referenced in Section VI.C.3. within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method.

VI.C.4.a.(ii) Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of VI.C.2.a.(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Section VI.C.4.a.(i).

VI.C.4.a.(iii) The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VI.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VI.C.4.b.(i) through (iii).

VI.C.4.b. Recordkeeping

VI.C.4.b.(i) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain at a minimum, the following data:

VI.C.4.b.(i)(A) The name of the process unit where the component is located.

VI.C.4.b.(i)(B) The type of component (e.g., valve, seal).

VI.C.4.b.(i)(C) The tag number of the component.

VI.C.4.b.(i)(D) The date on which a leaking component is discovered.

VI.C.4.b.(i)(E) The date on which a leaking component is repaired.

VI.C.4.b.(i)(F) The date and instrument reading found during the recheck procedure subsequent to repairing a leaking component.

VI.C.4.b.(i)(G) A record of the calibration of the monitoring instrument.

VI.C.4.b.(i)(H) Those leaks that cannot be repaired until turnaround.

VI.C.4.b.(i)(I) The total number of components checked and the total number of components found leaking.

VI.C.4.b.(i)(J) The total number of components subject to Section VI.C.2.a.(v) which upon retest were still leaking as defined in Section VI.C.3.

VI.C.4.b.(ii) Copies of the monitoring log shall be retained by the owner or operator for a minimum of two (2) years after the date on which the record was made or report prepared.

VI.C.4.b.(iii) Copies of the monitoring log shall be made available to the Division upon oral or written request.

VI.C.4.c. Reporting

The owner or operator of a petroleum refinery, upon the completion of each yearly and/or quarterly monitoring procedure, shall:

VI.C.4.c.(i) Submit a report to the Division by the 15th day of February, May, August, and November that lists all leaking components that were located during the previous three (3) calendar months (quarter), but not repaired within fifteen (15) working days, all leaking components awaiting unit turnaround, the total number of components inspected, and the total number of components found leaking.

VI.C.4.c.(ii) Submit a signed statement with the report attesting to the fact that, with the exception to those leaking components listed in Section VI.C.4.b.(i)(H), all monitoring and repairs were performed as stipulated in the monitoring program.

VII. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities

VII.A. General Provisions

VII.A.1. Applicability

This section is applicable to all gasoline terminals, gasoline bulk plants, and gasoline dispensing facilities (e.g., service stations) which are located in ozone nonattainment areas and which must have a vapor collection system pursuant to Section IV. and other applicable rules.

VII.A.2. Exemptions

This section is not applicable to those operations involving transfer of gasoline from gasoline dispensing facilities to motor vehicle fuel tanks nor to other dispensing operations at such facilities.

VII.A.3. Definitions

For the purpose of this section, the following definitions apply:

VII.A.3.a. "Gasoline Dispensing Facility” means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks, (e.g., service stations, fleet pumps, etc.)

VII.A.3.b. "Gasoline Transport Truck" means tank trucks or trailers equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants or gasoline terminals.

VII.A.3.c. "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

VII.B. Specific Provisions

VII.B.1. The operator of a vapor collection system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

VII.B.1.a. Gauge pressure from exceeding 33.6 torr (18 inches of H2O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H2O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.

VII.B.1.b. A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," December 1978, EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.c. Avoidable liquid or vapor leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.

VII.B.1.d. Division representatives may monitor for excessive back pressure as defined by Section VII.B.1.a. and vapor leakage as is defined by Section VII.B.1.b. or by detection methods incorporating sight, sound, and smell.

VII.B.2. Repairs and Modifications

VII.B.2.a. The operator shall within fifteen (15) days, repair and retest a vapor collection system that exceeds the pressure limits (Section VII.B.1.a.), excepting that;

VII.B.2.b. Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

Appendix B Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks

I. Drop Tube Specifications. Submerged fill is specifically required. The drop tube must extend to within 15.24 cm (6 in.) of the tank bottom.

II. Vapor Hose Return. Vapor return line and any manifold must be minimum 7.6 cm (3 in.) ID. All tanks must be provided with individual overfill protection. (Liquid must not be allowed in the vent line or vapor recovery line.) Disconnect on liquid line should assure that all liquid in the hose is drained into the storage tank. The requirements for overfill protection as specified may be waived for existing storage tanks when it is demonstrated to the satisfaction of the appropriate local Fire Marshal, and where applicable, the State Oil Inspection Office that the installation of overfill protection devices on existing tanks is physically not possible.

III. Size of Vapor Line Connections. For separate vapor lines, nominal three inch (7.6 cm) or larger connections must be utilized at the storage tank and truck. However, short lengths of 2-inch (5.1 cm) vertical pipe no greater than 91.4 cm (3 ft.) long are permissible if the fuel delivery rate is less than 400 gallons per minute.

Where concentric (coaxial) connections are utilized, a 45 cm2 (7 sq. in.) area for vapor return shall be provided. Four-inch concentric designs are acceptable only when using a venturi-shaped outer tube or where normal drop rate of 1,700 liters per minute (450 gpm) is reduced by at least 25%. Six-inch (15.24 cm) risers should be installed in new stations with concentric connections.

IV. Type of Liquid Fill Connection. Vapor tight caps are required for the liquid fill connection for all systems. A positive closure utilizing a gasket is necessary to prevent vapors from being emitted at ground level. Cam-lock closures meet this requirement. Dry break closures are preferred.

V. Tank Truck Inspection. Tank trucks are specifically required to be vapor-tight and to have valid leak-tight certification. The visual inspection procedure must be conducted at least once every six months to ensure properly operating manifolding and relief valves, using the test procedure of Section IV.D.3.b.

VI. Dry Break on Underground Tank Vapor Riser. Dry-break closures are required to assure transfer of displaced vapors to the truck and to prevent ground-level, gasoline-vapor emissions caused by failure to connect the vapor return line to the underground tanks (closure on riser to mate with opening on hose). These devices keep the tank sealed until the hose is connected to the underground tank. Concentric couplers without dry-breaks are required to have a dry-break on the vapor line connection to the coupler itself, rather than on the rise pipe from the storage tank. The liquid fill riser should be provided with a gap having a positive closure (threaded or latched).

VII. Equipment Ensuring Vapor-Hose Connection during Gasoline Deliveries. An equipment system aboard the tank truck shall insure (barring deliberate tampering) that a vapor return hose is connected from the truck's vapor return line to the tank receiving gasoline.

VIII. Vent Line Restriction Devices. Vent line restriction devices are required. If the liquid fill line were attached to the underground tank and the vapor return line were disconnected, then dry break closures would seal the vapor return path to the truck, forcing all vapors out the vent line. In such instances, a restriction device on this vent line greatly reduces fill rate, warning the operator that the vapor line is not connected.

Pressure/vacuum (PV) vent valves installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

IX. Fire and Safety Regulations. All new or modified installations must comply in their entirety with all code requirements including NFPA, Pamphlet 30 (fiberglass is preferred for new manifold lines). For any questions concerning compliance, please contact State Oil Inspection or your local Fire Marshal.

X. State Oil Inspection. Requirements of the State Oil Inspection office make accurate measurements of the liquid in the underground tank necessary. Vapor-tight gauging devices will be required in all systems designed such that a pressure other than atmospheric will be held or maintained in the storage tank. The volume of liquid in the tanks maintained at atmospheric pressure may be determined with a stick through the submerged drop tube or through a separate submerged gauging tube extending to within 15.24 cm (6 in.) of the tank bottom.

Appendix C Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants

I. Storage Tank Requirements:

A. Drop Tube Specification: Underground tanks must contain a drop tube that extends to within six inches (15.24 cm) of the tank bottom. All top loaded above-ground tanks must contain a similar drop tube. Above-ground tanks using bottom loading, where the inlet is flush with the tank bottom, must meet the submerged fill requirement.

B. Size of Vapor Lines from Storage Tanks to Loading Rack: See nomograph (Attachment 1). NOTE: Affected sources are free to choose a pipe diameter different from the one suggested by the nomograph if sufficient justification and documentation is presented.

C. Pressure Relief Valves: All pressure relief valves and valve connections must be checked periodically for leaks, and be repaired as required. The relief valve pressures should be set in accordance with Sections 2-2.5.1 and 2-2.7.1 inclusive of the current National Fire Protection Agency Pamphlet Number 30.

D. Liquid Level Check Port: Access for checking liquid level by other than a vapor-tight gauging system shall be vapor-tight when not being used. Tank level shall be checked prior to filling to avoid overfills.

E. Miscellaneous Tank Openings: All other tank openings, e.g., tank inspection hatches, must be vapor tight when not being used, and must be closed at all times during transfer of fuel.

F. Storage Tank Overfill Protection: Except for concentric (coaxial) delivery systems, underground tanks must have ball check valves (stainless steel ball). Tanks with concentric delivery systems must have Division-approved overfill protection, (e.g., cutoff pressure-switch in vent line).

II. Loading Rack Requirements:

A. Loading Specification: A vapor-tight bottom-loading or top-loading system using submerged fill with a positive seal, e.g., the Wiggins (tm) system, is required. NOTE: Bulk plants delivering solely to exempt accounts are required to have submerged fill, but loading need not be vapor-tight.

B. Dry-Break on Storage Tank Vapor Return Line: A dry-break is required to prevent ground-level gasoline vapor emissions during periods when gasoline transfer is not being made. This device keeps the tank sealed until the vapor return hose is connected.

III. Tank Truck* Requirements:

A. Vapor Return Modification: Tank trucks must be modified to recover vapors during loading and unloading operations. NOTE: Tank trucks making deliveries solely to exempt accounts do not require this modification. However, 97% submerged fill is required when top loading.

B. Loading Specifications: Bottom loading or top loading using submerged fill with a positive seal is required for tank trucks modified for vapor recovery. NOTE: When loading a tank truck with this modification without the vapor return hose connected (this is allowed at bulk plants servicing exempt accounts returning without collected vapors in the tank), the requirements of National Fire Protection Agency Pamphlet Number 385, "Loading and Unloading Venting Protection in Tank Vehicles, Section 2219, Paragraph c", must be met.

C. Vapor Return Hose Size: A minimum three-inch (7.6 cm) ID vapor return hose is required.

D. Tank Truck Inspection: Tank trucks are required to be vapor-tight and have valid leak-tight certification. Periodic visual inspection is necessary to insure properly operating manifolding and relief valves.

* The term "tank truck" is meant to include all trucks with tanks used for the transport of gasoline, such as tank wagons, account trucks and transport trucks.

PART C Surface Coating, Solvents, Asphalt, Graphic Arts and Printing, and Pharmaceuticals

I. Surface Coating Operations

I.A. General Provisions

I.A.1. Definitions, unless otherwise specified in Sections I.B. through I.O.

I.A.1.a. "Coating" means a protective, functional or decorative film applied in a thin layer to a surface. This term often applies to paints such as lacquers or enamels, but is also used to refer to films applied to paper, plastics, or foils.

I.A.1.b. "Coating Applicator" means an apparatus used to apply a surface coating.

I.A.1.c. "Coating Line" means an operation which includes both (1) a coating applicator and (2) device(s) and/or area(s) to accomplish one or more of the following processes: flash-off, drying, curing, heat-setting and/or polymerization.

I.A.1.d. "Coating Solids" means that portion of a surface coating, which remains after volatile components have escaped.

I.A.1.e. "Final Repair Application" means that application of surface coating specifically intended to repair damage and imperfections in existing surface coats.

I.A.1.f. "Finished Coating Solids" means those coating-solids that remain on a coated substance after completion of all production processes.

I.A.1.g. "Flash-off Area" means the space between the application area and the oven.

I.A.1.h. "Prime Coat" (also termed "primer") means the first film of coating applied in a multiple-coat operation.

I.A.1.i. "Single Coat" means a single film of coating applied directly to the metal substrate, omitting the primer application.

I.A.1.j. "Surface Coating" means a liquid, liquefiable, or mastic composition which is converted to a solid (or semi-solid) protective, decorative, or adherent film or deposit after application as a thin layer or by impregnation.

In a machine which has both coating and printing units, all units shall be considered as performing a printing operation. Such a machine is subject to the standards governing graphic arts, and thus is not covered by coating standards.

I.A.1.k. "Surface Coating Oven" means a chamber within which heat is used to bake, cure, polymerize, and/or dry a surface coating.

I.A.1.l. "Topcoat" means the final film of coating applied in a multiple-coat operation.

I.A.2. Abbreviations

I.A.2.a. Kg/lc shall be the abbreviation for: kilograms of solvent VOC per liter of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.2.b. Lb/gc shall be the abbreviation for: (avoirdupois) pounds of solvent VOC per gallon of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.3. Test Methods and Procedures

I.A.3.a. The owner or operator of any VOC source required to comply with this section shall, at their own expense, demonstrate compliance using EPA reference method 24 of 40 CFR Part 60 (September 14, 1989) for surface coatings, and reference method 25 and reference methods 1 through 4 (September 14, 1989) for add-on controls.

I.A.3.b. The test protocol should be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No test shall be conducted without prior approval from the Division.

I.A.3.c. The Division may use independent tests to verify test data submitted by the source operator or owner. The test methods shall be those listed in Section I.A.3.a. and the Division test results shall take precedence.

I.A.3.d. The Division may accept, instead of the testing required in this section, a certification by the manufacturer of the composition of the coatings if supported by actual batch formulation records. The owner or operator of the VOC source required to comply with this section shall obtain certification from the coating manufacturer(s) that the test method(s) used for determination of VOC content meet the requirements specified in Section I.A.3.a. The owner or operator shall have this certification readily available to Division personnel, in order to allow the results to be used in the daily compliance calculations specified in Section I.A.10.

I.A.3.e. The performance of add-on control device equipment shall be established with the required test methods of I.A.3.a. at equipment startup, and after major modification to the control equipment. Baseline operating parameters shall be established during the satisfactory (i.e. in-compliance) operation of the control equipment, including operation during all anticipated ranges of process throughput. During subsequent process operation, the owner or operator shall maintain the operating conditions of the add-on controls as close to these baseline conditions as possible. If serious operational problems with an add-on control system are evidenced from the daily monitoring required by Section I.A.8.b. (such problems may be indicated by changes from baseline conditions), repeat performance tests may be required by the Division, as necessary.

I.A.4. Sampling

To determine compliance with applicable surface coating standards, samples shall be taken from the coating as freshly delivered to the reservoir of the coating applicator.

I.A.5. Alternative compliance methods for processes and operations

For each process specified in Sections I.B. through I.N. the emission limits designated for that process shall be achieved by:

I.A.5.a. Use of coatings with proportions of VOC less than or equal to the maximums specified by the applicable section of this regulation; or

I.A.5.b. Use of the specified equipment and procedures prescribed by the applicable section of this regulation; or

I.A.5.c. Use of an alternative means of control which satisfies the requirements of Section I.A.5.e., I.A.5.f., and Part A, Section II.D.; or

I.A.5.d. Use of crossline averaging. The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met. In addition, the following requirements apply:

I.A.5.d.(i) The actual reduction shall be equivalent to the actual reduction that would be achieved on a line-by-line basis.

I.A.5.d.(ii) Credit shall not be received for downtime, however, credit is allowed for enforceable production limits.

I.A.5.d.(iii) Crossline averaging shall be used only across lines in the same control technique guidance group.

I.A.5.d.(iv) The emission trading policy shall be met on a daily weighted average.

I.A.5.d.(v) Sources subject to best available control technology (BACT) and lowest achievable emission rate (LAER) requirements shall not use cross line averaging.

I.A.5.d.(vi) VOC emissions shall be expressed as lbs/gallons solids to determine reduction over baseline (lb VOC/lb solids for graphic arts).

I.A.5.d.(vii) Organisol and plastisol coatings shall not be used to bubble emissions from vinyl surface or automobile topcoating operations.

I.A.5.d.(viii) Before crossline averaging may be used, the control methodology shall be approved as a revision to the State Implementation Plan.

I.A.5.e. The design, operation and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Unless the capture system meets the requirements for a total enclosure as specified in the New Source Performance Standard for the Magnetic Tape Manufacturing Industry, 53FR38892, October 3, 1988, or unless Division approved material balance techniques are used to adequately determine overall VOC capture and destruction/recovery efficiency, the efficiency of the capture system shall be determined by test methods approved as a revision to the State Implementation Plan. Testing for capture efficiency shall be performed on a case-by-case basis as required by the Division. The requirements of Sections I.A.3.e. and I.A.8.b. shall apply to the capture and control device system. When capture and control device efficiency must be independently determined, the overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

I.A.5.f. Sources which use add-on controls, crossline averaging, or an approved alternative control strategy instead of low solvent technology to meet the applicable emission limit shall meet the equivalent VOC emission limit, on the basis of solids applied (lb VOC/gal solids applied, or lb VOC/lb solids applied, for graphic arts sources). Appendix E sets forth the procedure for converting emission limits and lists equivalent limits for various coating operations.

I.A.5.g. Owners or operators of sources which use a carbon adsorption system shall provide for the proper disposal or reuse of all VOC recovered.

I.A.6. Exemptions

I.A.6.a. The requirements of this Section I. do not apply to sources used exclusively for chemical or physical analysis or determination of product quality and commercial acceptance, provided;

I.A.6.a.(i) the operation of the source is not an integral part of the production process; and

I.A.6.a.(ii) the emissions from the source do not exceed 363 kilograms (800 lbs.) in any calendar month; and

I.A.6.a.(iii) the exemption is approved in writing by the Division.

I.A.6.b. The requirements of Sections I.C., D., E., F., G., H., I., L. and M. are not applicable to sources whose actual emissions, including fugitive emissions, before add-on controls, are less than 6.8 kilograms (15 lbs.) per day and less than 1.4 kilograms (3 lbs.) per hour. Emissions from all sources within the same control technique guidance group shall be totaled to determine actual emissions.

I.A.7. Fugitive emission control

I.A.7.a. Control techniques and work practices shall be implemented at all times to reduce VOC emissions from fugitive sources. Control techniques and work practices include, but are not limited to:

I.A.7.a.(i) tight-fitting covers for open tanks;

I.A.7.a.(ii) covered containers for solvent wiping cloths;

I.A.7.a.(iii) proper disposal of dirty cleanup solvent.

I.A.7.b. Emissions of organic material released during clean-up operations, disposal, and other fugitive emissions shall be included when determining total emissions, unless the source owner or operator documents that the VOCs are collected and disposed of in a manner that prevents evaporation to the atmosphere.

I.A.8. Recordkeeping, Reporting, and Monitoring

I.A.8.a. If add-on control equipment is used, continuous monitors of the following parameters shall be installed, calibrated, and operated at all times that the associated control equipment is operating:

I.A.8.a.(i) exhaust gas temperature of all incinerators;

I.A.8.a.(ii) temperature rise across a catalytic incineration bed;

I.A.8.a.(iii) breakthrough of VOC on a carbon adsorption unit;

I.A.8.a.(iv) any other monitoring and/or recording device, maintenance and/or control-media-replacement schedule(s) specified on a case-by-case basis by the Division.

I.A.8.b. If add-on control equipment is used, in addition to the requirements of Section I.A.8.a., the following information and any other necessary information, as determined applicable for each source by the Division, shall be monitored and recorded daily in order to assure continuous compliance. The substitution of continuous recordings for daily recording may be allowed by the Division.

I.A.8.b.(i) For the capture system: fan power use, duct flow, duct pressure.

I.A.8.b.(ii) For carbon adsorbers: bed temperature, bed vacuum pressure, pressure at the vacuum pump, accumulated time of operation, concentration of VOC in the outlet gas, solvent recovery.

I.A.8.b.(iii) For refrigeration systems: compressor discharge and suction pressures, condenser fluid temperature, solvent recovery.

I.A.8.b.(iv) For incinerator systems: exhaust gas temperature, temperature rise across a catalytic incinerator bed, flame temperature, accumulated time of incinerator.

I.A.8.c. Recordkeeping procedures shall follow the guidance in "Recordkeeping Guidance Document for Surface Coating Operations and the Graphic Arts Industry," July 1989, EPA 340/1-88-003.

I.A.9. Required and Prohibited Acts

I.A.9.a. No owner or operator of a source of VOCs subject to this section shall operate, cause, allow or permit the operation of the source, unless:

I.A.9.a.(i) For each category of surface coating as specified in Sections I.B. through I.M., the owner or operator of a surface coating line or facility subject to that section does not cause, allow or permit the discharge into the atmosphere of any VOCs in excess of the specified emission limit, calculated as delivered to the coating applicator or as applied to the substrate, whichever is greater.

I.A.9.a.(ii) The owner or operator of a surface coating operation maintains and operates surface coating operations in a manner consistent with good air pollution control practices for minimizing emissions, such as, but not limited to, coating application methods capable of achieving a transfer efficiency achieved by HVLP spraying.

I.A.10. Compliance Calculation Procedures

I.A.10.a. Compliance with this section shall be determined on a daily basis. Sources may request a revision to the State Implementation Plan for longer times for compliance determination.

I.A.10.b. Compliance calculation procedures shall follow the guidance in "Procedure for Certifying Quantity of Volatile Organic Compounds Emitted by Paint, Ink, and Other Coatings," December 1984, EPA-450/3-84/019. In addition, for add-on controls or other compliance alternatives, calculation procedures shall follow the guidance of Section I.A.5.f.

I.A.11. The requirements of Sections I.A.1. through I.A.10. apply to each category of surface coating as specified in Sections I.B. through I.M. The requirements of Sections I.A.7. through I.A.10. apply to the category in Section I.N. The requirements of Sections I.A.1. through I.A.9 apply to the category in Section I.O.

I.A.12. The Division shall approve utilization of alternative compliance methods to the following sources pursuant to this Section I.

I.A.12.a. Lexmark International, Inc. shall be allowed to utilize the alternative compliance method of crossline averaging for processes and operations within the Manufactured Metal Parts and Metal products (Subgroup L) and within the Plastic Film Coating Operations (Subgroup J). The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met, and utilization of the alternative compliance method shall be subject to the following generic conditions, which shall be written and specifically described as enforceable permit terms and conditions in its permits:

I.A.12.a.(i) The alternative compliance method shall result in an actual reduction that is equivalent to the actual reduction that would otherwise be achieved on a line-by-line basis pursuant to this Regulation Number 7.

I.A.12.a.(ii) Credit shall not be received for downtime; however, credit is allowed for emission reductions from enforceable production limits.

I.A.12.a.(iii) Cross line averaging shall be used only across lines of the same control technique guidance group. Lexmark shall use cross line averaging between Metal Parts and Metal Products lines or between Plastic Film Coating lines. Lexmark shall not use cross line averaging where the emissions from Plastic film coating lines are averaged with Metal Parts and Metal Products lines.

I.A.12.a.(iv) The emission trading policy set forth in Regulation Number 3, Part A, Section V., shall be met on a daily weighted average.

I.A.12.a.(v) Sources subject to Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) shall not use cross line averaging.

I.A.12.a.(vi) To determine reduction over baseline, VOC emissions shall be expressed according to Section I.A.5.f., as lbs/gallons solids.

I.A.12.a.(vii) Monthly records shall be kept at the source to verify ongoing compliance with these conditions. The recordkeeping format shall be approved by the Division.

I.A.12.a.(viii) An annual report demonstrating ongoing compliance with this regulation and all permit terms shall be filed with the Division. The report format shall be approved by the Division and specifically described in the permit.

I.A.12.a.(ix) The Division shall issue a permit with federally enforceable terms and conditions to Lexmark limiting Lexmark's alternative compliance method emissions to those allowable under Section I.L. and Section I.J.

I.A.12.a.(x) Commercial and Product quality control laboratory equipment are exempt from APEN filing and construction permit requirements under Regulation Number 3, Part A, Section II.D.1.(i), and Regulation Number 3, Part B, Section II.D.1.a.; and from construction permit requirements under Regulation Number 3, Part B, Section II.D.1.(i). Qualifying sources shall be exempt from Regulation Number 7, Section I. A.6.

I.A.12.a.(xi) Nothing in the alternative compliance method is intended to relax any emissions limitation of this Regulation Number 7.

I.B. Automobile and Light-Duty Truck Assembly Plants

I.B.1. Definitions

I.B.1.a. "Application Area” means the area where the surface coating is applied by spraying, dipping or flow coating.

I.B.1.b. "Automobile” means a passenger motor-vehicle or a derivative of same, capable of seating twelve (12) or fewer passengers, and having at least two driven wheels.

I.B.1.c. "Automobile Assembly Facility” means a facility where parts (including assembled or partially assembled components) of automobiles are received, and finished automobiles are produced, partially or wholly by an assembly line.

I.B.1.d. "Light-Duty Truck” means any motor vehicle rated at 8,500 pounds (3,855 kilograms) gross vehicle weight or less, and having at least two driven wheels, which is designed primarily for purposes of transportation of property or is a derivative of such vehicles. It includes, but is not limited to, pickup trucks, vans, and window vans rated at 8,500 pounds’ gross vehicular weight or less.

I.B.1.e. "Light-Duty Truck Assembly Facility” means a facility where parts (including assembled or partially assembled components) of light-duty trucks are received, and finished light-duty trucks are produced, partially or wholly by an assembly line.

I.B.2. Applicability

This section applies to all assembly and subassembly lines in an automobile or light-duty truck assembly facility, including those for frames, small parts, wheels, and main body parts. This section applies only to the manufacture of new vehicles.

I.B.3. Emission Limitations

	Kg/lc	Lb/gc
Prime application, flashoff area, and oven	0.23	1.9
Topcoat application area, flashoff area, and oven	0.34	2.8
Final repair application, flashoff area and oven	0.58	4.8

I.B.4. Coatings other than primer, surfacer (guidecoat), topcoat and final repair shall be considered under the miscellaneous metal parts Section I.L.

I.B.5. For topcoat application, if a complying coating is not used to meet the emission limit of Section I.B.3, then:

I.B.5.a. the alternate method shall meet an emission limit of 15.1 lb VOC/gal. solids deposited on the coated part; and

I.B.5.b. compliance shall be determined on a daily weighted average basis.

I.B.6. Topcoat operation shall include all spray booths, flash-off areas and ovens in which topcoat is applied, dried and cured, except for final offline repair.

I.C. Can Coating Operations

I.C.1. Definitions

I.C.1.a. "Can Coatings" means any coatings containing organic materials and applied -- or intended for application -- by spray, roller, or other means onto the inside and/or outside surfaces of formed cans and components of cans.

I.C.1.b. "End Sealing Compound" means a substance which is coated onto can ends and which functions as a seal when the end is assembled onto the can.

I.C.1.c. "Exterior Base Coat" means a coating applied to the exterior of a can to provide protection to the metal and/or to provide background for any lithographic or printing operation.

I.C.1.d. "Interior Base Coat" means the initial coating applied to the interior surface of a can by roller coater or spray.

I.C.1.e. "Interior Body Spray" means a coating sprayed onto the interior surface of the can body to provide a protective film between the can and its contents.

I.C.1.f. "Overvarnish" means a coating applied directly over ink to reduce the coefficient of friction, provide gloss, protect against abrasion, enhance product quality, and protect against corrosion.

I.C.1.g. "Three-Piece Can Side Seam Spray" means a coating sprayed onto the interior and/or exterior of a can body seam on a three-piece can to protect the exposed metal.

I.C.1.h. "Two-Piece Can Exterior End Coat" means a coating applied to the exterior of the bottom end of a two-piece can.

I.C.2. Applicability

This section applies to coating applicator(s), and oven(s) of sheet can or end coating lines involved in sheet basecoat (exterior and interior) and over varnish, two-and three-piece can interior body spray, two-piece can exterior end (spray or roll coat), three-piece can side-seam spray, and end sealing compound operations.

I.C.3. Emission Limitations

Can Coating	**Kg/lc**	**Lb/gc**
Sheet base coat (exterior and interior) and overvarnish two-piece can exterior (base coat and overvarnish)	0.34	2.8
Two and three-piece can interior body spray, two-piece can exterior end (spray or roll coat)	0.51	4.2
Three-piece can side-seam spray	0.66	5.5
End sealing compound	0.44	3.7
Any additional coats	0.51	4.2

I.D. Coil Coating Operations

I.D.1. Definitions

I.D.1.a. "Coil Coating" means any surface coating applied by spray, roller, or other means onto one or both surfaces of flat metal sheets or strips that come in rolls or coils.

I.D.1.b. "Quench Area" means a chamber where the hot metal exiting the oven is cooled by either a spray of water or a blast of air followed by water cooling.

I.D.2. Applicability

This section applies to the coating applicator(s), oven(s), and quench area(s) of coil coating operations involved in primer, intermediate, top-coat or single-coat operations.

I.D.3. Emission Limitations:

Coil Coating	**Kg/lc**	**Lb/gc**
Any coat (primer, intermediate coat, topcoat, single coat)	0.31	2.6

I.E. Fabric Coating Operations

I.E.1. Definitions

I.E.1.a. “Fabric Coating" means the process of coating or impregnating the full, usable surface of a fabric web or sheet to impart properties that are not initially present such as strength, stability, water or acid repellency, or appearance. "Fabric Coating" excludes those processes normally included under fabric finishing (e.g. dyeing, treating for stain and wrinkle resistance, etc.).

I.E.2. Applicability

This section applies to fabric coating lines which includes, but is not limited to, coaters and drying ovens.

I.E.3. Emission Limitations

	Kg/lc	**Lb/gc**
Fabric Coating Line	0.35	2.9

I.F. Large Appliance Coating Operations

I.F.1. Definition

I.F.1.a. "Large Appliances” includes doors, cases, lids, panels, interior support parts, and any other large (greater than one square decimeter (15.5 square inches)) coated surfaces of residential and commercial washers, dryers, ovens, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners, and all other products under SIC Code 363 according to the "Standard Industrial Classification Manual", Executive Office of the President, Office of Management and Budget, designated by convention of the industry as large appliances.

I.F.2. Applicability

This section applies to all large appliance coating lines.

I.F.3. Emission Limitations

	Kg/lc	**Lb/gc**
Large Appliance Coating Line; prime, single or topcoat application area, flashoff area, and oven	0.34	2.8

I.G. Magnet Wire Coating Operations

I.G.1. Definition

I.G.1.a. "Magnet Wire Coating" means those operations which apply a coating of electrically insulating varnish or enamel (or similar substance) to wire which is known as "magnet wire." Magnet wire is usually copper or aluminum, and is used for electric motors, generators, transformers, magnets, and related products.

I.G.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of magnet wire coating operations.

I.G.3. Emission Limitations

	Kg/lc	**Lb/gc**
Magnetic wire coating operation	0.20	1.7

I.H. Metal Furniture Coating Operations

I.H.1. Definitions

I.H.1.a. "Metal Furniture" means furnishings commonly considered furniture, for domestic, business, and/or institutional use, which have one or more essential, major components made of metal. "Metal furniture" includes, but is not limited to, tables, chairs, wastebaskets, beds, desks, lockers, shelving, cabinets, room dividers, clothing racks, chests of drawers, and sofas.

I.H.1.b. "Metal Furniture Coating" means applying a "surface coating" to "metal furniture" as defined. It excludes coating of non-metal components.

I.H.2. Applicability

This section applies to all metal furniture coating lines.

I.H.3. Emission Limitations

	Kg/lc	**Lb/gc**
Metal Furniture Coating Line: All coats (including prime, single, and topcoat)	0.36	3.0

I.I. Paper Coating Operations

I.I.1. Definition

"Paper Coating" means impregnating or applying a uniform layer of "surface coating" to paper. It includes, but is not limited to, the production of: coated, glazed, decorated, and varnished paper; carbon and pressure-sensitive copy papers; paper adhesive-labels and tapes; blue-print; photographic and copier paper. It also includes coating of metal foil such as gift wrap and packaging. Paper coating does not include impregnation using a batch dipping process.

I.I.2. Applicability

This section applies to paper coating lines, which includes, but is not limited to, coaters and drying ovens.

I.I.3. Emission Limitations

	Kg/lc	Lb/gc
Paper Coating Line	0.35	2.9

I.J. Plastic-Film Coating Operations

I.J.1. Definition

I.J.1.a. "Plastic-Film Coating" means applying a uniform layer of "surface coating" to a flexible web or sheet of thin plastic substance, excluding all rubbers and vinyl's* (polyvinyl chloride) except for the following two categories of vinyl products: (1) vinyl tapes and (2) vinyl's coated with an adhesive or pressure-sensitive coating. It includes, but is not limited to: plastic typewriter ribbons, photographic film, adhesive tapes, and magnetic recording tapes. (*see Section I.K.)

I.J.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of plastic-film coating lines.

I.J.3. Emission Limitations

	Kg/lc	Lb/gc
Plastic-Film Coating Line	0.35	2.9

I.K. Vinyl Coating Operations

I.K.1. Definition

"Vinyl Coating" means applying a uniform layer, decorative or protective topcoat to a vinyl (polyvinyl chloride) coated fabric or vinyl sheet. It includes printing of same. Excluded are*: (1) the coating of same with adhesive or pressure-sensitive coatings and (2) vinyl tapes. (*see Section I.J.)

I.K.2. Application

This section applies to vinyl coating lines which includes, but is not limited to, coaters and drying ovens.

I.K.3. Emission Limitations

	Kg/lc	Lb/gc
Vinyl Coating Line	0.45	3.8

I.L. Manufactured Metal Parts and Metal Products

I.L.1. General Provisions

I.L.1.a. Applicability

This section applies to the application area(s), flashoff area(s), oven(s), and drying areas including (but not limited to) air and forced air drier(s) used in the surface coating of the metal parts and products listed below. This section applies to prime coat, top coat, and single coat operations. This section is applicable to surface coating of manufactured metal parts and metal products which include:

I.L.1.a.(i) Large farm machinery (harvesting, fertilizing, and planting machines, tractors, combines, etc.);

I.L.1.a.(ii) Small-farm, lawn and garden machinery (lawn and garden tractors, lawn mowers, rototillers, etc.);

I.L.1.a.(iii) Small appliances (fans, mixers, blenders, crock pots, dehumidifiers, vacuum cleaners, etc.);

I.L.1.a.(iv) Commercial machinery (office equipment, computers and auxiliary equipment, typewriters, calculators, vending machines, etc.);

I.L.1.a.(v) Industrial machinery (pumps, compressors, conveyor components, fans, blowers, transformers, etc.);

I.L.1.a.(vi) Fabricated metal products (metal covered doors, frames, etc.);

I.L.1.a.(vii) Furniture hardware made of metal for use with non-metal furniture; and

I.L.1.a.(viii) Any other industrial category which coats metal parts or products under the standard industrial classification code of major group 33 (primary metal industries), major group 34 (fabricated metal products), major group 35 (non-electric machinery), major group 36 (electrical machinery), major group 37 (transportation equipment), major group 38 (miscellaneous instruments), and major group 39 (miscellaneous manufacturing industries), according to the "Standard Industrial Classification Manual" Executive Office of the President, Office of Management and Budget.

I.L.1.b. Exemptions

I.L.1.b.(i) This Section I.L. is not applicable to the surface coating of the following metal parts and products inasmuch as these are previously covered in Sections I.B., C., D., F., G., and H., respectively:

I.L.1.b.(i)(A) Automobiles and light-duty trucks

I.L.1.b.(i)(B) Metal cans

I.L.1.b.(i)(C) Flat metal sheets and strips in the form of rolls or coils

I.L.1.b.(i)(D) Large appliances

I.L.1.b.(i)(E) Magnet wire for use in electrical machinery

I.L.1.b.(i)(F) Metal furniture

I.L.1.b.(ii) This Section I.L. is not applicable to the following special purpose coatings:

I.L.1.b.(ii)(A) Division-approved exemptions for high performance coatings on a case-by-case basis.

I.L.1.b.(ii)(B) Full exterior repainting of automobiles and light-duty trucks if fewer than 18 vehicles are painted per day.

I.L.1.c. Definitions

For the purpose of this section, the following definitions apply:

I.L.1.c.(i) "Air Dried Coating" means coatings which are dried by the use of air or forced warm air at temperatures up to 90°C (194°F);

I.L.1.c.(ii) "Clear Coat" means a coating, which lacks color and opacity or a coating which is transparent;

I.L.1.c.(iii) "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, flashoff areas, air dryers and ovens;

I.L.1.c.(iv) "Extreme Environmental Conditions" means exposure to any of the following: temperatures consistently above 95°C, detergents, abrasive and scouring agents, solvents, and corrosive environments;

I.L.1.c.(v) "Extreme Performance Coatings" means coatings designed for extreme environmental conditions.

I.L.2. Provisions for Specific Processes

I.L.2.a. No owner or operator of a facility or operation engaging in the surface coating of manufactured metal parts or metal products may operate a coating application system subject to this regulation that emits VOC in excess of:

I.L.2.a.(i) Clear coatings: 0.52 kg/lc (4.3 lb/gc)

I.L.2.a.(ii) Extreme Performance Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iii) Air-Dried Coatings: 0.42 kg/lc (3.5 lb/gc)

I.L.2.a.(iv) Other coatings and systems: 0.36 kg/lc (3.0 lb/gc) delivered to a coating applicator for all other coatings and coating application systems.

I.L.2.b. If more than one emission limitation in Section I.L.2.a. applies to a specific coating, then the least stringent emission limitation shall be applied.

I.L.2.c. Pioneer Metal Finishing, Inc., a surface coating operation, is authorized pursuant to Regulation Number 3, Part A, Section V. and Regulation Number 7, Part A, Section II.D.1.a. to use up to twenty (20) tons of certified emission reduction credits of volatile organic compounds (VOC) as an alternative compliance method to satisfy the surface coating emission limitations of Regulation Number 7 in accordance with and upon demonstration of the conditions set forth below:

I.L.2.c.(i) Certified emission reduction credits for VOCs (methanol) to be used in this transaction were formerly owned by the Coors Brewing Company, registered and issued in Emissions Reduction Credit Permit 91AR120R on July 25, 1994;

I.L.2.c.(ii) Those emission reduction credits were originally obtained by Coors from Verticel, a company that produced honeycomb packaging material and was located within five miles of the PMF facility;

I.L.2.c.(iii) The use of these VOC emission reduction credits identified above shall be used to satisfy VOC limitations of certain specified surface coatings in excess of Control Technique Guidance as specified in Regulation Number 7, Section I.L.2.a. and Section I.A.6.b., and applicable to the Pioneer Metal finishing operations;

I.L.2.c.(iv) Such emission reduction credits identified above will be used by PMF to achieve compliance with Regulation Number 7 to compensate for ozone precursor emission of VOCs from non-compliant coatings which meet the emission trading requirements of Regulation Number 3, Part A, Section V. In order to satisfy the photochemical reactivity equivalency requirement of VOC trades, the methanol VOC ERCs will be reduced on a ratio of 1.1:1 for VOCs of toluene, ethylbenzene, xylene and ketones emitted from non-compliant coatings. All other VOCs involved in this transaction are considered to be of the same degree of photochemical reactivity;

I.L.2.c.(v) The requirement in Regulation Number 3, Part A, Section V.F.2. shall not apply to this transaction;

I.L.2.c.(vi) This transaction is only valid within the Denver/Boulder nonattainment area as described at 40 CFR 81, Subchapter C - Air Programs, Subpart C, Section 107 - Attainment Status Designations, Section 81.306 (February 16, 1995);

I.L.2.c.(vii) This transaction shall be calculated upon a pound for pound basis and averaged over a maximum 24-hour period.

I.L.2.c.(viii) This transaction shall be effective upon approval by the U.S. Environmental Protection Agency as a revision to the Colorado State Implementation Plan and after issuance of a State Construction Permit incorporating, but not limited to, the conditions and requirements of the Section;

I.L.2.c.(ix) This transaction may not be used to satisfy any current or future requirements of NSPS, BACT, LAER, or MACT requirements of HAPs which may apply to PMF, except that this transaction may be used to satisfy control technique guidance or RACT requirements contained in Regulation Number 7 which are applicable to PMF;

I.L.2.c.(x) This transaction shall not interfere with any applicable requirement concerning attainment and reasonable further progress in the Colorado State Implementation Plan or any other applicable requirements of the Clean Air Act;

I.L.2.c.(xi) This transaction shall be registered and enforced through a State Construction Permit issued to Pioneer Metal Finishing, Inc. containing, but not limited to the conditions and limitations set forth in this Section;

I.L.2.c.(xii) Such state Construction Permit issued to Pioneer Metal Finishing, Inc. shall specify, among other, things the necessary monitory, recordkeeping and reporting requirements to insure that the emission reduction credits are applied in accordance with the conditions and requirements of this Section;

I.L.2.c.(xiii) The state Construction Permit shall allow a daily maximum limitation of 160 lbs. of VOC emissions from non-compliant surface coatings and an annual limitation of 40,000 lbs. of non-compliant VOC emissions. The annual limitation shall be calculated on a 12-month rolling total calculated on the first day of each month using the previous 12 months.

I.L.2.c.(xiv) The state Construction Permit shall limit the VOC-HAP emissions to less than ten (10) per year of any one HAP or twenty-five (25) tons per year of any combination of HAP emissions; and

I.L.2.c.(xv) PMF will maintain records of daily and monthly totals of non-compliant surface coatings used in its operation and report such usages on an annual basis to the Division or as otherwise requested.

I.M. Flat Wood Paneling Coating.

I.M.1. Definitions

I.M.1.a. "Class II Hardboard Paneling Finish" means finishes which meet the specifications of Voluntary Product Standard PS-59-73 as approved by the American National Standards Institute.

I.M.1.b. "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, conveyers, flashoff areas, air dryers and ovens.

I.M.1.c. "Hardboard" is a panel manufactured primarily from inter-felted ligno-cellulosic fibers which are consolidated under heat and pressure in a hot press.

I.M.1.d. "Hardboard Plywood" is plywood whose surface layer is a veneer of hardwood.

I.M.1.e. "Natural Finish Hardwood Plywood Panels" means panels whose original grain pattern is enhanced by essentially transparent finishes frequently supplemented by fillers and toners.

I.M.1.f. "Printed Interior Panels" means panels whose grain or natural surface is obscured by fillers and basecoats upon which a simulated grain or decorative pattern is printed.

I.M.1.g. "Thin Particleboard" is a manufactured board 1/4 inch or less in thickness made of individual wood particles which have been coated with a binder and formed into flat sheets by pressure.

I.M.1.h. "Tileboard" means paneling that has a colored waterproof surface coating.

I.M.2. Applicability

This section applies to all flat wood manufacturing and surface finishing facilities that manufacture printed interior panels made of hardwood plywood and thin particle board; natural finish hardwood plywood panels, or hardboard paneling with Class II finishes. This section does not apply to the manufacture of exterior siding, tileboard, or particleboard used as a furniture component.

I.M.3. Emission Limitations

I.M.3.a. 2.9 kg per 100 square meters of coated finished product (6.0 lb/1,000 sq. ft.) from printed interior panels, regardless of the number of coats applied;

I.M.3.b. 5.8 kg per 100 square meters of coated finished product (12.0 lb/1,000 sq. ft.) from natural finish hardwood plywood panels, regardless of the number of coats applied; and

I.M.3.c. 4.8 kg per 100 square meters of coated finished product (10.0 lb/1,000 sq. ft.) from Class II finishes on hardboard panels, regardless of the number of coats applied.

I.N. Manufacture of Pneumatic Rubber Tires

I.N.1. Definitions

I.N.1.a. "Bead Dipping" means the dipping of an assembled tire bead into a solvent-based cement.

I.N.1.b. "Green Tires" means assembled tires before holding and curing have occurred.

I.N.1.c. "Green Tire Spraying" means the spraying of green tires, both inside and outside, with release compounds which help remove air from the tire during molding and prevent the tire from sticking to the mold after curing.

I.N.1.d. "Pneumatic Rubber Tire Manufacture" means the production of pneumatic rubber, passenger type tires on a mass production basis.

I.N.1.e. "Passenger Type Tire" means agricultural, airplane, industrial, mobile home, light and medium duty truck, and passenger vehicle tires with a bead diameter up to 20.0 inches and cross section dimension up to 12.8 inches.

I.N.1.f. "Tread End Cementing" means the application of a solvent-based cement to the tire tread ends.

I.N.1.g. "Undertread Cementing" means the application of a solvent-based cement to the underside of a tire tread.

I.N.1.h. "Water Based Sprays" means release compounds, sprayed on the inside and outside of green tires, in which solids, water, and emulsifiers have been substituted for organic solvents.

I.N.2. Applicability

This section applies to VOC emissions from the following operations in all pneumatic rubber tire facilities: undertread cementing, tread end cementing, bead dipping, and green tire spraying.

The provisions of this section do not apply to the production of specialty tires for antique or other vehicles when produced on an irregular basis or with short production runs. This exemption applies only to tires produced on equipment separate from normal production lines for passenger type tires.

I.N.3. Provisions for Specific Processes

I.N.3.a. The owner or operator of an undertread cementing, tread end cementing, or bead dipping operation subject to this regulation shall:

I.N.3.a.(i) Install and operate a capture system, designed to achieve maximum reasonable capture, up to 85 percent by weight of VOC emitted, from all undertread cementing, tread end cementing and bead dipping operations. Maximum reasonable capture shall be consistent with the following documents:

I.N.3.a.(i)(A) Industrial Ventilation, A Manual of Recommended Practices, 17th Edition, American Federation of Industrial Hygienists, 1982.

I.N.3.a.(i)(B) Recommended Industrial Ventilation Guidelines, U.S. Department of Health, Education and Welfare, National Institute of Occupational Safety and Health, January 1976.

I.N.3.a.(ii) Install and operate a control device that meets the requirements of one of the following:

I.N.3.a.(ii)(A) A carbon adsorption system designed and operated in a manner such that there is at least a 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.3.a.(ii)(B) An incineration system that oxidizes at least 90.0 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) which enter the incinerator to carbon dioxide and water.

I.N.4. The owner or operator of a green tire spraying operation subject to this regulation must implement one of the following means of reducing volatile organic compound emissions:

I.N.4.a. Substitute water-based sprays for the normal solvent-based mold release compound; or,

I.N.4.a.(i) Install a capture system designed and operated in a manner that will capture and transfer at least 90.0 percent of the VOC emitted by the green tire spraying operation to a control device; and,

I.N.4.a.(ii) In addition to Section I.N.4.a.(i), install and operate a control device that meets the requirements of one of the following:

I.N.4.a.(ii)(A) a carbon adsorption system designed and operated in a manner such that there is at least 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.4.a.(ii)(B) an incineration system that oxidizes at least 90 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) to carbon dioxide and water.

I.N.5. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

I.N.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

I.N.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

I.O. Wood Furniture Coating

I.O.1. Definitions

I.O.1.a. “As Applied” means the VOC and solids content of the finishing material that is actually used for coating the substrate. It includes the contribution of materials used for in-house dilution of the finishing material.

I.O.1.b. “Cleaning Operation” means operations in which organic solvent is used to remove coating materials from equipment used in wood furniture manufacturing operations.

I.O.1.c. “Conventional Air Spray” means a spray coating method in which the coating is atomized by mixing it with compressed air at an air pressure greater than 10 pounds per square inch (gauge) at the point of atomization. Airless and air assisted spray technologies are not conventional air spray because the coating is not atomized by mixing it with compressed air. Electrostatic spray technology is also not considered conventional air spray because an electrostatic charge is employed to attract the coating to the workplace.

I.O.1.d. “Equipment Leak” means emissions of VOCs from pumps, valves, flanges, or other equipment used to transfer or apply finishing materials or organic solvents.

I.O.1.e. “Finishing Material” means a coating used in the wood furniture industry including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats.

I.O.1.f. "Finishing Operation" means those activities in which a finishing material, including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats, is applied to a substrate and is subsequently air-dried, cured in an oven, or cured by radiation.

I.O.1.g. "Organic Solvent" means a liquid containing VOCs that is used for dissolving or dispersing constituents in a coating, adjusting the viscosity of a coating, cleaning, or washoff. When used in a coating, the organic solvent evaporates during drying and does not become part of the dried film.

I.O.1.h. "Sealer" means a finishing material used to seal the pores of a wood substrate before additional coats of finishing material are applied. Washcoats, which are used in some finishing systems to optimize aesthetics, are not sealers.

I.O.1.i. "Strippable Booth Coating" means a coating that is applied to a booth wall to provide a protective film to receive overspray during finishing operations that is subsequently peeled off and disposed, and reduces or eliminates the need to use organic solvents to clean booth walls.

I.O.1.j. "Topcoat" means the last film-building finishing material applied in a finishing system. Non-permanent final finishes are not topcoats.

I.O.1.k. "Washcoat" means a transparent special purpose coating that has a solids content by weight of 12 percent or less. Washcoats are applied over initial stains to protect and control color and to stiffen the wood fibers in order to aid sanding.

I.O.1.l. "Washoff Operation" means those operations in which organic solvent is used to remove coating from a substrate.

I.O.1.m."Wood Furniture" means any product made of wood, a wood product such as rattan or wicker, or an engineer wood product such as particleboard.

I.O.1.n. "Wood Furniture Component" means any part that is used in the manufacture of wood furniture including, but not limited to, drawer sides, cabinet doors, seat cushions, and laminated tops.

I.O.1.o. "Wood Furniture Manufacturing Operation" means the finishing, cleaning, and washoff operations associated with the production of wood furniture or wood furniture components.

I.O.2. Applicability

This section applies to wood furniture manufacturing operations with uncontrolled actual VOC emissions greater than or equal to 25 tons per calendar year.

I.O.3. Emission Limitations

I.O.3.a. The owner or operator of a wood furniture manufacturing operation must limit VOC emissions from finishing operations by:

I.O.3.a.(i) Using topcoats with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids); or

I.O.3.a.(ii) Using a finishing system of:

I.O.3.a.(ii)(A) Sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids), as applied; and

I.O.3.a.(ii)(B) Topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied; or

I.O.3.a.(iii) For sources using acid-cured alkyd amino vinyl sealers or acid-cured alkyd amino conversion varnish topcoats:

I.O.3.a.(iii)(A) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and an acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied; or

I.O.3.a.(iii)(B) Use acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied, and sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids); or

I.O.3.a.(iii)(C) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied.

I.O.3.b. The owner or operator of a wood furniture manufacturing operation must use strippable booth coatings with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids), as applied.

I.O.3.c. The owner or operator of a wood furniture manufacturing operation must use compounds containing equal to or less than 8.0 percent by weight of VOC for cleaning spray booth components other than conveyors, continuous coaters and their enclosures, and/or metal filters, unless the spray booth is being refurbished. If the spray booth is refurbished (i.e., spray booth coating or other material used to cover the booth is being replaced), the owner or operator must use equal to or less than 1.0 gallon of organic solvent to prepare the booth prior to applying the booth coating.

I.O.4. Work Practices

I.O.4.a. In addition to complying with Sections I.A.7. and I.A.9., the owner or operator of a wood furniture manufacturing operation must:

I.O.4.a.(i) Develop an operator training program that includes, at a minimum, appropriate application techniques, appropriate cleaning and washoff procedures, appropriate equipment setup and adjustment to minimize finishing material usage and overspray, and appropriate management of cleanup wastes;

I.O.4.a.(ii) Conduct monthly visual inspections of all equipment used to transfer or apply finishing materials or organic solvents for equipment leaks and repair equipment leaks within 15 working days, or within 3 months if the leaking equipment must be replaced by a new purchase;

I.O.4.a.(iii) Collect cleaning and washoff solvents into closed containers;

I.O.4.a.(iv) Use conventional air spray guns only to:

I.O.4.a.(iv)(A) Apply finishing materials with a VOC content equal to or less than 1.0 lb VOC/lb solids (1.0 kg VOC/kg solids), as applied;

I.O.4.a.(iv)(B) Touch-up and repair after completion of the finishing operation, after stain and before other finishing material, or to apply stain on a part for which it is technically or economically infeasible to use any other spray application technology.

I.O.5. Recordkeeping

I.O.5.a. The owner or operator of a wood furniture manufacturing operation must keep the following records for five (5) years and make them available for inspection by the Division upon request:

I.O.5.a.(i) Records of calendar year VOC emission estimates demonstrating whether the wood furniture manufacturing operation means or exceeds the applicability threshold in Section I.O.2.;

I.O.5.a.(ii) Records of the operator training program;

I.O.5.a.(iii) Records of the date and results of the monthly equipment inspections and any repairs that were made;

I.O.5.a.(iv) Records such as, but not limited to, data sheets documenting how the as applied values were determined and safety data sheets or other analytical data from the manufacturer showing the VOC content of each sealer, topcoat, strippable booth coating, or cleaning booth compound subject to the emission limits in Section I.O.3.; and

I.O.5.a.(v) Monthly records of the quantity and type of organic cleaning and washoff solvent used.

II. Solvent Use

II.A. General Provisions

II.A.1. Applicability

The provisions of this section apply to cold cleaners, non-conveyorized vapor degreasers, conveyorized degreasers, industrial cleaning solvent operations, and other operations that use solvents. Open top vapor degreasers are a subset of non-conveyorized vapor degreasers. The owner or operator of a unit subject to this section shall ensure that no such unit is used unless the requirements of this section are satisfied. Section II.E. requirements are effective on January 1, 2017. Section II.F. requirements are effective on May 1, 2021.

II.A.2. Definitions

II.A.2.a. "Cold-Cleaner" means a container of non-aqueous liquid solvent held below its boiling point, which is designed, used, or intended for cleaning solid objects in a batch-loaded process. A "cold-cleaner" may have provisions for heating the solvent. It does not include vapor degreasers or continuously loaded conveyorized degreasers.

II.A.2.b. "Composite Partial Vapor Pressure" means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the "i"th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the "i"th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

II.A.2.c. "Conveyorized Degreaser" means an apparatus that performs degreasing or other cleaning functions through the use of non-aqueous liquid solvent and/or solvent vapors within a container, and which has a conveyor mechanism allowing continuous loading of items conveyed into and out of the solvent.

II.A.2.d. "Freeboard" in a vapor degreaser means the vertical distance from the top of the vapor zone (as established by normal operations within the specifications of the degreaser manufacturer) to the top of the degreaser.

For cold-cleaners "freeboard" means the vertical distance from the surface of the solvent liquid to the top of the degreaser.

If all sides are not even, the vertical distance to the top of the lowest side shall be used to make the determination of freeboard.

II.A.2.e. "Freeboard Ratio" means the ratio of the freeboard to the width of the solvent surface.

II.A.2.f. "Industrial Cleaning Solvent" means a VOC-containing liquid used to perform industrial cleaning solvent operations.

II.A.2.g. "Industrial Cleaning Solvent Operation" means the use of an industrial cleaning solvent for cleaning industrial operations such as spray gun cleaning, spray booth cleaning, large manufactured parts cleaning, equipment cleaning, floor cleaning, line cleaning, parts cleaning, tank cleaning, and small manufactured parts cleaning. Residential and janitorial cleaning are not considered industrial cleaning solvent operations.

II.A.2.h. "Non-Conveyorized Vapor Degreaser" means an apparatus, which uses non-aqueous solvent vapors within some type of container to degrease or otherwise clean solid objects in a batch-loaded process. It excludes continuously loaded conveyorized degreasers.

II.A.2.i. "Residential and Janitorial Cleaning" means the cleaning of a building or building components including, but not limited to, floors, ceilings, wall, windows, doors, stairs, bathrooms, furnishings, and exterior surfaces of office equipment, excluding the cleaning of work areas where manufacturing or repair activity is performed.

II.A.2.j. "Solvent Metal Cleaning" means the process of cleaning soils from metal surfaces by cold cleaning, conveyorized degreasing, or non-conveyorized vapor degreasing.

II.A.3. Transfer of waste solvent and used solvent

In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

II.A.4. Storage of waste solvent and used solvent

Waste or used solvent shall be stored in closed containers unless otherwise required by law.

II.A.5. Any control device shall meet the applicable requirements of Sections I.A.3.a., b., c., e., and I.A.8.a. and b.

II.B. Control of Solvent Cold-Cleaners

II.B.1. Control Equipment

II.B.1.a. Covers

II.B.1.a.(i) All cold-cleaners shall have a properly fitting cover.

II.B.1.a.(ii) Covers shall be designed to be easily operable with one hand under any of the following conditions:

II.B.1.a.(ii)(A) Solvent true vapor pressure is greater than 15 torr (0.3 psia) at 38°C (100°F).

II.B.1.a.(ii)(B) The solvent is agitated by an agitating mechanism.

II.B.1.a.(ii)(C) The solvent is heated.

II.B.1.b. Drainage Facility

II.B.1.b.(i) All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts.

II.B.1.b.(ii) For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38°C (100°F) either:

II.B.1.b.(ii)(A) There shall be an internal drainage facility within the confines of the cold-cleaner, so that parts are enclosed under the (closed) cover to drain after cleaning, or if such a facility will not fit within;

II.B.1.b.(ii)(B) An enclosed, external drainage facility that captures the drained solvent liquid from the cleaned parts.

II.B.1.c. A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements.

II.B.1.d. Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing.

For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38°C (100°F), or, for solvents heated above 50°C (120°F), one of the following techniques shall be used:

II.B.1.d.(i) A freeboard ratio greater than or equal to 0.7.

II.B.1.d.(ii) A water or a non-volatile liquid cover. The cover liquid shall not be soluble in the solvent and shall not be denser than the solvent and the depth of the cover liquid shall be sufficient to prevent the escape of solvent vapors.

II.B.2. Operating requirements

II.B.2.a. The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines.

II.B.2.b. Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank.

II.C. Control of Non-Conveyorized Vapor Degreasers

II.C.1. Control Equipment

II.C.1.a. The non-conveyorized vapor degreaser shall have a cover which shall be designed and operated so that it can be easily opened and closed through the use of mechanical assists such as spring loading, counterweights, etc.; opening and closing the cover shall not disturb the vapor zone.

II.C.1.b. Safety Switches

The following two types of switches shall be installed on vapor degreasers:

II.C.1.b.(i) Condenser flow switch and thermostat - (shuts off sump heat if the condenser coolant is either not circulating or is too warm); and

II.C.1.b.(ii) Spray safety switch - (shuts off spray pump if the vapor level drops more than four (4) inches).

II.C.1.c. Control Device

II.C.1.c.(i) For non-conveyorized vapor degreasers with an open area (with the cover open) of one square meter (10.8 ft^2) or less, either the freeboard ratio shall be greater than or equal to 0.75, or one of the control devices in II.C.1.c.(ii) shall be used.

II.C.1.c.(ii) For non-conveyorized vapor degreasers with an open area (with the cover open) greater than one (1) square meter, (10.8 ft^2), at least one of the following control systems shall be used:

II.C.1.c.(ii)(A) Both a powered cover and a freeboard ratio greater than or equal to 0.75.

II.C.1.c.(ii)(B) A refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix C.

II.C.1.c.(ii)(C) An enclosed design: A system where the cover(s) or door(s) opens only when a dry part is entering or exiting the degreaser.

II.C.1.c.(ii)(D) A carbon adsorption system with ventilation greater than or equal to 15 cubic meters each minute per square meter (50 cfm/ft^2) of air/vapor area (when the cover(s) is [are] open), exhausting less than 25 parts per million (by volume) of solvent averaged over one complete adsorption cycle.

II.C.1.d. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.C.2. Operating Requirements

II.C.2.a. Keep cover closed at all times except when processing work loads into or out of the degreaser.

II.C.2.b. The following operations shall be performed to minimize solvent carry-out:

II.C.2.b.(i) Rack parts to allow full drainage.

II.C.2.b.(ii) Move parts as slowly as is practicable in and out of the degreaser. A maximum of one foot every five seconds by hand or a maximum of 5.5 cm/sec. (10.8ft/min) for a mechanically operated system.

II.C.2.b.(iii) Allow the workload to clean in the vapor zone at least 30 seconds or until condensation ceases.

II.C.2.b.(iv) Tip out any pools of solvent that remain on the cleaned parts before removal from the vapor zone.

II.C.2.b.(v) Allow parts to dry within the degreaser at least 15 seconds and/or until visually dry.

II.C.2.c. Solvents shall not be used to clean porous or absorbent materials; for example, cloth, leather, wood, rope, etc.

II.C.2.d. Workloads shall not occupy more than half of the degreaser's open top area.

II.C.2.e. Spraying shall not be done above the vapor level.

II.C.2.f. Solvent leaks shall be repaired immediately, or the degreaser shall be shut down.

II.C.2.g. Exhaust ventilation shall not exceed twenty (20) cubic meters per minute per square meter (65.6 cfm per sq. ft.) of degreaser open area, unless greater exhaust rates are necessary to meet Occupational and Safety Health Act requirements. Ventilation fans shall not be used near the degreaser opening, unless necessary to meet Occupational and Safety Health Act requirements.

II.C.2.h. The water separator shall function so that no visible water is present in the solvent exiting the separator.

II.D. Control of Conveyorized Degreasers

II.D.1. Control Equipment

II.D.1.a. Control Device

For all conveyorized degreasers with a solvent surface area greater than two (2) square meters (21.5 square feet), the degreasing shall be controlled by at least one of the following:

II.D.1.a.(i) Carbon adsorption system, with ventilation greater or equal to 15 cubic meters per minute per square meter (49.2 cfm/ft_2) of air/vapor interface for vapor degreasers (of air/liquid interface for non-vapor types) when down-time covers are open, and exhausting less than 25 parts per million of solvent (by volume) averaged over a complete adsorption cycle.

II.D.1.a.(ii) For vapor degreasers only: a refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix D.

II.D.1.b. Prevention of Carry-out

A drying tunnel, tumbling basket(s), or other demonstrably effective method(s) shall be employed to prevent cleaned parts from carrying out solvent liquid or vapor.

II.D.1.c. Safety Switches

II.D.1.c.(i) The following two (2) switch-circuits (or equivalent) shall be installed.

II.D.1.c.(i)(A) A spray safety switch shall shut off the spray pump and/or the conveyor if the vapor level drops more than four (4) inches.

II.D.1.c.(i)(B) A vapor level control thermostat shall shut off sump heat when the vapor level rises too high.

II.D.1.c.(ii) All conveyorized degreasers shall have a condenser thermostat and flow-detector switch (or equivalent) which shuts off sump heat if coolant is too warm or is not circulating.

II.D.1.d. Minimized Openings: Degreaser entrance and exit openings shall silhouette workloads so that the average clearance between parts (or parts-and the edge of the degreaser opening) is either:

II.D.1.d.(i) less than 10 centimeters (4 inches) or;

II.D.1.d.(ii) less than 10 percent of the width of the opening

II.D.1.e. Covers shall be provided to close off all the entrance(s) and exit(s) when the conveyor is not in use.

II.D.1.f. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.D.2. Operating Requirements

II.D.2.a. Exhaust ventilation shall not exceed 20 m^3/minute per square meter of degreaser opening (65.6 cf/m per square foot), unless necessary to meet OSHA requirements. Work place fans shall not be located near, nor directed at degreaser openings, unless necessary to meet OSHA requirements. Exhaust flow shall be measured by EPA reference methods 1 and 2 of 40 CFR Part 60 (September 14, 1989).

II.D.2.b. Carry-out emissions shall be minimized by:

II.D.2.b.(i) Racking parts in such a manner to achieve best drainage.

II.D.2.b.(ii) Maintaining the vertical component of conveyor speed at less than 3.3 meters per minute (10.8 feet per minute).

II.D.2.c. Repair solvent leaks immediately, or shut down the degreaser.

II.D.2.d. The water separator shall function with an efficiency sufficient to prevent water from being visible in the solvent exiting the separator.

II.D.2.e. Down-time cover(s) shall be placed over entrances and exits of conveyorized degreasers immediately after the conveyor and exhaust are shut down. Covers shall be retained in position until immediately before start-up.

II.E. Control of Industrial Cleaning Solvent Operations

II.E.1. Control Requirements

The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section II.E.4.) must:

II.E.1.a. Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter); or

II.E.1.b. Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit); or

II.E.1.c. Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater.

II.E.2. Work Practice Requirements

The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.E.2.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.E.2.b. Properly dispose of used solvent and shop towels; and

II.E.2.c. Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free.

II.E.3. Monitoring, Recordkeeping and Reporting Requirements

II.E.3.a. The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request:

II.E.3.a.(i) If applicable, records demonstrating that a listed exemption to this Section II.E. applies.

II.E.3.a.(ii) If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections II.E.1.a. and II.E.1.b.

II.E.3.a.(iii) If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section II.E.1.c.

II.E.3.a.(iv) Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section II.E.1.

II.E.3.b. Compliance with the control requirements in Section II.E.1. must be demonstrated using one of the following methods as applicable:

II.E.3.b.(i) Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections II.E.1.a. and II.E.1.b.;

II.E.3.b.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section II.E.1.c.; or

II.E.3.b.(iii) A performance test conducted during representative operations using one of the following methods, as applicable:

II.E.3.b.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content;

II.E.3.b.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.E.4. Exemptions

II.E.4.a. Industrial cleaning solvent operations are not subject to Section II.E. if they are subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT.

II.E.4.b. The VOC control requirements in Section II.E.1. do not apply to:

II.E.4.b.(i) Cleaning of electrical and electronic components;

II.E.4.b.(ii) Cleaning of precision optics;

II.E.4.b.(iii) Cleaning of numismatic dies;

II.E.4.b.(iv) Stripping of cured inks, coatings, and adhesives;

II.E.4.b.(v) Cleaning of resin, coating, ink, and adhesive manufacturing, mixing, molding, and application equipment;

II.E.4.b.(vi) Cleaning of research and development laboratories;

II.E.4.b.(vii) Cleaning of medical device or pharmaceutical manufacturing equipment;

II.E.4.b.(viii) Performance testing to determine coating, adhesive, ink or ink performance;

II.E.4.b.(ix) Cleaning of equipment and materials used in testing for quality control or quality assurance purposes;

II.E.4.b.(x) Cleaning of digital printing operations; and

II.E.4.b.(xi) Cleaning of screen printing operations.

II.E.4.c. In lieu of compliance with Section II.E.1. and II.E.2., the owner or operator of an area source aerospace facility, as defined in 40 CFR Part 63, Section 63.742 (November 17, 2016), may implement the solvent cleaning provisions of the National Emission Standards for Hazardous Air Pollutants for Aerospace Manufacturing and Rework facilities contained in 40 CFR Part 63, Section 63.744 (November 17, 2016) along with the applicable definitions contained in 40 CFR Part 63, Section 63.742 (November 17, 2016), except that:

II.E.4.c.(i) VOC-containing solvents which meet the definition of “non-HAP materials” in 40 CFR Part 63, Section 63.742 (November 17, 2016) are not excluded from the housekeeping measures contained in 40 CFR Part 63, Section 63.744(a) (November 17, 2016); and

II.E.4.c.(ii) The baseline reduction compliance option contained in 40 CFR Part 63, Section 63.744(b)(3) (November 17, 2016) is not available for purposes of compliance with this VOC control rule.

II.F. General Solvent Use

II.F.1. Applicability

II.F.1.a. Within the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to two (2) tons per year that existed at major sources of VOC (greater than or equal to 50 tpy VOC) as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.1.b. (State Only) Outside the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to five (5) tons per year that existed at sources of VOC greater than or equal to 50 tpy VOC as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.2. Exemptions

The requirements of this Section II.F. do not apply to:

II.F.2.a. Operations that are subject to a solvent work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that constitutes RACT, or;

II.F.2.b. Solvent use where the solvent does not contain VOCs.

II.F.3. Work practice requirements

The owner or operator of operations that use solvents must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.F.3.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.F.3.b. Properly dispose of used solvent and solvent contaminated waste (e.g. shop towels and carbon filtration or other control device media), and;

II.F.3.c. Implement good air pollution control practices that minimize emissions, including but not limited to:

II.F.3.c.(i) Using low or no-VOC solvents, if possible;

II.F.3.c.(ii) Using only volumes of solvent necessary for operations;

II.F.3.c.(iii) Using submerged fill pipes in storage tanks and containers;

II.F.3.c.(iv) Using closed loop systems to minimize solvent loss during transfer and use of solvents;

II.F.3.c.(v) Maintaining solvent storage, transfer, and use operations equipment in such a way that it minimizes evaporation loss and remains leak free, and;

II.F.3.c.(vi) Owners or operators of sources that use a carbon adsorption system must provide for the proper disposal or reuse of all VOC recovered.

II.F.4. Control of general solvent use

The owner or operator of operations that use solvents with uncontrolled actual VOC emissions greater than or equal to twenty-five (25) tons per year on a calendar year basis, and that are located in the 8-Hour Ozone Control Area, must reduce solvent use VOC emissions by 90%.

II.F.5. Monitoring requirements

II.F.5.a. The owner or operator of operations that use solvents that utilize a closed-loop system for emission control must inspect the control system using audio, visual, olfactory (AVO) on a monthly basis for perceptible emissions. First attempt to repair must be made upon detection if feasible, but no later than three (3) calendar days from detection.

II.F.5.b The owner or operator of operations that use solvents that utilize a control device must operate and maintain the control device consistent with the manufacturer's specifications.

II.F.5.c. The owner or operator of operations that use solvents that are subject to the 90% control requirement in Section II.F.4. must:

II.F.5.c.(i) Complete a performance test once every three (3) years during representative operations to verify compliance with Section II.F.4. using one of the following methods, as applicable:

II.F.5.c.(i)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content.

II.F.5.c.(i)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.F.5.c.(ii) Conduct all performance tests in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.F.5.c.(iii) Comply with control device and monitoring system manufacturers' specifications for operation and maintenance for equipment used to demonstrate compliance with Section II.F.4.

II.F.6. Recordkeeping

II.F.6.a. Records of calendar year VOC emission estimates demonstrating whether the solvent operation meets or exceeds the applicability threshold in Section II.F.1.

II.F.6.b. If applicable, records demonstrating that an exemption to Section II.F.2. applies.

II.F.6.c. Monthly solvent losses based on beginning and ending inventories, solvent received, inventory adjustments, solvent destroyed in a control device, solvent recovered, and any volume of solvent normally retained in recovery equipment. Solvent losses must be totaled on a rolling 12-month basis.

II.F.6.d. Monthly records such as safety data sheets or other analytical data from the solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent operations.

II.F.6.e. Records of negative pressure ranges, and other records necessary to demonstrate compliance with Section II.F.3.

II.F.6.f. Manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section II.F.4.

II.F.6.g. If applicable, monthly records of operation and maintenance of control device and monitoring system according to manufacturer's specifications to demonstrate compliance with Sections II.F.4. and II.F.5.

II.F.6.h. If applicable, Records of performance tests conducted to demonstrate compliance with Section II.F.5.

II.F.6.i. If applicable, monthly records of AVO inspections including:

II.F.6.i.(i) The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.F.6.i.(ii) A list of the leaks requiring repair,

II.F.6.i.(iii) The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

II.F.6.i.(iv) The date the leak was repaired and type of repair method applied.

II.F.6.j. Records must be maintained for two (2) years and made available for inspection by the Division upon request.

III. Use of Cutback Asphalt

III.A. Definitions

III.A.1. "Asphalt or Asphalt Cement" The dark-brown to black cementitious material (solid, semi-solid, or liquid in consistency) of which the main constituents are bitumen's which occur naturally or as a residue of petroleum refining.

III.A.2. "Asphalt Concrete" A waterproof and durable paving material composed of dried aggregate, which is evenly coated with hot asphalt cement.

III.A.3. "Cutback Asphalt or Cutback Asphalt Cement" Any asphalt which has been liquefied by blending with a VOC, such as a petroleum solvent diluents or, in the case of some slow cure asphalts (Road Oils), which has been produced directly from the distillation of petroleum.

III.A.4. “Emulsified Asphalt” Asphalt emulsions produced by combining asphalt and water with emulsifying agent.

Emulsified Asphalt or any other coating or sealant, including but not limited to those produced from petroleum or coal, which contain more than five (5) percent of oil distillate as determined by ASTM Method D-244 is included in this definition.

III.A.5. “Penetrating Prime Coat” An application of low-viscosity liquid asphalt to an absorbent surface in order to prepare it for overlaying with a layer or layers of asphalt cement or asphalt emulsion and mineral aggregate paving materials.

III.B. Limitations

III.B.1. Applicability

The provisions of this Section III. apply to the use and storage of cutback asphalt for the paving and maintenance of all public roadways (including alleys), private roadways, parking lots, and driveways only within ozone nonattainment areas.

III.B.2. Storage

Stockpiles of aggregate mixed with cutback asphalt are permitted October 1 through February 28 (29). Such storage is not permitted March 1 through September 30 except where it can be demonstrated to the Division that such storage is necessary.

III.B.3. Use

Cutback asphalt may be used for any paving purpose October 1 through February 28 (29). No person shall use cutback asphalt or any coating included in the definition of cutback asphalt in Section III.A.3. March 1 through September 30 except as provided:

III.B.3.a. If used solely as a penetrating prime coat, or

III.B.3.b. If the user can demonstrate to the Division that under the conditions of its intended use, there will be no emissions of volatile organic compounds to the ambient air.

III.C. Recordkeeping

During the months of March through September, the person responsible for the use or storage of any cutback asphalt as permitted in Sections III.B.3.a., III.B.3.b., and Section III.B.2. shall keep records of same, including type and amount of solvent(s) used.

IV. Graphic Arts and Printing

IV.A. Packaging Rotogravure, Publication Rotogravure, and Flexographic Printing

IV.A.1. Definitions

For the purpose of this section, the following definitions apply:

IV.A.1.a. "Flexographic Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique in which the pattern to be applied is raised above the printing roll and the image carrier is made of rubber or other elastomeric materials.

IV.A.1.b. "Packaging Rotogravure Printing" means rotogravure printing upon paper, paperboard, metal foil, plastic film, and other substrates, which are, in subsequent operations, formed into packaging products and labels for articles to be sold.

IV.A.1.c. "Publication Rotogravure Printing" means rotogravure printing upon paper, which is subsequently formed into books, magazines, catalogues, brochures, directories, newspaper supplements, and other types of printed materials.

IV.A.1.d. "Roll Printing" means the application of words, designs, and pictures to a substrate usually by means of a series of hard rubber or steel rolls each with only partial coverage.

IV.A.1.e. "Rotogravure Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique, which involves an intaglio or recessed image areas in the form of cells.

IV.A.2. Applicability

IV.A.2.a. This section applies to all packaging rotogravure, publication rotogravure, and flexographic printing facilities whose potential emissions of volatile organic compounds before control (determined at design capacity and 8760 hrs/year, or at maximum production, and accounting for any capacity or production limitations in a federally-enforceable permit) are equal to or more than 90,000 Kg per year (100 tons/year). Potential emissions are to be estimated by extrapolating historical records of actual consumption of solvent and ink. (e.g., the historical use of 20 gallons of ink for 4,000 annual hours would be extrapolated to 43.8 gallons for 8760 hours.) The before-control volatile organic compound emissions calculations shall be the summation of all volatile organic compounds in the inks and solvents (including cleaning liquids) used.

IV.A.3. Provisions for Specific Processes

IV.A.3.a. No owner or operator of a facility subject to this section and employing VOC-containing ink shall operate, cause, allow, or permit the operation of the facility unless:

IV.A.3.a.(i) The volatile fraction of ink, as it is applied to the substrate, contains 25.0 percent or less (by volume) of VOC and 75.0 percent or more (by volume) of water; or

IV.A.3.a.(ii) The ink (minus water) as it is applied to the substrate, contains 60.0 percent or more (by volume) non-volatile material; or

IV.A.3.a.(iii) The owner or operator installs and operates a control device and capture system in accordance with Sections IV.A.3.b. and IV.A.3.c.; or

IV.A.3.a.(iv) A combination of solvent-borne inks and low solvent inks that achieve a 70% (volume) overall reduction of solvent usage (compared to an all solvent borne ink usage) is used; or

IV.A.3.a.(v) Flexographic and packaging rotogravure printing facilities limit emissions to 0.5 pounds of VOC per pound of solids in the ink. The limit includes all solvent added to the ink: solvent in the purchased ink, solvent added to cut the ink to achieve desired press viscosity, and solvent added to ink on the press to maintain viscosity during the press run. (Publication rotogravure facilities shall not use this option); or

IV.A.3.a.(vi) Crossline averaging is used. The requirements of Section I.A.5.d. apply.

IV.A.3.b. A capture system shall be used in conjunction with the emission control system in Section IV.A.3.a. The design and operation of a capture system shall be consistent with good engineering practice, and in conjunction with control equipment shall be required to provide for an overall reduction in volatile organic compound emissions of at least:

IV.A.3.b.(i) 75.0 percent where a publication rotogravure process is employed;

IV.A.3.b.(ii) 65.0 percent where a packaging rotogravure process is employed; or

IV.A.3.b.(iii) 60.0 percent where a flexographic printing process is employed.

IV.A.3.c. The design, operation, and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Testing of any capture system may be required by the Division on a case-by-case basis, in cases where a total enclosure is not used or when material balance results are questionable. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

IV.A.3.d. The overall reduction in VOC emissions specified in Section IV.A.3.b. shall be calculated by material balance methods approved by the Division, or by determination of capture and control device efficiencies. The overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

IV.A.4. Testing and Monitoring

The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Part C, Sections I.A.3., I.A.7, I.A.9., and I.A.10. In Part C, Section I.A.3., EPA reference method 24A shall be the test method used for publication rotogravure inks, while EPA Reference method 24 data is acceptable for all other inks. Test methods as set forth in Appendix A, Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR), in effect July 1, 1993.

IV.A.5. The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section I.A.8. "A Guideline for Graphic Arts Calculations" shall be used for compliance determination.

IV.B. Lithographic and Letterpress Printing

IV.B.1. General Provisions

IV.B.1.a. Definitions

IV.B.1.a.(i) “Alcohol” means any of the hydroxyl-containing organic compounds with a molecular weight equal to or less than 74.12, which includes methanol, ethanol, propanol, and butanol.

IV.B.1.a.(ii) “Alcohol substitute” means nonalcohol additives that contain VOCs and are used in the fountain solution to reduce the surface tension of water or prevent ink piling.

IV.B.1.a.(iii) “Cleaning material” means a VOC-containing material used to remove ink and debris from the printing press area, operating surfaces of the printing press and, printing press parts. Blanket wash is a type of cleaning material.

IV.B.1.a.(iv) “Composite partial vapor pressure” means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^{n} \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{e=1}^{n} \frac{W_e}{MW_e} + \sum_{i=1}^{n} \frac{W_i}{MW_i}}$$

Where:

Wi	=	Weight of the “i”th VOC compound, in grams
Ww	=	Weight of water, in grams
We	=	Weight of exempt compound, in grams
MWi	=	Molecular weight of the “i”th VOC compound, in g/g-mole
MWw	=	Molecular weight of water, in g/g-mole
MWc	=	Molecular weight of exempt compound, in g/g-mole
PPc	=	VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VPi	=	Vapor pressure of the “i”th VOC compound at 20°C(68°F), in mm Hg

IV.B.1.a.(v) “Fountain solution” means a mixture of water, nonvolatile printing chemicals, and a liquid additive that reduces the surface tension of the water so that it spreads easily across the printing plate surface. The fountain solution wets the non-image areas so that the ink is maintained within the image areas.

IV.B.1.a.(vi “Heatset” means any lithographic or letterpress printing operation where printing inks are set by the evaporation of the ink oils in a heatset dryer.

IV.B.1.a.(vii) “Heatset dryer” means a hot air dryer used in heatset lithography to heat the printed substrate and to promote the evaporation of ink oils.

IV.B.1.a.(viii) “Lithographic printing” means a planographic printing process where the image and non-image areas are chemically differentiated (the image area is oil receptive and the non-image area is water receptive). This printing process differs from other conventional printing methods, where the image is a raised or recessed surface.

IV.B.1.a.(ix) “Letterpress printing” means a printing process in which the image area is raised relative to the non-image area and the paste ink is transferred to the substrate directly from the image surface.

IV.B.1.a.(x) “Non-heatset” means any printing operation where the printing inks are set without the use of heat. For the purpose of Section IV.B., ultraviolet-cured and electron beam-cured inks are considered non-heatset.

IV.B.1.a.(xi) “Offset lithographic printing” means a printing process that transfers the ink film from the lithographic plate to an intermediary surface (blanket), which in turn transfers the ink film to the substrate.

IV.B.1.a.(xii) “Press” means a printing production assembly composed of one or more print units used to produce a printed substrate including any associated coating, spray powder application, heatset web dryer, ultraviolet or electron beam curing units, or infrared heating units.

IV.B.1.a.(xiii) “Sheet-fed printing” means a printing process where individual sheets of paper or substrate are fed into the printing press.

IV.B.1.a.(xiv “Web printing” means a printing process where continuous rolls of substrate material are fed to the press and rewound or cut to size after printing.

IV.B.1.b. Applicability

IV.B.1.b.(i) The provisions of this Section IV.B. apply to fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses. These materials are not subject to the requirements of Sections I. and II.

IV.B.1.b.(ii) The work practice requirements in Section IV.B.1.c. apply to all lithographic and letterpress printing operations.

IV.B.1.b.(iii) The VOC content limit for inks in Section IV.B.1.d. applies to lithographic and letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(iv) The cleaning material requirements in Section IV.B.2. apply to letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(v) The cleaning material and fountain solution requirements in Sections IV.B.2. and IV.B.3. apply to offset lithographic printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.

IV.B.1.b.(vi) The control requirements in Section IV.B.4. apply to each heatset web offset lithographic and heatset web letterpress printing press with the potential to emit from the dryer, prior to controls, at least 25 tons per calendar year of VOC (petroleum ink oil) from heatset inks.

IV.B.1.c. Work Practice Requirements

Lithographic and letterpress printing operations must implement the following work practices at all times to reduce VOC emissions from fugitive sources:

IV.B.1.c.(i) Cover open containers and keep cleaning materials in closed containers when not in use;

IV.B.1.c.(ii) Properly dispose of used cleaning materials, fountain solutions, and used shop towels; and

IV.B.1.c.(iii) Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintain cleaning equipment to repair cleaning materials leaks.

IV.B.1.d. VOC Content Limit for Inks

IV.B.1.d.(i) Lithographic and letterpress printing operations, excluding heatset web offset and heatset web letterpress printing operations, must use low-VOC inks, which average less than 30% (by weight) VOC on a monthly basis.

IV.B.1.d.(ii) Heatset web offset lithographic and heatset web letterpress printing operations must use low-VOC inks, which average less than 40% (by weight) VOC on a monthly basis.

IV.B.2. Offset lithographic printing and letterpress printing operations must comply with the following cleaning materials requirements;

IV.B.2.a. All cleaning materials must contain less than 70% (by weight) VOC or have a VOC composite vapor pressure less than 10 mmHg at 20°C.

IV.B.2.b. Exemptions

The following materials and operations are exempt from the cleaning material requirements in Section IV.B.2.a.:

IV.B.2.b.(i) Cleaners used on electronic components of a press.

IV.B.2.b.(ii) Pre-press cleaning operations.

IV.B.2.b.(iii) Post-press cleaning operations.

IV.B.2.b.(iv) Floor cleaning supplies (other than those used to clean dried ink).

IV.B.2.b.(v) Cleaning performed in parts washers or cold cleaners that are subject to Section II.

IV.B.2.c. Use of non-compliant cleaning materials

Cleaning materials not meeting the limits in Section IV.B.2.a. are limited to less than or equal to 110 gallons per calendar year.

IV.B.3. Offset lithographic printing operations must comply with the following fountain solution requirements:

IV.B.3.a. Heatset web offset lithographic printing operations must:

IV.B.3.a.(i) Use a fountain solution containing 1.6% alcohol (by weight) or less as applied;

IV.B.3.a.(ii) Use a fountain solution containing 3% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.a.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b. Sheet-fed printing operations must

IV.B.3.b.(i) Use a fountain solution containing 5% alcohol (by weight) or less as applied;

IV.B.3.b.(ii) Use a fountain solution containing 8.5% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or

IV.B.3.b.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b.(iv) The following are exempt from the fountain solution requirements in Section IV.B.3.b.:

IV.B.3.b.(iv)(A) Fountain solution use associated with a sheet-fed printing press with maximum sheet size 11x17 inches or smaller.

IV.B.3.b.(iv)(B) Fountain solution use associated with a sheet-fed printing press having a total fountain solution reservoir less than one (1) gallon.

IV.B.3.c. Non-heatset web printing must use a fountain solution containing 5% alcohol substitute (by weight) or less and no alcohol.

IV.B.4. Heatset web offset lithographic and heatset web letterpress printing operations must comply with the following control requirements:

IV.B.4.a. Heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 90% or greater.

IV.B.4.b. If the control device was first installed on or after January 1, 2017, heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 95% or greater.

IV.B.4.c. Where inlet VOC concentration is low and a 90 or 95% control efficiency is not achievable due to low inlet concentrations or measurable due to equipment configuration, heatset web offset lithographic and heatset web letterpress printing operations may reduce the control device outlet concentration to 20 ppmv (as hexane on a dry basis).

IV.B.4.d. The following are exempt from the control requirements in Section IV.B.4.:

IV.B.4.d.(i) Heatset presses used for book printing.

IV.B.4.d.(ii) Heatset presses with maximum web width of 22 inches or less.

IV.B.4.d.(iii) Waterborne or radiation (ultra-violet or electron beam) cured materials that are not heatset.

IV.B.5. Monitoring, Recordkeeping and Reporting

IV.B.5.a. The owner or operator of a heatset web offset lithographic or heatset web letterpress printing operation required to demonstrate compliance with Section IV.B.4. must install, calibrate, maintain, and operate a temperature monitoring device, according to the manufacturer’s specifications.

IV.B.5.b. The owner or operator of a lithographic and letterpress printing operations subject to Sections IV.B.1.d. and IV.B.2. through IV.B.4. must keep the following records for two (2) years and make them available for inspection by the Division upon request:

IV.B.5.b.(i) If applicable, records demonstrating that a listed exemption to this Section IV.B. applies.

IV.B.5.b.(ii) If applicable, monthly records of the type, alcohol content or alcohol substitute content, and total volume of fountain solution used in printing operations.

IV.B.5.b.(iii) If applicable, monthly records of the type, VOC content or composite vapor pressure, and total volume of the cleaning materials used in printing operations.

IV.B.5.b.(iv) If applicable, monthly records of the type, VOC content, and total volume of inks (including varnishes) and coatings used in printing operations.

IV.B.5.b.(v) If applicable, monthly records demonstrating compliance with the control requirements in Section IV.B.4.

IV.B.5.b.(vi) Records of calendar year VOC emission estimates demonstrating whether the printing operation meets or exceed the applicability thresholds in Section IV.B.1.b.

IV.B.5.c. Compliance with control requirements must be demonstrated using the following methods as applicable:

IV.B.5.c.(i) Safety data sheets or other analytical data from the ink, cleaning material, or fountain solution manufacturer to demonstrate compliance with VOC content limit for inks in Section IV.B.1.d., the cleaning material requirements in Section IV.B.2., and the fountain solution requirements in Section IV.B.3.;

IV.B.5.c.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with the control equipment requirements in Section IV.B.4.; or

IV.B.5.c.(iii) A performance test conducted during representative conditions using one of the following methods as applicable:

IV.B.5.c.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content for inks, fountain solutions and cleaning materials; or

IV.B.5.c.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency or outlet concentration of the emission control equipment.

V. Pharmaceutical Synthesis

V.A. General Provisions

V.A.1. Applicability

This section applies to all sources of volatile organic compounds associated with pharmaceutical manufacturing activities, including, but not limited to, reactors, distillation units, dryers, storage of VOCs, extraction equipment, filters, crystallizers, and centrifuges.

V.A.2. Exemptions

Extraction of organic substances from animal or vegetable material; fermentation and culturing; formulation and packaging of pharmaceutical or medicinal products.

V.A.3. Definitions

For the purpose of this section, the following definitions apply:

V.A.3.a. "Control System" means any number of control devices, including condensers, which are designed and operated to reduce the quantity of VOC emitted to the atmosphere.

V.A.3.b. "Pharmaceutical" means a medicine or drug which appears in the United States Pharmacopoeia National Formulary, or which is so designated by the National Drug Code of the United States FDA Bureau of Drugs.

V.A.3.c. "Production Equipment Exhaust System" means a device for collecting and directing out of the work area VOC fugitive emissions from reactor openings, centrifuge openings, and other vessel openings for the purpose of protecting workers from excessive VOC exposure.

V.A.3.d."Reactor" means a vat or vessel, which may be jacketed to permit temperature control, designed to contain chemical reactions.

V.A.3.e."Separation Operation" means a process that separates a mixture of compounds and solvents into two or more components. Specific mechanisms include, but are not limited to, extraction, centrifugation, filtration, distillation, and crystallization.

V.A.3.f. "Synthesized Pharmaceutical Manufacturing" means manufacture of pharmaceutical products by chemical synthesis. It includes the manufacture of chemical intermediates (of sufficient purity) which are typically used by the pharmaceutical industry as precursors to finished mixtures of chemicals. (Thus, it excludes those chemical processes which are not directed at creating finished pharmaceutical or chemical intermediates to finished pharmaceuticals.)

V.B. Provisions for Specific Processes

V.B.1. The owner or operator of a facility subject to this section shall control the volatile organic compound emissions from each vent which has the potential to emit 6.80 kg/day (l5 lb./day) or more of VOC from reactors, distillation operations, crystallizers, centrifuge and vacuum dryers. Surface condensers or equivalent controls shall be used, provided that, if surface condensers are used, the condenser outlet gas temperature shall not exceed the following values:

VOCs True Vapor Pressure* at 20° in torr (and psia) from (minimum) up to ** (maximum)	Maximum temperature of Gas Stream immediately exiting the condenser
0-26(0-0.5)	35°C (95°F)
26-52(0.5-1.0)	25°C(77°F)
52-78(1.0-1.5)	10°C(50°F)
78-150(1.5-2.9)	0°C(32°F)
150-300(2.9-5.8)	-15°C(5°F)
Greater than 300(Greater than 5.8)	-25°C(-13°F)

*The calculation methods for gases containing more than one condensable component are complex. As a simplification, the temperature necessary for control by condensation can be roughly approximated by the weighted average of the temperatures necessary for condensation of each VOC considered separately but at concentrations equal to the total organic concentration.

**But not including the maximum value of the range.

V.B.2. Division approval shall be required for control equipment used to control VOCs of 570 torr (11 psia) and above.

V.B.3. The owner or operator of a facility subject to this section shall reduce the VOC emissions from each air dryer and production equipment exhaust system:

V.B.3.a.By at least 90 percent if emissions are 150 kg/day (330 lbs/day) or more of VOC, or,

V.B.3.b.To 15.0 kg/day (33 lb/day) or less if emissions are less than 150 kg/day (330 lb/day) of VOC.

V.B.4. The owner or operator of a facility subject to this section shall:

V.B.4.a. Provide a vapor balance system or equivalent control that is at least 90.0 percent effective in reducing emissions from truck or railcar deliveries to storage tanks with capacities greater than 7,570 liters (2,000 gallons) that store VOC with true vapor pressure greater than 210 torr (4.1 psia) at 20°C; and,

V.B.4.b. Install pressure/vacuum conservation vents set at plus or minus 0.2 kPa on all storage tanks that store VOC with true vapor pressures greater than 10.0 kPa (1.5 psi) at 20°C.

V.B.5. The owner or operator of a facility subject to this section shall enclose all centrifuges, rotary vacuum filters, and other filters having an exposed liquid surface, where the liquid contains VOC and exerts a total VOC true vapor pressure of 26 torr (0.5 psia) or more at 20°C.

V.B.6. The owner or operator of a synthesized pharmaceutical facility subject to this section shall install covers on all in-process tanks containing a volatile organic compound at any time. These covers shall remain closed unless sampling, maintenance, short-duration production procedures or inspection procedures require access.

V.B.7. The owner or operator of a facility subject to this section shall repair all leaks from which a liquid, containing VOC, can be observed running or dripping. The repair shall be completed the first time the equipment is off-line for a period of time long enough to complete the repair, except that no leak shall go unrepaired for more than 14 days after initial detection unless the Division issues written approval.

V.B.8. Each surface condenser shall have at least one temperature indicator with its sensor located in the outlet gas stream.

V.C. Testing and Monitoring

V.C.1. Sources subject to the requirements of this section are also subject to the requirements of Sections I.A.3., I.A.7., I.A.8., and I.A.9.

Appendix D Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers

The specifications in this Appendix apply only to vapor degreasers that have both condenser coils and refrigerated freeboard chillers. (The coolant in the condenser coils is normally water.) The amount of refrigeration capacity is expressed in Calories/Hour per meter of perimeter. This perimeter is measured at the air/vapor interface.

For refrigerated chillers operated below 0°C., the following requirements apply:

DEGREASER WIDTH	*CALORIES/HR METER OF PERIMETER	BTU/HR FOOT OF PERIMETER
Less than 1.1 meters (3.5 ft.)	165	200
1.1 - 1.8 meters (3.5 - 6.0 ft.)	250	300
1.8 - 2.4 meters (6.0 - 8.0 ft.)	335	400

2.4 - 3.0 meters (8.0 - 10.0 ft.)	145	500
Greater than 3.0 meters (10 ft.)	500	600

* Kilocalories (1 Kilocalorie = 4184.0 joules)

For refrigerated chillers operating above 0°C., there shall be at least 415 Calories/Hr. - meter of perimeter (500 BTU/Hr-ft.), regardless of size.

Definition:

"Air/Vapor Interface" - means the surface defined by the top of the solvent vapor layer within the confines of a vapor degreaser.

Appendix E Emission Limit Conversion Procedure

The following procedure shall be used to convert emission limits expressed as lb VOC/gallon coating less water and exempt solvents to limits expressed as lb VOC/gallon solids. This example uses the emission limit of 3.7 lb VOC/gallon coating.

Assume VOC density of the `Presumptive' RACT coating is 7.36 pounds per gallon because this same value was used to determine the "Presumptive" recommended RACT emission limits from volume solids data.

(3.7) LB VOC / GAL COATING LESS WATER x I GAL VOC x 100 / 7.36 LB VOC = (50) V0L% VOC
100 - (50) V0L% VOC = (50) V0L% SOLIDS
(3.7) LB VOC / GAL COATING LESS H2O x 100 GAL COATING / (50) GAL SOLIDS = (7.4) LB VOC / GAL SOLIDS

See "A Guideline for Surface Coating Calculations" EPA - 340/1-86-0l6 for additional examples.

The following table lists equivalent mass VOC/volume solids emission limits for various coating operations.

Equivalency Data for Surface Coating Processes (VOC Density = 7.36 lb/gal)

Industrial Finishing Categories	Lb VOC per Gallon Coating less water	Lb VOC per Gallon of Solids	Kg VOC per Liter of Solids
Can Industry			
Sheet Basecoat (Exterior and Interior) and over-varnish; two-piece can exterior (base-coat and over-varnish)	2.8	4.5	0.55

Two- and three-piece can interior body spray, two-piece can exterior end spray or roll coat	4.2	9.8	1.19
Three-piece can side-seam spray	5.5	21.7	2.61
End sealing compound	3.7	7.4	0.88
Any additional coats	4.2	9.8	1.19
Coil Coating			
Any coat	2.6	4.0	0.48
Fabric Coating			
Fabric coating line	2.9	4.8	0.58
Vinyl coating line	3.8	7.9	0.93
Paper Coating			
Coating line	2.9	4.8	0.58
Automotive and Light-Duty Truck Assembly Plant			
Primer (electrodeposition) application, flashoff area and oven	1.9	2.6	0.31
Topcoat application, flashoff area and oven	2.8	4.5	0.55
Final repair application, flashoff area and oven	4.8	13.8	1.67
Metal Furniture			
Coating line	3.0	5.1	0.61
Magnet Wire			
Wire coating operation	1.7	2.2	0.26
Large Appliances			
Prime, single, or topcoat application area, flashoff area and oven	2.8	4.5	0.55

Miscellaneous Metal Parts and Products			
Air-dried items	3.5	6.7	0.80
Clear-coated items	4.3	10.3	1.25
Extreme performance coatings	3.5	6.7	0.80
Other coatings and systems	3.0	5.1	0.61
Plastic Film Coating			
Plastic film coating line	2.9	4.8	0.58

PART D Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.2., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area) and that are located at or upstream of a natural gas plant.

I.A.2. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. “Affected Operations” means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. “Air Pollution Control Equipment”, as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. “Approved Instrument Monitoring Method” means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. “Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks” means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. “Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. “Calendar Week” means a week beginning with Sunday and ending with Saturday.

I.B.7. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.8. “Condensate Storage Tank” means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.9. “Centrifugal Compressor” means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.10. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

I.B.11. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

I.B.12. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

I.B.13. "Downtime" means the period of time when a well is producing and the air pollution control equipment is not in operation.

I.B.14. "Existing" means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.

I.B.15. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

I.B.16. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquids does not include produced water.

I.B.17. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

I.B.18. "Modified or Modification" means any physical change or change in operation of a stationary source that results in an increase in actual uncontrolled volatile organic compound emissions from the previous calendar year that occurs on or after February 1, 2009. For atmospheric condensate storage tanks (and beginning March 1, 2020, for all storage tanks), a physical change or change in operation includes but is not limited to drilling wells and recompleting, refracturing or otherwise stimulating existing wells.

I.B.19. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

I.B.20. "Natural Gas-Driven Diaphragm Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

I.B.21. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

I.B.22. "New" means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

I.B.23. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

I.B.24. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

I.B.25. "Stabilized" when used to refer to stored hydrocarbon liquids, means that the hydrocarbon liquids have reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses".

I.B.26. "Storage tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

I.B.27. "Storage vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

I.B.28. (State Only) "Surveillance System" means monitoring pilot flame presence or temperature in a combustion device either by visual observation or with an electronic device to record times and duration of periods where a pilot flame is not detected at least once per day.

I.B.29. "System-Wide Control Strategy" means the collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.

I.B.30. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

I.C. General Provisions

I.C.1. General Requirements

I.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section I. must be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates required by this Section I. and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

I.C.1.b. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.

I.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections I.D., I.J., and I.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment is a violation of this regulation.

I.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.

I.C.1.e. All combustion devices used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. must be equipped with and operate an auto-igniter as follows:

I.C.1.e.(i) (State Only) For condensate storage tanks that are constructed or modified after May 1, 2009, and before January 1, 2017, and controlled by a combustion device, auto-igniters must be installed and operational, beginning the date of first production after any new tank installation or tank modification.

I.C.1.e.(ii) (State Only) For all existing condensate storage tanks controlled by a combustion device in order to comply with the emissions control requirements of Section I.D.1., auto-igniters must be installed and operational beginning May 1, 2009, for condensate storage tanks with actual uncontrolled emissions of greater than or equal to 50 tons per year, and beginning May 1, 2010, for all other existing condensate storage tanks controlled by a combustion device, or within 180 days from first having installed the combustion device, whichever date comes later.

I.C.1.e.(iii) All combustion devices installed on or after January 1, 2017, must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.e.(iv) All combustion devices installed on or after January 1, 2018, and used to comply with Sections I.J. or I.K. must be equipped with an operational auto-igniter upon installation of the combustion device.

I.C.1.f. (State Only) If a combustion device is used to control emissions of volatile organic compounds, surveillance systems must be employed and operational as follows:

I.C.1.f.(i) (State Only) Beginning May 1, 2010, for all existing condensate storage tanks with uncontrolled actual emissions of 100 tons per year or more based on data from the previous twelve consecutive months.

I.C.1.f.(ii) (State Only) For all new and modified condensate storage tanks controlled by a combustion device for the first 90 days surveillance systems must be employed and operational beginning 180 days from commencement of operation after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated, if uncontrolled actual emissions projected for the first twelve months based on data from the first 90 days of operation from the condensate storage tank are 100 tons or more of uncontrolled VOCs.

I.C.2. The emission estimates and emission reductions required by Section I.D. must be demonstrated using one of the following emission factors:

I.C.2.a. In the 8-Hour Ozone Control Area

I.C.2.a.(i) For atmospheric condensate storage tanks at oil and gas exploration and production operations, a default emission factor of 13.7 pounds of volatile organic compounds per barrel of condensate must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii). The Division may require a more specific emission factor that complies with Section I.C.2.a.(iii).

I.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations a source may use a specific emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003. The Division may, however, require the source to develop and use a more recent specific emission factor pursuant to Section I.C.2.a.(iii) if such a more recent emission factor would be more reliable or accurate.

I.C.2.a.(iii) Except as otherwise provided in Section I.C.2.a.(i), a specific emission factor is one for which the Division has no objection, and which is based on collection and analysis of a representative sample of the hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.a.(iv) For storage tanks storing produced water or hydrocarbon liquids other than condensate, the most recent Division-approved default emission factors must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii).

I.C.2.a.(v) If the Division has reason to believe that a specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require the use of an alternative emission factor that complies with Section I.C.2.a.(iii).

I.C.2.b. (State Only) For any other Ozone Nonattainment Area or Attainment/Maintenance Areas

I.C.2.b.(i) (State Only) For storage tanks at oil and gas exploration and production operations, the source must use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a site-specific emission factor has been established pursuant to Section I.C.2.b.(iii). If the Division has established no default emission factor, if the Division has reason to believe that the default emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(ii) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, the source must use a site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.(iii). If the Division has reason to believe that the site-specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).

I.C.2.b.(iii) (State Only) Establishment of or Updating Approved Emission Factors

I.C.2.b.(iii)(A) (State Only) The Division may require the source to develop and/or use a more recent default basin-specific or site-specific volatile organic compound emission factor pursuant to Section I.C.2.b., if such emission factor would be more reliable or accurate.

I.C.2.b.(iii)(B) (State Only) For storage tanks at oil and gas exploration and production operations, the source may use a site-specific volatile organic compound emission factor for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.C.2.b.(iii)(C) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, a source may use a volatile organic compound emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003, or an alternative site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.

I.C.2.b.(iii)(D) (State Only) A default basin-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water or an alternative method, pursuant to a test method approved by the Division, except as otherwise provided in I.C.2.b.(i).

I.C.2.b.(iii)(E) (State Only) A site-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.D. Storage Tank Emission Controls

I.D.1. System-Wide Control Strategy for Condensate Storage Tanks

I.D.1.a. Beginning May 1, 2011, through April 30, 2020, owners and operators of all atmospheric condensate storage tanks that emit greater than or equal to two tons per year of actual uncontrolled volatile organic compounds must employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks by 90% from uncontrolled actual emissions on a calendar weekly basis May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

Emission reductions are not required for each and every unit, but instead shall be based on overall reductions in uncontrolled actual emissions from all the atmospheric condensate storage tanks associated with the affected operations for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, due to either having exceeded reporting thresholds or retrofitting with air pollution control equipment in order to comply with the system-wide control strategy.

I.D.1.b. The system-wide control strategy does not apply to natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.1.c. The system-wide control strategy does not apply to any owner or operator where the APENs for all of the atmospheric condensate storage tanks associated with the affected operations owned or operated by such person in calendar year 2019 or January 1, 2020, through April 30, 2020, reflect a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area.

I.D.2. New and Modified Condensate Tanks

I.D.2.a. Beginning February 1, 2009, through March 1, 2020, owners or operators of any new or modified atmospheric condensate storage tank at exploration and production sites shall collect and control emissions by routing emissions to and operating air pollution control equipment pursuant to Section I.D. The air pollution control equipment shall have a control efficiency of at least 95%, and shall control volatile organic compounds during the first 90 calendar days after commencement of operation of the storage tank, or after the well was re-completed, re-fractured or otherwise stimulated. The air pollution control equipment and associated monitoring equipment required pursuant to Section I.C.1. may be removed after the first 90 calendar days as long as the source can demonstrate compliance with the applicable system-wide standard.

I.D.3. Storage Tank Control Strategy

I.D.3.a. Applicability

I.D.3.a.(i) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(ii) (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total and not subject to Section I.D.3.a.(i) must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.b. Compliance Deadlines

I.D.3.b.(i) A storage tank subject to Section I.D.3.a.(i) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(ii) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(iii) A storage tank subject to Section I.D.3.a.(i) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(iv) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

I.D.3.b.(v) A storage tank subject to Section I.D.3.a.(i) and not otherwise subject to Sections I.D.3.b.(i). or I.D.3.b.(iii) that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.

I.D.3.b.(vi) (State Only) A storage tank subject to Section I.D.3.a.(ii) and not otherwise subject to Sections I.D.3.b.(ii) or I.D.3.b.(iv) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.

I.D.3.b.(vii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iii) or I.D.3.b.(v), compliance with Section I.D.3.a.(i) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iii) or I.D.3.b.(v) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(viii) (State Only) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iv) or I.D.3.b.(vi), compliance with Section I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iv) or I.D.3.b.(vi) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

I.D.3.b.(ix) This Section I.D.3. does not apply to storage tanks at natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.

I.D.4. Alternative emissions control equipment and pollution prevention devices and processes installed and implemented after June 1, 2004, shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and/or vapor recovery units to achieve the emission reductions required by this Section I.D., if the following conditions are met:

I.D.4.a. The owner or operator obtains a construction permit authorizing such use of the alternative emissions control equipment or pollution prevention device or process. The proposal for such equipment, device or process shall comply with all regulatory provisions for construction permit applications and shall include the following:

I.D.4.a.(i) A description of the equipment, device or process;

I.D.4.a.(ii) A description of where, when and how the equipment, device or process will be used;

I.D.4.a.(iii) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;

I.D.4.a.(iv) An adequate method for measuring actual control efficiency; and

I.D.4.a.(v) Description of the records and reports that will be generated to adequately track emission reductions and implementation and operation of the equipment, device or process, and a description of how such matters will be reflected in the records and reports required by Section I.F.

I.D.4.b. Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.D.4.c. EPA approves the proposal. The Division shall transmit a copy of the permit application and any other materials provided by the applicant, all public comments, all Division responses and the Division’s permit to EPA Region 8. If EPA fails to approve or disapprove the proposal within 45 days of receipt of these materials, EPA shall be deemed to have approved the proposal.

I.E. Monitoring of Storage Tanks and Air Pollution Control Equipment

I.E.1. Applicability

I.E.1.a. The owner or operator of any storage tank that is being controlled pursuant to this Section I. (except storage tanks subject to Section I.D.3.a.(ii)).

I.E.1.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii).

I.E.2. Monitoring Requirements

I.E.2.a. The owner or operator of any storage tank controlled by air pollution control equipment other than a combustion device must follow manufacturer's recommended maintenance. Air pollution control equipment must be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

I.E.2.b. Beginning January 1, 2017, through April 30, 2020, owners or operators of atmospheric condensate storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must conduct and document audio, visual, olfactory (AVO) inspections of the storage tank at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days.

I.E.2.c. Weekly Monitoring Requirements

The owner or operator must inspect or monitor the air pollution control equipment at least weekly to ensure that it is operating properly. The inspection must include and document the following

I.E.2.c.(i) For combustion devices, a check that the pilot light is lit by either visible observation or other means approved by the Division. For devices equipped with an auto-igniter, a check that the auto-igniter is properly functioning.

I.E.2.c.(ii) For combustion devices, a check that the valves for piping of gas to the pilot light are open.

I.E.2.c.(iii) (State Only) In addition to complying with Sections I.E.2.c.(i). and I.E.2.c.(ii)., the owner or operator of tanks controlled pursuant to Section I.D. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.

I.E.2.c.(iv) For combustion devices, the owner or operator must visually check for the presence or absence of smoke and that the burner tray is not visibly clogged.

I.E.2.c.(v) For vapor recovery units, the owner or operator must check that the unit is operating and that vapors from the storage tank are being routed to the unit.

I.E.2.c.(vi) For all control devices, the owner or operator must check that the valves for the piping from the storage tank to the air pollution control equipment are open.

I.E.2.c.(vii) For all storage tanks, the owner or operator must check that the thief hatch is closed and latched, the pressure relief valve is properly seated, and all vent lines are closed.

I.E.2.c.(viii) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.c.(ix) (State Only) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks subject to Section I.D.3.a.(ii) must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.d. (State Only) For storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator must check weekly that the system is functioning properly and that necessary information is being collected. Any loss of data or failure to collect required data may be treated by the Division as if the data were not collected.

I.F. Storage Tank Recordkeeping and Reporting

I.F.1. Recordkeeping and Reporting for Tanks Subject to the System-Wide Control Strategy (through April 30, 2020)

The owner or operator shall, at all times, track the emissions and specifically volatile organic compound emissions reductions on a calendar weekly and calendar monthly basis to demonstrate compliance with the applicable emission reduction requirements of the system-wide control strategy. This shall be done by maintaining a Division-approved spreadsheet of information describing the affected operations, the air pollution control equipment being used, and the emission reductions achieved, as follows.

I.F.1.a. The Division-approved spreadsheet shall:

I.F.1.a.(i) List all atmospheric condensate storage tanks subject to the system-wide control strategy by name and AIRS number, or if no AIRS number has been assigned the site location. The spreadsheet also shall list the monthly production volumes for each tank. The spreadsheet shall list the most recent measurement of such production at each tank, and the time period covered by such measurement of production.

I.F.1.a.(ii) List the emission factor used for each atmospheric condensate storage tank. The emission factors shall comply with Section I.C.2.

I.F.1.a.(iii) List the location and control efficiency value for each unit of air pollution control equipment. Each atmospheric condensate storage tank being controlled shall be identified by name and an AIRS number.

I.F.1.a.(iv) List the production volume for each tank, expressed as a weekly and monthly average based on the most recent measurement available. The weekly and monthly average shall be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the refinery purchaser for delivery of condensate from such tank, over the time such delivered condensate was collected. The weekly and monthly average from the most recent measurement will be used to estimate weekly and monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.1.a.(v) Show the calendar weekly and calendar monthly-uncontrolled actual emissions and the calendar weekly and calendar monthly controlled actual emissions for each atmospheric condensate storage tank.

I.F.1.a.(vi) Show the total system-wide calendar weekly and calendar monthly-uncontrolled actual emissions and the total system-wide calendar weekly and calendar monthly controlled actual emissions.

I.F.1.a.(vii) Show the total system-wide calendar weekly and calendar monthly percentage reduction of emissions.

I.F.1.a.(viii) Note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the spreadsheet shall record the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.1.a.(ix) Be maintained in a manner approved by the Division and shall include any other information requested by the Division that is reasonably necessary to determine compliance with the system-wide control strategy.

I.F.1.a.(x) Be updated on a calendar weekly and calendar monthly basis and shall be promptly provided by e-mail or fax to the Division upon its request. The U.S. mail may also be used if acceptable to the Division.

I.F.1.b. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the spreadsheet shall be a violation of this regulation.

I.F.1.c. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.

I.F.1.d. Each owner or operator shall maintain records of the inspections required pursuant to Section I.E. and retain those records for five years. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Sections I.C. and I.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

I.F.1.e. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.

I.F.1.f. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

I.F.1.g. Reporting for Tanks Subject to the System-Wide Control Strategy.

On or before April 30, 2020, each owner or operator shall submit a report describing the air pollution control equipment used during calendar year 2019 and how each company complied with the system-wide control strategy during calendar year 2019. On or before August 30, 2020, each owner or operator must submit a report describing the air pollution control equipment used from January 1, 2020, through April 30, 2020, and how each company complied with the system-wide control strategy during that time period. Such reports shall be submitted to the Division on a Division-approved form provided for that purpose.

I.F.1.g.(i) The report shall list all condensate storage tanks subject or used to comply with the system-wide control strategy and the production volumes for each tank. Production volumes may be estimated by the amounts shown on the receipt from refinery purchasers for delivery of condensate from such tanks.

I.F.1.g.(ii) The report shall list the emission factor used for each tank. The emission factors shall comply with Section I.C.2.

I.F.1.g.(iii) The report shall list the location and control efficiency value for each piece of air pollution control equipment, and shall identify the atmospheric condensate storage tanks being controlled by each.

I.F.1.g.(iv) The April 30 report shall show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, 2020.

I.F.1.g.(v) The April 30 report shall show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, 2020.

I.F.1.g.(vi) The April 30 report shall show the calendar monthly total system-wide percentage reduction of emissions for May 1 through September 30 of the previous year, and for the combined periods of January 1 through April 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide percentage reduction of emissions for January 1 through April 30, 2020.

I.F.1.g.(vii) The report shall note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating should be recorded in the report.

I.F.1.g.(viii) The report shall state whether the required emission reductions were achieved on a calendar monthly basis during the preceding year for the April 30 report and for January 1 through April 30, 2020, for the August 30 report. If the required emission reductions were not achieved, the report shall state why not, and shall identify steps being taken to ensure subsequent compliance.

I.F.1.g.(ix) The report shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section I.

I.F.1.g.(x) A copy of each semi-annual report shall be retained for five years.

I.F.1.g.(xi) In addition to submitting the semi-annual reports, on or before the 30th of each month commencing in June 2007 and ending April 30, 2020, the owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to Sections I.A. and I.D. shall notify the Division of any instances where the air pollution control equipment was not properly functioning during the previous month. The report shall include the time and date that the equipment was not properly operating, the time and date that the equipment was last observed operating properly, and the date and time that the problem was corrected. The report shall also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number of each of the condensate tanks being controlled by the equipment or if no AIRS number has been assigned the site name, and the estimated production from those tanks during the period of non-operation.

I.F.1.g.(xii) Commencing in 2007, on or before April 30 of each year (ending on April 30, 2020), the owner or operator shall submit a list identifying by name and AIRS number or if no AIRS number has been assigned the site name, each condensate storage tank that is being controlled to meet the requirements set forth in Section I.D.1. On the 30th of each month during ozone season (May through September) and on November 30 and February 28 (ending on February 28, 2020), the owner or operator shall submit a list identifying any condensate storage tank whose control status has changed since submission of the previous list.

I.F.1.g.(xiii) (State Only) Semi-annual report submittals shall be signed by a responsible official who shall also sign the Division-approved compliance certification form for atmospheric condensate storage tanks. The compliance certification shall include both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions shall be identified separately from compliance certifications required under the State Implementation Plan.

I.F.1.g.(xiv) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. 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.

I.F.1.h. The record-keeping and reporting required in Sections I.F.1. shall not apply to the owner or operator of any natural gas compressor station or natural gas drip station that is authorized to operate pursuant to a construction permit or Title V operating permit issued by the Division if the following criteria are met:

I.F.1.h.(i) Such permits are obtained by the owner or operator on or after the effective date of this provision and contain the provisions necessary to ensure the emissions reductions required by Section I.D.;

I.F.1.h.(ii) The owners and operators of such natural gas compressor stations or natural gas drip stations do not own or operate any exploration and production operation(s); and

I.F.h.1.(iii) Total emissions from atmospheric condensate storage tanks associated with such natural gas compressor stations or drip stations subject to APEN reporting requirements under Regulation Number 3, Part A owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

I.F.2. Recordkeeping for storage tanks subject to Section I.D.3.

I.F.2.a. The owner or operator of any storage tank subject to control pursuant to Section I.D.3. (except storage tanks subject to Section I.D.3.a.(ii)) must maintain records and make them available to the Division upon request.

I.F.2.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii) must maintain records and make them available to the Division upon request.

I.F.2.c. Records maintained under this Section I.F.2. must include:

I.F.2.c.(i) The AIRS number for the storage tank. The AIRS number assigned by the Division must be marked on all storage tanks required to file an APEN.

I.F.2.c.(ii) If air pollution control equipment is required to comply with Section I.D.3. visible signage must be located with the control equipment identifying the AIRS number for each storage tank that is being controlled by that equipment.

I.F.2.c.(iii) Records of the inspections required in Section I.E.

I.F.2.c.(iii)(A) The time and date of each inspection.

I.F.2.c.(iii)(B) The person conducting the inspection.

I.F.2.c.(iii)(C) A notation that each of the checks required under Section I.E. were completed.

I.F.2.c.(iii)(D) A description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions.

I.F.2.c.(iv) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month totals for each storage tank subject to control under Section I.D.3.

I.F.2.c.(v) The emission factor used for each storage tank. The emission factors must comply with Section I.C.2. and the owner or operator must use the most recent emission factor on file with the Division (i.e., either the default emission factor or the specific emission factor established pursuant to Section I.C.2.a.(iii)).

I.F.2.c.(vi) The control efficiency of each unit of air pollution control equipment and the AIRS number of the storage tank being controlled.

I.F.2.d. (State Only) The owner or operator of each storage tank subject to Section I.D.3. must maintain records of

I.F.2.d.(i) The monthly production volumes for each storage tank, based on the most recent measurement available. The monthly average must be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the purchaser for delivery of hydrocarbon liquids or produced water from such tank, over the time such delivered hydrocarbon liquids or produced water was collected. The monthly average from the most recent measurement will be used to estimate monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

I.F.2.d.(ii) Any downtime of air pollution control equipment, including the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.

I.F.2.d.(iii) Any required surveillance system or other monitoring data.

I.F.2.d.(iv) When a storage tank is installed, or when a well is drilled, re-completed, re-fractured, or otherwise stimulated. Records must be maintained per well associated with each storage tank and the date of commencement of operation associated with these activities.

I.F.3. Reporting for storage tanks subject to Section I.D.3.

I.F.3.a. On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks (except storage tanks subject to Section I.D.3.a.(ii)) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.b. (State Only) On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks subject to Section I.D.3.a.(ii) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.

I.F.3.c. The report under this Section I.F.3. must include:

I.F.3.c.(i) The report must list all storage tanks (by AIRS number and location name) controlled pursuant to Section I.D.3. during the previous calendar year (starting calendar year 2020) and

I.F.3.c.(i)(A) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month total for each storage tank.

I.F.3.c.(i)(B) The emission factor used for each storage tank for each month.

I.F.3.c.(i)(C) The control efficiency for the air pollution control equipment for each storage tank.

I.F.3.c.(ii) (State Only) The report must identify any storage tank whose control status has changed, and the date of the change, since submission of the previous report.

I.F.3.c.(iii) (State Only) The report must list the production volume for each storage tank. Production volumes may be estimated by the amounts shown on the receipt from the purchaser.

I.F.3.c.(iv) (State Only) The report must list any downtime of air pollution control equipment, including the date, time, and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating must be recorded in the report.

I.F.3.c.(v) (State Only) The report must list any instances where the air pollution control equipment was not properly functioning, including the date and time the equipment was not properly operating, the date and time the equipment was last observed operating properly, and the date and time the problem was corrected. The report must also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number, or site name if no AIRS number has been assigned, of each storage tank being controlled by the equipment and the estimated production from those storage tanks during the period of non-operation.

I.F.3.c.(vi) (State Only) Reports must be signed by a responsible official who must also sign the Division-approved compliance certification form for storage tanks. The compliance certification includes both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, the certification must include the citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions must be identified separately from compliance certifications required under the State Implementation Plan.

I.F.3.c.(vii) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. must 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.

I.G. Natural gas-processing plants located in the 8-hour Ozone Control Area (State Only: or any specific Ozone Nonattainment or Attainment/Maintenance Area) shall comply with requirements of this Section I.G., as well as the requirements of Sections I.B., I.C.1.a., I.C.1.b., I.H., I.J., I.K., and Part E, Section I.A. through C.

I.G.1. For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

I.G.2. Air pollution control equipment shall be installed and properly operated to reduce emissions of volatile organic compounds from any atmospheric condensate storage tank (or tank battery) used to store condensate that has not been stabilized that has uncontrolled actual emissions of greater than or equal to two tons per year. Such air pollution control equipment shall have a control efficiency of at least 95%.

I.G.3. Natural gas processing plants within the 8-hour Ozone Control Area constructed before January 1, 2018, must comply with the requirements of Section I.G. beginning January 1, 2019. (State Only: Existing natural gas processing plants within any new Ozone Nonattainment or Attainment/Maintenance Area shall comply with this regulation within three years after the nonattainment designation.)

I.G.4. The provisions of Sections I.B., I.C.1.a., I.C.1.b., I.G., I.H., I.J., I.K., and Part E, Section I.A. through C., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area or Ozone Nonattainment (State Only: or Attainment/Maintenance Area) after the effective date of this section.

I.H. Emission Reductions from glycol natural gas dehydrators

I.H.1. Beginning May 1, 2005, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in any Ozone Nonattainment or Attainment/Maintenance Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.

I.H.3. The control requirements of Sections I.H.1. and I.H.2. apply where:

I.H.3.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than one ton per year; and

I.H.3.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than one ton per year.

I.H.4. For purposes of Section I.H., emissions from still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator shall be calculated using a method approved in advance by the Division.

I.H.5. Monitoring and recordkeeping

I.H.5.a. Beginning January 1, 2017, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections I.H.1. or I.H.2. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

I.H.5.a.(i) The date of each inspection;

I.H.5.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

I.H.5.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

I.H.5.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

I.H.5.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

I.H.5.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

I.H.6. Reporting

I.H.6.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format

I.H.6.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section I.H.;

I.H.6.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

I.H.6.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

I.I. The requirements of Sections I.D. through I.F. do not apply to the owner or operator of any natural gas compressor station or natural gas drip station located in an Ozone Nonattainment or Attainment/Maintenance Area if:

I.I.1. Air pollution control equipment is installed and properly operated to reduce emissions of volatile organic compounds from all atmospheric condensate storage tanks (or tank batteries) that have uncontrolled actual emissions of greater than or equal to two tons per year;

I.I.2. The air pollution control equipment is designed to achieve a VOC control efficiency of at least 95% on a rolling 12-month basis and meets the requirements of Sections I.C.1.a. and I.C.1.b;

I.I.3. The owner or operator of such natural gas compressor station or natural gas drip station does not own or operate any exploration and production facilities in the Ozone Non-attainment or Attainment-maintenance Area; and

I.I.4. The owner or operator of such natural gas compressor station or natural gas drip station does the following and maintains associated records and reports for a period of five years:

I.I.4.a. Documents the maintenance of the air pollution control equipment according to manufacturer specifications;

I.I.4.b. Conducts an annual opacity observation once each year on the air pollution control equipment to verify opacity does not exceed 20% during normal operations;

I.I.4.c. Maintains records of the monthly stabilized condensate throughput and monthly actual VOC emissions; and

I.I.4.d. Reports compliance with these requirements to the Division annually.

I.I.5. A natural gas compressor station or natural gas drip station subject to Section I.I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated is subject to Sections I.H., I.J., and/or Part E, Section I. A natural gas compressor station subject to Section I.I. is also subject to Section I.L.

I.J. Compressors

I.J.1. Centrifugal compressor

I.J.1.a. Beginning January 1, 2018, uncontrolled actual volatile organic compound emissions from wet seal fluid degassing systems on wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%. A centrifugal compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.1.

I.J.1.b. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must equip the wet seal fluid degassing system with a continuous, impermeable cover that is connected through a closed vent system that routes the emissions from the wet seal fluid degassing system to the process or control device.

I.J.1.c. The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.1.e. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.1.f. Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.1.f.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.1.f.(ii) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.1.f.(iii) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.1.f.(iv) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.1.g. The owner or operator must conduct monthly inspections of a combustion device used to reduce emissions to ensure the device is operating with no visible emissions.

I.J.1.h. Recordkeeping

I.J.1.h.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.1.h.(i)(A) Identification of each centrifugal compressor using a wet seal system;

I.J.1.h.(i)(B) Each combustion device visible emissions inspection and any resulting responsive actions;

I.J.1.h.(i)(C) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.1.h.(i)(D) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.1.i. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.1.c. through I.J.1.f., I.J.1.h.(i)(C), and I.J.1.h.(i)(D), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.1.j. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.1.a. through I.J.1.i., the owner or operator may comply with wet seal centrifugal compressors emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.J.2. Reciprocating compressor

I.J.2.a. Beginning January 1, 2018, the rod packing on reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be replaced every 26,000 hours of operation or every thirty six (36) months. A reciprocating compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.2.

I.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, must

I.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018; or

I.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section I.J.2. prior to January 1, 2021.

I.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor.

I.J.2.b. As an alternative to the requirement described in Section I.J.2.a., beginning May 1, 2018, the owner or operator may collect rod packing volatile organic compound emissions using a rod packing emissions collection system that operates under negative pressure and routes the rod packing emissions through a closed vent system to a process.

I.J.2.b.(i) The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

I.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.J.2.b.(iii) In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.J.2.b.(iv) Owners or operators may delay inspection or repair of a cover or closed vent system if:

I.J.2.b.(iv)(A) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.J.2.b.(iv)(B) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.J.2.b.(iv)(D) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.2.c. Recordkeeping

I.J.2.c.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.J.2.c.(i)(A) Identification of each reciprocating compressor;

I.J.2.c.(i)(B) The hours of operation or the number of months since the previous rod packing replacement, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure;

I.J.2.c.(i)(C) The date of each rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system;

I.J.2.c.(i)(D) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.2.c.(i)(E) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.2.b., I.J.2.c.(i)(D), and I.J.2.c.(i)(E), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.2.a. through I.J.2.d., the owner or operator may comply with reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.K. Pneumatic pumps

I.K.1. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

I.K.2. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a well production facility must reduce volatile organic compound emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to an existing control device or process at the well production facility. Natural gas-driven diaphragm pneumatic pumps that are in operation during any period of time during a calendar day less than 90 days per calendar year are not subject to Section I.K.2.

I.K.2.a. If the control device available onsite is unable to achieve a 95% emission reduction and it is not technically feasible to route the emissions to a process at the well production facility, the owner or operator must still route the pneumatic pump emissions to the existing control device.

I.K.2.b. If the owner or operator subsequently installs a control device or it becomes technically feasible to route the emissions to a process, the owner or operator must reduce volatile organic compound emissions from the pneumatic pump by 95% within thirty (30) days of startup of the control device or of the feasibility of routing emissions to a process at the well production facility.

I.K.2.c. The owner or operator is not required to control pneumatic pump emissions if, through an engineering assessment by a qualified professional engineer, routing a pneumatic pump to a control device or process at the well production facility is shown to be technically infeasible.

I.K.2.d. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must connect the pneumatic pump through a closed vent system that routes the pneumatic pump emissions to the process or control device.

I.K.2.e. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices.

I.K.2.f. The owner or operators must conduct annual EPA Method 21 inspections of the closed vent system to determine whether the closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.K.2.g. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.K.2.h. Owners or operators may delay inspection or repair of a closed vent system if:

I.K.2.h.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.K.2.h.(ii) The closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.K.2.h.(iii) The closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.K.2.h.(iv) The closed vent system is inaccessible to inspect or repair because the closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.K.3. Recordkeeping

I.K.3.a. Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.K.3.a.(i) Identification of each natural gas-driven diaphragm pneumatic pump;

I.K.3.a.(ii) For natural gas-driven diaphragm pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year;

I.K.3.a.(iii) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve;

I.K.3.a.(iv) Records of the engineering assessment and certification by a qualified professional engineer that routing natural gas-driven diaphragm pneumatic pump emissions to a control device or process is technically infeasible;

I.K.3.a.(v) Each closed vent system inspection and any resulting responsive actions; and

I.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such closed vent system.

I.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.K.2.e. through I.K.2.h., I.K.3.a.(v), and I.K.3.a.(vi), the owner or operator may inspect, repair, and document the closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.K.1. through I.K.4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area.

I.L.1. Natural gas compressor stations

I.L.1.a. Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.

I.L.1.b. Owners or operators of natural gas compressor stations constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no later than ninety (90) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted at least quarterly.

I.L.2. Well production facilities

I.L.2.a. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least annually.

I.L.2.b. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

I.L.2.c. For purposes of Sections I.L.2.a. and I.L.2.b., the estimated uncontrolled actual volatile organic compound emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual volatile organic compound emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

I.L.2.d. Owners or operators of well production facilities constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted in accordance with Sections I.L.2.a. and I.L.2.b.

I.L.3. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

I.L.3.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

I.L.3.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

I.L.3.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

I.L.4. Leaks requiring repair: Only leaks from components exceeding the thresholds in Section I.L.4. require repair under Section I.L.5.

I.L.4.a. For EPA Method 21 monitoring, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.b. For infra-red camera monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

I.L.4.c. For other approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in an approval under Section I.L.8.

I.L.4.d. For leaks identified using an approved non-quantitative instrument monitoring method, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section I.L.5. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section I.L.4.a., the leak must be repaired and remonitored in accordance with Section I.L.5.

I.L.4.e. Owners or operators must maintain and operate approved non-quantitative instrument monitoring methods according to manufacturer recommendations.

I.L.5. Repair and remonitoring

I.L.5.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

I.L.5.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

I.L.5.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.L.5.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

I.L.5.b. Within fifteen (15) working days of completion of a repair the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

I.L.5.c. Leaks discovered pursuant to the leak detection methods of Section I.L.4. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section I.L.5. or keep required records in accordance with Section I.L.6.

I.L.6. Recordkeeping

I.L.6.a. Documentation of the initial approved instrument monitoring method inspection for well production facilities and natural gas compressor stations;

I.L.6.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

I.L.6.c. A list of the leaks requiring repair and the monitoring method(s) used to determine the presence of the leak;

I.L.6.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

I.L.6.e. The date the leak was repaired and type of repair method applied;

I.L.6.f. The delayed repair list, including the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;

I.L.6.g. The date the leak was remonitored and the results of the remonitoring; and

I.L.6.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section I.L.3., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

I.L.6.i. Records must be maintained for a minimum of five years and made available to the Division upon request.

I.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section I.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

I.L.7.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

I.L.7.b. The total number of inspections performed per inspection frequency tier of well production facilities and the total number of inspections performed at natural gas compressor stations;

I.L.7.c. The total number of identified leaks requiring repair broken out by component type, monitoring method, and inspection frequency tier of well production facility as reported in Section I.L.7.b. and the total number of identified leaks requiring repair at natural gas compressor stations broken out by component type and monitoring method;

I.L.7.d. The total number of leaks repaired for each inspection frequency tier of well production facilities as reported in Section I.L.7.b. and the total number of leaks repaired for natural gas compressor stations;

I.L.7.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facility as reported in Section I.L.7.b. or natural gas compressor station, and the basis for each delay of repair;

I.L.7.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

I.L.7.g. Each report shall be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

I.L.8. Alternative approved instrument monitoring methods may be used in lieu of, or in combination with an infra-red camera, EPA Method 21, or other approved instrument monitoring method to inspect for leaks as required by Section I.L., if the following conditions are met:

I.L.8.a. The proponent of the alternative approved instrument monitoring method applies for a determination of an alternative approved instrument monitoring method or program. The application must include, at a minimum, the following:

I.L.8.a.(i) The proposed alternative approved instrument monitoring method manufacturer information;

I.L.8.a.(ii) A description of the proposed alternative approved instrument monitoring method including, but not limited to:

I.L.8.a.(ii)(A) Whether the proposed alternative approved instrument monitoring method is a quantitative detection method, and how emissions are quantified, or qualitative leak detection method;

I.L.8.a.(ii)(B) Whether the proposed alternative approved instrument monitoring method is commercially available;

I.L.8.a.(ii)(C) Whether the proposed alternative approved instrument monitoring method is approved by other regulatory authorities and for what application (e.g., pipeline monitoring, emissions detected);

I.L.8.a.(ii)(D) The leak detection capabilities, reliability, and limitations of the proposed alternative approved instrument monitoring method, including, but not limited to, the ability to identify specific leaks or locations, detection limits, and any restrictions on use, as well as supporting data;

I.L.8.a.(ii)(E) The frequency of measurements and data logging capabilities of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(F) Data quality indicators for precision and bias of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(G) Quality control and quality assurance procedures necessary to ensure proper operation of the proposed alternative approved instrument monitoring method;

I.L.8.a.(ii)(H) A description of where, when, and how the proposed alternative approved instrument monitoring method will be used; and

I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.

I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.

I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division’s approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

II.A.1. “Air Pollution Control Equipment,” as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.

II.A.2. “Approved Instrument Monitoring Method,” means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations.

II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.

II.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

II.A.5. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

II.A.6. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

II.A.7. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

II.A.8. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

II.A.9. "Dump Valve" means a liquid-control valve in a separator that controls liquid level within the separator vessel.

II.A.10. "Dump Event" means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.

II.A.11. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

II.A.12. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.

II.A.13. "Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.

II.A.14. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.

II.A.15. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.

II.A.16. "Occupied Areas" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

II.A.17. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

II.A.18. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

II.A.19. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

II.A.20. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.

II.A.21. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.

II.A.22. "Storage Tank Measurement System" means equipment and methods used to determine the quantity and quality of the liquids inside a storage tank without requiring direct access through the storage tank thief hatch.

II.A.23. "Storage Vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

II.A.24. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.

II.A.25. "Vapor Collection and Return System" means a closed system designed to control the release of VOCs displaced from a vessel during transfer of hydrocarbon liquids by using the transferred hydrocarbon liquids for direct displacement to force vapors from the vessel being loaded into either the storage tank being unloaded or to air pollution control equipment.

II.A.26. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

II.B. (State Only) General Provisions

II.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.B.1.a. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

II.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

II.B.2. General requirements for air pollution control equipment used to comply with Section II.

II.B.2.a. All air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of VOCs and other hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

II.B.2.b. If a combustion device is used to control emissions of VOCs and other hydrocarbons, it must be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

II.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

II.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-igniter as follows

II.B.2.d.(i) All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device.

II.B.2.d.(ii) All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

II.B.2.e. Alternative emissions control equipment will qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section II., if the Division approves the equipment, device, or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section II.

II.B.3. Requirements for compressor seals and open-ended valves or lines

II.B.3.a. Beginning January 1, 2015, each open-ended valve or line at well production facilities and natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line. Alternatively, an open-ended valve or line may be treated as if it is a “component” as defined in Section II.A.7., and may be monitored under the provisions of Section II.E.

II.B.3.b. Beginning January 1, 2015, uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter.

II.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

II.B.4. Oil refineries are not subject to Section II.

II.B.5. Glycol natural gas dehydrators that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63 (December 17, 2006), a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard (“NSPS”) under 40 CFR Part 60 (December 17, 2006) are not subject to Section II., except for the leak detection and repair requirements in Section II.E.

II.C. Emission reduction from storage tanks at oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.C.1. Control and monitoring requirements for storage tanks

II.C.1.a. (State Only) Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that has a control efficiency of at least 95% for VOCs.

II.C.1.b. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

II.C.1.b.(i) (State Only) Control requirements of Section II.C.1.b. must be achieved in accordance with the following schedule:

II.C.1.b.(i)(A) A storage tank constructed on or after May 1, 2014, must be in compliance within ninety (90) days of the date that the storage tank commences operation.

II.C.1.b.(i)(B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

II.C.1.b.(i)(C) A storage tank not otherwise subject to Sections II.C.1.b.(i)(A) or II.C.1.b.(i)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve-month basis after May 1, 2014, must be in compliance within sixty (60) days of discovery of the emissions increase.

II.C.1.b.(ii). Control requirements within ninety (90) days of commencement of operation.

II.C.1.b.(ii)(A) Beginning May 1, 2014, through March 1, 2020, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after commencement of operation. The air pollution control equipment must achieve a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after commencement of operation.

II.C.1.b.(ii)(B) The air pollution control equipment and any associated monitoring equipment required pursuant to Section II.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section II.C.1.b.

II.C.1.c. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to March 1, 2020.

II.C.1.c.(i) Control requirements of Section II.C.1.c. must be achieved in accordance with the following schedule

II.C.1.c.(i)(A) A storage tank constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

II.C.1.c.(i)(B) A storage tank constructed before March 1, 2020, that is not already controlled under Sections I.D. or II.C.1.b. must be in compliance by May 1, 2021.

II.C.1.c.(i)(C) A storage tank not otherwise subject to Sections II.C.1.c.(i)(A) or II.C.1.c.(i)(B) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B) must be in compliance within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.1.c.(ii) If air pollution control equipment is not installed by the applicable compliance date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C), compliance with Section II.C.1.c. may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

II.C.1.c.(iii) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

II.C.1.d. (State Only) Beginning May 1, 2014, or the applicable compliance date in Sections II.C.1.b.(i) or II.C.1.c.(i), whichever comes later, owners or operators of storage tanks subject to Section II.C.1. must conduct audio, visual, olfactory (AVO) and additional visual inspections of the storage tank and any associated equipment (e.g., separator, air pollution control equipment, or other pressure reducing equipment) at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days. Monitoring is not required for storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e. The additional visual inspections must include, at a minimum

II.C.1.d.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly sealed.

II.C.1.d.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment.

II.C.1.d.(iii) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

II.C.1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open.

II.C.1.d.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

II.C.1.d.(vi) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, visual observation of the dump valve(s) of the last separator(s) before the storage tank(s) to ensure the dump valve is free of debris and not stuck open. The owner or operator is not required to observe the actuation of the dump valve during this inspection; however, if a dump event occurs during the inspection, the owner or operator must confirm proper operation of the valve.

II.C.1.d.(vii) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, a check for the presence of liquids in liquid knockout vessels that do not drain automatically, underground lines, and aboveground piping.

II.C.1.d.(vii)(A) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids.

II.C.1.d.(vii)(B) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.

II.C.1.d.(vii)(C) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids and drain liquids as needed.

II.C.1.d.(vii)(D) For underground lines and aboveground piping that is not sloped to a liquid knockout vessel or tank and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids quarterly.

II.C.1.e. (State Only) If storage tanks or associated equipment is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor such equipment until it becomes feasible to do so.

II.C.1.e.(i) Difficult to monitor means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

II.C.1.e.(ii) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.C.1.e.(iii) Inaccessible to monitor means buried, insulated, or obstructed by equipment or piping that prevents access by monitoring personnel.

II.C.2. (State Only) Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections I.D. or II.C.1.

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator compiles with Section II.C.4.), or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

II.C.2.a.(i) Venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which:

II.C.2.a.(i)(A) Are primarily the result of over-pressurization, whether related to design, operation, or maintenance; or

II.C.2.a.(i)(B) Are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole).

II.C.2.a.(ii) When emissions from a controlled storage tank are observed, the Division may require the owner or operator to submit sufficient information demonstrating whether or not the emissions were primarily the result of over-pressurization. Absent a demonstration that such emissions were not primarily the result of over-pressurization, such emissions will be considered venting for purposes of Section II.C.2.a.

II.C.2.a.(iii) When venting is observed, the owner or operator must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. If the venting was observed using an approved instrument monitoring method, the confirmation must be made using an approved instrument monitoring method.

II.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections I.D., II.C.1.a, II.C.1.b., or II.C.1.c. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section II.C.2.a. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed.

II.C.2.b.(i) STEM plans must include selected control technologies, monitoring practices, operational practices, and/or other strategies; an analysis of the engineering design of the storage tank and air pollution control equipment; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section II.C.2.b.(ii).

II.C.2.b.(ii) Owners or operators must achieve the requirements of Sections II.C.2.a. and II.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule

II.C.2.b.(ii)(A) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed on or after May 1, 2014, must comply with the requirements of Section II.C.2.a. by the date the storage tank commences operation. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of the date that the storage tank commences operation.

II.C.2.b.(ii)(B) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed before May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2015.

II.C.2.b.(ii)(C) A storage tank subject to Section II.C.1.c. and constructed on or after March 1, 2020, must comply with the requirements of Section II.C.2.a. by commencement of operation of the storage tank. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of commencement of operation of the storage tank.

II.C.2.b.(ii)(D) A storage tank subject to Sections II.C.1.c. and I.D.3. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

II.C.2.b.(ii)(E) A storage tank subject to Section II.C.1.c. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2021. Approved instrument monitoring method inspections of the storage tank must begin in 2021.

II.C.2.b.(ii)(F) A storage tank with uncontrolled actual emissions of VOCs equal to or greater than six (6) and less than or equal to twelve (12) tons per year must begin semi-annual approved instrument monitoring method inspections in 2020.

II.C.2.b.(ii)(G) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) or II.C.2.b.(ii)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis..

II.C.2.b.(ii)(H) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) through II.C.2.b.(ii)(F) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B), must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.2.b.(ii)(I) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table 1.

Table 1 – Storage Tank Inspections

Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency
$\geq$ 2 and $\leq$ 12	Semi-annually
> 12 and $\leq$ 50	Quarterly
> 50	Monthly

II.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e.

II.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy(ies) are designed to minimize emissions from storage tanks and associated equipment at the facility(ies), including thief hatches and pressure relief devices.

II.C.3. (State Only) Recordkeeping: The owner or operator of each storage tank subject to Sections I.D. or II.C. must maintain records of STEM, if applicable, including the plan, any updates, and the certification, and make them available to the Division upon request. In addition, for a period of two (2) years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including

II.C.3.a. The AIRS ID for the storage tank.

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance, gauging (unless use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment.

II.C.3.c. The date and duration of any period where the air pollution control equipment is not operating.

II.C.3.d. Records of the inspections required in Sections II.C.1.d. and II.C.2.b.(ii), including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.C.3.e. Where a combustion device is being used, the date and result of any EPA Method 22 test or investigation pursuant to Section II.C.1.d.(v).

II.C.3.f. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions, including the dates and results of action(s) taken and the monitoring used to confirm the action(s) were successful.

II.C.3.g. A list of equipment associated with the storage tank that is designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.C.1.e., an explanation stating why the equipment is so designated, and the plan for monitoring such equipment.

II.C.3.h. Records of any exemption, and associated documentation, applied for under Section II.C.1.c.(iii).

II.C.4. (State Only) Storage tank measurement system requirements at well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.4.a. Applicability

II.C.4.a.(i) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after May 1, 2020, and at any facilities that are modified on or after May 1, 2020, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quantity of liquids in the storage tank(s).

II.C.4.a.(ii) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after January 1, 2021, and at any facilities that are modified on or after January 1, 2021, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quality and quantity of liquids in the storage tank(s).

II.C.4.b. Owner or operators subject to the storage tank measurement system requirements in Section II.C.4.a., must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s).

II.C.4.c. Operators may inspect, test, and/or calibrate the storage tank measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Section II.C.4.b.

II.C.4.d. The owner or operator must install signage at or near the storage tank that indicates which equipment and method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.4.e. The owner or operator must develop and implement an annual training program for employees and/or third parties conducting activities subject to Section II.C.4. that includes, at a minimum, operating procedures for each type of system.

II.C.4.f. Owner or operators must retain records for at least two (2) years and make such records available to the Division upon request, including

II.C.4.f.(i) Date of construction of the storage vessel or facility.

II.C.4.f.(ii) Description of the storage tank measurement system used to comply with Section II.C.4.a.

II.C.4.f.(iii) Date(s) of storage tank measurement system inspections, testing, and/or calibrations pursuant to Section II.C.4. c.

II.C.4.f.(iv) Manufacturer specifications regarding storage tank measurement system inspections, and/or calibrations, if followed pursuant to Section II.C.4.c.

II.C.4.f.(v) Records of the annual training program, including the date and names of persons trained.

II.C.5. (State Only) Storage tank hydrocarbon liquids loadout requirements at Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.5.a. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

II.C.5.a.(i) Compliance with Section II.C.5. must be achieved in accordance with the following schedule

II.C.5.a.(i)(A) Facilities constructed or modified on or after May 1, 2020, must be in compliance by commencement of operation.

II.C.5.a.(i)(B) Facilities constructed before May 1, 2020, must be in compliance by May 1, 2021.

II.C.5.a.(i)(C) Class II disposal well facilities constructed or modified on or after January 1, 2021, must be in compliance by commencement of operation.

II.C.5.a.(i)(D) Class II disposal well facilities constructed before January 1, 2021, must be in compliance by May 1, 2021.

II.C.5.a.(i)(E) Facilities not subject to Sections II.C.5.a.(i)(A) or II.C.5.a.(i)(B) that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from loadout upon exceeding the loadout threshold.

II.C.5.a.(i)(F) Facilities not subject to Sections II.C.5.a.(i)(C) or II.C.5.a.(i)(D) that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.

II.C.5.a.(ii) Storage tanks must operate without venting at all times during loadout.

II.C.5.a.(iii) The owner or operator must, as applicable:

II.C.5.a.(iii)(A) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.

II.C.5.a.(iii)(B) Include devices to prevent the release of vapor from vapor recovery hoses not in use.

II.C.5.a.(iii)(C) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.

II.C.5.a.(iii)(D) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.

II.C.5.a.(iii)(E) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv) Loadout observations and operator training

II.C.5.a.(iv)(A) The owner or operator must observe loadout to confirm that all storage tanks operate without venting when loadout operations are active. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,

II.C.5.a.(iv)(B) If observation of loadout is not feasible, the owner or operator must document the annual loadout frequency and the reason why observation is not feasible and inspect the facility within 24 hours after loadout to confirm that all storage tank thief hatches (or other access point to the tank) are closed and latched.

II.C.5.a.(iv)(C) The owner or operator must install signage at or near the loadout control system that indicates which loadout control method(s) is used and the appropriate and necessary operating procedures for that system.

II.C.5.a.(iv)(D) The owner or operator must develop and implement an annual training program for employees and/or third parties conducting loadout activities subject to Section II.C.5. that includes, at a minimum, operating procedures for each type of loadout control system.

II.C.5.a.(v) Owners or operators must retain records for at least two (2) years and make such records available to the Division upon request.

II.C.5.a.(v)(A) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughput.

II.C.5.a.(v)(B) Inspections, including a description of any problems found and their resolution, required under Sections II.C.5.a.(iii) and II.C.5.a.(iv) must be documented in a log.

II.C.5.a.(v)(C) Records of the infeasibility of observation of loadout.

II.C.5.a.(v)(D) Records of the frequency of loadout.

II.C.5.a.(v)(E) Records of the annual training program, including the date and names of persons trained.

II.C.5.a.(v)(F) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling-12 month basis.

II.C.5.a.(vi) Air pollution control equipment used to comply with this Section II.C.5. must comply with Section II.B., be inspected in accordance with Sections II.C.1.d.(ii) through (v), and achieve a hydrocarbon control efficiency of 95%.

II.D. (State Only) Emission reductions from glycol natural gas dehydrators

II.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.

II.D.2. The control requirement in Section II.D.1. apply where:

II.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and

II.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.

II.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:

II.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

II.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

II.D.4. The control requirement in Section II.D.3. apply where:

II.D.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after May 1, 2015, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section II.D.3. by the date that the glycol natural gas dehydrator commences operation.

II.D.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

II.D.4.c. For purposes of Sections II.D.3. and II.D.4.:

II.D.4.c.(i) Building Unit means a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

II.D.4.c.(ii) A Designated Outside Activity Area means an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government had established as a designated outside activity area by the COGCC; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

II.E. (State Only) Leak detection and repair program for well production facilities and natural gas compressor stations

II.E.1. The following provisions of Section II.E. apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

II.E.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section II.E. may estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

II.E.3. Beginning January 1, 2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method, in accordance with the following schedule

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 2.

II.E.3.d. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2 – Natural Gas Compressor Station Component Inspections

Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table 3.

II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table 3; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 3.

II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year, based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.

II.E.4.e. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 3 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.d.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

II.E.6.a. For EPA Method 21 monitoring, at facilities constructed before May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 2,000 parts per million (ppm) not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation, except for well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.b. For EPA Method 21 monitoring, at facilities constructed on or after May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.c. For infra-red camera and AVO monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

II.E.6.d. For other Division approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in the Division's approval.

II.E.6.e. For leaks identified using an approved non-quantitative instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section II.E.6., the leak must be repaired and remonitored in accordance with Section II.E.7.

II.E.7. Repair and remonitoring

II.E.7.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and repair of a leak discovered on or after January 1, 2018, completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

II.E.7.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

II.E.7.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

II.E.7.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

II.E.7.b. Within fifteen (15) working days of completion of a repair, the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

II.E.7.c. Leaks discovered pursuant to the leak detection methods of Section II.E.6. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section II.E.7. or keep required records in accordance with Section II.E.8.

II.E.8. Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

II.E.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

II.E.8.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.E.8.c. A list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

II.E.8.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

II.E.8.e. The date the leak was repaired and for leaks discovered and repaired on or after January 1, 2018, the type of repair method applied;

II.E.8.f. The delayed repair list, including the basis for placing leaks on the list;

II.E.8.g. For leaks discovered on or after January 1, 2018, the delayed repair list must include the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;

II.E.8.h. The date the leak was remonitored and the results of the remonitoring; and

II.E.8.i. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.E.5., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

II.E.9. Reporting. The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:

II.E.9.a. The total number of well production facilities and total number of natural gas compressor stations inspected;

II.E.9.b. The total number of inspections performed per inspection frequency tier of well production facilities and inspection frequency tier of natural gas compressor stations;

II.E.9.c. The total number of identified leaks requiring repair, broken out by component type, monitoring method, and inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;

II.E.9.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair;

II.E.9.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and

II.E.9.g. Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

II.F. Control of emissions from well production facilities

Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from commencement of operation by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

II.G. (State Only) Emissions during downhole well maintenance, well liquids unloading events, and well plugging

II.G.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with downhole well maintenance, well liquids unloading, and well plugging (beginning January 31, 2020), unless emitting is necessary for safety.

II.G.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without emitting. If these methods are not successful in unloading the liquids from the well, the well may emit in order to create the necessary differential pressure to bring the liquids to the surface.

II.G.1.b. The owner or operator must be present on-site during any planned downhole well maintenance, well liquids unloading, or well plugging event and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable.

II.G.2. Recordkeeping

II.G.2.a. Through January 31, 2020, the owner or operator must keep records of the cause, date, time, and duration of venting events under Section II.G. Records must be kept for two (2) years and made available to the Division upon request.

II.G.2.b. Beginning January 31, 2020, or the date specified in Section II.G.2.b.(iii), the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.b.(i) The cause of emissions (i.e., downhole well maintenance, well liquids unloading, well plugging), date, time, and duration of emissions under Section II.G.

II.G.2.b.(ii) The best management practices used to minimize hydrocarbon emissions or the safety needs that prevented the use of best management practices.

II.G.2.b.(iii) Beginning July 1, 2020, the emissions associated with well liquids unloading, downhole well maintenance, and well plugging.

II.G.3. Reporting

II.G.3.a. The owner or operator must submit a single annual report using a Division-approved format on or before June 30th of each year (beginning June 30th, 2021) that includes the following information regarding each downhole well maintenance, well liquids unloading, and well plugging event conducted the previous calendar year that resulted in emissions.

II.G.3.a.(i) The API number of the well and the AIRS number of any associated storage tanks.

II.G.3.a.(ii) Whether the emissions occurred due to downhole well maintenance, well liquids unloading, or well plugging.

II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.

II.G.3.a.(iv) The best management practices used to minimize emissions.

II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.

II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B. Definitions

III.B.1. "Affected Operations" means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B.2. "Continuous Bleed" means an intentional continuous bleed rate of natural gas from a pneumatic controller.

III.B.3. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

III.B.4. "Enhanced Response" means to return equipment to proper operation and includes but is not limited to, cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.

III.B.5. "High-Bleed Pneumatic Controller" means a pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

III.B.6. (State Only) "Intermittent pneumatic controller" means a pneumatic controller that vents non-continuously.

III.B.7. "Low-Bleed Pneumatic controller" means a pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

III.B.8. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

III.B.9. "No-Bleed Pneumatic Controller" means any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.

III.B.10. "Pneumatic Controller" means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature.

III.B.11. “Self-contained Pneumatic Controller” means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.

III.C. Emission Reduction Requirements

Owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

III.C.1. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.c.

III.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section III.C.1.c.

III.C.1.c. All high-bleed pneumatic controllers that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

III.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.C.2.a. All pneumatic controllers placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.c.

III.C.2.b. All pneumatic controllers with a bleed rate greater than zero in service prior to January 1, 2018, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by May 1, 2018, unless allowed pursuant to Section III.C.2.c.

III.C.2.c. All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.2.c.(i) For pneumatic controllers with a natural gas bleed rate greater than zero in service prior to January 1, 2018, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by May 1, 2018.

III.C.2.c.(ii) For pneumatic controllers with a natural gas bleed rate greater than zero placed in service on or after January 1, 2018, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.3. (State Only) Statewide:

III.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014, must:

III.C.3.a.(i) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.

III.C.3.a.(ii) If on-site electrical grid power is not being used or a no-bleed pneumatic controller is not technically and economically feasible, utilize pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.a.(iii) For purposes of Section III.C.3.a.(ii), instead of a low-bleed pneumatic controller, owners or operators may utilize a natural gas-driven intermittent pneumatic controller.

III.C.3.a.(iv) Utilizing self-contained pneumatic controllers satisfies Section III.C.3.a.(i).

III.C.3.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.

III.C.3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.

III.C.3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015.

III.C.3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation.

III.D. Monitoring

This section applies to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.D.1. In the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.1.b. Effective May 1, 2009, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band, eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.2. In the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.D.2.a. Effective May 1, 2018, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.2.b. Effective May 1, 2018, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.3. (State Only) Statewide:

III.D.3.a. Effective May 1, 2015, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.E. Recordkeeping

III.E.1. In the 8-Hour Ozone Control Area:

III.E.1.a. Continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.E.1.a.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.

III.E.1.a.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section III.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:

III.E.1.b.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.

III.E.1.b.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section III.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).

III.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.

III.E.2. This section applies only to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

III.E.2.a. The owner or operator must maintain a log of the total number of pneumatic controllers and their associated controller numbers per facility, the total number of pneumatic controllers per company and the associated justification that the pneumatic controllers must be used pursuant to Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.). The log shall be updated on a monthly basis.

III.E.2.b. The owner or operator must maintain a log of necessary maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

III.F.1. General Requirements

III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.

III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.

III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.

III.F.2.c. For purposes of Sections III.F.2.a. and III.F.2.b., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

III.F.2.d. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

III.F.2.d.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.d.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least

III.F.2.e.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.

III.F.2.e.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.e.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f. For purposes of Sections III.F.2.d. and III.F.2.e., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

III.F.2.g. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.2.h. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

III.F.3. Enhanced response and remonitoring

III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.

III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

III.F.4. Owners or operators must maintain the following records for a minimum of three (3) years and make records available to the Division upon request.

III.F.4.a. The date, facility name, facility AIRS ID or facility location if the facility does not have an AIRS ID, and approved instrument monitoring method used for each inspection;

III.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;

III.F.4.c. For intermittent pneumatic controllers observed to have detectable emissions but determined to be operating properly, a brief explanation of the basis for concluding that the intermittent pneumatic controller was operating properly. The explanation can include, but is not limited to, an owner or operator’s standard operating procedure detailing how to determine whether an intermittent pneumatic controller is operating properly, or an individual explanation;

III.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;

III.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and

III.F.4.f. The delayed repair list, including the date and duration of any period where the enhanced response was delayed beyond thirty (30) days after determining the pneumatic controller is not operating properly due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced response due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for pneumatic controller inspection and enhanced response compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May 31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year:

III.F.5.a. The total number and type of pneumatic controllers returned to proper operation, the types of actions taken to return the pneumatic controllers to proper operation, and the facility type (by inspection frequency tier of well production facility or natural gas compressor station);

III.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st broken out by the facility type (by inspection frequency tier of well production facility or natural gas compressor station), and the basis for each delay; and

III.F.5.c. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year.

III.F.6. The provisions in Section III.F. will be reassessed by the Division and stakeholders in 2020.

IV. (State Only) Control of Emissions from the Natural Gas Transmission and Storage Segment

IV.A. Definitions

IV.A.1. "Best management practice" (BMP) means a demonstrated and commercially available or innovative emission-reducing technology or work practice.

IV.A.2. "Best management practices plan" (BMP plan) means a written plan that includes, but is not limited to, each natural gas transmission and storage segment owner or operator's planned and implemented BMPs to reduce methane emissions from its facilities within the natural gas transmission and storage segment.

IV.A.3. "Natural gas transmission and storage segment" (segment) includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

IV.A.4. "Natural gas transmission and storage segment Colorado throughput" (segment throughput) means the total volume of natural gas, as adjusted for methane, transported through transmission pipelines in Colorado as reported to the Department of Energy's (DOE) Energy Information Administration (EIA) for Form 176, excluding net volumes stored as liquefied natural gas or in underground storage facilities.

IV.A.5. "Natural gas transmission and storage segment emissions inventory protocol" (inventory protocol) means the requirements by which natural gas transmission and storage segment owners or operators will quantify and report methane, ethane, carbon monoxide (CO), carbon dioxide (CO2), nitrous oxide (N2O), nitrogen oxides (NOx), and volatile organic compound (VOC) emissions. The protocol will specify the segment facilities and types of activity data collected, emissions quantification methodologies, throughput calculation methodologies, criteria for determining whether events are beyond the control of the owner or operator, and the process for designating and protecting confidential business information (CBI), consistent with Colorado law.

IV.A.6. "Performance-based program" means a program of BMPs implemented and documented by each natural gas transmission and storage segment owner or operator to reduce methane emissions in order to achieve the system-wide emissions intensity target.

IV.A.7. "Steering committee" means five members approved by the Division to serve as a technical working group for developing program guidance documents and evaluating progress against the system-wide emissions intensity target. The committee members will include two representatives from natural gas transmission and storage segment owners or operators (or industry trade organizations representing owners or operators), two members representing the general public (including but not limited to environmental organizations, local government groups, or citizens), and one Division member.

IV.A.8. "Segment-wide emissions intensity" means the natural gas transmission and storage segment methane emissions divided by the natural gas transmission and storage segment throughput.

IV.A.9. "Segment-wide emissions intensity target" (segment-wide target) means the target established by the steering committee reflected as annual segment-wide methane emissions from Colorado's natural gas transmission and storage segment divided by the annual natural gas transmission and storage segment Colorado throughput.

IV.B. Beginning January 1, 2020, each segment owner or operator must participate in this performance based program to reduce segment-wide methane emissions.

IV.B.1. By April 1, 2020, a steering committee charter and the steering committee members will be approved by the Division.

IV.B.2. By September 30, 2020, the Division will publish the inventory protocol and any associated program guidance documents developed by the steering committee.

IV.B.3. By December 31, 2020, each segment owner or operator must develop a company-specific BMP plan. The BMP plan must contain each element from the BMP plan template chapter of the program guidance document, which will include, but is not limited to, a list of information the owner or operator must collect to demonstrate the BMPs performed. By December 31st of each year (beginning December 31st, 2021), each owner or operator must review and update, as appropriate, its company-specific BMP plan and document in the BMP plan any changes.

IV.B.4. Beginning January 1, 2021, each segment owner or operator will

IV.B.4.a. Implement company specific BMP plans.

IV.B.4.b. Collect emissions inventory data in accordance with the inventory protocol and its company-specific BMP plan.

IV.B.5. By May 1, 2022, the segment owners or operators will select a third-party contractor from a pool of qualified applicants to receive, safeguard, and aggregate company-specific reports as described in Sections IV.D.3. and IV.D.4. The steering committee will establish criteria for the selection of the third-party contractor. The segment owners and operators will use a competitive bidding process to solicit applications from contractors who meet the criteria and will provide an opportunity for the steering committee to reject unqualified applicants.

IV.B.6. By October 1, 2023, the steering committee will determine the segment-wide emissions intensity target using the 2021 and 2022 emissions inventory data. In developing the initial or updated segment-wide emissions intensity target and evaluating the program, the steering committee may request non-company specific information from the Division (in accordance with the Colorado Opens Record Act) or the third-party contractor to assist in setting such target or such evaluation. The steering committee may ask companies to explain emission factors and methodologies used to calculate or measure emissions.

IV.C. The segment-wide emissions intensity target must first be achieved by January 1, 2025, based on the 2024 reporting year.

IV.C.1. By October 1 of each year (beginning October 1, 2025), the steering committee will submit a compliance certification to the Division that the segment achieved the segment-wide emissions intensity target for the prior calendar year.

IV.C.2. If the steering committee cannot certify compliance with the segment-wide emissions intensity target, the steering committee will develop a plan (which may include amendments to program guidance documents) and timeline for the segment to achieve compliance with the segment-wide emissions intensity target.

IV.C.3. Beginning January 1, 2026, and every three (3) years thereafter if appropriate, the steering committee will assess the segment-wide emissions intensity target for continual improvement.

IV.D. Recordkeeping and reporting

IV.D.1. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Commission meeting on or after January 2021.

IV.D.2. Segment owners or operators must maintain BMP plans and emissions inventory reports for a period of five (5) years and make records available to the Division upon request.

IV.D.3. By June 30 of each year (beginning June 30, 2022), owners or operators of the natural gas transmission and storage segment will submit company-wide reports to the third-party contractor.

IV.D.3.a. Emissions claimed to be beyond the control of the owner or operator, using the criteria and methods established by the steering committee, must be included in the company-wide report but will not be used to set or determine compliance with the segment-wide emissions intensity target.

IV.D.3.b. Emissions and emission reductions associated with any requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Colorado Public Utilities Commission (CPUC), and/or the Federal Energy Regulatory Commission (FERC) must be included in the report and used for purposes of calculating compliance with the system-wide emissions intensity target, unless they qualify under Section IV.D.3.a., but this Section IV. does not supersede or alter these agencies applicable regulations or requirements.

IV.D.4. The third-party contractor must aggregate the company-wide reports into a segment-wide report and provide it to the steering committee by August 15 of each year (beginning August 15, 2022) on a form developed by the steering committee and approved by the Division. The segment-wide report must include, at a minimum

IV.D.4.a. The segment-wide emissions, apportioned by county,

IV.D.4.b. A report of the numbers and types of events subject to Section IV.D.3.a. and the segment-wide emissions resulting from each type of event.

IV.D.4.c. The BMPs implemented to mitigate or avoid emissions and a description of how the BMPs mitigate, reduce, and/or avoid emissions.

IV.D.4.d. The segment-wide segment throughput.

IV.D.4.e. The segment-wide emissions intensity. If the steering committee determines that one or more types of events reported under Section IV.D.4.b. were not beyond the control of the owner or operator, the steering committee will revise the segment-wide emissions intensity calculation to include the methane emissions from those events.

IV.D.5. Segment owners or operators must submit an annual certification to the Division by June 30 of each year (beginning June 30, 2021) that includes

IV.D.5.a. A certification that the company-specific BMP plan was developed or reviewed in accordance with Section IV.B.3.

IV.D.5.b. A certification that the company-wide report was submitted to the third-party contractor in accordance with Section IV.D.3.

IV.D.5.c. Beginning in 2022, a certification of company BMP plan compliance in accordance with Section IV.B.4., including

IV.D.5.c.(i) The company's implementation of the BMPs in the company-specific BMP plan.

IV.D.5.c.(ii) Instances of non-conformance with the company-specific BMP plan, reason(s) for non-conformance, and any modifications of the applicable element(s) of the BMP plan.

IV.D.5.c.(iii) Any use of alternative emission reduction approaches not specified in the company-specific BMP plan.

IV.D.5.d. With each submission under Sections IV.D.5.a. through IV.D.5.c., a certification by a responsible official that, based on information and belief after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IV.D.6. The Division may provide an update briefing to the Air Quality Control Commission during a scheduled Commission meeting on or after October 1 of each year (beginning October 1, 2022). The update briefing will include any assessment of the segment-wide target, as specified in Section IV.C.3.

V. (State Only) Oil and Natural Gas Operations Emissions Inventory

V.A. Applicability

V.A.1. On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.A.2. On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator or class II disposal well facilities that are not subject to reporting under Section IV. must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.B. General reporting requirements

V.B.1. The following information must be reported in accordance with Section V.A.

V.B.1.a. Company name, physical street address, and name and contact information of the company representative, for reporting purposes.

V.B.1.b. The date of submittal and the year covered by the report.

V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported.

V.B.1.d. The company's monthly actual emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), nitrous oxide (N2O), carbon dioxide (CO2), carbon monoxide (CO), methane, and ethane for each month of May through September.

V.B.1.e. The company's annual actual emissions of VOCs, NOx, N2O, CO2, CO, methane, and ethane for the entire calendar year.

V.B.1.f. The actual emissions of VOCs, NOx, N2), CO2, CO, methane, and ethane for each activity or equipment listed in Section V.C. per facility, or per pipeline between facilities where the pipeline is not located at a stationary source.

V.B.1.f.(i) The report must include the actual emissions from each activity or equipment per month for each month of May through September.

V.B.1.f.(ii) The report must include the actual emissions from each activity or equipment for the entire calendar year.

V.B.1.g. A certification by the company representative that supervised the development and submission of the inventory report that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

V.B.2. The owner or operator must submit a revised annual report after discovering that an annual report submitted within the previous two (2) years contained one or more substantive errors. A substantive error is a mass of emissions of any individual pollutant subject to reporting under Section V. that is at least 10% higher or lower than the mass of emissions of the pollutant reported across the owner or operator's activity or equipment, as listed in Section V.C., in Colorado. A refinement of or improvement to an emissions estimation technique or emission factor is not a substantive error but must be noted in the subsequent annual report after the refinement or improvement. Revised annual reports must be submitted by August 31 if the substantive error is discovered between January 1 and June 30, and by February 28 if the substantive error is discovered between July 1 and December 31 of the preceding calendar year.

V.C. Beginning July 1, 2020, and each calendar year thereafter, owners or operators must maintain the following information for inclusion in the annual report, except that beginning January 1, 2021, owners or operators must maintain the information described in Sections V.C.2.g. and V.C.2.h. Beginning May 1, 2021, owners or operators of class II disposal well facilities must maintain the following information for inclusion in the annual report.

V.C.1. AIRS number of the activity or equipment and associated facility or pipeline (if a pipeline between facilities) location, including latitude and longitude coordinates. If the activity or equipment does not have an AIRS number, a description of the activity or equipment.

V.C.2. Actual emissions from each activity or equipment listed below, unless otherwise specified in the Division-approved report format, and the emission factor(s), assumptions, and calculation methodology used to calculate the emissions.

V.C.2.a. Abnormal events, except those reported as malfunctions under the Common Provisions or in another activity or equipment.

V.C.2.b. Acid gas removal units.

V.C.2.c. Associated gas venting and flaring, aggregated per facility.

V.C.2.d. Blowdowns from facility equipment piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet, aggregated per activity below per facility.

V.C.2.d.(i) Pipeline venting within the facility boundary.

V.C.2.d.(ii) Compressors.

V.C.2.d.(iii) Scrubbers/strainers.

V.C.2.d.(iv) Pig launchers and receivers.

V.C.2.d.(v) Emergency shutdowns (regardless of equipment type).

V.C.2.d.(vi) All other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) with a physical volume between isolation valves greater than or equal to 50 cubic feet.

V.C.2.e. Boilers.

V.C.2.f. Centrifugal compressor leaks or vents, aggregated per facility.

V.C.2.g. Class II disposal well facility fluids accepted for injection. Owners or operators will take periodic, representative samples of the liquids for estimating emissions for the annual report.

V.C.2.h. Class II disposal well facility produced water ponds.

V.C.2.i. Drilling mud and mud pits.

V.C.2.j. Flares and enclosed combustion devices, where not otherwise reported in the emissions of another emissions source category.

V.C.2.k. Fugitive emissions from components, aggregated per facility.

V.C.2.l. Hydrocarbon liquid storage tanks.

V.C.2.m. Hydrocarbon liquid loadout.

V.C.2.n. Maintenance and safety, where not otherwise reported in the emissions of another emissions source category.

V.C.2.o. Natural gas dehydration (glycol and desiccant).

V.C.2.p. Natural gas pneumatic controllers, aggregated per facility.

V.C.2.q. Natural gas pneumatic pumps, aggregated per facility.

V.C.2.r. Non-road internal combustion engines.

V.C.2.s. Pipeline segments between facilities.

V.C.2.t. Process heaters.

V.C.2.u. Produced water storage tanks.

V.C.2.v. Produced water loadout.

V.C.2.w. Reciprocating compressor leaks or vents, aggregated per facility.

V.C.2.x. Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.).

V.C.2.y. Stationary combustion turbines.

V.C.2.z. Stationary compression ignition internal combustion engines.

V.C.2.aa. Stationary spark ignition internal combustion engines.

V.C.2.bb. Temporary completion and/or workover equipment (e.g., tanks).

V.C.2.cc. Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.

V.C.2.dd. Well completions (includes flowback).

V.C.2.ee. Well workovers.

V.C.2.ff. Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

VI.A.2. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.

VI.A.3. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

VI.A.4. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

VI.A.5. “Flowback vessel” means a vessel that contains flowback.

VI.A.6. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

VI.A.7. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

VI.A.8. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

VI.A.9. “Tank measurement system” means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.

VI.A.10. “Well” means a hole drilled for the purpose of producing oil and/or natural gas.

VI.A.11. “Well completion” means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).

VI.A.12. “Well re-completion” means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).

VI.B. General provisions

VI.B.1. At all times the facility and equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.

VI.B.2. Air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.

VI.C. Air quality monitoring

VI.C.1. Owners or operators of drilling operations that begin on or after May 1, 2021, must monitor air quality at and/or around the pre-production and early production operations.

VI.C.1.a. Owners or operators must monitor air quality for at least ten (10) days prior to beginning pre-production operations, during all pre-production operations, and for at least six months after the well is capable of consistently producing either separable gas or salable liquid hydrocarbons (i.e., early production).

VI.C.1.b. Owners or operators must submit an air quality monitoring plan to the Division and the local government with jurisdiction over the location of the operations and any other local government unit, where applicable, within 2,000 feet of the proposed operations at least sixty (60) days prior to beginning air quality monitoring. Upon the request of any of these local government units within 14 days of receiving the plan, the Division will consult with them as part of its review process. Owners or operators must receive approval from the Division of the air quality monitoring plan prior to beginning air quality monitoring. Owners or operators must comply with the plan once approved. The air quality monitoring plan must include, at a minimum:

VI.C.1.b.(i) The owner or operator name and the contact information of the owner or operator representative for monitoring purposes.

VI.C.1.b.(ii) The planned schedule for drilling and pre-production operations.

VI.C.1.b.(iii) The operations to be monitored including the API number of the well(s), location of the operations including latitude and longitude coordinates, and any associated facility or equipment AIRS number(s).

VI.C.1.b.(iv) Whether the local government with jurisdiction over the location of the operations has air quality monitoring requirements applicable to pre-production and/or early production operations, a description of those requirements, and a local government contact for air quality monitoring purposes.

VI.C.1.b.(v) The monitoring objective(s), which must include one or more of the following (and may include additional objectives such as field-testing new air quality monitoring technologies or improving emissions inventories):

VI.C.1.b.(v)(A) Detect, evaluate, and reduce as necessary hazardous air pollutant emissions;

VI.C.1.b.(v)(B) Detect, evaluate, and reduce as necessary ozone precursor emissions;

VI.C.1.b.(v)(C) Detect, evaluate, and reduce as necessary methane emissions.

VI.C.1.b.(vi) The air pollutant(s) and other parameters to be monitored. Pollutants must include at least one of the following: total VOCs, methane, benzene or BTEX (benzene, toluene, ethyl benzene and xylenes) or other indicator of hydrocarbon emissions from pre-production and early production operations, as appropriate to meeting the specified monitoring objectives.

VI.C.1.b.(vii) A description of the monitoring equipment to be deployed, including the manufacturer and model information and any manufacturer specifications for the monitoring equipment and data systems. The description of pollutant monitoring equipment should explain why it was chosen and document or provide references describing relevant prior use and evaluations that are known to the owner or operator.

VI.C.1.b.(viii) A description of the meteorological monitoring equipment to be deployed. If meteorological data will not be collected on-site, the plan must provide reasoning and justification, and identify the meteorological station from which data will be obtained and demonstrate that the station represents conditions at the oil and gas development site.

VI.C.1.b.(ix) A monitor siting plan, which must include but is not limited to:

VI.C.1.b.(ix)(A) The number of monitors and/or sensors to be deployed.

VI.C.1.b.(ix)(B) The location and height of the monitoring equipment, including for each phase of operations if location and height of the equipment will change (e.g., monitoring placement impacted by sound walls).

VI.C.1.b.(ix)(C) A topographic map and plan of the site, showing the expected equipment layout, including air quality and meteorological monitor locations and their distance from pre-production and production operations. The map must indicate any obstructions to air flow to the monitor(s) and also show all roads and access ways within a half-mile of the facility and any contiguous structures, whether or not they are part of the production operations.

VI.C.1.b.(ix)(D) A description of how the placement of monitoring equipment minimizes surface disturbances, in alignment with the Colorado Oil and Gas Conservation Commission's site preparation requirements.

VI.C.1.b.(ix)(E) An explanation of how the number and placement of monitoring equipment will be adequate to achieve the desired air quality monitoring objectives, considering the monitoring equipment's detection limit and other limitations.

VI.C.1.b.(x) The standard operating procedures that will be employed, to include at minimum:

VI.C.1.b.(x)(A) The sampling and/or measurement interval, averaging times, minimum detection concentration or level, expected precision, and confidence level at which pollutant data will be reported.

VI.C.1.b.(x)(B) The response level for each pollutant or indicator monitored and/or sampled and the response procedures or actions that will be taken if elevated levels are observed.

VI.C.1.b.(vii)(C) The data quality indicators for precision and bias of the monitoring equipment.

VI.C.1.b.(vii)(D) The quality control and quality assurance procedures, including calibration intervals and frequency, which will be used to ensure proper operation of the monitoring equipment. Owners or operators may reference and attach an existing methodology.

VI.C.1.b.(x)(E) A discussion of known limitations of the pollutant monitoring equipment and, if applicable, how they will be addressed.

VI.C.1.b.(x)(F) The protocol that will be used for acquiring, processing, and recording relevant meteorological data.

VI.C.1.b.(x)(G) The data system and operating protocol to be used for data collection, including, but not limited to, data logging, data processing, recording, downloading, backup and storage, and reporting.

VI.C.1.b.(x)(H) The methods for collecting and analyzing speciated or other samples of chemical constituents identified by the Division when indicated necessary based on site-specific concentration thresholds, if applicable.

VI.C.1.b.(xi) A description of how the monitoring equipment, pollutant(s) monitored, and siting plan are expected to detect elevated emissions and achieve at least one of the monitoring objectives listed in Section VI.C.1.b.(v).

VI.C.1.c. Within ten (10) days of approving a monitoring plan, the Division will notify all local government units identified in Section VI.C.1.b. of the plan approval.

VI.C.2. Recordkeeping and reporting

VI.C.2.a. Owners or operators must keep the following records for a minimum of three (3) years, unless otherwise specified, and upon request make records available to the Division. Local governments identified in Section VI.C.1.b may request those records from the Division. If the Division has not requested the records and a local government(s) identified in Section VI.C.1.b requests the records from the Division, the Division shall request the records from the owner or operator.

VI.C.2.a.(i) The air quality monitoring plan.

VI.C.2.a.(ii) Monthly reports and the data necessary to inform the monthly reports, as provided in Section VI.C.2.b.

VI.C.2.a.(iii) Activity logs to inform Section VI.C.2.b.(iii)(A) of the monthly report.

VI.C.2.a.(iv) For a period of one year after the monthly report, the underlying raw data associated with each monitor.

VI.C.2.a.(v) For a period of one year after the monthly report, the meteorological data in the time intervals as close to the sampling and/or measurement intervals as possible.

VI.C.2.b. Owners or operators must submit monthly reports of monitoring conducted to the Division by the last day of the month following the previous month of monitoring (e.g., by June 30 for the previous May 1-31), including

VI.C.2.b.(i) The month and year of the monitoring period.

VI.C.2.b.(ii) A description of the monitoring equipment and the pollutant(s) monitored.

VI.C.2.b.(iii) A description of the monitored operations including

VI.C.2.b.(iii)(A) The phase of operation (e.g., prior to pre-production, during pre-production operations, early production) and activities occurring during the monitored period.

VI.C.2.b.(iii)(B) API number of the well(s).

VI.C.2.b.(iii)(C) Location of the operations, including latitude and longitude coordinates.

VI.C.2.b.(iii)(D) Any associated facility or equipment AIRS number(s).

VI.C.2.b.(iii)(E) The date, time, and duration of any monitoring equipment downtime.

VI.c.2.b.(iii)(F) The date, time, and duration of operations malfunctions and shut-in periods or other events investigated for influence on monitoring.

VI.C.2.b.(iv) For the first monthly report after beginning monitoring during pre-production operations, a summary of air quality condition results monitored prior to beginning pre-production operations, including time series of the results at hourly or higher time resolution and a statistical summary of the air quality results monitored prior to beginning pre-production operations, including number of observations, maximum concentrations or levels, periodic averages, and data distributions including 5th, 25th, median, 75th and 95th percentile values.

VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.

VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.

VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.

VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.

VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.

VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.

VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).

VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.

VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.

VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.

VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including

VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.

VI.D.3.a.(ii) The date and time of the onset of flowback.

VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.

VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.

VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

PART E Combustion Equipment and Major Source RACT

I. Control of Emissions from Engines

I.A Requirements for new and existing engines.

I.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section I.B.

I.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section I.B.

I.A.3. Stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower are subject to Section I.D.5.

I.B. Air pollution control technology requirements

I.B.1. For rich burn reciprocating internal combustion engines, a non-selective catalyst reduction and an air fuel controller shall be required. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.B.3. The emission control equipment required by this Section I.B shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.

I.C. The air pollution control technology requirements in Sections I.A. and I.B. do not apply to:

I.C.1. Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31.

I.C.2. Reciprocating internal combustion engines that the Division has determined will be permanently removed from service or replaced by electric units on or before May 1, 2007. The owner or operator of such an engine shall provide notice to the Division of such intent by May 1, 2005 and shall not operate the engine identified for removal or replacement in the 8-hour Ozone Control Area after May 1, 2007.

I.C.3. Any emergency power generator exempt from APEN requirements pursuant to Regulation Number 3, Part A.

I.C.4. Any lean burn reciprocating internal combustion engine operating in the 8-hour Ozone Control Area prior to June 1, 2004, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $5,000 per ton of VOC emission reduction. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by May 1, 2005. Any reciprocating internal combustion engine qualifying for this exemption shall not be moved to any other location within the 8-hour Ozone Control Area.

I.D. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.

I.D.1. (State Only) Exemptions

I.D.1.a. The requirements of this Section I.D. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.1.b. Internal combustion engines that are subject to an emissions control requirement in a federally maximum achievable control technology (MACT) standard under 40 CFR Part 63, a Best Available Control Technology (BACT) limit, or a New Source Performance Standard (NSPS) under 40 CFR Part 60 are not subject to Section I.D.3.

I.D.2. (State Only) General Provisions

I.D.2.a. At all times, including periods of start-up and shutdown, engines and their associated equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

I.D.2.b. All engines and their associated equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file.

I.D.2.c. Any of the effective dates for installation of controls on internal combustion engines as required in Section I.D.3. may be extended at the Division’s discretion for good cause shown.

I.D.3. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.3.a. Except as provided in Section I.D.3.b., the owner or operator of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in Table 1 shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section I.D.3.b. Table 1.

I.D.3.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1

Maximum Engine Hp	Construction or Relocation Date	Emission Standards is G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥ 100 Hp and < 500 Hp	On or after January 1, 2008	2.0	4.0	1.0
	On or after January 1, 2011	1.0	2.0	0.7
≥ 500 Hp*	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

**These engines may also be subject to emission standards under Section I.D.5.*

I.D.4. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.4.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

I.D.4.a.(i) Except as provided in Sections I.D.4.a.(i)(B) and (C) and I.E.4.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.D.4.a.(i)(A) All control equipment required by this Section I.D.4.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

I.D.4.a.(i)(B) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology (“MACT”) standard under 40 CFR Part 63 (January 1, 2011), a Best Available Control Technology (“BACT”) limit, or a New Source Performance Standard under 40 CFR Part 60 (January 1, 2011) are not subject to this Section I.D.4.a.

I.D.4.a.(i)(C) The requirements of this Section I.D.4.a. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.4.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.4.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

I.D.4.b.(i) Except as provided in Section I.D.4.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.D.4.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.5. (State Only) Additional Requirements for Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.5.a. Applicability

I.D.5.a.(i) This Section I.D.5. applies to stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower.

I.D.5.a.(i)(A) For purposes of this Section I.D.5., modified means any physical change to the engine or change in method of operation that results in an increase in the emission rate of any air pollutant, and does not include any physical or operational changes excluded by 40 C.F.R. 60.14(e).

I.D.5.a.(i)(B) For purposes of this Section I.D.5., placed in service means the bringing of an engine on-site for use. The placed in service date is the date the engine begins to operate. The following is not considered placed in service: (1) moving an engine subject to an Alternative Company-Wide Compliance Plan to another site with the same owner or operator; (2) for engines in service on or before November 14, 2020, replacement under an authorized alternative operating scenario.

I.D.5.a.(i)(C) For purposes of this Section I.D.5., relocated means the bringing of an engine into the 8-Hour Ozone Control Area from outside the 8-Hour Ozone Control Area or the bringing of an engine into the State of Colorado from outside the State of Colorado. The relocation date is the date the subject engine begins to operate.

I.D.5.a.(ii) Exemptions.

I.D.5.a.(ii)(A) Engines that burn less than 100 MMBtu per year of natural gas on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.a.(ii)(B) Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31 are not subject to this Section I.D.5.

I.D.5.a.(ii)(C) Any emergency power generator exempt from APEN or construction permit requirements pursuant to Regulation Number 3, Parts A or B are not subject to this Section I.D.5.

I.D.5.a.(ii)(D) Emergency power generators that operate less than 250 hours per year on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.b. Emission Standards for Engines Subject to Section I.D.5.a.

I.D.5.b.(i) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine that is placed in service, modified, or relocated after November 14, 2020, must comply with the emission standards in Table 2 upon placement in service, modification, or relocation.

I.D.5.b.(ii) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine not subject to Section I.D.5.b.(i) must comply with the emission standards in Table 2 in accordance with the timing set forth Section I.D.5.b.(v).

TABLE 2			
Engine Type	Emission Standards (g/hp-hr)		
	NOx	CO	VOC
4-Stroke Lean Burn engines in service on or before November 14, 2020, (unless subject to a more stringent emission standard under Section I.D.3.b, above)	1.2	2.0	0.7
Rich Burn engines in service on or before November 14, 2020,	0.8	2.0	0.7
4-Stroke Lean Burn engines placed in service, modified, or relocated after November 14, 2020,	0.7	2.0	0.7
Rich Burn engines placed in service, modified, or relocated after November 14, 2020,	0.5	2.0	0.7
2-Stroke Lean Burn engines	3.0	2.0	0.7

I.D.5.b.(iii) By May 1, 2021, owners and operators of an engine placed in service on or before November 14, 2020, that is subject to an emission standard in Table 2 must submit a notification to the Division containing the following information:

I.D.5.b.(iii)(A) The list of engines subject to an emission standard in Table 2, including AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), historical annual hours of operation averaged over calendar years 2017, 2018, and 2019, manufacturer model, serial number, horsepower, and engine configuration. The notification must also identify or calculate the g/hp-hr limit in an existing permit and the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the permitted rate. Engine configuration (e.g. rich burn or lean burn) for purposes of the emission standards in Table 2 is determined by the characterization on the engine's permit or APEN as of May 1, 2021. If the engine configuration is not identified in a permit or APEN, the owner or operator must submit an APEN with the current configuration information as determined by the owner or operator by May 1, 2021 to the Division.

I.D.5.b.(iii)(B) An identification of the applicable standard and a declaration as to whether each subject engine meets the applicable standard as of May 1, 2021. If an engine will meet the applicable standard through a permit modification only, as described in Section I.D.5.b.(iv)(A), below, the declaration should note the date of permit modification submittal.

I.D.5.b.(iii)(C) For all engines that do not meet the applicable emission standard as of May 1, 2021 or that cannot comply through a permit modification described in Section I.D.5.b.(iv)(A), below, a declaration of what action the owner or operator will take to meet the standard (e.g., control equipment installation, retrofit, replacement, electrification, shut-down). This declaration can be amended at any time prior to the applicable compliance date for that engine.

I.D.5.b.(iii)(D) The compliance deadline for each engine under Sections I.D.5.b.(i) or I.D.5.b.(v). An owner or operator may change a proposed compliance deadline for an engine subject to Section I.D.5.b.(v)(B) prior to that engine's compliance deadline, only after submittal of an updated notification to the Division that includes the updated compliance date and a demonstration that the requirements of Table 3 are met.

I.D.5.b.(iii)(E) Owners or operators that submit an Alternative Company-Wide Compliance Plan under Section I.D.5.c. are not subject to this Section I.D.5.b.(iii) for the emission standards in Table 2 for the engines covered by the Alternative Company-Wide Compliance Plan.

I.D.5.b.(iv) Permit Modification.

I.D.5.b.(iv)(A) An engine in service on or before November 14, 2020 that requires only a modification of an existing permit to meet the emission standards in this Section I.D.5.b. must submit a complete permit application containing the necessary limitations no later than May 1, 2021.

I.D.5.b.(iv)(B) For any engine not subject to Section I.D.5.b.(iv)(A), owners and operators must modify existing permits to reflect the emission standards or other operating conditions necessary to achieve compliance with Table 2. Complete permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.b.(iii)(D) above for that engine.

I.D.5.b.(v) Compliance Deadlines for engines subject to Section I.D.5.b.(ii).

I.D.5.b.(v)(A) Engines that comply with the emission standards on or before November 14, 2020, or are subject to Section I.D.5.b.(iv)(A) must meet the emission standards in Table 2 by May 1, 2022.

I.D.5.b.(v)(B) Engines not subject to Section I.D.5.b.(v)(A) must meet the emission standards in Table 2 in accordance with the timing set forth in Table 3.

TABLE 3					
Location of Subject Engines by Owner or Operator	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of engines that must comply with Table 2 limits				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 34% of engines inside the 8-Hour Ozone Control Area	At least 67% of engines inside the 8-Hour Ozone Control Area; and at least 25% of engines outside the 8-Hour Ozone Control Area	100% of engines in the 8-Hour Ozone Control Area; and at least 50% of engines outside the 8-Hour Ozone Control Area	At least 75% of engines outside the 8-Hour Ozone Control Area	100% of all engines
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.b.(vi) If an owner or operator replaces an engine subject to an emission standard under this Section I.D.5.b. with a different stationary natural gas fired reciprocating internal combustion engine, the replacement engine must:

I.D.5.b.(vi)(A) if being placed under an alternative operating scenario pursuant to an existing Division issued permit, meet the same emission standard as the engine being replaced; or

I.D.5.b.(vi)(B) if the owner or operator of an engine chooses to comply via an Alternative Company-Wide Compliance Plan under Section I.D.5.c., meet an emission standard at least as stringent as the engine being replaced as provided for in the applicable Alternative Company-Wide Compliance Plan.

I.D.5.c. Alternative Company-Wide Compliance Plan.

I.D.5.c.(i) Owners and operators with five or more engines that are subject to Section I.D.5.b.(v)(B) may comply with the NOx requirements of Section I.D.5.b. through an Alternative Company-Wide Compliance Plan. Any owner or operator electing to develop an Alternative Company-Wide Compliance Plan must submit a Compliance Plan that meets the requirements of Section I.D.5.c.(ii) on or before May 1, 2021.

I.D.5.c.(i)(A) Only engines subject to an emission standard in Table 2 and that were placed in service on or before the November 14, 2020, can be included in an Alternative Company-Wide Compliance Plan submitted pursuant to this Section I.D.5.c.

I.D.5.c.(i)(B) Engines in an Alternative Company-Wide Compliance Plan must still meet the VOC and CO standards in Table 2 by the deadline established for that engine pursuant to Table 4.

I.D.5.c.(i)(C) Owners and operators owned by the same parent company may collectively submit a Compliance Plan in accordance with this Section I.D.5.c. However, the Compliance Plan must be signed and certified by a responsible official from each owner or operator with engines subject to the Compliance Plan acknowledging that each owner and operator is jointly and severally liable for compliance with the Compliance Plan and the provisions of this Section I.D.5.c. No engine may be included in multiple Alternative Company-Wide Compliance Plans.

I.D.5.c.(ii) The Compliance Plan must be submitted on the Division-approved form and include all of the following elements:

I.D.5.c.(ii)(A) A list of all of the engines that will rely on this Section I.D.5.c. to comply with the standards established in Section I.D.5.b. Each engine must be identified by AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), horsepower, manufacturer, model and serial number, historical annual operating hours (averaged over 2017, 2018, and 2019), and engine configuration.

I.D.5.c.(ii)(B) For each engine included in the Alternative Company-Wide Compliance Plan:

I.D.5.c.(ii)(B)(1) Identification of the most stringent NOx emission standard (in g/hp-hr or converted to g/hp-hr, if not expressed as such in the applicable permit) and operating conditions applicable to the engine under any rule or permit condition in effect on or before November 14, 2020.

I.D.5.c.(ii)(B)(2) Identification of the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the rate identified in Section I.D.5.c.(ii)(B)(1), above.

I.D.5.c.(ii)(B)(3) The emission standards (in g/hp-hr) and any operating conditions with which each engine will comply under the Alternate Company-Wide Compliance Plan, including any intended shut-downs, including any modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(B)(4) The date by which each engine will meet the emission standards or other operating conditions identified in Section I.D.5.c.(ii)(B)(3) above, consistent with Table 4.

I.D.5.c.(ii)(B)(5) The maximum allowable NOx emissions (in tons/year) based on limits applicable on or before November 14, 2020, as identified in Section I.D.5.c.(ii)(B)(1).

I.D.5.c.(ii)(B)(6) The historic NOx emissions (in tons/year) averaged over calendar years 2017, 2018 and 2019, based on actual operating hours and permitted emission standards.

I.D.5.c.(ii)(B)(7) The NOx emissions that would be allowed on an annual basis (in tons/year) assuming the engine was complying with the emission standards established in Table 2.

I.D.5.c.(ii)(B)(8) Each engine's allowable NOx emissions (in tons/year) when operated in accordance with limitations identified in Section I.D.5.c.(ii)(B)(3), above, including any increase in NOx emissions that result from modifications or changes made to comply with the VOC or CO standards in Table 2.

I.D.5.c.(ii)(C) The total allowable NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(5).

I.D.5.c.(ii)(D) The total NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(6).

I.D.5.c.(ii)(E) The total NOx emissions calculated for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with the emission standards established in Table 2, as specified in Section I.D.5.c.(ii)(B)(7).

I.D.5.c.(ii)(F) The total allowable NOx emissions (in tons/year) calculated for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(8) above.

I.D.5.c.(ii)(G) A calculation of:

I.D.5.c.(ii)(G)(1) The difference between Section I.D.5.c.(ii)(C) and Section I.D.5.c.(ii)(F). This difference is called the "Plan Emission Reductions".

I.D.5.c.(ii)(G)(2) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with Table 2, as specified in Section I.D.5.c.(ii)(E).

I.D.5.c.(ii)(G)(3) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(F).

I.D.5.c.(ii)(H) A demonstration that:

I.D.5.c.(ii)(H)(1) The total NOx emissions allowed under the Alternative Company-Wide Compliance Plan (Section I.D.5.c.(ii)(F)) are less than or equal to the total NOx emissions that would be allowed under Table 2 (Section I.D.5.c.(ii)(E)).

I.D.5.c.(ii)(H)(2) The reductions from emissions achieved by the Alternative Company-Wide Compliance Plan are greater than or equal to the reductions from actual emissions achieved by Table 2 (i.e. that the figure calculated in Section I.D.5.c.(ii)(G)(3) is greater than or equal to the figure calculated in Section I.D.5.c.(ii)(G)(2)).

I.D.5.c.(ii)(I) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the Compliance Plan are true, accurate, and complete.

I.D.5.c.(iii) Any owner or operator utilizing this Alternative Company-Wide Compliance Plan must meet the emission standards for NOx, CO and VOC as identified in I.D.5.c.(ii)(B)(3) by the compliance deadlines listed in Table 4, below.

I.D.5.c.(iv) Owners and operators must modify existing permits to reflect the emission standards or other operating conditions identified in the Compliance Plan (Section I.D.5.c.(ii)(B)(3)) for that engine. Permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.c.(ii)(B)(4) above for that engine.

I.D.5.c.(v) Compliance Plan Updates. By May 1st of each year (beginning in 2022) and continuing through and including the final year of a Compliance Plan, an owner or operator must submit an update to the Compliance Plan with the following information:

I.D.5.c.(v)(A) For each engine, any change in location and any action taken under the Compliance Plan (e.g., permit modification applied for, engine retrofit completed, engine taken offline) and the date;

I.D.5.c.(v)(B) A calculation of the percentage of Plan Emission Reductions achieved as of the date of submittal of the update (in each compliance period and cumulatively);

I.D.5.c.(v)(C) Any changes made to the Compliance Plan (e.g. change in compliance date for an engine). No change to the compliance date for an engine can be made after the date established in the Compliance Plan for that engine.;

I.D.5.c.(v)(D) If ownership or operation of an engine in the Compliance Plan for which emission reductions were included in the calculation of Plan Emission Reductions was sold or transferred in the previous year, an identification of how the owner or operator will achieve the portion of Plan Emission Reductions attributed to that engine under the Compliance Plan (the difference between Section I.D.5.c.(ii)(B)(5) and (8)).

I.D.5.c.(v)(E) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the update are true, accurate, and complete.

I.D.5.c.(vi) Nothing in this section I.D.5.c exempts an engine that is part of an Alternative Company-Wide Compliance Plan from compliance with the performance testing, monitoring, recordkeeping or reporting requirements of this Section I.D.5.

TABLE 4					
Location of Subject Engines covered by the Alternative Company-Wide Compliance Plan	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of Plan Emission Reductions Achieved				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 50% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 25% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 50% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100%of Plan Emission Reductions

Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.d. Performance Testing

I.D.5.d.(i) Engines subject to this Section I.D.5. must conduct a performance test consistent with the requirements of this Section I.D.5.d.

I.D.5.d.(i)(A) The owner or operator of an engine subject to Section I.D.5.b.(ii) must conduct a performance test for NOx, CO, and O2 by May 1, 2021.

I.D.5.d.(i)(B) The owner or operator of an engine placed in service, modified, relocated or replaced after May 1, 2021 must conduct a performance test within 12 months of the date the engine is placed in service, modified, relocated or replaced.

I.D.5.d.(i)(C) The following engines are exempt from the requirements of this Section I.D.5.d.

I.D.5.d.(i)(C)(1) Engines subject to the performance testing requirements of 40 C.F.R. Part 60, Subpart JJJJ (July 1, 2019).

I.D.5.d.(i)(C)(2) Engines subject to at least semi-annual portable analyzer testing or ongoing performance testing in a permit issued on or before November 14, 2020.

I.D.5.d.(i)(D) A performance test conducted in accordance with 40 C.F.R. §60.4244 (July 1, 2019) between January 1, 2020 and May 1, 2021 will satisfy the initial performance testing requirements in Section I.D.5.d.(i)(A).

I.D.5.d.(ii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 C.F.R. Part 60, Appendix A (DATE), and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

I.D.5.d.(iii) Tuning of an engine prior to the performance test required by this Section I.D.5.d is not a violation of this rule. However, readjustment of an engine set point following the performance test that would negatively impact the performance of the engine (i.e. result in increased emissions above applicable permit limits) is a violation of this rule.

I.D.5.e. Monitoring. Except as provided in Section I.D.5.a.(ii), owners or operators of an engine subject to Section I.D.5.a must:

I.D.5.e.(i) Beginning on May 1, 2022, conduct semi-annual portable analyzer monitoring for NOx, CO, and O2. At least one calendar month must separate the semi-annual tests.

I.D.5.e.(i)(A) If the engine is operated for less than 200 hrs in any semi-annual period, then the portable analyzer monitoring need not occur during that semi-annual period (i.e. the engine does not need to be started for the sole purpose of portable monitoring).

I.D.5.e.(i)(B) All portable analyzer testing required by this section must be conducted using the Division's Portable Analyzer Monitoring Protocol (version: March 2006).

I.D.5.e.(i)(C) Tuning of an engine prior to semi-annual monitoring events required by this Section I.D.5.e.(i) is not a violation of this rule. However, readjustment of an engine set point following the monitoring event that would negatively impact the performance (i.e. result in increased emissions above applicable permit limits) of the engine is a violation of this rule.

I.D.5.e.(i)(D) A performance test conducted pursuant to Section I.D.5.d., 40 C.F.R. Part 60, JJJJ, or a permit requirement may take the place of the next required semi-annual portable analyzer test required by this section.

I.D.5.e.(i)(E) An engine subject to at least semi-annual portable analyzer testing requirements in an existing permit issued by the Division can comply with this Section I.D.5.e.(i) by complying with the testing requirements in the permit.

I.D.5.e.(ii) Beginning May 1, 2021, if a catalyst is used to reduce emissions:

I.D.5.e.(ii)(A) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within applicable limits.

I.D.5.e.(ii)(B) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semi-annual portable analyzer monitoring.

I.D.5.e.(ii)(C) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements in an existing permit issued by the Division or 40 C.F.R. Part 63, Subpart ZZZZ (July 1, 2019) satisfy the monitoring requirements of this Section I.D.5.e.(ii).

I.D.5.e.(iii) Beginning May 1, 2021 or the date the engine is placed in service, modified, relocated or replaced (if later), install (if not already) and operate an hour meter or Division approved alternate method to continuously track the hours of operation of the subject engine.

I.D.5.e.(iv) Conduct the following inspections and adjustments at least annually, unless otherwise specified below, beginning in 2022

I.D.5.e.(iv)(A) Change oil and filters as necessary; and, I.D.5.e.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary; and,

I.D.5.e.(iv)(C) Inspect spark plugs and replace as necessary; or,

I.D.5.e.(iv)(D) Conduct a combustion process adjustment according to the manufacturer recommended procedures and schedule. Alternatively, the owner or operator may rely on a combustion process adjustment conducted in accordance with requirements and schedules of a New Source Performance Standard in 40 CFR Part 60 (July 1, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2019) conducted during the same annual period to satisfy the annual combustion process adjustment requirement of this Section I.D.5.c.(iv)(D) for that 12 month period.

I.D.5.f. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request.

I.D.5.f.(i) Records of performance tests conducted pursuant to Section I.D.5.d, including I.D.5.d.(i)(D)., including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

I.D.5.f.(ii) Records of semi-annual portable analyzer monitoring, including the date, engine settings on the date of the monitoring, and documentation of the results of the monitoring. These records must include any demonstration that no semi-annual portable analyzer monitoring was required as provided under Section I.D.5.e.(i)(D) or I.D.5.e.(i)(E), if applicable.

I.D.5.f.(iii) Records of catalyst monitoring required by Section I.D.5.e.(ii) and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

I.D.5.f.(iv) If claiming an exemption under Section I.D.5.a.(ii), records demonstrating that fuel combustion was less than 100 MMBtu per year or hours of operation are less than 250 hours per year.

I.D.5.f.(v) Hours of operation as recorded by the hour meter or alternative device approved by the Division continuously tracking hours as required by Section I.D.5.e.(iii), at least on a calendar month basis.

I.D.5.f.(vi) Records of tuning, adjustments, or other combustion process adjustments required under Section I.D.5.e.(iv), including:

I.D.5.f.(vi)(A) The date of the adjustment.

I.D.5.f.(vi)(B) A description of any corrective action taken.

I.D.5.f.(vi)(C) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation since the last combustion process adjustment and the procedures followed. The owner or operator must retain documentation of any relied upon manufacturer recommended procedures, specifications, and maintenance schedule for five years after the owner or operator ceases to rely upon it.

I.D.5.f.(vi)(D) If the owner or operator conducts the combustion process adjustment according to a New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants, what standard applied and what procedures were followed.

I.D.5.g. Reporting. Beginning on the date specified below and by May 1 of each year thereafter, the owner or operator of each engine subject to this Section I.D.5. must submit the following information covering the preceding calendar year:

I.D.5.g.(i) Beginning May 1, 2021, a statement of the status of performance testing required under Section I.D.5.d, and the date and results of that testing;

II.D.5.g.(ii) Beginning May 1, 2022, an identification of any engines placed in service, modified, relocated, or replaced, including AIRS number, serial number, location, engine configuration, and a certification as to whether the emission standards in Table 2 are met;

I.D.5.g.(iii) Beginning May 1, 2022, the date on which the monitoring required by Sections I.D.5.e.(iv) was performed;

I.D.5.g.(iv) Beginning May 1, 2023, the date that all required semi-annual portable analyzer testing was performed under Section I.D.5.e.(i), and the results of that testing.

II. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area

II.A. Requirements for major sources of NOx

II.A.1. Applicability.

II.A.1.a. Except as provided in Section II.A.2., the requirements of this Section II.. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, located in the 8-Hour Ozone Control Area.

II.A.1.b. Except as provided in Section II.A.2., the requirements of Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 50 tpy NOx) as of [EFFECTIVE DATE OF THE RECLASSIFICATION], located in the 8-Hour Ozone Control Area, that is not already subject as provided under Section II.A.1.a.

II.A.2. Exemptions. The following stationary combustion equipment are exempt from the emission limitation requirements of Section II.A.4., the compliance demonstration requirements in Section II.A.5., and the related recordkeeping and reporting requirements of Sections II.A.7.a-e. and II.A.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section II.A.6., when required by II.A.6.a.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section II.A. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section II.A.4.

II.A.2.a. Any stationary combustion equipment whose utilization is less than:

II.A.2.a.(i) 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers; or

II.A.2.a.(ii) 10% of its capacity factor on an annual average basis over a 3-year rolling period for stationary combustion turbines and compression ignition reciprocating internal combustion engines.

II.A.2.b. An engine testing operation or process line.

II.A.2.c. Any gaseous fuel fired stationary combustion equipment used to control VOC emissions from a commercial or industrial process.

II.A.2.d. Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis.

II.A.2.e. Any natural gas-fired reciprocating internal combustion engines subject to a work practice or emission control requirement contained in this Regulation 7, Section I.A. or B.

II.A.2.f. Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7, Section III.A.-B. or Regulation 3, Part F.

II.A.3. Definitions

II.A.3.a. “Affected unit” means any stationary combustion equipment that is subject to or becomes subject to an emission limitation in Section II.A.4.

II.A.3.b. “Boiler” means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

II.A.3.c. "Capacity factor" means the ratio of the amount of fuel burned by an emissions unit in a calendar year to the amount of fuel it could have burned if it had operated at the designed heat input rating for 8,760 hours during the calendar year. Alternatively, for electric generating units, capacity factor can mean the ratio of the unit's actual annual electric output (expressed in MWe/hr) to the electric output the unit could have achieved if it operated at its nameplate capacity (or maximum observed hourly gross load (expressed in MWe/hr) if greater than the nameplate capacity) for 8,760 hours during the calendar year.

II.A.3.d. "Ceramic kiln" means equipment used for the curing or firing of ceramic products or glaze on ceramic products. A kiln may operate continuously or by batch process.

II.A.3.e. "Continuous emission monitoring system" ("CEMS") or "Continuous emission rate monitoring system" ("CERMS") means the total equipment required to sample, condition (if applicable), analyze, and provide a written record of such emissions and/or emission rates, expressed on a continuous basis in terms of an applicable emission limitation. Such equipment includes, but is not limited to, sample collection and calibration interfaces, pollutant analyzers, a diluent analyzer (oxygen or carbon dioxide), stack gas volumetric flow monitors (if appropriate for CERMS), and data recording and storage devices.

II.A.3.f. "Compression ignition reciprocating internal combustion engine (RICE)" means a type of stationary RICE that is liquid fuel-fired and not ignited with a spark plug or other sparking device.

II.A.3.g. "Digester gas" means any gaseous byproduct of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide.

II.A.3.h. "Duct burner" means a device that combusts fuel and is placed in the exhaust duct from another source (e.g., stationary combustion turbine, internal combustion engine, or kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

II.A.3.i. "Dryer" means a device that is used to reduce or evaporate moisture content or remove organic contaminants.

II.A.3.j. "Furnace" means an enclosed device that is an integral component of a manufacturing process and that uses thermal treatment to accomplish recovery of materials or energy.

II.A.3.k. "Gaseous fuel" means natural gas, landfill gas, refinery fuel gas, digester gas, methane, ethane, propane, butane, or any gas stored as a liquid at high pressure such as liquefied petroleum gas.

II.A.3.l. "Glass melting furnace" means an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass.

II.A.3.m. "Kiln" means the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating.

II.A.3.n. "Lightweight aggregate" means the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln.

II.A.3.o. "Liquid fuel" means any fuel which is a liquid at standard conditions including but not limited to distillate oils, kerosene and jet fuel. Liquefied gaseous fuels are not liquid fuels.

II.A.3.p. "Process heater" means an enclosed device using controlled flame and a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

II.A.3.q. "Reciprocating internal combustion engine" means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not used to propel a motor vehicle or a vehicle used solely for competition.

II.A.3.r. "Stationary combustion equipment" means an emissions unit that combusts solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. Stationary combustion equipment includes, but is not limited to, boilers, duct burners, engines, glass melting furnaces, kilns, process heaters, stationary combustion turbines, dryers, furnaces, and ceramic kilns.

II.A.3.s. "Stationary combustion turbine" means a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.

II.A.4. Emission limitations.

By October 1, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.a. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis.

By July 20, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.b. may cause, allow, or permit NOx to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis.

II.A.4.a. Boilers

II.A.4.a.(i) For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(ii) For a liquid fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iii) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of [EFFECTIVE DATE OF THE RECLASSIFICATION]) with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(iv) For a liquid or gaseous fuel-fired boiler at a major source of NOx (greater than or equal to 50 tpy NOx as of [EFFECTIVE DATE OF THE RECLASSIFICATION]) with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr but less than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.

II.A.4.a.(v) Boilers subject to the categorical limits in Section II.A.4.a.(i) through (iv) or boilers with a maximum design heat input capacity less than 100 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b. Stationary combustion turbines

II.A.4.b.(i) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction on or before February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart GG (July 1, 2017).

II.A.4.b.(ii) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction, modification or reconstruction after February 18, 2005 must comply with the applicable NOx emission limits in 40 CFR Part 60, Subpart KKKK (July 1, 2017).

II.A.4.b.(iii) Stationary combustion turbines subject to the categorical limits in Section II.A.4.b.(i) or (ii) above and stationary combustion turbines with a maximum design heat input capacity less than 10 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.c. Lightweight aggregate kilns. For lightweight aggregate kilns with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr, 56.6 pounds of NOx per hour.

II.A.4.d. Glass melting furnaces

II.A.4.d.(i) For, glass melting furnaces, 1.2 pounds of NOx per ton of glass pulled. However, days in which a glass melting furnace is operated at less than 35% of maximum designed production may be excluded from the 30-day rolling average for purposes of demonstrating compliance with this Section II.A.4.d.(i). During each day excluded from the 30-day rolling average, NOx emissions must be measured continuously in accordance with the applicable monitoring requirements of Section II.A.5, and the furnace must be operated in accordance with good air pollution control practices.

II.A.4.e. Compression ignition RICE

II.A.4.e.(i) For a compression ignition RICE with a maximum design power output equal to or greater than 500 horsepower, 9 grams per brake horsepower-hour.

II.A.4.e.(ii) Compression ignition RICE subject to the emission limit in Section II.A.4.e.(i) above and compression ignition RICE with a maximum design power output less than 500 horsepower must comply with the combustion process adjustment requirements contained in Section II.A.6.

II.A.5. Compliance demonstration.

II.A.5.a. By October 1, 2021, for stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in this Section II.A.5.

II.A.5.b. By July 20, 2021, for stationary combustion equipment specified in Section II.A.1.b., the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in Sections II.A.5.

II.A.5.c. Emissions monitoring requirements for major source RACT limits

II.A.5.c.(i) Continuous emission monitoring

II.A.5.c.(i)(A) Owners or operators of an affected unit subject to a NOx emission limit in Section II.A.4.a.(i)-(iii), c. or d. must install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i). Owners or operators of affected units' subject to a NOx emission limit in Section II.A.4.b. or Section II.A.4.e. may install, operate and maintain a NOx CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i) in lieu of performance testing pursuant to Section II.A.5.c.(ii).

II.A.5.c.(i)(A)(1) The owner or operator of an affected unit that is subject to or becomes subject to the monitoring requirements of 40 CFR part 75 and 40 CFR part 75, Appendices A to I (July 19, 2018), must use those monitoring methods and specifications for monitoring NOx emissions for purposes of this Section II.A.5. and for demonstrating compliance with Section II.A.4. The missing data substitution procedures and bias adjustment requirements of 40 CFR Part 75 (July 19, 2018) do not apply for purposes of demonstrating compliance with Section II.A.4. or this Section II.A.5.

II.A.5.c.(i)(A)(2) For an affected unit equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60 (July 19, 2018), the owner or operator must use the definition of operating day, data averaging methodology, and data validation requirements of the applicable subpart of 40 CFR Part 60 for purposes of demonstrating compliance with an applicable emission limit in Section II.A.4. The owner or operator must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable requirements of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018).

II.A.5.c.(i)(A)(3) For an affected unit that is not equipped with a NOx CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 (July 19, 2018) or Part 75 (July 19, 2018), the owner or operator must install, operate, and maintain a NOx CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018). The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section II.A.4.:

II.A.5.c.(i)(A)(3)(a) A unit operating day is a calendar day when any fuel is combusted in the affected unit.

II.A.5.c.(i)(A)(3)(b) 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days.

II.A.5.c.(i)(A)(4) When an affected unit utilizes a common flue gas stack system with one or more affected units, but no non-affected units, the owner or operator must follow the applicable procedures of 40 CFR Part 75, Appendix F (July 19, 2018) for the determination of all sampling locations and apportionment of emissions to an individual affected unit.

II.A.5.c.(ii) Initial and periodic performance testing

II.A.5.c.(ii)(A) An owner or operator of a stationary combustion turbine subject to 40 CFR Part 60, Subparts GG or KKKK (July 19, 2018) that has used and continues to use performance testing to demonstrate compliance with either Subpart GG or KKKK (July 19, 2018), as applicable, may use those performance testing procedures to demonstrate continued compliance with an applicable limitation contained in Section II.A.4.b., thereby satisfying the requirements of this section II.A.5.c.(ii).

II.A.5.c.(ii)(B) Except as otherwise provided for in Section II.A.5.a.(ii)(A), the owner or operator of an affected unit subject to a NOx emission limitation contained in Sections II.A.4.a.(iv), 4.b., or 4.e. that is not equipped with NOx CEMS or CERMS, must conduct an initial performance test and subsequent performance tests every 2 years thereafter, according to the following requirements, as applicable, to determine the affected unit's NOx emission rate for each fuel fired in the affected unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year.

II.A.5.c.(ii)(B)(1) Initial performance test must include a determination of the capacity load point of the unit's maximum NOx emissions rate based on one 30-minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NOx emissions rate.

II.A.5.c.(ii)(B)(2) Performance tests must determine compliance with Section II.A.4. based on the average of three 60-minute test runs performed at the capacity load determined in II.A.5.c.(ii)(B)(1).

II.A.5.c.(ii)(C) All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

II.A.5.c.(iii) For affected units' subject to a production-based or output based emission limit contained in Section II.A.4. (e.g. lb of NOx/ton of product), the owner or operator must install, operate, and maintain monitoring equipment for measuring and recording the affected unit's production or output, on an hourly basis, in units consistent with the applicable emission limitation.

II.A.5.c.(iv) Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D (July 19, 2018) are acceptable for demonstrating compliance with this section. The installation of fuel-flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 (July 19, 2018) or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen).

II.A.6. Combustion process adjustment

II.A.6.a. Applicability

II.A.6.a.(i) As of January 1, 2017, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016.

II.A.6.a.(ii) As of May 1, 2020, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of [EFFECTIVE DATE OF THE RECLASSIFICATION], that is not already subject as provided under Section II.A.6.a.(i).II.A.6.b. Combustion process adjustment

II.A.6.b.(i) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable:

II.A.6.b.(i)(A) Inspect the burner and combustion controls and clean or replace components as necessary.

II.A.6.b.(i)(B) Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern.

II.A.6.b.(i)(C) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.

II.A.6.b.(i)(D) Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections II.A.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer.

II.A.6.b.(ii) The owner or operator of a duct burner must inspect duct burner elements, baffles, support structures, and liners and clean, repair, or replace components as necessary.

II.A.6.b.(iii) The owner or operator of a stationary combustion turbine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iii)(A) Inspect turbine inlet systems and align, repair, or replace components as necessary.

II.A.6.b.(iii)(B) Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.

II.A.6.b.(iii)(C) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.

II.A.6.b.(iv) The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable:

II.A.6.b.(iv)(A) Change oil and filters as necessary.

II.A.6.b.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary.

II.A.6.b.(iv)(C) Inspect spark plugs and replace as necessary.

II.A.6.b.(v) The owner or operator of a dryer or furnace must inspect the burner and combustion controls and adjust, clean, and/or replace components as necessary.

II.A.6.b.(vi) The owner or operator of a ceramic kiln must inspect and maintain the combustion controls and adjust the burners as necessary to ensure a proper air-to-fuel ratio. At units where entry into a piece of process equipment is required to complete the combustion process adjustment, in-kiln inspections and adjustments are required only during planned entries.

II.A.6.b.(vii) The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, stationary internal combustion engine, dryer, furnace, or ceramic kiln consistent with manufacturer’s specifications, if available, or good engineering and maintenance practices.

II.A.6.b.(viii) Frequency

II.A.6.b.(viii)(A) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016) to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017.

II.A.6.b.(viii)(B) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of [EFFECTIVE DATE OF THE RECLASSIFICATION], must conduct the initial combustion process adjustment by May 1, 2020. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) to satisfy the requirement to conduct an initial combustion process adjustment by May 1, 2020.

II.A.6.b.(viii)(C) The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(1). or II.A.6.c.(ii).

II.A.6.c. As an alternative to the requirements described in Sections II.A.6.b.(i) through II.A.6.b.(viii):

II.A.6.c.(i) The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; or

II.A.6.c.(ii) The owner or operator of combustion equipment that is subject to and required to conduct a periodic tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 (December 19, 2019) or 40 CFR Part 63 (December 19, 2019).

II.A.7. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request:

II.A.7.a. The applicable emission limit and calculated heat input weighted emission limit for stationary combustion equipment demonstrating compliance for multiple fuels.

II.A.7.b. The 30-day rolling average emission rate calculated on a daily basis for sources using CERMS to comply with Section II.A.

II.A.7.c. The type and amount of fuel used.

II.A.7.d. The stationary combustion equipment's annual capacity factor on a calendar year basis.

II.A.7.e. All records generated to comply with the reporting requirements contained in Section II.A.8.

II.A.7.f. For stationary combustion equipment subject to the combustion process adjustment requirements in Section II.A.6., the following recordkeeping requirements apply:

II.A.7.f.(i) The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section II.A. and including for each combustion equipment:

II.A.7.f.(i)(A) The date of the adjustment;

II.A.7.f.(i)(B) Whether the combustion process adjustment under Sections II.A.6.b.(i) through II.A.6.b.(vi) was followed, and what procedures were performed;

II.A.7.f.(i)(C) Whether a combustion process adjustment under Sections II.A.6.c.(i). and II.A.6.c.(ii). was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any; and

II.A.7.f.(i)(D) A description of any corrective action taken.

II.A.7.f.(i)(E) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation.

II.A.7.f.(i)(F) If multiple fuels are used, the type of fuel burned and heat input provided by each fuel.

II.A.7.f.(ii) The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section II.A.6.c.(i). for the life of the equipment.

II.A.7.f.(iii) As an alternative to the requirements described in Section II.A.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016).

II.A.7.g. All sources qualifying for an exemption under Section II.A.2. must maintain all records necessary to demonstrate that an exemption applies.

II.A.8. Reporting

II.A.8.a. For affected units demonstrating compliance with Section II.A.4. using CEMS or CERMS in accordance with Section II.A.5.c.(i)(A), the owner or operator must submit to the Division the following information:

II.A.8.a.(i) Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section II.A.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018).

II.A.8.b. For affected units demonstrating compliance with Section II.A.4 using performance testing pursuant to Section II.A.5.c.(ii)(C), the owner or operator must submit to the Division the following information:

II.A.8.b.(i) Performance test reports within 60 days after completion of the performance test program. All performance test reports must determine compliance with the applicable emission limitations set by Section II.A.4.

III. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-hour Ozone Control Area

III.A. Specific major sources of VOC and/or NOx (greater than or equal to 100 tpy) as of June 3, 2016, located in the 8-hour Ozone Control Area.

III.A.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017:

III.A.1.a. National Reconnaissance Office (NRO) – Aerospace Data Facility (005-0028) – engines (pt 128, 139, 144).

III.A.1.b. Colorado State University (069-0011) – engines (pt 024, 035, 036, 037, 038, 040, 043, 052).

III.A.1.c. DCP Midstream, Greeley (123-0099) – engine (pt 102).

III.A.1.d. DCP Midstream, Kersey/Mewbourn (123-0090) – engine (pt 101).

III.A.1.e. DCP Midstream, Spindle (123-0015) – engines (pt 059, 075).

III.A.1.f. IBM (013-0006) – engines (pt 092, 094).

III.A.1.g. Owens-Brockway (123-4406) – engine (pt 024).

III.A.1.h. Plains End (059-0864) – engine (pt 005).

III.A.1.i. PSCo Cherokee (001-0001) – engine (pt 031).

III.A.1.j. Spindle Hill (123-5468) – engine (pt 005).

III.A.1.k. Suncor (001-0003) – engines (pt 150, 151).

III.A.1.l. Timberline Energy (123-0079) – engines (pt 010, 011).

III.A.2. Cemex Construction Materials (013-0003) must comply with applicable THC requirements and associated monitoring, recordkeeping, and reporting in 40 CFR Part 63, Subpart LLL (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.A.3. Denver Regional Landfill and Front Range Landfill (123-0079) (pt 007, 013) must comply with applicable flare requirements in 40 CFR Part 60, Subpart WWW (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.B. Specific major sources of VOC and/or NOx (greater than or equal to 50 tpy) as of [EFFECTIVE DATE OF THE RECLASSIFICATION], located in the 8-hour Ozone Control Area.

III.B.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (January 30, 2013) as expeditiously as practicable, but no later than July 1, 2021:

III.B.1.a. University of Colorado Denver, Anschutz Medical Campus (001-0106) – engines (pts 011, 012, 013, 014, 015, 016, 017, 018, 020, 021).

III.B.1.b. Centura Health St. Anthony (059-1511) – engines (pts 002, 003).

III.B.2. Flares at the following major sources must comply with applicable flare requirements in 40 CFR Part 60, Section 60.18 (December 22, 2008) as expeditiously as practicable, but no later than July 1, 2021.

III.B.2.a. Waste Management of Colorado Denver Arapahoe Disposal Site (005-1291) (pt 003).

III.B.3. Front Range Energy (123-5097) must comply with applicable monitoring, recordkeeping, and reporting in 40 CFR Part 60, Subpart VV (July 1, 2019) as expeditiously as practicable, but no later than July 1, 2021.

III.B.4. Owners or operators of the following sources that emit or have the potential to emit 50 tons per year or more of VOC or NOx as of [EFFECTIVE DATE OF THE RECLASSIFICATION], and are located in the 8-hour Ozone Control Area must submit a RACT analysis for the facility (if applicable due to the lack of specific emission points) or specified emission point to the Division or obtain permit limits such that the facility no longer emits or has the potential to emit equal to or greater than 50 tons per year of VOC and/or NOx no later than July 1, 2020. Approved RACT determinations will be addressed in the relevant source permit or through rule revisions, as appropriate.

III.B.4.a. Owens Corning Denver Roofing Plant (001-0009) – emission points equal to or greater than 2 tpy VOC.

III.B.4.b. University of Colorado Denver – Anschutz Medical Campus (001-0106) – boilers greater than or equal to 50 MMBtu/hr and less than 100 MMBtu/hr (008).

III.B.4.c. Atlas Roofing Corporation (001-0505) – emission points equal to or greater than 2 tpy VOC.

III.B.4.d. Insulfoam (001-0560) – emission points equal to or greater than 2 tpy VOC.

III.B.4.e. ACH Foam Technologies-EPS Products (001-0576) – emission points equal to or greater than 2 tpy VOC.

III.B.4.f. TruStile Doors (001-1295) – emission points equal to or greater than 2 tpy VOC.

III.B.4.g. Waste Management of Colorado Denver Arapahoe Disposal Site (005-1291) – engines (pt 002).

III.B.4.h. City of Boulder 75th Street Wastewater Plant (013-0057) – flare (pt 002) and engines (pts 004, 005).

III.B.4.i. Circle Graphics (013-1303) – emission points equal to or greater than 2 tpy VOC.

III.B.4.j. King Soopers-Bakery (031-1662) – emission points equal to or greater than 2 tpy VOC.

III.B.4.k. Leprino Foods (123-0002) – engines (pt 021) and boilers (011, 012, 016).

III.B.4.l. Swift Beef Company (123-0018) – boilers (006, 013, 017, 018)

III.B.4.m. Golden Aluminum (123-0089) – emission points equal to or greater than 5 tpy NOx.

III.B.4.n. Any source that emits or has the potential to emit 50 tons per year or more of VOC or NOx as of [EFFECTIVE DATE OF THE RECLASSIFICATION] and is located in the 8-hour Ozone Control Area that is not listed above must submit a RACT analysis for emission points equal to or greater than 5 tpy NOx (for facilities with NOx emissions of 50 tpy or more) and/or for emission points equal to or greater than 2 tpy VOC (for facilities with VOC emissions of 50 tpy of more) if the facility or facility point is not subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7 or Regulation 3, Part F or analyzed in the 2019 Major Source RACT Technical Support Document.

IV. Control of Emissions from Breweries in the 8-hour Ozone Control Area

IV.A. Requirements for Brewing Operations

IV.A.1. Applicability

Except as provided in Section IV.A.2., the requirements of Section IV. apply to owners or operators of breweries that existed at a major source of VOC (greater than or equal to 100 tpy VOC) as of June 3, 2016, located in the 8-hour Ozone Control Area.

IV.A.2. Exemptions

The following emissions units are exempt from Sections IV.A.4. through IV.A.7. but must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Owners or operators must also maintain records necessary to demonstrate than an exemption applies and make such records available to the Division upon request.

Once an emissions unit at a brewery no longer qualifies for an exemption, the owner or operator must comply with the applicable requirements of Sections IV.A.4. through IV.A.7. as expeditiously as practicable but no later than twelve (12) months after the exemption no longer applies, except as specified in Sections IV.A.2.c. and IV.A.2.d.

IV.A.2.a. An emissions unit subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7.

IV.A.2.b. An emissions unit with total uncontrolled actual emissions less than two (2) tons per year VOC on a calendar year basis.

IV.A.2.c. Equipment or activities related to research and development. Research and development ends when the product is sold or offered for sale.

IV.A.2.d. Newly installed, upgraded, or replaced packaging operations for a duration of six months after startup.

IV.A.3. Definitions

IV.A.3.a. “Brewery” means a source that produces malt beverage and is comprised of emissions units related to brewhouse operations, fermentation, aging or secondary fermentation, and/or packaging operations.

IV.A.3.b. “Packaging operation” means the canning, bottling, or filling of malt beverages into a container. Packaging operations include keg filling. Packaging operations do not include the railcar loading and unloading of beer concentrate shipped off-site for packing.

IV.A.3.c. "Pilot brewery operation" means an operation where total packaging operations are less than 50,000 barrels per year.

IV.A.3.d. "Process loss" means the difference between the quantity of malt beverage sent to packaging and the quantity of malt beverage packaged into a container. Process loss does not include malt beverage in filled containers if the malt beverage is processed after filling to remove or recover ethanol.

IV.A.4. Emission limitations. By May 1, 2019, no owner or operator of a brewery may exceed an average of 6 percent process loss across all packaging operations in a calendar month and 4 percent process loss on a 12-month rolling average during packaging operations.

IV.A.5. Packaging operation work practices

IV.A.5.a. The owner or operator must develop performance objectives and metrics for each packaging operation to reduce spillage and process loss. Process loss records must be summarized annually and compared to performance objectives established by the owner or operator. Process loss records and summaries must be made available to the Division upon request.

IV.A.5.b. The owner or operator must develop and implement an operator training program for employees engaged in packaging operations to understand the operation of the filling lines and minimize breakdowns, spillage, and process loss. The operator training materials must be made available to the Division upon request. At a minimum, the training program must include:

IV.A.5.b.(i) A brewery training manager, coordinator, or equivalent;

IV.A.5.b.(ii) Written standard operating procedures for packaging operations;

IV.A.5.b.(iii) A requirement that initial training be conducted for employees performing packaging operations and more frequently for the following:

IV.A.5.b.(iii)(A) Employees changing packaging operation responsibilities; and

IV.A.5.b.(iii)(B) Startup of new, upgraded, or replaced packaging operations.

IV.A.5.c. The owner or operator must use and maintain packaging operation equipment to reduce container breakage and process loss. For packaging operations, except at pilot brewery operations, this includes, but is not limited to:

IV.A.5.c.(i) Using and maintaining automated filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.c.(ii) Installing and operating fill level detectors to monitor the liquid fill levels in containers;

IV.A.5.c.(ii) Installing and operating crown inspectors to monitor the condition of crowns and/or caps applied to bottles, if applicable; and

IV.A.5.c.(iv) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.5.d. The owner or operator of pilot brewery operations must use and maintain packaging operation equipment to reduce container breakage and process loss. This includes, but is not limited to:

IV.A.5.d.(i) Maintaining filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.d.(ii) Monitoring the liquid fill levels in containers; and

IV.A.5.d.(iii) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.6. Wastewater management and treatment. Owners or operators employing microbial and vegetative destruction of VOCs through the land application of wastewater must ensure that the areas where wastewater is applied are areas covered with vegetation at all times when wastewater is applied, except as required following tilling and seeding for crop rotation and field work per standard agricultural practices.

IV.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request:

IV.A.7.a. Monthly records of the percent process loss for packaging operations;

IV.A.7.b. Records necessary to demonstrate compliance with the packaging operation work practice requirements in Section IV.A.5.; and

IV.A.7.c. If applicable, pursuant to Section IV.A.6., monthly and annual records of the amount of wastewater (gallons) sent to the land application site.

PART F Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

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

Regulation Numbers 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

These revisions to Regulations Numbers 3, 7, and the Common Provision 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 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 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.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Pursuant to Section 25-7-107(2.5), C.R.S., the Commission is required to take expeditious action to redesignate the area as an attainment area for ozone. The CAA requires the submittal of a maintenance plan demonstrating maintenance of the ozone standard for any such redesignation request. The changes to Regulation Number 7 are consistent with continued maintenance of the ozone standard and are not otherwise more stringent than the relevant federal requirements.

The purpose of the revisions to Regulation Number 7, Section I.A is to provide a de minimis source with an opportunity to obtain an exemption from the requirements of Regulation Number 7 through rule-making. This revision will be submitted to the EPA for inclusion in the State Implementation Plan (SIP). Upon inclusion of this revision in the SIP, exemptions from Regulation Number 7 adopted by the Commission shall apply for purposes of both federal and state law, pending review by the state legislature pursuant to § 25-7-133(2), C.R.S. The rule revision includes several limitations on the scope of such exemptions:

1. The aggregate of all emissions from de minimis sources may not exceed five tons of emissions per day. The purpose of this limitation is to protect the projections contained in the emissions inventory, and to prevent growth in such emissions from exceeding the National Ambient Air Quality Standard (NAAQS) for ozone.

2. An exemption may not be granted if the Division demonstrates that such exemption will cause or contribute to air pollution levels that exceed the NAAQS, even if the total aggregate emissions from such sources is less than five tons per day.

3. The Commission rule prohibits more than one rulemaking hearing per year to consider potential de minimis exemptions in the aggregate. The purpose of this provision is to prevent the granting of case-by-case exemptions, and to conserve agency resources. The granting of exemptions on a case-by-case basis would grant an unfair advantage for those sources that are able to have their case heard by the Commission before other, similarly situated sources, submit a request for a de minimis exemption. However, upon a showing of an emergency, and at the discretion of the Commission, the Commission may always grant an exemption on a case-by-case basis.

4. The Commission rule provides that the growth in emissions due to such de minimis exemptions may not exceed the growth that was included in the emissions inventory in the SIP.

5. The Commission rule requires the de minimis exemptions to be included in a permit that is subject to review and comment by the public and by EPA.

The rule revision proposed by the Regional Air Quality Council (RAQC) did not include these limitations. However, the Commission may not have used the rule as proposed by RAQC to grant unlimited exemptions from the requirements of Regulation Number 7 because such an action would undermine the regulation and the maintenance demonstration contained in the SIP. The limitations adopted by the Commission were the subject of an alternative proposal submitted by the Division. The purpose of the limit is to ensure that the de minimis exemption provision cannot be used to jeopardize attainment of the NAAQs. Such a limit is necessary in order to obtain EPA approval of this SIP revision. The alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity. Even without an express provision limiting the de minimis exemptions to five tons per day, the Commission generally would not have granted de minimis exemptions in excess of that amount because such emissions are not accounted for in the emissions inventory and would undermine the maintenance demonstration. Furthermore, the alternative proposed by the Division does not, by itself, create an exemption from any regulatory requirement. The alternative simply limits the scope of the exemptions that may become fully effective without a SIP revision. However, the rule does not in any way limit the Commission's authority to amend the SIP.

The emissions inventory submitted to EPA anticipated growth in emissions in both the area source and minor source categories, as well as the major source category. In order to ensure that any growth in emissions due to the granting of de minimis exemptions will not cause total emissions to exceed the growth projections for these categories, the Division will keep track of the permitted allowable emissions that may result from sources and source categories entitled to such exemptions. In addition, the growth in emissions from area, major and minor source categories will be tracked when the Division performs the periodic inventories described in the SIP for the years 1999, 2002 and 2003. Any permitted growth in emissions due to de minimis exemptions will be added to the emissions for the source categories as reflected in the most recent periodic inventory. No further de minimis exemptions will be granted if the total growth in emissions exceeds the growth projections contained in the SIP. In addition, if the total growth exceeds the growth projections contained in the SIP, one or more of the contingency measures will be implemented to offset such growth, or the SIP will be revised as necessary to ensure continued maintenance of the standard.

The purpose of the addition of Regulation Number 7, Section II.E. is to provide sources with a process to obtain approval of an alternative emission control plan, compliance method, test method, or test procedure without waiting for EPA to approve of a site-specific SIP revision. The rule provides that any such alternative must be just as effective as the relevant regulatory provision, and that such effectiveness must be demonstrated using equally effective test methods and procedures. The changes to this section delegate the authority to the Division to approve of such alternatives. Since rulemaking is not required under Section II.E., the language allowing a source to assert that the relevant regulatory provision does not represent RACT has been omitted from this section. Such a change to the substantive requirements of Regulation Number 7 would require a rule change.

The rule revision proposed by the RAQC provided that alternative emissions control plans and compliance methods must be just as effective as those contained in the rule, but did not describe the test methods to be used to demonstrate such effectiveness. The Division proposed an alternative rule requiring such effectiveness to be demonstrated using test methods and procedures that are just as effective as those set out in the rule, or that have otherwise been approved by EPA. Such criteria for test methods and procedures are necessary in order to obtain EPA approval of this SIP revision. However, even without this language in the rule the Division would have required approved test methods and procedures in order to approve of proposed alternatives. The Division's alternative proposal provides the needed certainty in the most flexible manner possible. Furthermore, the alternative proposed by the Division does not impose any new regulatory requirement. Instead, it merely establishes criteria for allowing persons subject to the regulation to propose, in their discretion, an alternative means of complying with the existing regulatory requirements. Therefore, the alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity.

The rule revisions provide that no permit may be issued based on the provisions allowing for the creation of de minimis exemptions and the approval of alternative compliance plans without first revising the SIP unless EPA first approves of such regulatory revisions as part of the State Implementation Plan. The purpose of this condition is to address the possible disapproval of these revisions by EPA. In the event these changes are not approved by EPA, the remaining regulatory provisions of Regulation Number 7 will remain in full force and effect, and therefore, the EPA may approve of the maintenance plan and the redesignation request.

The revisions to Regulation Number 7 are procedural changes that are not intended to reduce air pollution.

For clarification, the Commission adopted these regulation revisions as follows:

REGULATION REVISION	OZONE SIP AND MAINTENANCE PLAN
Section I.A.1	Exists in Appendix C of the Ozone Maintenance Plan to become a part of that document approved March 21, 1996
Sections I.A.2., 3., 4.; Section II.D., II.E.	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA separately and concurrently as a revision to the Ozone SIP (and 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. The authority to adopt such rules includes the authority to adopt exceptions to the rules, and the process for applying for any such exemptions.

C. November 21, 1996 (Section XII.)

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

Regulation Numbers 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 Numbers 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)(I)(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 Regulation Numbers 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.

D. October 15, 1998 (Section II.F.)

The Gates Rubber Co. Site-specific Revision

The Gates Rubber Co. (Gates), by and through its attorney, submitted this Statement of Basis, Specific Statutory Authority and Purpose for amendments to Regulation Number 7, Control of Emissions of Volatile Organic Compounds.

Basis

Regulation Number 3 contains a certification and trading of emission reduction credits section (Section V), which sets forth the definitions and process for obtaining emission credits and using those credits. This section was amended to permit the use of emission reduction credits (ERC) to satisfy reasonably available control technology (RACT) requirements. The criteria for approval of ERC transactions specifies that they must involve like pollutants (for volatile organic compounds, the same degree of toxicity and photochemical reactivity), must be within the same nonattainment area, may not be used to satisfy Federal technology control requirements and may not be inconsistent with standards or regulations or to circumvent new source performance standards, best available control technology, lowest available emission rate technology controls or NESHAPs.

Regulation Number 7 sets forth CTG and RACT emission limitations, equipment requirements and work practices intended to control emission of volatile organic compounds (VOC) from new and existing stationary sources. The control measures specified in Regulation Number 7 are designed to reduce the ambient concentrations of ozone in ozone nonattainment areas and to maintain adequate air quality in other areas.

Specific Statutory Authority

The provisions of C.R.S. §§ 25-7-105 and 25-7-109 to 110 provide the specific statutory authority for the amendments to this regulation adopted by the Commission. The Commission has also adopted in compliance with C.R.S. § 24-4-103(4), this Statement of Basis, Specific Statutory Authority and Purpose.

Purpose

The purpose of this amendment to Regulation Number 7 is to establish a source specific rule for Gates to allow the use of emission reduction credits to satisfy the RACT requirements for VOC emissions pursuant to Regulation Number 7 for surface coatings operations not specifically listed in Section IX of Regulation Number 7. Regulation Number 3 provides specific authorization to use emission reduction credit transactions as an alternative compliance method to satisfy CTG and RACT requirements.

Specifically, the VOC certified emissions reduction credits to be used in this emission credit transaction in an amount up to 12 tons per year are from Coors Brewing Company pursuant to their emissions reduction credit Permit. The emission reduction credits will be used to satisfy the general requirements that all sources apply RACT. These emission reduction credits will be used by Gates so that Gates can use solvent-based surface coatings which contain VOCs periodically in lieu of the water-based coatings normally used on its 10 Cord coating line (S033, S034, and S035). These credits will allow Gates to meet RACT requirements without applying control technology to the 10 Cord line, other than the currently installed catalytic incinerator on the emissions from the drying oven from the fourth dip, which reduces those emissions by at least 90%.The relevant portion of Regulation Number 3, which applies to the Gates credit transaction is Section V.F., entitled “Criteria for Approval of all Transactions.” The first requirement is that the transaction involve like pollutants. In the present case, the emission credit transaction involves the exchange of VOC pollutants. Coors credits for methanol will be exchanged for m-pyrol. Exhaust from the catalytic incinerator, which contains unconverted toluene and xylene, is routed to the curing ovens of the other zones of the 10 Cord line, including the first zone. The Division has previously found that, excluding the emissions from the non-compliant coatings addressed in this rule, the 10 Cord line has met RACT standards. The use of the non-compliant coatings adds no HAPs to the Gates emissions. Other non-criteria reportable pollutants are present at well below APEN de minimis quantities under scenario 2, which is applicable to the 10 Cord line. Regulation Number 3 further requires that toxic or VOC pollutants involve the same degree of toxicity and photochemical reactivity or else a greater reduction may be required. Since these pollutants are both toxics and VOCs (except that m-pyrol is not a toxic), both have been addressed.

All of these compounds are commonly used in the surface coating industry with appropriate safeguards during their use. With respect to toxicity of the Gates compounds, m-pyrol is not listed as a toxic compound on either the federal or state lists. Methanol, the VOC in the Coors credit, is a Bin C HAP. Because the m-pyrol in the non-compliant coatings is not a HAP, the Gates VOCs have equal or lower toxicity than those being purchased from Coors. Therefore, HAP emissions will be reduced in the airshed.

The photochemical reactivities of VOCs are important because of their impact on the ozone formation process in an airshed. The Air Pollution Control Division relied upon the work of Dr. William P.L. Carter, Professor at the University of California, whose article entitled “Development of Ozone Reactivity Scales for Volatile Organic Compounds” describes relative photochemical reactivity scales and comparisons. Dr. Carter notes that there are a number of ways to quantify VOC reactivities, but the most relevant measure of VOC effects on ozone is the actual change in ozone formation in an airshed. This results from changing the emissions of the VOC in that airshed which depends not only on how rapidly the VOC reacts and the nature of its atmospheric reaction mechanism, but also the nature of the airshed where it is emitted, including the effects of other pollutants which are present.

Dr. Carter further states that the VOC effect on ozone in the atmosphere can only be estimated using computer airshed models. The effect of changing the emissions of a given VOC on ozone formation in a particular episode will, in general, depend on the magnitude of the emissions change and on whether the VOC is being added to, subtracted from, or replacing a portion of the base case emissions.

Dr. Carter's derived relative reactivity scale includes reactive organic gases whose indices for maximum incremental reactivity (MIR) range from 0.004 to 6.5. The MIR values were updated in 1997. The VOCs and their respective MIR involved with this exchange are as follows:

Methanol	0.16
m-Pyrol	0.57

The pending emission credits of VOCs being used in the proposed emissions credit transaction are for methanol. The VOCs emitted from uncontrolled use of solvent-based coatings at Gates are from m-pyrol. Regulation Number 3 provides that if the VOCs are not of the same photochemical reactivity, a greater offset may be required. The Commission required that, based on a past ERC trade for Pioneer Metal Finishing, that methanol credits in a 1.1:1 offset ratio be exchanged for toluene and xylenes. Here, however, the Commission finds that m-pyrol and methanol have similar photochemical reactivities, so no offset will be required.

The second requirement states that the transaction must not result in an increased concentration, at the point of maximum impact of hazardous air pollutants. This provision was derived from the EPA Emissions Trading Policy Statement and referred to NESHAP requirements involved in bubble transactions. If this provision is interpreted to apply generally to a facility which is limited by an existing permit to some level of VOC emissions on a twenty-four hour basis, any additional VOCs allowed pursuant to an emission transaction would by its application increase the concentration of VOCs at the maximum point of impact. Since it appears to have been intended to limit NESHAP offsets in bubble transactions, and no NESHAPs are applicable in the Gates transaction, and recognizing the earlier action of the Commission in approving the use of ERC transactions to satisfy CTG requirements and in approving a previous ERC transaction for Pioneer Metal Finishing, the Commission determined that this requirement should not apply to this transaction.

The next requirement states that no transaction may be approved which is inconsistent with any standard established by the Federal Act, the state Air Quality Control Act or the regulations promulgated under either, or to circumvent NSPS requirements or BACT or LAER, although the Commission may approve a transaction using a certified emission reduction credit in lieu of a specified CTG method or RACT. The emissions involved in this transaction at Gates are not subject to NSPS, BACT, or LAER. Regulation Number 7 applies only RACT to the Gates operations involved. Regulation Number 3 clearly permits the use of emission reduction credits to satisfy RACT.

The emission must involve sources which are located within the same nonattainment area. In the present case, both Gates, whose operations are located at 900 S. Broadway, Denver, Colorado, who is proposing to use the credits, and the source of the credits, Verticel, whose operations were located at 4607 South Windermere Street, Englewood, Colorado, are located in the Denver nonattainment area, less than five miles apart.

The next requirement prohibits the use of emission reduction credits to meet applicable technology-based requirements for new sources, such as NSPS, BACT, or LAER. As stated, the Gates operations involved in this transaction are not subject to NSPS, BACT, or LAER or any other technology-based requirement except for RACT requirements for which an ERC transaction may be used to satisfy such requirements.

The next requirement states that VOC trades will be considered equal in ambient effect where the trade is a pound for pound trade in the same control strategy demonstration area. It appears that this requirement, which was taken from the EPA Emissions Trading Policy Statement, made the assumption that the “pound for pound” trend would have an equal impact on the ambient environment, with respect to ozone. Since there was no independent photochemical reactivity equivalency requirement in the 1986 Policy Statement, this requirement appears to be redundant with the requirement for insuring the same degree of photochemical reactivity among traded pollutants.

For VOC trades involving surface coating, the requirements state that emissions must be calculated on a solids-applied basis and must specify the maximum time period over which the emissions may be averaged, not to exceed 24 hours. The proposed emissions credit transaction is based on a 24-hour period. With respect to the solids-applied basis calculation, this transaction will be calculated on the basis of the pounds of VOCs from uncontrolled solvent-based coatings.

The emissions credit transaction will require a SIP revision. The source specific rule for Gates will be forwarded to EPA for approval. The state emission permit for Gates pursuant to the emissions credit transaction will be state effective (but not federally effective) until the SIP revision is approved by EPA.

Gates proposed the following VOC emissions limitation in its state permit taking into consideration the pounds per year VOC emissions allowed by this emissions credit transaction:

1. A daily maximum limitation of 400 lbs. of VOC emissions from uncontrolled solvent-based surface coatings, calculated on a monthly basis for compliance purposes. Calculations will be performed by the 30th of the following month.

2. An annual limitation of no more than 24,000 lbs. (12 tons) of VOC emissions from uncontrolled solvent-based surface coatings.

Gates proposes to calculate the annual total VOC limitation on a rolling 12-month basis. Gates further proposes to keep monthly totals of non-compliant surface coatings used and to calculate daily usage based on monthly usage divided by the number of days non-compliant surface coatings were used. Records of usages and calculations will be kept and produced at the Division's request.

This source-specific rule has a negligible or no effect upon the other provisions of the ozone SIP.

It is contemplated that a State construction permit will be issued to Gates upon final approval by the Commission. Should the approval come after the issuance of Gates' Title V operating permit, the terms of the construction permit will be added to the operating permit.

E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

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.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

   "Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 PSIA at actual conditions are exempt from the provisions of Section III.B."

2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.

3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

F. November 20, 2003 (Sections I.A.2. through I.A.4., II.D. and II.E.)

The Commission repealed the provisions establishing a procedure for granting exemptions for de minimis sources, and the procedure for approving alternative compliance plans without source-specific SIP revisions. The Commission had adopted the repealed provisions in March 1996, but had delayed the effective date pending EPA approval through the SIP revision process. Earlier this year, EPA informed the Commission of its intent to disapprove the provisions unless they were withdrawn. Thus, the provisions that are the subject of this rulemaking action never took effect. The Commission hereby repeals such provisions in order to avoid disapproval of the earlier SIP submittal, and to remove extraneous provisions from Regulation Number 7. Such repeal is required in order to comply with federal requirements, and is not otherwise more stringent than the requirements of the federal act.

Sections 25-7-105(1)(a)(I) and 25-7-301 authorize the Commission to adopt and revise a comprehensive SIP, and to regulate emissions from stationary sources, as necessary to maintain the national ambient air quality standard for ozone in accordance with the federal act.

G. (March 2004, Sections I.A, I.B., XII., and XVI.

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the "Denver Metro Attainment Maintenance Area", which is not a defined term, in Section I.A was changed to refer to the "Denver 1-hour ozone attainment/maintenance area", which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the "Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan" was changed to the "Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area," which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both "lean" and "rich" burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost $5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than $5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to “affected facilities” and “process units” at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

H. (December 2004, SECTIONS I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for emission reduction credit a pollution prevention measures must, among other things, be included in a permit even if it does not involve the construction of an air pollution source and would not otherwise trigger a requirement for a permit. The revisions to the regulation do not, however, create a requirement for sources to obtain a permit for pollution prevention measures for which the source will not take emissions reduction credit.

The Commission has the statutory authority to adopt the revisions pursuant to Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The control measures necessary to achieve the 8-hour ozone standard were adopted in March 2004. The December 2004 rule changes do not impose new emission control requirements or emission reduction requirements on industry. Instead, the December 2004 rule revisions are intended to make the previously adopted requirements more enforceable, and to make sure that the requisite emission reductions occur during the ozone season when they are needed. Thus, the December 2004 are administrative in nature in that they are intended to assist with the administration and enforcement of the previously adopted controls. The Commission recognizes that the December 2004 rule amendments impose additional recordkeeping and reporting requirements, and therefore costs, on the regulated community. The changes, however, are not intended to achieve further reduction in emissions of volatile organic compounds beyond the reduction requirements adopted in March 2004. They are instead intended to make the March 2004 revisions fully enforceable and acceptable to EPA. Since the December 2004 rule changes are administrative in nature, the requirements of Section 25-7-110.8 C.R.S. do not apply.

I. December 17, 2006 (Section XII.)

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

Regulation Number 7, Section XII imposes emission control requirements on oil and gas condensate tanks located in Adams, Arapahoe, Boulder, Douglas and Jefferson Counties, the Cities and Counties of Broomfield and Denver and parts of Larimer and Weld Counties (“8-Hour Ozone Control Area”). The condensate tank requirements, along with other requirements applicable to oil and gas operations and natural gas fired reciprocating internal combustion engines, were initially promulgated in March 2004, and later revised in December 2004, in connection with an Early Action Compact Ozone Action Plan (“EAC”) entered into between the State of Colorado and the United States Environmental Protection Agency. The purpose of the EAC is to prevent exceedances of the 8-Hour Ozone Standard and avoid a nonattainment designation for the area. Pursuant to the EAC, Colorado committed to limiting Volatile Organic Compound (“VOC”) emissions from condensate tanks located in the 8-Hour Ozone Control Area to 91.3 tons per day (“TPD”) as of May 1, 2007 and 100.9 TPD as of May 1, 2012. Because of unanticipated growth of condensate tank emissions since 2004, the control requirements for condensate tanks adopted during the 2004 rulemaking are insufficient to meet these daily emission numbers. The current revisions require a greater level of control of condensate tank emissions in the 8-Hour Ozone Control Area in order to meet the commitments set forth in the EAC and to prevent future exceedances of the 8-Hour Ozone Standard. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Section, 25-7-105(1)(a), C.R.S., which gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of a comprehensive state implementation plan that will assure attainment of national ambient air quality standards. Additional authority for these revisions is set forth in Sections, 25-7-106 and 25-7-109, which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to specified areas within the state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XII. were adopted in order to meet the commitments with respect to condensate tank emissions set forth in the Early Action Compact Ozone Action Plan entered into between the State of Colorado and U.S. EPA, prevent exceedances of the 8-Hour Ozone Standard, and simplify recordkeeping and reporting requirements.

To accomplish these goals the revised regulation raises the system-wide control requirements for the ozone season from the current 47.5% to 75% commencing in 2007 and 78% in 2012. While the rule establishes a higher percentage reduction in 2012 the Commission recognizes that given the uncertainty of emissions growth over the next 6 years, this reduction requirement may be too high and may need to be revisited as the 2012 deadline approaches. For the non-ozone season the required reduction has been raised from 38% to 60% commencing October 2007, and 70% commencing January 1, 2008. Determination of compliance during the ozone season under the revisions will be on a weekly basis instead of a daily basis, in recognition of the fact that condensate production is not typically measured on a daily basis. Under the previous version of the Rule, production could be tracked on something greater than a daily basis and the total divided by the number of days to obtain a daily number. As such, the prior rule did not truly give a daily average and thus the move to a weekly average is of little substance. Apart from this change, calculation of emissions for compliance purposes will remain the same as under the previous version of the rule.

In addition to raising the system-wide reduction requirements, the current rule adds significant new monitoring, record-keeping and reporting requirements, and a “backstop” threshold requirement to have emission controls on all condensate storage tanks with uncontrolled actual emissions of 20 tpy or more of VOC flash emission, as a state-only requirement within the EAC area pursuant to Section XVII.C.1. of Regulation Number 7. Owners and operators will continue to keep a spreadsheet that tracks emission reductions and submit an Annual Report as required under the previous version of the rule. Owners and operators are now also required to submit a semi-annual report on November 30 of each year detailing their emissions during the preceding ozone season. Additional record keeping has been added so as to require that a weekly checklist be maintained detailing inspections of control devices. This checklist will assist operators in the inspection and maintenance practice and provide a record that proper inspections have been done. If the inspections show a problem with the control device, the owner or operator will be required to notify the Division of problems on a monthly basis. This requirement will allow the Division to track problems on a more timely basis and ensure compliance with the rule. Finally, a provision has been added to require owners or operators to submit a list of all their controlled tanks on April 30 of each year and notify the Division monthly during ozone season if the control status of any tank changes.

J. December 17, 2006 (Sections I.A.1.b. and XVII.)

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 these state-only provisions as a means of reducing air emissions from oil and gas operations throughout Colorado. Due to the large growth in oil and gas production in a number of regions of the state emissions from oil and gas operations have rapidly increased over the past few years and are expected to increase further in the foreseeable future. These revisions are a proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards and adversely affect visibility in Class I Areas. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-106 and 25-7-109 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Additional authority is set forth in Section 25-7-105.1, which allows the Commission to adopt state-only standards. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to the entire state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XVII. were adopted in order to reduce air emissions from oil and gas operations and natural gas fired reciprocating internal combustion engines in Colorado. These revisions constitute a forward-looking approach to deal with a rapidly growing source of air emissions, and are designed to reduce the possibility of future problems with respect to the attainment of National Ambient Air Quality Standards and state and federal Class I Area visibility goals. Since the requirements are not mandated under federal law and are not currently necessary to meet National Ambient Air Quality Standards they are being adopted as a state-only requirement in accordance with the Act and as provided for under the Federal Clean Air Act.

These revisions establish emission control requirements for condensate storage tanks, glycol dehydrators and natural gas fired reciprocating internal combustion engines in Colorado. These provisions require that condensate tank and dehydrator controls meet a 95% percent control efficiency. As in the EAC Area, this requirement does not contemplate stack testing in order to verify the control efficiency. The insertion of the word average allows operators some downtime without a violation occurring so long as the downtime does not result in an average control efficiency of less than 95% considering the actual engineered control efficiency. For the purposes of XVII.C.4.b. observed operation of flare auto-igniters can include telemetric monitoring systems, physical on-site function tests or auditory confirmation of the auto-igniter function.

The requirements applicable to glycol dehydrators mirror the requirements applicable in the 8-Hour Ozone Control Area set forth in Section XII, and should be interpreted consistently with those provisions notwithstanding the addition of clarifying language. For example, language has been added clarifying that grouping of dehydrators is limited to dehydrators at a single site. Similarly, the word "production" has been added to the definition of condensate tank to clarify that the requirements, as within the EAC, do not apply to produced water tanks.

Determination of whether a condensate tank's emissions are at or above the threshold is based on the emissions from the tank during the preceding twelve-month period. If a tank has been in service for less than twelve months, applicability shall be based on uncontrolled actual emissions over the service period of the tank multiplied out to twelve months. Accordingly, if a tank has been in service for three months, applicability of the control requirements will be based on the uncontrolled actual emissions from the tank for those three months multiplied by four. If emissions from a controlled tank decrease, operators may remove the controls when emissions from the previous twelve-month period falls below the applicable threshold. Operators will remain responsible, however, for controlling a tank if a subsequent emission increase results in emissions being over the applicable threshold during the preceding twelve months. For tanks serving newly drilled, recompleted or restimulated wells (including refrac'd wells) the owner or operator will have 90 days to determine anticipated production and, if necessary install a control device. In determining anticipated production the owner or operator may use an appropriate decline factor to determine expected emissions over the first 12 months after the new drilling, recompletion or re-stimulation. If the owner or operator determines that emissions will be below the 20 tpy threshold following the new drilling, recompletion or restimulation, the owner or operator shall notify the Division of this determination.

Certain differences with the requirements applicable to the 8-Hour Ozone Control Area have been included in order to provide greater flexibility to operators in other areas of the state and in light of the fact that the regulation represents a proactive attempt to avoid future impacts from oil and gas emissions. Specifically, the standards for obtaining approval of an alternative pollution control device have been relaxed to promote innovative control strategies. Additionally, a provision has been added to allow an extension of the control requirement deadlines at the Division's discretion for good cause shown. This provision allows the Division to extend a deadline where shortages of control equipment, and crews may prevent an operator from meeting the deadlines, particularly in areas where access is limited by the weather or other issues. With respect to Section VII.B.1.c. of the General Provisions, the Commission has determined that as a general rule during normal operations no emissions should be visible from the air pollution control equipment. Normal operations include reasonably foreseeable fluctuations in emissions from the condensate tank, including the fluctuations that occur during a separator dump. However, a transient (lasting less than 10 seconds) "puff" of smoke when the main burner ignites or shuts down would not be considered a violation of the "no visible emission" standard. Finally, a provision has been included that exempts units subject to the rule if such units are also subject to a control standard under the MACT, BACT or NSPS Programs. This exception is of most importance for new and newly relocated engines that may become subject to a currently pending NSPS Standard under Subpart JJJJ.

The engine provisions only apply to engines that are constructed or relocated into Colorado after the applicability date and do not impose requirements on units that are currently located in the state.

The Commission recognizes that the adopted emission control requirements represent a first step in addressing rapidly growing emissions from oil and gas operations throughout the state. Accordingly the Commission directs the Division to provide an annual update on emission growth trends, environmental impacts, modeling and monitoring efforts, the adequacy of emission controls to protect the NAAQS and the health impacts of emissions from the oil and gas sector.

K. December 12, 2008 (Title, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F)

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 throughout Regulation Number 7 to address ozone formation in the 8-Hour Ozone Nonattainment Area (NAA), including the 9-county Denver Metropolitan Area and North Front Range (DMA/NFR) NAA. 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 with the current 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) set at 0.08 parts per million (ppm), and to achieve additional ozone reductions in light of both the new ozone NAAQS set at 0.075 ppm and the Governor's July 27, 2007 directive to proactively and pragmatically reduce ozone levels.

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the area in question expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-hour Ozone NAAQS of 0.08 ppm for ground level ozone. The DMA/NFR includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties. This area is now known as the DMA/NFR NAA.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a revision to the State Implementation Plan (SIP) to the EPA no later than June 30, 2009 that demonstrates attainment of the 8-Hour Ozone NAAQS no later than 2010. The Commission has adopted an Attainment Plan that satisfies this requirement. The Attainment Plan demonstrates attainment with no additional control measures.

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. Photochemical dispersion modeling analysis is the primary tool used to assess present and future air quality trends, and is required for EPA to approve the state attainment demonstration in the SIP.

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 evidence" analysis and other supplemental analyses 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.

The Commission is also adopting State-only revisions to Regulation Number 7 to further address ozone formation in the DMA/NFR NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. 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.

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(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 7 are part of an overall ozone reduction strategy. The Commission intends that this overall ozone reduction strategy accomplishes six objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the Ozone NAA and across the state, B) revise the control requirements for condensate tanks by a refined system-wide control strategy in the Ozone NAA, C) expand VOC RACT requirements for listed source categories for 100 tpy sources such that all Ozone NAAs are subject to Regulation Number 7's RACT requirements, D) clarify how the RACT requirements in Regulation Numbers 3 and 7 interact in the Ozone NAA, E) improve the Division's inventory of condensate emissions and other relevant sources in the NAA; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

In support of objectives A-D and F, the Commission adopts these revisions to Regulation Number 7 to revise condensate tank regulations, set pneumatic controller regulations, expand RACT applicability and make associated corrections (Regulation Number 7, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F).

In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein. The Commission is requiring an increase from 75% to 81% control on a system-wide basis in 2009; to 85% control on a system-wide basis in 2010; and to 90% control on a system-wide basis in 2011 in the 8-Hour Ozone NAA. The Commission is adopting new VOC controls for pneumatic controllers in the 8-Hour Ozone NAA in Regulation Number 7, Section XVIII.

These system-wide control percentages achieve significant ozone precursor reductions in 2009, 2010 and 2011, with emphasis on significant VOC emissions reductions in 2010, during the monitoring period for the attainment demonstration. These revisions will help to ensure that the non-attainment area realizes the necessary reductions during the 2010 attainment year. Further, these revisions are an important step in putting the State on a path towards attaining the 2008 8-Hour ozone standard. A number of parties including the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization supported this proposal to secure VOC reductions from this source at these levels and according to this schedule. The system-wide approach has been approved by the Commission in the past, as well as by EPA in revisions to the State Implementation Plan. The Commission decided to defer decision making on the implementation of a 95% system-wide level of control, given concerns regarding the notable incremental cost associated with control to the equivalent of 2 tpy tanks as well as concerns regarding the flexibility intended to be afforded by a system-wide approach. Tank operators also expressed concern about the loss of incentive to over-control their systems to meet the standard, and the difficulty for small operators to control at the 95% system-wide level at this time. The proposed control percentages continue to afford flexibility in operations to condensate tank operators, while ensuring attainment of the standard by 2010. Therefore, the Commission is deferring further control for future modeling, air quality analysis, and/or administrative review, whether to control this source in the future at the 95% system-wide control level or through some other approach for purposes of the 2008 8-Hour standard.

The provisions of the compromise proposal, including the commensurate emissions reductions, support the State Implementation Plan's ability to assure attainment and maintenance of the 1997 8-Hour Ozone NAAQS. Inclusion of these provisions enhances the Weight of Evidence demonstration supporting attainment by 2010 pursuant to this State Implementation Plan. The Commission recognizes parties subject to the compromise Regulation Number 7 provisions for condensate tank system-wide emissions reductions concur that these provisions are appropriate for inclusion in the State Implementation Plan.

Further the Commission intends to expand the applicability of RACT requirements to existing, new and modified sources in Ozone NAAs outside of the historic one-hour Ozone NAA or attainment/maintenance area (Regulation Number 7, Sections I and II). The Commission further intends to clarify how the control technology requirements of Regulation Number 7 interact with Regulation 3, Part B, Section II.D.2.

Finally, the Commission intends to make grammatical, typographical, formatting revisions, and other editing revisions throughout Regulation Number 7.

Condensate Tank Emissions Control

Condensate storage tank control requirements in Regulation Number 7, Section XII. are revised by reorganizing the rule, adding/revising definitions, adding monitoring requirements, revising recordkeeping and reporting requirements, and setting additional control requirements for tanks. The current requirements are reorganized by specifying applicability, definitions, general provisions, emissions controls, monitoring, and recordkeeping and reporting sections. The terms new, existing, modified/modification, auto-igniter, and surveillance system were defined.

Tanks serving newly drilled, recompleted or stimulated wells are required to employ air pollution control equipment during the first 90 days of production. After the first 90 calendar days, the control device may be removed. This requirement is designed to address the fact that production, and thus emissions, is at their greatest during the period immediately after drilling, recompletion or stimulation, and the fact that the actual production/emission level is not known prior to drilling, recompletion or stimulation. By requiring controls on all tanks serving newly drilled, recompleted or stimulated wells, the proposed rule significantly reduces emissions during the initial period, while allowing owners and operators to remove control devices afterward, as part of the overall system-wide control regime. All tanks over 2 tpy must participate in the overall system-wide program. Furthermore, since Regulation Number 7's system-wide program is essentially RACT for condensate tanks in the NAA, new and modified 2 tpy or greater condensate tanks (affected by Regulation Number 3 RACT) may also move their control devices after the first 90 days when participating in the overall system-wide control regime, as long as the overall system-wide requirements are being met. Such flexibility is provided as to avoid two regulatory programs: one for tanks that might never be allowed to move their control devices under Regulation Number 3 RACT and one for tanks that would be allowed the flexibility under a system-wide program. Finally, it is the intent of this rule that sources may use their 2 tpy or greater "modified" tanks emissions (i.e., during those tanks' first 90 days of production) in the source's overall system wide calculation. After 90 days, sources must include – whether controlled or otherwise - the 2 tpy or greater "modified" tanks in the overall system-wide calculation. In the case of modified tanks that fall below 2 tpy, it is not the intent of the commission for sources to include these less than 2 tpy tanks in any system-wide calculation. However, sources may use the less than 2 tpy controlled tanks, if necessary to demonstrate system-wide compliance.

The Commission is requiring the installation and operation of auto-igniters for each combustion device. In many cases, condensate tanks are remotely located and unmanned. Auto-igniters will provide greater assurance that the control devices are functioning, under these circumstances. Auto-igniters may be relied on to identify when the pilot is not lit and attempt to relight it, and ensure control operation. The Commission is also requiring surveillance on batteries with uncontrolled emissions greater than 100 tpy. Operators must use surveillance to document the duration of time when the pilot is not lit, and to discover if repairs are necessary to ensure proper control operation. The Commission is targeting this size of battery in order to strike a balance between the need to more carefully monitor performance among the largest batteries, the cost associated with surveillance and the division's capacity to manage the information. The Commission acknowledges that three well operators, Encana, Anadarko and Noble Energy, have agreed to participate with the Division in a pilot program regarding the implementation of electronic surveillance systems.

With regard to recordkeeping and reporting requirements, operators will still record estimated emissions each week (as part of the current Regulation Number 7 requirements) and will report this information to the Division semi-annually. In addition, the Division has revised these requirements so that sources now must keep monthly records throughout the year and provide any of those records within 5 business days of a division request. Further, operators may only use a Division-approved spreadsheet to submit emissions records. Further, a responsible official must now certify the accuracy of the data in the semi-annual reports. This level of recordkeeping and reporting will allow the Division greater capacity to verify compliance and additional availability to work with sources (especially smaller operators). The Commission intends that record-keeping and reporting requirements for surveillance apply only to tanks with uncontrolled emissions greater than 100 tpy.

Controls on 2 Tons Per Year Tanks and Lower

The Commission intends that substantial emissions reductions be achieved from condensate storage tanks and that industry retain the flexibility to decide which tanks to control in order to achieve those reductions. The rule has been revised to subject any condensate storage tank to this rule in the Applicability Section, but stipulates in the Emission Control Section that in order to determine the appropriate system-wide emissions reductions, only two ton per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th. So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions “may be treated by the Division as if the data were not collected.”

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

<u>Pneumatics Emissions Control</u>

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs). VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0 and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

<u>RICE Controls</u>

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI. applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements’ applicability to a state-wide basis.

Expand and Clarify RACT Requirements

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7’s applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado’s SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

(I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.

(II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.

(III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.

(IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require more costly retrofitting in order to meet the Governor's directive as well as the new NAAQS.

(V) Since there are no applicable federal requirements, there is no timing issue with regard to implementing federal requirements. However, these controls are intended to help the DMA/NFR attain the NAAQS. If the standard is not attained by the 2010 ozone season, the area may face a "moderate" non-attainment designation.

(VI) The adopted rules will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.

(VII) The adopted rules establish reasonable equity for sources subject to the rules by providing the same standards for similarly situated sources.

(VIII) If the state rules were not adopted, other sectors may face a disproportionate share of the burden of reducing precursor pollutants.

(IX) There are no corresponding federal requirements.

(X) Demonstrated technology is available to comply. Sources are already using the control devices intended to be used to comply with these rules. However, sources face an additional burden of implementing auto-igniters and surveillance. The Commission anticipates a reasonable degree of delay in securing and installing the technology in question and has accommodated the sources by providing for a reasonable delay for the application of these requirements.

(XI) The adopted rules will reduce VOC and NOx emissions, thereby contributing to the prevention of the formation of ozone through the most cost-effective means available.

(XII) Alternative rules requiring additional controls for other sources would also provide gains toward attaining the ozone NAAQS. However, oil and gas industry members are the largest anthropogenic stationary source of precursor pollutants in the State. A disproportionate benefit to this industry would accrue if their uncontrolled emissions remain at current levels compared to other stationary sources.

(XIII) A no-action alternative may address the ozone NAAQS. Modeling and other analysis suggests that the NAA would attain the standard by 2010 without these rules. However, this analysis suggests that ambient levels of ozone would be very close to the NAAQS. These rules provide more assurance of attaining the ozone NAAQS while also providing for reductions that are necessary to make progress toward the new ozone NAAQS. No action would only delay the necessary reductions.

Further, pursuant to C.R.S. § 25-7-110.8(1), the Commission 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 ground-level ozone.

(III) Evidence in this 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, provide the regulated community flexibility, and achieve 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.

L. January 7, 2011 (Outline and Sections I. and XVII.)

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 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); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

The Commission intends that the current Regulation Number 7, Section XVII.E.3.a. identifying technology-based control requirements for existing rich burn reciprocating internal combustion engines (RICE), or rich burn RICE that were constructed or modified prior to February 1, 2009, become a NOx emission control measure that is included as part of the Regional Haze SIP and become federally enforceable upon EPA approval.

The technology-based control requirements of Section XVII.E.3.a. reduce NOx. This proposal only changes the enforceability of these currently state-only requirements such that they become federally enforceable. This proposal does not change emission control, monitoring, recordkeeping or reporting requirements.

The Commission also intends that the following provisions, added in Sections XVII.E.3.a.(i)(a) through (c), will continue to be effective under the Regional Haze SIP. Specifically, these provisions require good air pollution control practices and allow for exemptions from the requirements for existing rich burn RICE. The exemptions apply to any existing rich burn RICE either with uncontrolled actual emissions below permitting thresholds or that is subject to a New Source Performance Standard (NSPS), National Emission Standard for Hazardous Air Pollutants (NESHAP), or Best Available Control Technology (BACT) limit.

Existing lean burn RICE requirements are not incorporated into the Regional Haze SIP, as the associated controls do not reduce NOx or SO2.

Colorado has determined that it is reasonable and appropriate to make these RICE requirements federally enforceable in this first planning period, as part of the state's strategy for addressing reasonable progress towards achieving natural visibility conditions in federal Class I areas.

M. December 20, 2012 (Sections II., XII., and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), Colorado Revised Statutes (C.R.S.) for new and revised regulations.

Basis

Regulation Number 7 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 (SIP) 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) and authorization of the development of a program for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) in C.R.S. Section 25-7-301, as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were made to address the U.S. Environmental Protection Agency's ("EPA") partial disapproval of Colorado's ozone SIP. On August 5, 2011, EPA published the "Approval and Promulgation of State Implementation Plans; State of Colorado; Attainment Demonstration for the 1997 8-Hour Ozone Standard, and Approval of Related Revisions" (76 Fed. Reg. 47443, August 5, 2011). EPA partially approved and partially disapproved revisions to Colorado's SIP adopted by the Air Quality Control Commission (Commission) in December 2008 and submitted to the EPA in June 2009.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act, C.R.S. Section 25-7-101, et seq., specifically, C.R.S. Section 25-7-105(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 Section 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

The Commission revised Regulation Number 7 to address the EPA's partial disapproval of Colorado's Ozone State Implementation Plan ("SIP'). On August 5, 2011, the EPA issued a final action on Colorado's June 2009, Ozone SIP submittal, both approving Colorado's attainment demonstration for the 1997 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) and disapproving specific revisions to Regulation Number 7. 76 Fed. Reg. 47443, August 5, 2011. Specifically, the EPA disapproved both the repeal of Regulation Number 7, Section II.D. and all revisions to Section XII. as adopted by the Commission in December 2008. As a basis for its action, the EPA stated that Colorado demonstrated attainment with the 1997 8-Hour Ozone NAAQS, however Colorado did not adequately provide an anti-backsliding demonstration for the revisions to Regulation Number 7 that were adopted by the AQCC in December 2008, and submitted to the EPA in June 2009.

The Commission intends that these 2012 revisions include both SIP and state-only revisions that address EPA's partial disapproval of SIP provisions in Sections II.D and XII., and make related state-only revisions to Section XVII. for consistency.

The Commission does not intend that these 2012 revisions add or strengthen emissions control measures of Section II.D., XII. or XVII. at this time. All SIP revisions are intended to specifically address those provisions that EPA included as part of its basis for disapproving revisions to Regulation Number 7.

While the EPA indicated general approval of the concept of the June 2009 SIP submittal, the EPA took exception to some of the details in the SIP revisions, characterized as “deficiencies,” that formed the basis of EPA’s disapproval during the SIP review process. EPA’s objections to the 2009 SIP revisions and the Commission’s responses are summarized as follows:

1. Section II.D. – Alternative Control Plans and Test Methods

   EPA Objection: The EPA objected to the deletion of SIP approved language, allowing for alternative control plans and testing methods.

   Commission Response: The Commission reinstated the SIP approved language.

2. Section XII.C.2. – Emission Factor Calculation Methodology for Condensate Tanks

   EPA Objection: The EPA objected to the deletion of the term “gas-condensate-glycol separators” from the emission factor requirements for atmospheric condensate tanks.

   Commission Response: The Commission made no revision to the rule text, and instead explained to EPA that this term was used in error as such a separator does not exist. The term used here is a misnomer, which the Commission believes refers to a flash tank located on a glycol dehydration unit, covered by Section XII.H. It is inappropriate to apply emission factor calculation methodology for atmospheric condensate tanks to glycol dehydrators because their emissions vary greatly.

3. Section XII.D.2.a. – System-wide Control Requirements for Condensate Tanks

   EPA Objection: The EPA objected to the sunset of the system-wide control requirement in Section XII.D.2.a.(x), which ended the control requirement as of April 30, 2013.

   Commission Response: The Commission revised the system-wide control requirements so that the system-wide control requirements do not sunset. Neither the Commission nor the parties to the December 2008 rulemaking intended for the system-wide control to end. The sunset was unintentionally caused when making other revisions to the rule text.

4. Section XII.E.3. – Monitoring Combustion Devices as Control for Condensate Tanks

   EPA Objection: The EPA objected to providing a state-only monitoring option (electronic surveillance) as a substitution for the SIP required monitoring of combustion devices being used to control emissions from condensate tanks in accordance with Section XII.

   Commission Response: The Commission removed the option of conducting state-only electronic monitoring in lieu of the SIP approved monitoring requirement. This allowance to substitute a SIP required monitoring provision for a state-only monitoring provision was unintentional. None of the sources employing electronic surveillance may use it in place of the SIP approved requirement. If conducted, the electronic surveillance monitoring option must occur in addition to the SIP approved monitoring requirement.

5. Section XII.F.3. – Recordkeeping for Condensate Tanks

EPA Objection: The EPA objected to the lack of SIP required recordkeeping for the control requirement in Section XII.D.1., which requires all condensate tanks at exploration and production sites to be controlled during the first 90 days of well production.

Commission Response: The Commission revised Section XII.D.1. to specify it is state-only. The Commission and parties to the December 2008 rulemaking intended for this first 90 day control requirement to be state-only, which corresponds to the state-only designation on the recordkeeping requirements under Section XII.F.3. Therefore, the Commission made no revision to Section XII.F.3., and instead revised Section XII.D.1. to alleviate this discrepancy.

6. Section XII.F.5. – Recordkeeping and Reporting Exemption for Compressor Stations and Drip Stations

EPA Objection: The EPA objected to the removal of a SIP approved provision that exempted natural gas compressors or drip stations from recordkeeping and reporting requirements, where total emissions from such facilities are less than 30 tons per year.

Commission Response: The Commission reinstated the SIP approved 30 ton per year provision.

7. Section XII.G.2. – Control Equipment Requirement for Natural Gas Processing Plants

EPA Objection: The EPA objected to two aspects of the revisions to this section. The first objection was replacement of the term “APEN de minimus levels” with “greater than or equal to two tons per year.” The second objection was inclusion of a rolling 12-month averaging period for the 95% control requirement.

Commission Response: The Commission made no revision to the replacement of the term “APEN de minimus levels.” The Commission explained to the EPA that the associated modeling relied on evaluating condensate tanks with emissions greater than or equal to two tons of volatile organic compounds per year. Therefore, the change in reference does not constitute a lessening of the stringency of the rule. In addition, the Commission removed the rolling 12-month averaging period.

8. Section XII.G.5. Recordkeeping and Reporting for Alternative Compliance Option

EPA Objection: The EPA objected to the reliance on Title V or construction permits as the location for recordkeeping and reporting requirements for condensate tanks at natural gas compressor or drip stations.

Commission Response: The Commission revised this section to specify recordkeeping and reporting requirements for condensate tanks at natural gas compressor and drip stations.

9. Section XII.H. Control Requirements for Glycol Dehydrators

EPA Objection: The EPA stated this entire section lacked clarity and contained redundant language.

Commission Response: The Commission revised the section in its entirety, while maintaining the intent and applicability of the requirements. Along with this revision, the Commission specified that this control requirement is applicable only to glycol dehydrators with emissions equal to or greater than one ton per year, but that all glycol dehydrators at a stationary source must be included for comparison to the 15 ton per year threshold. The term stationary source is defined in the Common Provisions. Further, the Commission revised the provision to include emission calculation methodology requirements in Section XII. H.

Items 1-9 are all SIP revisions.

In addition, the Commission is also revising the state-only Section XVII.D. for consistency with the 2012 SIP revisions. The Commission does not intend that this state-only revision change the applicability of the control requirements for glycol natural gas dehydrators.

Finally, the Commission made typographical, grammatical, and formatting revisions, as necessary.

N. February 23, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), 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.

<u>Basis</u>

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 CFR Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result and further addresses the volatile organic compound ("VOC"), an ozone precursor, and other hydrocarbon emissions, such as methane, from the oil and gas sector.

The Commission supports the EPA's development of NSPS OOOO and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. First, the Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"); it is likely that EPA will lower the ozone NAAQS in the near future, potentially expanding Colorado's nonattainment area; and Division air monitors and other sampling indicate elevated levels of oil and gas related air emissions in oil and gas development areas. Second, Colorado has seen substantial growth of oil and gas development in recent years, which is a significant source of VOC emissions, and expects that growth to continue in the foreseeable future. In particular, oil and gas storage tanks contribute significantly to the VOC emissions from oil and gas development. Further, oil and gas operations also emit methane, a negligibly reactive ozone precursor and potent greenhouse gas. Third, oil and gas operators have had difficulty meeting the current 95% control requirements in Regulation Number 7 established for condensate tanks in 2004 and 2006 due to "flash" emissions. Fourth, improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs and methane in a cost-effective manner. These technologies and practices include, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras).

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both SIP and state-only requirements. During the rulemaking process, various parties provided extensive evidence concerning whether the proposed revisions, in particular the STEM and LDAR requirements, should apply either statewide or only in the ozone nonattainment area. Based upon careful consideration of all the evidence provided during the rulemaking, the Commission determined it was appropriate to apply the proposed requirements statewide. Further, in addition to the extensive evidence concerning the benefits of statewide hydrocarbon emission reductions, the Commission believes that the tiered and phased nature of many of the requirements properly focuses on emissions. Under this tiered approach, lower emitting sources such as marginal, stripper, and coal bed methane wells will appropriately be subject to less rigorous and costly requirements. In addition, evidence in the rulemaking record and testimony of industry members supports the conclusion that the rules can be effectively implemented. Accordingly, the Commission concludes that the proposed rules are technologically feasible and cost-effective. Moreover, because these revisions apply on a state-wide, state-only basis, and are not a part of Colorado's SIP, the Commission, the Division, and stakeholders have the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("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. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and natural gas compressor stations. The Commission expands existing oil and gas control requirements and establishes additional monitoring, recordkeeping, and reporting requirements. For example, the revisions increase control requirements and improve capture efficiency requirements for oil and gas storage tanks. The Commission also seeks to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells and wells undergoing maintenance and during liquids unloading events. The Commission also expands control requirements for pneumatic devices and glycol natural gas dehydrators. The Commission believes that this combination of revisions is appropriate to complement the full adoption of NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;

- Amend definitions in Section XVII.A. and XVIII.B.;

- Strengthen good air pollution control practices, require use of auto-igniters, remove the off-ramp for condensate tanks if subject to a NSPS, MACT, or BACT, and remove the leak detection and repair requirements off-ramp for glycol natural gas dehydrators and internal combustion engines if subject to a NSPS, MACT, or BACT in Section XVII.B.;

- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;

- Limit venting and establish a storage tank emissions monitoring system ("STEM"), and associated recordkeeping and reporting requirements in Section XVII.C.;

- Expand glycol natural gas dehydrator control requirements in Section XVII.D.;

- Establish a leak detection and repair program for natural gas compressor stations and well production facilities in Section XVII.F.;

- Establish control measures for oil and gas wells in Section XVII.G.;

- Limit venting during well maintenance and liquids unloading in Section XVII.H.; and

- Expand pneumatic device requirements in Section XVIII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Joint Applicability of NSPS OOOO and Regulation Number 7, Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates some overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with six (6) tons per year ("tpy") of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. It is the Commission's intent that compliance with Regulation Number 7, Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions from storage vessels under NSPS OOOO. In those limited cases where storage tanks are subject to both NSPS OOOO and Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring. However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy, the equivalent of the NSPS OOOO six (6) tpy VOC on a controlled actual basis. While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary and intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT control requirement to avoid having to comply with Section XVII.

It is also possible for glycol natural gas dehydrators and internal combustion engines to be subject to both federal and Regulation Number 7, Section XVII. leak detection and repair requirements. NESHAP HH and HHH require glycol natural gas dehydrators at major sources of hazardous air pollutants ("HAP") that utilize a closed-vent system to conduct annual visual inspections for leaks and defects that could result in air emissions. NESHAP HH and HHH also require detected leaks and defects be repaired within fifteen days, as long as it is technically feasible to do so without a shutdown. NESHAP HH also requires triethylene glycol ("TEG") natural gas dehydrators located at area sources of HAPs that utilize a closed-vent system to conduct annual visual inspections. However, the revisions to Regulation Number 7 require more frequent inspections of all types of glycol natural gas dehydrators at all facilities, resulting in more emissions reductions than NESHAP HH and HHH. Therefore, the Commission believes joint applicability concerning leak detection and repair requirements is necessary.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC and other hydrocarbon emissions, such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of greater than or equal to one (1) minute during a fifteen (15) minute time period, pursuant to EPA Method 22. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. The regulated community may, alternatively, immediately shut-in the equipment to investigate the cause for smoke and perform repairs. While the presence of visible emissions constitutes a violation of the rules, the Commission recognizes that there may be instances where visible emissions occur notwithstanding the owner or operator's best efforts, such as when an upset or malfunction occurs. Accordingly, the Division should consider the owner or operator's efforts and whether the visible emissions resulted from factors outside the owner or operator's control in determining how to best enforce this requirement.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Approved instrument monitoring method" ("AIMM") means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

"Component" excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

"Natural gas compressor stations" are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

"Normal operation" is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of "malfunction" as set forth in the Common Provision regulations.

"Storage tank," means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of "storage tank," the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission's definition, and Colorado's approach to emissions reporting and permitting for storage tanks, differs from EPA's definition of "storage vessel" and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of "atmospheric condensate storage tank" and creates a new definition of "storage tank" which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The “owned, operated, or leased” qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from “well production facility” and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division’s assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;
- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;
- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations. The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator’s buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds. This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on “facility emissions.” The Commission has determined that “facility emissions” means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million (“ppm”) hydrocarbons for existing natural gas compressor stations and 500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources. Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission’s understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators’ annual reports as required by these rules be posted on the Division’s website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division’s website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA’s Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources. However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

Additional Considerations

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Sections XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado’s SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) The revisions to Regulation Number 7 address VOC and other hydrocarbon emissions from oil and gas facilities, including storage tanks, glycol natural gas dehydrators, pneumatic controllers, well production facilities, and natural gas compressor stations. In addition to NSPS OOOO, NSPS Kb, and NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks, glycol natural gas dehydrators, leaking components, and pneumatic controllers, and address more hydrocarbon emissions. For example, the Regulation Number 7 revisions address more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to TEG dehydrators. Similarly, the Regulation Number 7 revisions address more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. In addition, the Regulation Number 7 revisions address more component leaks than the major source provisions of NESHAP HH, as well as NSPS KKK, which has a 10,000 ppm leak threshold and only applies at natural gas processing plants.

Compared to NSPS OOOO, the revisions to Regulation Number 7 will apply a low- or no-bleed control requirement to more pneumatic controllers because NSPS OOOO only requires zero bleed pneumatic controllers at natural gas processing plants, while the Regulation Number 7 revisions no-bleed provision applies to all facilities. The revisions to Regulation Number 7 will also require a leak detection and repair program for more oil and gas operations because NSPS OOOO only requires leak detection and repair for natural gas processing plants, AVO inspections for storage vessels with controlled actual emissions greater than six (6) tpy, and annual visual inspections for leaks for subject centrifugal compressors. In contrast, the revisions to Regulation Number 7 require a leak detection and repair program for all components at all well production facilities and natural gas compressor stations. Further, the revisions to Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to further address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

(II) NSPS OOOO, and the other federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, which may be used to avoid NSPS OOOO applicability.

(III) Other federal requirements do not specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. Specifically during the development of NSPS OOOO, Colorado submitted comments regarding, among other things, concerns with the storage vessel definition, storage vessel control requirements, and lack of leak detection and repair requirements. Colorado's concerns were not fully addressed in NSPS OOOO, therefore, the Commission believes the revisions to Regulation Number 7 are necessary to: (a) address hydrocarbon emissions in a more comprehensive manner; (b) address oil and gas operations and equipment at lower thresholds than NSPS OOOO thresholds, yet that collectively have significant VOC and other hydrocarbon emissions in Colorado; (c) address venting of emissions from storage tanks at oil and gas facilities caused primarily by over pressurization; and (d) address leaks of fugitive hydrocarbon emissions, particularly from well production facilities and natural gas compressor stations.

(IV) Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for more costly retrofits at a later date. Colorado may be required to comply with a lower ozone NAAQS in the near future and the Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS, while other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. The revised rules are proactive and intended to reduce ozone levels now by utilizing controls and techniques already being used by some Colorado oil and gas operators, or that are readily available.

(V) Adoption of these revisions at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.

(VI) The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while utilizing many of the technologies and practices set forth in these revisions.

(VII) The revisions to Regulation Number 7 establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector. Furthermore, the application of the Regulation Number 7 revisions to oil and gas owners and operators regardless of location in the ozone nonattainment or attainment areas is equitable because the nonattainment area is not the only area in Colorado with ozone issues. For example, the Rangely monitor in western Colorado shows violations of the 2008 ozone standard and existing modeling shows that either the nonattainment area has increased its contribution to background ozone or ozone concentrations in the attainment area flowing into the nonattainment area have increased. Notably, the Division's inventory shows that the oil and gas industry contributes more than 50% of the VOC emissions outside the nonattainment area. This monitoring, modeling, and inventory data, considered with the likelihood of a lower ozone NAAQS and the expected growth of the oil and gas sector state-wide, supports the application of the Regulation Number 7 revisions to oil and gas sources in both the nonattainment and attainment areas.

(VIII) The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions. In reductions must come from other operations or sectors at this time, the cost effectiveness would decrease because these revisions reduce emissions from the most significant contributors to VOC emissions and costs will be higher for less emissions reductions from less significant contributors.

(IX) The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO (e.g. storage vessels emitting 120 tpy uncontrolled actual VOC emissions) or NESHAP HH and HHH (e.g. glycol natural gas dehydrators at major sources of HAPs and TEG glycol natural gas dehydrators at area sources of HAPs) and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to ensure compliance with and document the effectiveness of the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the requirements for auto-igniters and pneumatic controllers. In addition, oil and gas owners and operators are already using many of the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides owners and operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the revisions provide for Division approved extensions to compliance.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions, such as methane, add to the already cost-effective and appropriate emission reduction requirements.

(XII) Alternative rules, such as the alternative proposals provided by several parties during the rulemaking process, requiring differing or additional controls for oil and gas facilities could also provide reductions in hydrocarbon emissions. The Commission could have adopted some or all of the proposed revisions or proposed alternatives. However, the proposed revisions to Regulation Number 7 were developed during a lengthy stakeholder process and provided a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado’s economy and the nation’s energy independence. The alternative proposals provided during the rulemaking process were primarily either more or less stringent versions of the proposed revisions, further illustrating the balanced approach of the proposed revisions. Furthermore, a no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursor pollutants, necessary for reducing ozone in Colorado.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. 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 hydrocarbon emissions.

(III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(VI) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

O. November 17, 2016 (Sections I., X., XII., XIII., XVI., XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), 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

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data. Due to the reclassification, additional planning requirements were triggered, including the requirement to submit revisions to the State Implementation Plan ("SIP") that address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA Section 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)).

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., (“Act”), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive state implementation plan that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 25-7-109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council (“RAQC”) and the Colorado Department of Public Health and Environment, Air Pollution Control Division (“Division”) conducted a public process to develop the associated SIP and supporting rule revisions. Separately, EPA had expressed concerns with approving previous Regulation Number 7 revisions related to oil and gas control requirements and submitted in 2009 and 2013 for inclusion in Colorado’s ozone SIP.

In response to these related but separate issues, the Commission revised Regulation Number 7 to strengthen Colorado’s ozone SIP; and include reasonably available control technology (“RACT”) requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of volatile organic compounds (“VOC”) or nitrogen oxides (“NOx”). More specifically, the Commission revised the applicability of Regulation Number 7 in Section I.A.1.; included the existing combustion device auto-igniter requirements in Section XII.C.1.e. and XII.E.2. in Colorado’s ozone SIP; included existing audio, visual, olfactory (“AVO”) storage tank inspection requirements for condensate storage tanks in Colorado’s ozone SIP in Section XII.E.4.e.; added requirements for lithographic and letterpress printing in Section XIII.B.; added requirements for industrial cleaning solvents in Section X.E.; and added requirements for major sources in Sections XVI. and XIX.

Apart from the Moderate nonattainment area ozone SIP, the Commission revised Regulation Number 7 to address EPA’s monitoring, recordkeeping, reporting, and other concerns with previously submitted Regulation Number 7 revisions. The Commission updated federal rule references for natural gas processing plants in Section XII.G.1.; renumbered the current Sections XII.G.5. and XII.G.6. under Section XII.I.; added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in Sections XII.H.5. and XII.H.6.; and addressed other EPA concerns in Sections XII.C.1.c., XII.C.1.d., XII.C.2.a.(ii)(B), XII.E.3., and XII.H.4.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission’s intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Ozone reclassification SIP revisions

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked “state-only” continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were “state-only”. The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a “state-only” basis. The Commission revised Section XII. to include in the SIP the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year (“tpy”) or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado’s ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline (“CTG”). EPA’s Offset Lithographic Printing and Letterpress Printing CTG (“Printing CTG”) addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado’s SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard (“NSPS”) or National Emission Standard for Hazardous Air Pollutants (“NESHAP”). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NOx in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NOx emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NOx sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NOx in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NOx at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NOx sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C.through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NOx and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NOx emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation By Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, 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 the ozone precursors VOC and NOx.

(III) Evidence in the record supports the finding that the rules shall being 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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

P. November 16, 2017 Revisions to Section II., XII., Section XVII., and Section XVIII.

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

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. Therefore, the Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP (Sections XII. and XVIII.). In order to make additional progress towards attainment of the NAAQS, the Commission is also adopting State Only revisions to require owners or operators of natural gas-driven pneumatic controllers in the DMNFR area to inspect and maintain pneumatic controllers.

Further, the Commission is making clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

Specific Statutory Authority

Section 25-7-105(1) of the Act 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 the Act. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides the Commission broad authority to regulate hydrocarbons.

Purpose

As discussed above, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (*i.e.,* the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.,* pneumatic pumps). The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.,* components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Oil and Gas CTG, generally

The Oil and Gas CTG provides recommendations for states to consider in determining RACT for certain oil and natural gas industry emission sources. EPA included storage vessels, pneumatic controllers, pneumatic pumps, compressors, equipment leaks, and fugitive emissions in the Oil and Gas CTG because EPA determined that these sources are significant sources of VOC emissions. EPA defines RACT as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." States may implement approaches that differ from the recommendations in the Oil and Gas CTG so long as they are consistent with the CAA, EPA's implementing regulations, and policies on interpreting RACT.

Applicability to hydrocarbons (Section II.B.)

Section II.B. currently exempts negligibly reactive volatile organic compounds, such as methane and ethane, from requirements of the SIP, while making hydrocarbon emissions, including methane and ethane, subject to State Only regulation under Sections XVII. and XVIII. Section XVII. sets a threshold for leaks requiring repair that is based on the concentration of hydrocarbons, as determined using EPA Method 21. Section XII.L. applies the same EPA Method 21 hydrocarbon threshold for leaks requiring repair. The Commission revised Section II.B. to clarify that the Section XII.L. hydrocarbon threshold and Section XVIII. natural gas emission standards serve only as VOC indicators and the SIP does not regulate hydrocarbon emissions. The continuous bleed, natural gas-driven pneumatic controller requirements in Section XVIII. reduce natural gas emissions, which consists of other pollutants in addition to VOCs. Despite the presence of other constituents, natural gas is principally methane and the Commission intends to regulate emissions of natural gas as hydrocarbons, including methane and ethane, on a State Only basis as described in Sections II.B. and XVIII. The Oil and Gas CTG also utilizes a natural gas bleed rate standard for continuous bleed pneumatic controllers and the Oil and Gas CTG LDAR program employs a methane-based threshold for EPA Method 21 leak detection. Therefore, these revisions are consistent with the Oil and Gas CTG and the CAA.

While the revisions to Sections XII. and XVIII. to include provisions in Colorado's Ozone SIP are limited to the DMNFR, the Commission acknowledges the importance of reducing hydrocarbon emissions from the oil and gas sector (*i.e.*, upstream, midstream, and transmission) statewide. Therefore, without prescribing any particular outcome, the Commission directs the Division to initiate and lead a stakeholder process over the 2018-2019 timeframe to evaluate potential areas for cost-effective hydrocarbon emission reductions. Stakeholders will nominate topics for evaluation, which may include, but are not limited to, the frequency of LDAR inspections, transmission segment compressor emissions, natural gas-driven and zero emission pneumatic controllers outside the DMNFR (to be informed by the pneumatic study and inspection program), and potential expansion of the requirements adopted in the DMNFR as part of this rulemaking. The Division will brief the Commission on the stakeholder process in January 2019 and present recommendations for any new proposals for emission reductions by no later than January 2020. The Commission intends that one representative of industry, local government, and the environmental community each will have the opportunity to speak during the briefings.

Applicability of Section XII. (Section XII.A.)

The Commission is clarifying the applicability of Section XII. Historically, Section XII. has applied to operations that involve the collection, storage, or handling of condensate in the DMNFR. While this remains the case, the requirements in Section XII.J. for compressors, Section XII.K. for pneumatic pumps, and Section XII.L. for components at well production facilities and natural gas compressor stations also apply to those facilities and equipment collecting, storing, or handling other hydrocarbon liquids.

Section XII.A.5. further provides that subject well production facilities are those with uncontrolled actual VOC emissions greater than or equal to one ton per year ("tpy"). This applicability threshold addresses the Oil and Gas CTG's recommended barrels of oil equivalent ("BOE") exemption. EPA crafted the BOE exemption believing that well production facilities with an average production less than 15 BOE per well per day were inherently low emitting facilities. EPA later determined that information submitted on the draft CTG and proposed NSPS OOOOa did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an uncontrolled actual VOC tpy threshold for well production facility applicability. The use of a tpy threshold is also consistent with Colorado's current air pollutant reporting and permitting thresholds.

Further, Section XII.A. historically exempted from the requirements of Section XII. those operations reflecting a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the DMNFR area. That exemption continues to apply to Sections XII.B. through XII.I., but is not extended to Sections XII.J., XII.K., and XII.L.

Definitions (Sections XII.B. and XVII.A.)

The Commission is adopting definitions into Section XII.B., most of which are consistent with the existing definitions of Section XVII.

In the definition of "component", the Commission is clarifying both in Section XII.B. and in Section XVII.A., that thief hatches and other openings on storage tanks are included in the definition as a pressure relief device. This revision clarifies that leaks can occur from the thief hatch (*e.g.*, faulty or dirty seals) that are different than vented emissions under the standard in Section XVII.C.2.a., and that such leaks are subject to the LDAR program. The Commission anticipates that emissions from storage tanks identified as leaks requiring repair through the LDAR inspections under Sections XII.L. or XVIII.F. will be recorded and reported as leaks starting in 2018 for the 2019 annual report.

The Commission is adding a definition of "custody transfer" that applies to custody transfers of both natural gas and oil products. The Commission is also adding definitions for "natural gas driven diaphragm pump" and "natural gas processing plant" that correspond to federal definitions.

Operate without venting clarification (Section XVII.C.2.a.)

The Commission is providing additional detail concerning provisions adopted in 2014 that established an “operate without venting” standard for storage tanks. In response to industry concern that Section XVII. does not sufficiently define “venting” or delineate “venting” from “leaking,” the Commission is adopting provisions clarifying which emissions from storage tanks are considered “venting”. Section XVII.F. defines “leaking” in terms of infra-red camera or EPA Method 21 inspections of components. While storage tanks may also have leaks, as the Commission recognizes by including thief hatches or other openings on storage tanks in the definition of component, the Commission now further clarifies the “venting” standard by specifying that “venting” is emissions that are primarily the result of over-pressurization or that are from an open or visibly unseated pressure relief device (*e.g.*, thief hatch). The Commission intends that “visibly unseated” means visible from the outside of the pressure relief device and does not require an owner or operator to open a pressure relief device to determine if the seal is proper. The Commission also authorizes the Division to request a demonstration from the owner or operator that “venting” emissions observed by the Division were not primarily the result of over-pressurization. The Commission intends that such demonstration request allow an owner or operator to provide case specific information or other sufficient details that the design, operation, and maintenance of the facility is adequate to prevent over-pressurization. In clarifying a difference between “leaking” and “venting,” the Commission does not prohibit component leaks, per se, so long as leaks are repaired under the applicable repair time frames but does continue to prohibit “venting” from storage tanks.

Ozone season clarification (Sections XII.F.4. and XII.H.6.)

In October 2015, the EPA finalized a revision to the ozone NAAQS. (80 Fed. Reg. 65292 (Oct. 26, 2015)). In publishing its final rule, the EPA revised the length of Colorado’s ozone season. Colorado’s ozone season is now year-round, rather than the months of May through September. The Commission therefore revised references to “ozone season” in Sections XII.F.4. and XII.H.6. to reflect that the requirements now apply during the months of May to September. There are no substantive changes to the underlying requirements resulting from this revision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Commission is updating the LDAR program applicable to equipment leaks at natural gas processing plants in the DMNFR by requiring owners or operators to comply with 40 C.F.R. Part 60 (NSPS), Subparts OOOO or OOOOa instead of complying with NSPS Subpart KKK, which is an earlier NSPS and less stringent. Subpart KKK requires sources to implement a NSPS Subpart VV level LDAR program, while Subpart OOOO requires sources to implement a NSPS Subpart VVa level LDAR program. A Subpart VVa level LDAR program is recommended for equipment at natural gas processing plants in the Oil and Gas CTG. The Commission determined that a 2019 implementation date would provide owners and operators of existing natural gas processing plants a reasonable period of time to establish and obtain the necessary resources to transition from Subpart KKK to Subpart OOOO LDAR requirements.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into new Section XII.J. in order to include the requirements in Colorado’s Ozone SIP. The Commission is expanding the existing reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to address recommendations in the Oil and Gas CTG. Owners or operators of existing reciprocating compressors at natural gas processing plants must begin monitoring the reciprocating compressor hours of operation on January 1, 2018, starting at zero, in relation to the rod packing replacement requirement, conduct the first rod packing replacement prior to January 1, 2021, or route emissions to a process beginning May 1, 2018.

The Commission intends to allow owners or operators the option to reduce VOC emissions by routing centrifugal compressor emissions to a process or control and reciprocating compressor emissions to a process, consistent with the recommendations in the Oil and Gas CTG. With respect to centrifugal compressors, the Oil and Gas CTG and related federal requirements reveal that "process" generally refers to routing emissions via a closed vent system to any enclosed portion of a process unit (*e.g.*, compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Similarly, with respect to reciprocating compressors, routing to a process includes using a rod packing emissions collection system that operates under negative pressure and meets cover and closed vent system requirements. The negative pressure requirement ensures that all emissions are conveyed to the process and avoids inducing back pressure on the rod packing and resultant safety concerns. The Commission recognizes that there may a distinction between air pollution control equipment and process equipment (see e.g., U.S. EPA Letter to Timothy J. Mohin RE: Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment (Nov. 27, 1995)). For example, as noted in the Oil and Gas CTG, vapor recovery units and flow lines that "route emissions to a process" may be considered part of the process and not a control device, however, a related cover and closed vent system, if present, are still subject to applicable requirements. Further, components (as defined in these rules) located within a process or that are part of process equipment are subject to the Section XII.L. LDAR requirements. The Commission intends that owners or operators will follow similar procedures when complying with centrifugal and reciprocating compressor requirements in Section XII.J.

The Commission has adopted an inspection program for compressors, but also intends to provide owners or operators with the alternative of complying with other requirements, including the LDAR program adopted into Section XII.L. While the requirements of the LDAR program would replace the annual visual inspections and EPA Method 21 inspections of the cover and closed vent systems for defects and leaks, owners or operators would still need to conduct monthly inspections of their combustion devices. Compliance with the LDAR program is not limited to the inspection frequency and methods specified therein; owners or operators will also need to maintain records of the inspections and submit reports to the Division, consistent with the requirements of the LDAR program.

The Commission has specified an inspection and repair schedule for compressors, but has recognized that there may be reasons that a system is unsafe or difficult to inspect, or where a repair may not be feasible. Owners or operators will need to maintain records of each cover or closed vent system that is unsafe or difficult to inspect and schedule for inspection when circumstances allow. Similarly, when a repair is infeasible, insofar as it would require a shutdown of the equipment, repair can be delayed until the next scheduled shutdown but must be completed within two years after discovery. The Commission expects owners or operators to attempt to confirm repair before starting up operation after shutdown, to the extent practicable. The Commission also expects that if the repair attempt can be made during an unplanned shutdown, it will be.

The Commission adopts the monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, and recordkeeping requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Natural gas driven diaphragm pumps (Section XII.K.)</u>

The Oil and Gas CTG contains recommendations for RACT for natural gas-driven diaphragm pumps. The Commission has not previously adopted regulations specifically directed at this type of equipment, and does so in Section XII.K.

The Oil and Gas CTG recommends that the pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG also recommends that owners or operators of pumps located at well sites route VOC emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days or an engineering assessment shows that routing the pneumatic pump emissions to a control device or process is technically infeasible. The assessment of technical feasibility may include safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, gas pressure, and the capacity of the control device, among other things. The Commission acknowledges that RACT, by EPA definition, includes both technological and economic feasibility elements. The Commission determined that the cost of routing pneumatic pump emissions to an existing control device or process is reasonable and is, therefore, only providing an exemption from the emission control requirement based on technical infeasibility. However, the Commission does not intend to limit future RACT determinations due to limiting the pneumatic pump infeasibility analysis to technical ability. In addition, the 90 day exemption for pumps was included to address intermittently used or portable pumps. Consistent with the Oil and Gas CTG, the Commission intends that if a pump operates on any period of a calendar day, that day would be included in the calculation for applicability of the 90 day exemption. The Commission does not expect an owner or operator to install new equipment specifically to route pneumatic pump emissions to a control or process but intends that when an owner or operator subsequently otherwise installs a control device or it becomes technically feasible to route pump emissions to a process, then the owner or operator will capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or feasible process. Routing to a control or process generally refers to routing the emissions through a closed vent system to a vapor recovery unit, combustion device, or enclosed portion of a process where emissions are recycled and/or consumed.

The Commission has applied the same flexibility for pneumatic pumps as it has for compressors; owners or operators may comply with the inspection requirements in Section XII.K. or may follow the LDAR program in Section XII.L. Also similar to compressors, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair so long as repair is completed within two years after discovery. As with compressors, the Commission expects owners or operators to attempt to confirm repair before starting up operation after a shutdown and make an attempt to repair during unscheduled shutdowns, to the extent practicable.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.K., owners or operators may instead comply with pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

<u>Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)</u>

The Oil and Gas CTG recommends LDAR programs at well sites *(i.e.*, well production facilities) and gathering and boosting stations (*i.e.*, natural gas compressor stations), including inspection frequencies, recordkeeping, and reporting. The Commission established Colorado’s well production facility and natural gas compressor station LDAR program in 2014 in Section XVII.F., which is not part of the Ozone SIP. In creating a LDAR program in the Ozone SIP, the Commission intends to maintain as much of the current program as feasible. Where the Commission adopted revisions in Section XII.L. that differ from language currently found in the State Only LDAR program, the Commission in most cases made the same or similar revisions to the corresponding provisions in Section XVII.F.

Inspection, repair, and remonitoring

The Oil and Gas CTG recommends LDAR inspections at a minimum quarterly frequency for gathering and boosting stations and a minimum semi-annual frequency for well sites. The Commission is adopting inspection frequencies to address those recommendations in Section XII.L. The Commission is not modifying the LDAR schedules in Section XVII.F. The Commission intends that for those sources required by Section XVII.F. to conduct more frequent LDAR monitoring than specified in Section XII.L., the owner or operator may comply with Sections XII L.1. and XII.L.2. by complying with Sections XVII.F.3. and XVII.F.4. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners or operators will ensure that inspections are appropriately spaced on the frequency schedules (*e.g.,* quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Oil and Gas CTG does not recommend a semi-annual LDAR inspection frequency at well sites with a gas to oil ratio less than 300 and which produce, on average, less than or equal to 15 BOE per well per day. The Commission recognizes that a component of RACT is balancing the emission reductions with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequency does not apply. The Commission determined a threshold of one tpy VOC emissions addresses this balance and the recommendation in the Oil and Gas CTG. Adopting an emissions based threshold maintains consistency with the current Regulation Number 7 applicability program and promotes the clarity and effectiveness of the regulation. The Commission determined that annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy and semi-annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than six tpy address the Oil and Gas CTG's recommendations.

The Commission understands that the revised inspection frequencies will result in a significant number of new inspections. However, annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy will be less burdensome than semi-annual inspections. The Commission has determined that the emission reductions achieved by this program will improve the ability of the DMNFR area to attain the ozone standard and are cost-effective. While the rule specifies that the new inspection frequencies begin to apply as of June 30, 2018, the rule does not require that the first periodic inspection be completed by June 30, 2018. The Commission also does not require that monitoring be conducted in advance of this date; however, inspections done after January 1, 2018, that are in addition to current required LDAR monitoring frequencies may count towards the first annual or semi-annual inspection, or inspections done in the previous quarter at natural gas compressor stations. The Commission encourages owners or operators to conduct inspections prior to the 2018 summer ozone months to more effectively take advantage of the resulting emission reductions.

To ensure that the Ozone SIP LDAR program in Section XII.L. works with the existing State Only LDAR program in Section XVII.F., the Commission has maintained the same thresholds for identifying leaks that require repair. While the Oil and Gas CTG employs a methane concentration threshold when detected with EPA Method 21, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. to clarify that Section XII.L. includes the use of hydrocarbons as an indicator of VOC emission reductions.

Concerning the use of non-quantitative instrument monitoring methods, the Commission adopted a quality assurance requirement that owners or operators maintain and operate such devices according to manufacturer recommendations. This requirement corresponds to recommendations in the Oil and Gas CTG concerning the maintenance and operation of OGI uses to detect fugitive emission components. The Commission intends for the Division to work with owners or operator to address any concerns that arise from manufacturer specifications for the maintenance of non-quantitative instrument monitoring methods.

Consistent with the current LDAR program in Section XVII.F., the Commission adopted a requirement to make a first attempt to repair an identified leak within five working (*i.e.,* business) days of discovery. In both Section XII.L. and in Section XVII.F., the Commission has included a requirement that repairs be completed within 30 days unless one of the existing justifications for delay of repair applies. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair so long as repair is completed within two years of discovery. The Commission has also maintained the flexibility of the State Only LDAR program in the SIP by giving owners or operators detecting leaks with a non-quantitative method (*e.g.,* IR camera) the ability to quantify the leaks within five working days. If the quantification shows that the leak must be repaired under Section XII.L.5., the deadline to repair runs from the date of discovery, not from the date of quantification.

As it did for Section XVII.F.7.c. in 2014, the Commission has also memorialized its intent, in Section XII.L.5.c., that operators not be subject to enforcement for leaks so long as operators are complying with the LDAR program requirements. However, as it also explained in 2014, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Section XII.C. For example, closing an open thief hatch within five days of an LDAR inspection does not shield an owner or operator from a possible violation of the requirement to minimize emissions to the maximum extent practicable. Similarly, the Commission does not intend to relieve owners or operators of the obligation, on a State Only basis, to comply with the requirements of Section XVII., including the requirements in Sections XVII.B. and XVII.C.2. to minimize leakage to the extent reasonably practicable and operate without venting, respectively. However, the Commission does not intend these State Only provisions be enforceable under the Ozone SIP.

Recordkeeping and reporting

The Commission has determined that the current requirements did not adequately incentivize owners or operators to make all reasonable good faith efforts to obtain parts necessary to complete repairs. As a result, some leaks continued on delay of repair lists for an unreasonable length of time. Therefore, the Commission has determined that a review and record of such delays by a representative of the owner or operator is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

The Commission expanded the recordkeeping for repair dates to include records of the type of repair method applied. The Commission determined this recordkeeping element aligns with recommendations in the Oil and Gas CTG and will more accurately inform repair activities. The Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of repair to ensure that owners and operators are consistently recording the information required.

The Commission also expanded the requirements for the annual LDAR report to ensure that the data submitted to the Division more accurately represents and summarizes the activities and effectiveness of the LDAR program. The Commission intends that the LDAR reports include the number of inspections, leaks requiring repair, leaking component type, and monitoring method by which the leaks were found – broken out by facility type (*i.e.,* inspection frequency tier of well production facility or natural gas compressor station).

The Commission intends that both the SIP and State Only LDAR reporting requirement can be satisfied by one report. The Commission expects that the first annual report containing the information required by these revisions will be submitted by May 31, 2019 (*i.e.,* no changes are expected to current requirements for the May 31, 2018, annual report representing leak detection and repair activities conducted during 2017).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument monitoring methods. The CAA prohibits a state from modifying SIP requirements except through specified CAA processes. EPA interprets this CAA provision to allow EPA approval of SIP provisions that include state authority to approve alternative requirements when the SIP provisions are sufficiently specific, provide for sufficient public process, and are adequately bounded such that EPA can determine, when approving the SIP provision, how the provision will actually be applied and whether there are adverse impacts. (State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33917-33918, 33927 (June 12, 2015)) Therefore, the Commission includes an application and review process in the SIP for the potential approval of instrument monitoring methods as alternatives to an infra-red camera or EPA's Method 21. The approval may also include modified recordkeeping and reporting requirements based on the capabilities of the potential alternative instrument monitoring method. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative AIMM must be capable of reducing emissions through the detection and repair of leaks comparable to the leaks detected and repaired as specified in the SIP to be potentially approvable.

The Commission received comments from stakeholders requesting that the Commission explicitly provide for the ability to employ certain alternatives not equipped with the leak detection capabilities of infra-red cameras or Method 21. These stakeholders emphasized that monitoring technologies are evolving rapidly and new technologies and monitoring programs are being developed that, when used on their own or in conjunction with other methods, may provide the same or better leak detection and repair results, at potentially lower costs. The process outlined in Section XII.L.8. requires an applicant to demonstrate that the proposed alternative monitoring achieves emission reductions that are at least as effective as the leak detection and repair program in Section XII.L. The Commission intends that the rule be flexible enough to allow the Division to consider such alternative monitoring methods or programs, as long as the applicant can demonstrate that the proposed method or program achieves emission reductions that are as effective as other approved technologies or methods. To make this demonstration, an applicant may consider demonstrating that a program of alternative inspection frequencies, pollutants detected, or leak thresholds for repair achieves emission reductions comparable to the inspection frequencies and leaks requiring repair thresholds in Section XII.L., thus the consideration of an alternative leak detection program. The Commission recognizes that current, established approaches or methodologies to evaluate the performance of alternative monitoring technologies and programs as compared to baseline monitoring technologies (infra-red camera, EPA Method 21) do not yet exist. However, such methodologies are being developed. For example, the Interstate Technology and Regulatory Council (ITRC), in which Colorado participates, is developing, but has not yet published, a guidance document to establish, if possible, a consensus for evaluating and comparing the effectiveness of leak detection technologies. While the criteria for evaluating the effectiveness of an alternative program as compared to the base program is being developed, alternative monitoring method applicants may submit an application for approval of an alternative monitoring method but must be prepared to present a robust and complete evaluation of the technology or program's performance that allows for comparison to the base technologies in the SIP. It is possible the Division may delay consideration and final determination regarding an alternative monitoring method or program application until established comparison criteria are developed or submitted. Taking into account the deliberations of the ITRC process, the Commission expects that the Division will consider complete applications in a timely manner.

The Commission also received comments from stakeholders requesting that the Commission clarify EPA's participation regarding potential alternative monitoring methods. As discussed above, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA's technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered "leaks," only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to "clarify" that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

<u>Pneumatic controllers (Section XVIII.)</u>

The Commission is adopting both Ozone SIP and State Only revisions to Section XVIII.

The Commission added definitions of continuous bleed and intermittent pneumatic controller. The Commission also added "continuous bleed" to several provisions throughout Sections XVIII.C. through XVIII.E. to clarify that the provisions adopted in 2014 primarily applied to continuous bleed pneumatic controllers (which emit continuously) as opposed to intermittent pneumatic controllers (which emit only when actuating).

Pneumatic controllers at or upstream of natural gas processing plants

Section XVIII. already requires that owners or operators install low-bleed pneumatic controllers at or upstream of natural gas processing plants, unless a high-bleed pneumatic controller is required for safety or process purposes. This requirement is consistent with the Oil and Gas CTG and the Commission intends that these provisions be included in Colorado's Ozone SIP.

The Commission adopts additional requirements, consistent with the Oil and Gas CTG, related to pneumatic controllers at natural gas processing plants. The Commission is requiring that all continuous bleed, natural gas-driven pneumatic controllers at a natural gas processing plant have a bleed rate of zero (*i.e.,* no VOC emissions), unless a pneumatic controller with a bleed rate greater than zero is necessary due to safety and process reasons. To satisfy this requirement, owners or operators of natural gas processing plants could, for example, drive pneumatic controllers with instrument air, use mechanical or electrically powered pneumatic controllers, or use self-contained pneumatic controllers that release natural gas to a downstream pipeline instead of to the atmosphere. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for tagging and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. The requirement to maintain pneumatic controllers exceeding the applicable emission standard are also duplicated from the existing high-bleed maintenance requirement, but revised to include the suggested maintenance actions specifically in the applicable provisions, instead of referring to an “enhanced maintenance” definition. The Commission revised the maintenance requirement in this manner to separate the actions taken to maintain a pneumatic controller exceeding the applicable emission standard from the, potentially very similar, actions taken to return a pneumatic controller to proper operation. For example, the owner or operator of a high-bleed pneumatic controller or a pneumatic controller with a bleed rate greater than zero at a natural gas processing plant is required to perform specified maintenance on the pneumatic controller regardless of whether or not the pneumatic controller is determined to be properly operating. In contrast, the owner or operator of a pneumatic controller inspected under Section XVIII.F. must conduct enhanced response to return that pneumatic controller to proper operation.

Additionally, the Commission is requiring owners or operators to maintain records demonstrating their continuous bleed, natural gas-driven pneumatic controllers meet the applicable low-bleed or bleed rate of zero standards. These records are also intended to inform the extent to which continuous bleed pneumatic controllers are used in the DMNFR. The Commission understands that the number of continuous bleed, natural gas-driven pneumatic controllers in use by an operator can change frequently, and is not requiring a running log or count of each individual pneumatic controller. The Commission adopted these recordkeeping requirements with the expectation that owners or operators can keep records including, but not limited to, site-specific documentation of continuous bleed, natural gas-driven pneumatic controllers such as manufacturer specifications, engineering calculations, field test data, or documentation of a company’s continuous bleed, natural gas-driven pneumatic controller purchase and installation program ensuring that any such pneumatic controller meets the applicable bleed rate standard.

Clarification

The Commission is also clarifying the intent behind provisions adopted in 2014 regarding the use of pneumatic controllers powered by instrument air (as opposed to natural gas) when grid power is being used. In 2014, the Commission intended that when a pneumatic controller was proposed for installation, owners or operators would power the pneumatic controller via electrical power instead of natural gas when electrical grid power was being used on-site. The provisions adopted in 2014 allowed owners or operators to install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller in some situations. The Commission has learned that some owners or operators interpret the rule as providing the option of installing either no-bleed or low-bleed pneumatic controllers in all situations. Even though the Commission believes its intent was clear, the Commission recognizes that the rule could fairly be described as ambiguous and that there is a good faith legal argument for the alternative interpretation. The Commission is revising the rule to clarify that where electric grid power is being used on site and it is technically and economically feasible to install no-bleed pneumatic controllers, any newly installed pneumatic controllers must be no-bleed. Where the owner or operator determines it is not technically and economically feasible to install a no-bleed pneumatic controller, the owner or operator may install a low-bleed or intermittent pneumatic controller.

The Commission recognizes that the installation of an electrically-powered controller may have been feasible in 2014, but may not be feasible to retrofit at this time. The Commission nonetheless encourages owners or operators statewide who, based on a misreading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers – with no-bleed or self-contained pneumatic controllers – at this time is technically and economically feasible. The Commission also encourages owners and operators statewide to install, or retrofit with, no-bleed or self-contained pneumatic controllers at locations across the state, even where on site electrical grid power is not available to the extent there is no significant air quality disbenefit in doing so.

Natural gas driven pneumatic controller inspection and enhanced response (State Only)

Following the 2014 rulemaking, the Commission requested that the Division continue its investigation into potential regulations for intermittent pneumatic controllers. During the recent 2016 ozone rulemaking, stakeholders again asked the Commission to address intermittent pneumatic controllers. In response, the Commission again directed the Division to evaluate potential emission reduction measures for intermittent pneumatic controllers.

The Commission is adopting an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven pneumatic controllers. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore, while the Commission determined that these revisions are technically and economically feasible, the revisions are proposed as State Only in the DMNFR and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers include continuous bleed, intermittent, and self-contained pneumatic controllers. Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere. The Oil and Gas CTG suggests that maintenance of pneumatic controllers, including cleaning and tuning, can eliminate excess emissions from the devices. While the Oil and Gas CTG's recommended RACT (low-bleed or zero emissions) applies to continuous bleed, natural gas-driven pneumatic controllers, the discussion concerning enhanced maintenance of pneumatic controllers builds on earlier EPA discussions, such as EPA's 2014 Pneumatic Controller White Paper, and is not limited to continuous bleed pneumatic controllers. The Commission recognizes that continuous bleed and intermittent pneumatic controllers are designed to have emissions, however these pneumatic controllers can also have excess emissions when not operating properly. As a result, the Commission believes that a pneumatic controller inspection and response program will reduce the excess emissions from such pneumatic controllers.

The Commission intends to apply the same find and fix approach used in the LDAR requirements in Sections XII.L. and XVII.F. to all natural gas-driven pneumatic controllers in the DMNFR. The Commission is requiring that natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the pneumatic controller is operating properly, in contrast to quantitatively comparing pneumatic controller emissions to a regulatory threshold. The Commission is requiring that owners or operators inspect pneumatic controllers at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions. The Commission expects that owners or operators will inspect their pneumatic controllers during the same LDAR inspections, and using the same AIMM, conducted for compliance with Sections XII.L. or XVII.F.

The pneumatic controller inspection and enhanced response process is intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven pneumatic controller using AIMM to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those pneumatic controllers with detected emissions. Second, the owner or operator must determine whether the pneumatic controllers with detected emissions are operating properly. Use of an AIMM is not required during this second step; the Commission does not at this time intend to mandate to owners or operators how to determine if their pneumatic controllers are operating properly. During this second step, if an owner or operator determines that the pneumatic controller is operating properly, no further action is necessary. Third, where an owner or operator determines the pneumatic controller is not operating properly, the owner or operator must take actions to return an improperly operating pneumatic controller to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those pneumatic controllers that the owner or operator determined not to be operating properly. Similar to the LDAR records, owners or operators must keep records of the date the pneumatic controller was returned to proper operation and a description of the types of actions taken. As with well production facility and natural gas compressor station LDAR records, the Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of response actions to ensure that owners and operators are consistently recording the information required. The Commission expects that owners or operators will include the pneumatic controller information as State Only information in their LDAR annual reports. In returning a pneumatic controller to proper operation, the Commission relies upon the previously defined term, now enhanced response, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide responsive activities concerning all natural gas-driven pneumatic controllers. Recognizing that the function and potential maintenance or repair of pneumatic controllers can be variable, owners or operators are not restricted to using an AIMM to determine proper operation or verify the return to proper operation.

The Commission has adopted a “reassessment” provision for this inspection and enhanced response program following a Division led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The Commission also recognizes that owners and operators may currently have limited information on “good engineering and maintenance practices” for pneumatic controllers and intends that more information on these practices will be gathered during the pneumatic study and implementation of Section XVIII.F. to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry’s proposal, a task force will be convened by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection will begin no later than by May 1, 2018. The task force will brief the Commission annually and make any recommendations on its findings in a report to the Commission, due May 1, 2020. The Commission intends that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the Commission. The Commission intends that this information be used to reassess the natural gas-driven pneumatic controller requirements of Section XVIII.F. Section XVIII.F. will remain in effect until rescinded, superseded, or revised.

The Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers, which highlights the need for the reassessment of Section XVIII.F. as well as enforcement discretion. The Commission intends that while the task force is actively working on data collection and the 2020 report to the Commission, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator. Any information gathered through the task force, including on preventative, good engineering, and maintenance practices, will be used to reassess Section XVIII.F. and will not be used for enforcement purpose through 2020.

Additional Considerations

Colorado must revise Colorado's Ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. The Commission carefully considered what provisions to include in Colorado's Ozone SIP, especially given Colorado's pre-existing emission control requirements that address most of the same sources addressed by the Oil and Gas CTG, yet do so differently. Some of these pre-existing requirements were adopted into Colorado's SIP and some will remain as State Only requirements. In determining what existing provisions would be included in Colorado's Ozone SIP, the Commission considered: 1) whether or not Colorado had existing emission control measures for the same sources covered by the Oil and Gas CTG; 2) whether these existing requirements were already adopted for inclusion in the Ozone SIP; and 3) the degree of emissions reductions achieved by any existing Colorado emission control measures in comparison to the Oil and Gas CTG. In resolving differences between existing Colorado provisions and the Oil and Gas CTG, preference was given to existing Colorado provisions, especially those already incorporated into Colorado's Ozone SIP and Colorado's existing regulatory framework. For example, the Commission relied upon existing storage tank requirements already adopted into Colorado's Ozone SIP. In the case of well production facility LDAR, the Commission adopted a tpy applicability threshold in place of the Oil and Gas CTG's BOE threshold, which applies to more sources than the Oil and Gas CTG, yet adopted a less frequent inspection frequency into the Ozone SIP for the smaller facilities than the Oil and Gas CTG. In determining whether or not any additional requirements would be relied upon in establishing RACT in Colorado's Ozone SIP for the oil and gas sector, the Commission determined whether or not the emission control measures were necessary for the ozone attainment demonstration. In the case of LDAR for pneumatic controllers at well production facilities and natural gas compressor stations, the Commission adopted emission control measures as State Only measures given the need to obtain emission reductions as well as more information on this source type. These examples illustrate the Commission's careful consideration of what provisions to include in Colorado's Ozone SIP.

The CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a CTG, such as the emission sources addressed in the Oil and Gas CTG. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs.

The Commission is also revising certain State Only regulations to reduce emissions and promote attainment of current federal ozone standards. Specifically, the Commission is adopting requirements related to the inspection of natural gas-driven pneumatic controllers at oil and gas facilities. As discussed above, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016. While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

(I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

(II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.

(IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.

(V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.

(VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.

(VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, 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 the ozone precursors VOC.

(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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), 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.

<u>Basis</u>

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions.

In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NOx)

University of Colorado Boulder (013-0553 major for NOx)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NOx)

Many of the major sources listed above are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado's SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado's major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NOx (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado's existing major sources of NOx on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NOx emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NOx

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division’s own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NOx in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NOx as of June 3, 2016 (i.e. the effective date of the DMNFR’s reclassification to Moderate nonattainment).

Definitions

The definition for “stationary combustion equipment” refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NOx equal to or greater than 5 tons per year located at major sources of NOx. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NOx, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado's source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems (“CEMS”) and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NOx controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating (“MCR”). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard. The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice (“APEN”) submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a “once in/always in” approach with respect to emission control requirements of exemptions.) Similarly, this 180 day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems (“CERMS”) for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs). Further, it is the Commission’s intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NOx emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule.

Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NOx emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, 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 the ozone precursors VOC and NOx.

(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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

R. November 15, 2018 (Sections I., II., VI., VIII., IX., X., XII., XIII., XVI., XVII., XIX., XX., and XXI.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), 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.

<u>Basis</u>

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable marginal attainment deadline and therefore reclassified the DMNFR area to moderate, effective June 3, 2016.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 100 tons per year ("tpy") or more) and VOC source categories addressed by an EPA Control Techniques Guideline ("CTG").

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., (“Act”), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

In November 2016, the Commission determined that some major sources and CTG VOC source categories were adequately addressed under existing SIP requirements. The Commission also adopted new requirements for some major sources and CTG VOC source categories. In November 2017, the Commission adopted categorical RACT requirements for the oil and gas industry in response to EPA’s Oil and Gas CTG. In July 2018, the Commission adopted categorical RACT requirements for combustion equipment at major sources that the Commission determined in 2016 were not addressed by SIP RACT requirements.

In this rulemaking, the Commission adopts SIP requirements that further support and complete Colorado’s obligation as a moderate ozone nonattainment area to revise Colorado’s SIP to include provisions that implement RACT for all major sources of VOC and/or NOx and for all CTG VOC source categories in the DMNFR ozone nonattainment area. Specifically, the Commission adopts categorical RACT requirements for major source breweries, wood furniture manufacturing, and addresses EPA concerns with the industrial cleaning solvent, metal furniture surface coating, and miscellaneous metal surface coating requirements. The Commission also revises specific rule or reference methods incorporated by reference to add applicable citation dates. Last, the Commission adopts specific revisions in a SIP clean-up effort.

Further, the Commission corrects typographical, grammatical, and formatting errors found throughout Regulation Number 7.

Major source RACT

Colorado has major sources of VOC and/or NOx in the DMNFR. Under marginal and moderate ozone nonattainment classifications, major sources are sources with the potential to emit greater than or equal to 100 tpy of NOx or VOC. Many of the major sources analyzed in 2016 were already subject to regulatory RACT requirements in Colorado’s SIP, individual RACT requirements established in federally enforceable permits as a minor source RACT requirements, or an applicable federal New Source Performance Standard (“NSPS”) or National Emission Standard for Hazardous Air Pollutant (“NESHAP”). However, as a moderate nonattainment area, Colorado must include provisions in the SIP to implement RACT for Colorado’s major sources. In November 2016, the Commission directed some major sources to submit RACT analyses to the Division, including two major source breweries. The Commission adopts in this November 2018, rulemaking categorical RACT requirements for major source brewing activities.

Major source breweries

The Commission adopts RACT requirements for owners and operators of breweries producing malt beverages and their brewery related operations at a major source VOC as of June 3, 2016, located in the DMNFR. In a moderate ozone nonattainment area, a major VOC source is one that emits or has the potential to emit greater than 100 tpy VOC. A brewery includes brewhouse, fermentation, aging, and/or packaging operations. Brewery related operations include operations that support the production of malt beverages such as wastewater management, container manufacturing, and ethanol distillation. The Commission established RACT for combustion equipment, including at breweries, in July 2018, in Regulation Number 7, Section XVI. The Commission now adopts a process loss limit and pollution prevention requirements for brewery packaging operations. These pollution prevention provisions include performance metrics to reduce product loss, operator training, and packaging equipment to reduce container breakage and product loss. The Commission also adopts wastewater management and treatment requirements for land application of wastewater. Lastly, the Commission adopts requirements for owners or operators to keep records of production, pollution prevention activities, and wastewater to demonstrate compliance with the operational requirements.

The largest VOC emissions sources inside a brewery are associated with packaging operations, including can, bottle, and other container fillers. Breweries can reduce VOC emissions by optimizing packaging operations. The process loss limitation is representative of packaging and filling optimization and, therefore, is an indicator, and potential driver, of the resulting VOC emission reductions. The process loss limitation does not include the railcar loading of beer concentrate that is shipped off-site for packaging. In this process, empty railcars are filled with beer concentrate held in beer concentrate receiving tanks after the aging process. The process loss from the automated loading of the beer concentrate from tanks into railcars is minimal and emissions from the filling of cans, bottles, kegs, or other containers are included with the emissions of the off-site packaging facility.

The process loss is calculated on calendar month and rolling 12-month bases across all packaging operations (i.e., filling lines), which aligns with existing product tracking programs. Process loss equates to the difference in the quantity of malt beverage metered at the filler and the quantity in containers as tracked for the Alcohol and Tobacco Tax and Trade Bureau (“TTB”). Operators determine the average calendar month process loss by comparing the total volumes metered at the fillers to the total volume counted by the TTB case counters. Owners or operators will then determine monthly average process loss percentage by dividing the difference in meter and case counter values by the total volume metered at the fillers. Utilizing an average process loss limit also allows for variations in individual line or brand product loss due to specialty brands or innovative containers. The brewing industry is seeing decreased sales of high-volume brands and increased consumer demand for small-volume unique or complex brands. This market change impacts process loss as the high-volume brands have low process loss values whereas specialty brands often result in higher process loss values due to brand recipe complexity, brand mix complexity, and production schedule complexity. The packaging of more types of brands and more complex brands result in higher process loss values because of differences in recipes that require more time for the filler to adjust to the appropriate fill level, more frequent product change-overs of the filling lines, and more unique packaging. The requirement to completely flush a filling line between brands also increases process loss values when the specialty brands are produced in lesser quantities than high-volume brands. Further, bottle filling lines often have different process loss values than can filling lines, therefore the change in container demand can impact the overall process loss. The average process loss limit of 6 percent on a calendar month and 4 percent on a 12-month rolling average leaves the necessary margin for variability and innovation, while still providing an indicator of RACT-level control of brewery packaging operations VOC emissions.

The Commission exempts from the process loss, pollution prevention, and recordkeeping requirements emissions units subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 and emission units with total uncontrolled actual VOC emissions less than two tons per year. The first exemption was adopted to avoid subjecting sources to overlapping, duplicative, or contradictory RACT requirements. The second exemption was adopted for consistency with other major source RACT provisions and the use of Colorado's permitting thresholds for NOx and VOC to identify the emission points at major sources for which Colorado evaluated RACT.

The Commission also exempts equipment or activities related to research and development and newly installed, upgraded, or replaced packaging operations. Research and development activities include testing different recipes and packaging types before a product is distributed into commerce. The six-month startup exemption for newly installed, upgraded, or replaced packaging operations allows for the testing and adjustment of the new equipment to meet performance requirements. Examples of newly installed, upgraded, or replaced packaging operations include a new filling line or an upgraded or replaced man-to-machine-interface. Startup of newly installed, upgraded, or replaced packing operations does not include the startup or changeover of malt beverages or new recipes. Quality assurance teams follow a statistical process to verify that equipment is meeting quality standards prior to releasing salable product. These processes may include additional container testing, product sampling, or additional filler flushes while packaging operations are fine-tuned to meet key performance indicators. The volume of the product metered at the filler during the research and development and startup processes is excluded from the monthly process loss calculations. However, new, upgraded, or replaced packaging operations are not exempt from employees training requirements to ensure that employees understand the new packaging operations after startup.

Pollution prevention provisions also include the use and operation of packaging equipment to reduce container breakage and product loss. The Commission exempts from the automated filling equipment requirements packaging operations at pilot brewery operations. Automated filling equipment may be mechanical with a set fill quantity or electric with a flow meter and adjusting fill quantity. Both processes improve consistency, reduce spillage and product loss, and reduce the variation that may occur from human error. The automated filling lines also include fill level detectors that will reject inadequately filled containers for recovery and recycling. A pilot brewery operation may serve the purposes of research and development but can also be utilized to produce very small quantities of product that is distributed into commerce. Pilot brewery operations can include different filling operations (e.g., bottles, kegs) but may use some manual filling related processes instead of automated processes. The use of manual processes is consistent with industry practices for operations of this small size, less than 50,000 barrels per year, and provides flexibility to account for production variations that may occur during research and development or small batch production.

Wood furniture manufacturing

In 2016, the Commission determined that only one source in the DMNFR exceeded the Wood Furniture CTG applicability threshold, and that source was a major source of VOC. Therefore, the Commission incorporated by reference requirements in 40 CFR Part 63, Subpart JJ (National Emission Standards for Wood Furniture Manufacturing Operations) into the SIP for wood furniture surface coating operations. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could streamline their RACT analysis by relating MACT controls to VOC RACT considerations. However, EPA has since expressed concerns that the NESHAP JJ volatile hazardous air pollutant ("VHAP") coating content limits may not adequately address coating VOC emissions. The Commission therefore removes the incorporation by reference of NESHAP JJ for wood furniture manufacturing operations in Section XIX. and is instead including the CTG recommended coating VOC content limits and work practices in Section IX.O.

The coating VOC content limits apply to sealers, topcoats, acid-cured alkyd amino vinyl sealers, or acid-cured alkyd amino conversion varnish topcoats. EPA's Wood Furniture CTG does not define acid-cured topcoats or sealers but does describe acid-catalyzed finishes as the most common catalyzed finishes. The Wood Furniture CTG further states that the film-forming resins in these finishes are usually a urea-formaldehyde or melamine-formaldehyde prepolymer mixed with an alkyd resin that serves as a plasticizer. Common catalysts contained in the acid-catalyzed finishes include sulfuric acid and p-toluenesulponic acid and film formation occurs through curing (polymerization) of the resins rather than drying.

SIP Clean-up

Industrial Cleaning Solvent

In 2016, the Commission adopted provisions in Regulation Number 7, Section X. to include RACT requirements related to the use of industrial cleaning solvents. The Commission adopted several exemptions recommended by EPA's Industrial Cleaning Solvents CTG as well as exemption for sources complying with cleaning solvent requirements in a federally enforceable NSPS, NESHAP, Best Available Control Technology requirement, or Lowest Achievable Emissions Rate requirement, which was similar to an EPA approved exemption in Colorado's Regional Haze SIP. EPA has since indicated concerns with approving this broad exemption due to a perceived lack of specificity. The Commission therefore removes the broad exemption in Section X.E.4.a.(i).

Metal furniture and miscellaneous metal surface coating

EPA published Metal Furniture CTGs in 1977 and 2007 and Miscellaneous Metal Parts and Products CTGs in 1978 and in 2008. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could conclude that sources already addressed by RACT determinations for a previous ozone NAAQS do not need to implement additional controls because a new RACT determination would result in the same or similar control technology as the initial RACT determination and any incremental emissions reduction from the application of a second round of controls would be small and the cost unreasonable. Therefore, in 2016 the Commission relied on the RACT provisions relating to the 1977 and 1978 CTGs adopted into Regulation Number 7, Sections IX.H. and IX.L. in 1978 and 1980 to continue to establish RACT for metal furniture and miscellaneous metal coating operations. EPA has since indicated concerns with the existing provisions due to a lack of specified application technique. The Commission therefore revises Section IX. to specify the use of good air pollution control practices, including efficient application methods.

1990 and 1991 RACT Reports

In 1990, the Commission adopted one of several requirements in Regulation Number 7, specifically Sections I.B.2.f. and I.B.2.g., for existing sources to address EPA concerns with the design, implementation, and enforceability of Colorado's previously submitted and approved Ozone SIP. The provisions included one-time reporting requirements concerning source emissions and RACT for sources existing as of 1989. The provisions were not an ongoing reporting requirement potentially necessary for monitoring compliance with applicable emissions limits. EPA approved these provisions into Colorado's SIP in 1995, without discussion. Due to these one-time requirements having passed and Colorado's major stationary sources being subject to RACT requirements in Regulation Number 7, as adopted by the Commission through 2018, the Commission removed these historic provisions. Removal of these provisions does not remove or modify any control measures, therefore does not affect emissions nor interfere with attainment or reasonable further progress. Where information in the Sections I.B.2.f. and I.B.2.g. reports informed RACT requirements under Section II.C., sources remain subject to applicable RACT requirements and any emission reporting requirements as addressed by the emission statement rule last approved by EPA in 2015 (See 80 Fed. Reg. 50205 (August 19, 2015)).

Incorporation by Reference

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Sections II., VI., VIII., IX., X., XII., XIII., XVI., and XVII.

Additional Considerations

Colorado must revise its Ozone SIP to address the moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

(I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC in Colorado's ozone nonattainment area. Colorado's major sources of VOC are subject to various and numerous NSPS or NESHAP, Regulation Number 7 requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC in the SIP. Specifically, the Commission adopted RACT requirements in Section XX. for brewing activities located at major sources of VOC in the DMNFR. The Commission also adopted RACT requirements from EPA's Wood Furniture CTG for wood furniture surface coating in Section IX. MACT JJ may apply to wood furniture surface coating operations.

(II) The federal rule discussed in (I) is primarily technology-based in that it largely prescribes the use of specific coating VHAP contents in order to comply. The federal rule provides flexibility by allowing subject facilities to select any coating meeting the specified VHAP content limits.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.

(V) EPA has established a January 1, 2017, deadline for this SIP. There is no timing issue that might justify changing this time frame.

(VI) The revisions to Regulation Number 7, Sections IX., X., and XX. establish categorical RACT for major sources of VOC and CTG VOC source categories, and thus are necessary to satisfy RACT SIP requirements for moderate nonattainment areas. The provisions are specific to emission points at sources of VOC, allowing for continued growth at Colorado’s sources.

(VII) The Revisions to Regulation Number 7, Sections IX., X., and XX. establish reasonable equity for sources of VOC by providing the same categorical standards for similarly situated and sized sources.

(VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a one-year clean data extension) EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado’s SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado’s sources. Either of these outcomes may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC generally reflect current emission controls and work practices.

(XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.

(XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division’s proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an un-approvable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado’s ozone SIP to address the moderate nonattainment area requirements. However, 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 the ozone precursors VOC and NOx.

(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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

S. December 19, 2019 (Sections I. through XX. and Appendices A through F – reorganized into Parts A through F)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) Sections 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission (Commission). This proposed rulemaking focuses on the Air Quality Control Commission directives in Section 25-7-109, CRS, SB19-181 directs the Commission to adopt regulations to "minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx)" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Commission should consider including semi-annual leak detection and repair (LDAR) inspection requirements at all well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This rulemaking addressed many of the specific provisions for consideration, except continuous methane monitoring, but is only the first of many rulemakings to come in addressing SB 19-181.

Further, on August 15, 2019, the Environmental Protection Agency (EPA) proposed to reclassify the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). See 84 Fed. Reg. 41,674 (Aug. 15, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy and the DMNFR's attainment date becomes July 20, 2021. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Therefore, as a first step to addressing the new statutory directives, and ensuring progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to minimize emissions from the oil and gas sector and to include reasonably available control technology (RACT) requirements for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy. The oil and gas industry is a significant source of VOC, NOx, ethane, and methane emissions, and the Commission expects the industry's growth to continue in the foreseeable future. Improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs, ethane, and methane in a cost-effective manner. These technologies and practices include, without limitation, frequent LDAR inspections, reducing emissions from pneumatic controllers, reducing emissions from the transmission segment, storage tank measurement systems, and vapor collection and return equipment.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO (and NSPS OOOOa) are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both State Implementation Plan (SIP) requirements that apply in the DMNFR and state-only requirements that apply state-wide. In addition, evidence in the rulemaking record supports the conclusion that the rules can be implemented effectively. Accordingly, the Commission concludes that the rules are technologically feasible and cost-effective.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, *et seq.* (Act), specifically § 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 that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas operations, including well production facilities and natural gas compressor stations. The Commission expands the inspection and enhanced response program for pneumatic controllers it adopted in 2017 for pneumatic controllers in the DMNFR to a state-wide applicability. The Commission adopts a new, innovative performance based program to reduce emissions from the downstream transmission segment.

The Commission is replacing the system-wide condensate storage tank control strategy in the SIP with a more straight-forward storage tank control threshold. The Commission is also seeking to reduce emissions from storage tank measurement and sampling and loadout activities, and to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission is expanding the requirement to employ best management practices to minimize emissions at oil and gas wells during well plugging activities. The Commission is also establishing an annual emissions inventory report that oil and gas operators will submit to the Division, which will ensure accountability and assist the Commission in understanding the emissions of methane, ethane, VOC, CO, and NOx associated with different activities and equipment in oil and gas operations. The Commission believes that this combination of revisions is appropriate as a first step in minimizing emissions from oil and gas operations and continuing to make progress towards attainment of the ozone NAAQS.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, including categorical RACT requirements, and requiring the submission of RACT analyses.

The Commission is also updating requirements for gasoline transport trucks, bulk terminals, and service stations to align with current federal requirements in a SIP clean-up effort.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Reorganization

Over the years, Regulation Number 7 has grown. In an effort to facilitate readability, and to better allow the regulated community to identify and understand the provisions governing their activities, the Division is proposing a full reorganization of Regulation Number 7 into parts. A table identifying the new section(s) along with the prior section/location is below. This Statement of Basis and Purpose will refer to the reorganized section numbers in the discussion of revisions and new provisions.

Reorganized Regulation Number 7 Section	Regulation Number 7 Section (as of 11/15/2018)
Part A	
Part A, Section I.	I. Applicability
Part A, Section II.	II. General Provisions
Part A, Appendix A	Appendix A. Colorado Ozone Nonattainment or Attainment Maintenance Areas

Part B	
Part B, Section I.	III. General Requirements for Storage and Transfer of Volatile Organic Compounds
Part B, Section II.	IV. Storage of Highly Volatile Organic Compounds
Part B, Section III.	V. Disposal of Volatile Organic Compounds
Part B, Section IV.	VI. Storage and Transfer of Petroleum Liquids
Part B, Section V.	VII. Crude Oil
Part B, Section VI.	VIII. Petroleum Processing and Refining
Part B, Section VII.	XV. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities
Part B, Appendix B	Appendix B. Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks
Part B, Appendix C	Appendix C. Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants (Vapor Balance System)
	Appendix E – deleted, paragraphs B and E moved into section, and references replaced with EPA Method 27

Part C	
Part C, Section I.	IX. Surface Coating Operations
Part C, Section II.	X. Use of Cleaning Solvents
Part C, Section III.	XI. Use of Cutback Asphalt
Part C, Section IV.	XIII. Graphic Arts and Printing
Part C, Section V.	XIV. Pharmaceutical Synthesis
Part C, Appendix D	Appendix D. Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers
Part C, Appendix E	Appendix F. Emission Limit Conversion Procedure

Part D	
Part D, Section I.	XII. Volatile Organic Compound Emissions from Oil and Gas Operations
Part D, Section II.	XVII. (State Only, except Section XVII.E.3.a., which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines
Part D, Section III.	XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations
Part D, Section IV. (State Only) Control of emissions from the transmission and storage segment	NEW
Part D, Section V. (State Only) Oil and Natural Gas Operations Emissions Inventory	NEW

Part E	
Part E, Section I.	XVI.A.-C. (natural gas fired reciprocating internal combustion engines in the 8-hour ozone control area) and XVII.E. (new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines)
Part E, Section II.	XVI.D. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area
Part E, Section III.	XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-Hour Ozone Control Area
Part E, Section IV.	XX. Control of Emissions from Breweries in the 8-Hour Ozone Control Area

Part F	
	XXI. Statements of Basis, Specific Statutory Authority and Purpose

State Implementation Plan Revisions (Part D, Section I. (formerly Section XII.))

The Commission adopted several revisions to the SIP provisions that were previously found in Section XII. While not strictly necessary to comply with a particular CAA requirement pertaining to ozone, the revisions implement the mandate of SB 19-181, strengthen Colorado's Ozone SIP, and will achieve further reductions in ozone precursors and other hydrocarbons.

Applicability (Section I.A)

The Commission revised the applicability language of Part D, Section I. to clarify that all oil and gas operations at and upstream of the natural gas processing plant are subject to the provisions of Section I., as more specifically set forth in Sections I.A through L. The Commission also revised the applicability to ensure that storage tanks containing hydrocarbon liquids (*e.g.*, condensate, crude oil) and produced water are subject to the provisions of Section I., which previously applied only to condensate storage tanks.

Further, under previous provisions, owners and operators of condensate storage tanks for which the APENs reflecting emissions from all operations were 30 tpy VOC or less were exempted from Section I. Given the challenges with attaining the ozone NAAQS, the number of tanks that were exempt under this provision, and the need for further reducing emissions from those tanks, the Commission removed this exemption.

However, the Commission retained the exemption from the system-wide control strategy in Section I.I. (formerly Section XII.I.) for owners or operators of natural gas compressor stations that do not also own or operator exploration and production facilities and the exemption in Section I.G. (formerly XII.G.) for owners or operators of natural gas processing plants. Owners or operators of these facilities must continue to control condensate storage tanks as specified in Sections I.I. and I.G. By retaining these exemptions, the Commission does not intend to exempt these facilities from any applicable requirements in Part D, Section II.

Storage Tank Controls (Section I.D)

In 2004, the Commission adopted the initial system-wide control strategy, which required operators to reduce emissions from their system of condensate tanks. The “system” was comprised of condensate tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy, and allowed operators to decide which tanks to control so long as emissions from the “system” were reduced by specified percentages. The system-wide control strategy involved complicated and often times confusing recordkeeping and reporting. Further, the system-wide control strategy had the unintended impact of disincentivizing operators to build new facilities without storage tanks (a real emissions benefit), because operators could not take credit for the production at tankless facilities in their “system.” As a result, the Commission replaced the system-wide control strategy with a straightforward control threshold. Operators in the 8-hour Ozone Control Area will have until May 1, 2020, (prior to summer ozone season 2020) to install controls on storage tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy. Only the requirements for storage tanks with uncontrolled actual VOC emissions equal to or greater than 4 tpy are included in the SIP, while the requirements for the storage tanks between 2 and 4 tpy will remain state-only. This provision expands the control requirements to crude oil and produced water tanks, and will result in several hundred more tanks being controlled. The Commission has reviewed the evidence and has determined that the 4 tpy SIP threshold and implementation timetable is cost-effective, technically feasible, and will ensure no backsliding as provided for in the Clean Air Act, Section 110(l). In Sections I.D.3.b.(v) and I.D.3.b.(vi)., the Commission has required that storage tanks below the 2 tpy threshold that increase emissions above the threshold must be in compliance with 60 days of the first date of the month after which the threshold was exceeded. As a result, if a storage tank exceeds the 2 tpy threshold in September 2020, based on a rolling twelve-month total (*i.e.*, October 2019-September 2020), the tank must have controls installed and operating within 60 days of October 1, 2020. These provisions will not only minimize emissions from storage tanks but will ensure clarity in the applicability of control requirements and will assist Colorado in making additional progress towards attainment of the ozone NAAQS.

The Commission has also determined that storage tanks that cannot install controls by the applicable compliance date may shut-in all wells producing to the applicable storage tanks, so long as production from any well producing into the storage tank is not resumed until controls are installed. It is the Commission’s intent that this allowance not apply unless the operator shuts in all wells feeding in to the storage tank/battery requiring controls. This will avoid the need for operators to install control equipment when wells are shut-in and where the operator may determine not to return those wells to production. Further, the Commission intends that the Division will work with operators in the DMNFR to allow for appropriate time to conduct design analyses to comply with Sections I.C.1.b. and II.C.2.a., as long as operators install required controls by May 1, 2020, and are pursuing compliance with reasonable diligence.

The Commission has also included in the SIP in Sections I.D.2.a. and II.C.1.b.(ii) the existing requirements (formerly Sections XII.D.1. and XVII.C.1.c.) that operators of newly constructed tanks employ controls during the first 90 days after the date of first production (this provision was previously designated state-only). However, these revisions to Regulation Number 7, in conjunction with revisions to Regulation Number 3, use the term “commencement of operation” instead of “date of first production.” This SIP revision is not part of Colorado’s ozone attainment requirements but is directed at making this requirement enforceable by the EPA and members of the public under the CAA. While the Commission does not believe inclusion of this provision in the SIP was required for compliance with Colorado’s permitting program in Regulation Number 3 with CAA requirements, including ozone nonattainment area requirements, pursuant to Section 25-7-105.1(1), CRS, including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source’s potential to emit for purpose of permitting.

Storage Tank Monitoring (Section I.E)

The Commission revised Section I.E. to apply the monitoring requirements to all storage tanks controlled pursuant to Section I.D., which will ensure monitoring not only of condensate tanks, but also of crude oil and produced water tanks on a weekly basis. The required inspections have also been updated to include common-sense elements that can have a real impact on performance of well production facility equipment and can reduce emissions. For example, checking that burner trays are not visibly clogged can improve the performance of air pollution control equipment. The Commission does not intend that operators should shut-in the combustor for the sole purpose of performing this inspection to observe the burner tray, and need only inspect those portions of burner trays that are visible without shutting in. The Commission also adopted into Section I.E. requirements that previously existed in Section II. (formerly Section XVII.) to check that pressure relief valves are properly seated and that vent lines are closed. Similarly to the inspection in Section II.C.1.d.(i), operators are not expected to disassemble or otherwise manipulate the pressure relief valve to complete the inspection, unless the visual observation of the valve reveals it is unseated and corrective action needs to be taken. Further, the Commission does not expect operators to climb on top of a tank to observe the pressure relief valve. However, operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

The Commission has removed references to recordkeeping from Section I.E. and has attempted to condense all recordkeeping requirements in Section I.F. For example, Section I.E.2.c.(iv) no longer provides that operators must “check for and document” the inspection; instead, Section I.E.2.c. requires operators to “check”, and the requirement to “document” the inspection is found in Section I.F.2.c.

Recordkeeping and Reporting (Section I.F)

As a result of replacing the system-wide control strategy with the fixed control threshold, the Commission revised the recordkeeping and reporting requirements for demonstrating compliance with Section I.D. Operators subject to the system-wide control strategy will still be required to submit an annual report for calendar year 2019 by the same deadline of April 30, 2020, and are given until August 31, 2020, to submit the report for the time period in 2020 during which the system-wide control strategy remains effective (*i.e.* January 1 – April 30, 2020). In Sections I.F.2. and I.F.3., the Commission has created a new recordkeeping and reporting scheme for the tanks subject to the new control threshold provisions. The Commission has largely maintained the same recordkeeping and reporting requirements for the monitoring provisions in Section I.E. However, the Commission streamlined the new storage tank recordkeeping and reporting requirements, which are included in the SIP for storage tanks at or above the 4 tpy threshold, but are included on a state-only basis for the storage tanks between 2 and 4 tpy.

Miscellaneous

The Commission adopted revisions to definitions (Section I.B.) and the general provisions (Section I.C.). A new definition for “commencement of operation” was added for consistency with Regulation Number 3 and for clarity as to the applicability of other control requirements (previous versions of Regulation Number 7 were tied to the “date of first production,” which was not implemented consistently amongst operators). The Commission adopted the term “date of first production” in 2014 with the intent that it coincide with the date reported to the Colorado Oil and Gas Conservation Commission (COGCC) on COGCC Form 5A. Through implementation of the 2014 revisions, differences between the Commission’s and the COGCC’s use of the term were realized. Therefore, the Commission has replaced “date of first production” with the more clearly defined “commencement of operation” term.

The Commission also adopted new definitions for “hydrocarbon liquid,” “produced water,” “storage tank,” and “storage vessel” to ensure consistency with the state-only program in Part D, Section II. The definition of “storage tank” referred to the federal definition of “storage vessel” and, therefore, captured crude oil and produced water tanks, in addition to condensate tanks. The federal definition has now been included as a standalone definition of “storage vessel.”

The Commission also revised Section I.C.1.b. to reflect that Section I. now applies to oil and gas operations collecting, storing, processing, and handling hydrocarbon liquids and produced water, not just condensate. The Commission replaced the term “leakage” with the term “emission” in order to be consistent with the Common Provisions definition of “emission.” The Commission does not intend this latter revision to reflect a change in the meaning or applicability of Section I.C.1.b. (or Section II.B.1.a., where this revision is also made), but only to improve clarity.

The Commission revised Section I.C.2., which specifies how operators must calculate emissions and emission reductions for purposes of demonstrating compliance with the control requirements. These revisions expand the current provisions to storage tanks storing hydrocarbon liquids other than condensate and to storage tanks storing produced water. For crude oil tanks and produced water tanks, operators will need to refer to default emission factors as established and updated by the Division. *See, e.g.* PS Memo 14-03, *Oil & Gas Industry Crude Oil, Condensate and Produced Water Atmospheric Condensate Storage Tanks, Regulatory Definitions and Permitting Guidance for General Permit GP08.*

The Commission has not substantively revised the LDAR SIP provisions of Section I.L. but clarified that applicability is based on emissions on a rolling twelve-month basis, not a calendar year basis. Such was the Commission’s intention in adopting the program in 2017.

The Commission has also determined to incorporate Section II.F. (formerly Section XVII.G.) into the SIP. This provision requires control of emissions coming off a separator after a well is newly constructed, hydraulically fractured, or recompleted. These emissions must be routed to a gas gathering line or controlled by air pollution control equipment. This SIP revision is not part of Colorado’s ozone attainment compliance requirements, but is directed at clarifying that this requirement is enforceable by the EPA and members of the public under the CAA. Including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source’s potential to emit for purposes of permitting. *See* Section 25-7-105.1(1), CRS.

<u>State-wide, State-Only Revisions (Part D, Section II. (formerly Section XVII.))</u>

In Part D, Section II., the Commission adopted several revisions to begin its implementation of SB 19-181. These revisions further support existing control requirements and also seek reductions from previously unregulated emissions activities (*e.g.,* gauging and loadout).

Storage Tank Controls, Monitoring, Recordkeeping, and Reporting (Sections II.C.1.c., II.C.1.d., II.C.2.b. and II.C.3.)

Since 2011, Colorado has made significant progress in reducing emissions from storage tanks. However, storage tanks remain the largest source not only of oil and gas VOC emissions, but of all anthropogenic VOC emission sources in the state (per the 2017 nonattainment area emissions inventory in the Moderate area ozone nonattainment SIP). The Commission has determined that it is cost effective and technically feasible to lower the control threshold from 6 tpy VOC (as established in 2014) to 2 tpy VOC. However, the Commission does not want to facilitate or encourage the use of supplemental fuel to operate control equipment, and understands that this can occasionally be an issue on the West Slope, in particular, where the facilities have lower pressure. The Commission has therefore adopted a provision that allows operators to seek from the Division an exception to controlling tanks between 2 and 6 tpy VOC under these circumstances. Exceptions should be sought prior to compliance deadlines, and will be effective upon submittal unless and until the Division determines an exception is not appropriate. Storage tanks constructed on or after March 1, 2020, must have controls upon commencement of operation, ensuring reductions during the 2020 summer ozone season. Storage tanks outside the nonattainment area constructed prior to March 1, 2020, must be in compliance by May 1, 2021. The Commission determined it was appropriate to give tanks outside the nonattainment area between 2 and 6 tpy VOC extra time to install controls. The Commission does not intend to give extra time to storage tanks with air pollution control equipment already installed, even where controls are not currently required by Regulation Number 7 (e.g., where an operator has submitted an APEN claiming controls).

The Commission revised the approved instrument monitoring method (AIMM) schedule for inspections of controlled storage tanks to align with the Commission’s revision of the LDAR inspection frequencies in response to SB 19-181, discussed further below. The Commission adopted a semi-annual frequency for storage tanks with emissions greater than or equal to 2 tpy and less than or equal to 12 tpy. For storage tanks with emissions greater than or equal to 6 tpy and less than or equal to 12 tpy, this is an increase in inspection frequency from annual to semi-annual. Where the Commission specifies that semi-annual monitoring must “begin” in a certain year, the Commission intends that there be at least two AIMM inspections during that year. The Commission also removed the phase-in schedule for storage tanks inspections (within 90 days of January 1, 2016 for storage tanks ≥ 6 and within 30 days for storage tanks > 50 tpy) as those schedules have passed. The Commission updated the recordkeeping requirements for AIMM inspections to be consistent with the LDAR recordkeeping in Section II.E. Records of AIMM inspections under Sections II.C. and II.E. may be maintained together, and need not be kept separately.

The Commission has also strengthened monitoring requirements for storage tanks and associated equipment. In Section II.C.1.d., the Commission has determined that it is cost effective and feasible, while already on-site for visual inspection, to check the dump valve on the separator to ensure that it is not stuck open or visibly clogged. The Commission does not intend that operators will need to manipulate equipment or stay on-site for the purpose of observing actuation of the dump valve for purposes of this inspection requirement. The Commission has also determined that excess liquids in the vapor lines can cause a multitude of problems, including overpressurization of the tanks or smoking flares. Therefore, the Commission is directing operators to check liquid knockout vessels, when present, unless the vessel is set up to drain automatically, and to drain liquids if above the low-level indication point. If the knockout vessel is not equipped with a liquid level indicator, operators can comply with this requirement by draining the knockout vessel during the inspection. Further, for underground lines and above-ground lines where no knockout vessel is used, operators should establish a procedure by which they evaluate for the presence of liquids in the vapor lines, and drain as necessary. Appropriate operating and maintenance program documents should set forth this procedure so as to provide clarity on how an operator determines draining is necessary. These actions can be taken while the operator is already on-site for the inspections previously required, are consistent with actions the Commission generally understands operators are already taking in the field and therefore, the Commission does not expect these actions to create additional burden.

The LDAR program in Section II.E. (formerly Section XVII.F.) has required remonitoring following repair of a leak (as has Section I.L.). However, Section II.C. did not include an explicit remonitoring requirement following actions taken to address venting from storage tanks. Operators must now confirm that actions taken to address venting were effective through remonitoring. This confirmation must be made within 24 hours of the action taken to address the venting. This requirement does not reflect a timeframe in which the operator may address the venting without incurring liability for the violation. There is currently no regulatory period in which venting will not be considered a violation of Section II.C.2.a., unless the venting is reasonably necessary for one of the reasons expressly contemplated by Section II.C.2.a. Only where the initial emissions observation was observed through AIMM does the success of the response action need to be verified through AIMM. However, the Commission believes that if the venting was found with an IR camera and was addressed while the IR camera operator was on-site, then there is little to no burden to use the IR camera to confirm, for example, an effective seating of the thief hatch upon closure. In Section II.C.3.f., the Commission has established supplemental recordkeeping requirements when venting is observed and addressed.

In Section II.C.3.d., the Commission has strengthened recordkeeping requirements of inspections under Section II.C.1. These recordkeeping requirements are consistent with the recordkeeping required in Section I.F. (formerly Section XII.F.). The Commission has maintained the exemption from recordkeeping under Section II.C.3.b., for instances where venting is reasonably necessary for maintenance, gauging (unless a storage tank measurement system is required under and the operator complies with Section II.C.4.), or safety of personnel and equipment. However, the Commission expects that the emissions associated with these venting events will be reported in the annual emissions inventory.

Storage Tank Measurement Systems (Section II.C.4.)

Historically, operators have needed – for operational purposes – to open the thief hatch on storage tanks in order to sample and measure the level of the liquid to be sold (i.e., to determine quality and quantity). Technology has advanced over the past few years, including, without limitation, the use of Lease Automatic Custody Transfer (LACT) units, automated tank gauges, and the development of API 18.2 (Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods), which allow for the sampling and measurement of liquids without opening the thief hatch. It is the Commission's intention that owners and operators of facilities and tanks constructed after the deadlines in new Section II.C.4. must measure the level of the liquid (e.g., use tank level sensors) and sample the liquids (e.g., check for temperature, BS&W, and other indicia of merchantability) without opening the thief hatch. These storage tank measurement systems can be employed at facilities with and without automation. Further, a significant number of operators have already deployed such systems at large and small facilities in the DJ Basin, in some cases voluntarily and in some cases as required pursuant to a Consent Decree or Compliance Order on Consent. The Commission notes that a storage tank management system may be different for tanks where liquids are both sampled and measured than for tanks where liquids are not sampled. For example, Commission understands that some produced water tanks are not sampled for quality, and therefore do not need to have equipment to allow for the sampling of the liquids without opening of the thief hatch.

Therefore, the Commission adopted a requirement to employ storage tank measurement systems to determine the quantity of the liquid at well production facilities, natural gas compressor stations, and natural gas processing plants constructed on or after May 1, 2020. Any such facilities that are constructed after January 1, 2021, must have storage tank management systems in place that determine both the quality and the quantity of the liquid. This requirement also applies to storage tanks at existing well production facilities, natural gas compressor stations, and natural gas processing plants that are modified by adding storage tanks. When operators add new storage vessels to existing facilities (e.g., to add capacity because production or throughput is expected to increase), they must outfit the new storage vessels and retrofit the existing vessels in the same battery with a storage tank management system. However, the ability to retrofit an existing battery may not exist, and is therefore not required, where a single storage tank is replaced due to maintenance concerns or where a tank is installed to provide extra head space in the vapor control system, but no production increase is associated with the installation.

The Commission has adopted minimal recordkeeping provisions for this requirement, including a description of the storage tank measurement system and records of the annual training program. The description must be sufficiently detailed to enable the Division to determine whether the operator is in compliance (e.g., sampling the liquids without opening the thief hatch). If an operator relies on a third party (e.g., hauler) to perform the gauging activities, those operators will need to work with the haulers to facilitate the training that will familiarize haulers with this new requirement.

The Commission has also adopted a requirement to allow for periodic calibration and testing of the storage tank measurement system. The Commission recognizes that while the Bureau of Land Management expressly allows for automatic tank gauging (*see e.g.* 42 C.F.R. Section 3174.3(33), incorporating by reference API 18.2), it can be necessary to test and calibrate the automatic tank gauging system. *See* 42 C.F.R. Section 3174.6(b)(5)(ii)(B). It is not the Commission's intent to adopt requirements at odds with the Bureau of Land Management. Further, some manufacturers may recommend inspection, testing, or calibration more frequently than specified by the Commission; the Commission intends to allow for those maintenance procedures, as reasonably necessary (i.e., the exception should not render ineffective the Commission's intent that thief hatches remain closed during the sampling and measurement process). Operators that perform maintenance procedures more frequently than semi-annually need to document the manufacturer's recommendation for the increased frequency and provide those materials to the Division upon request.

Hydrocarbon Liquids Loadout (Section II.C.5)

In Section II.C.5., the Commission has adopted new requirements to control or avoid emissions associated with the unloading of hydrocarbon liquids into transport vehicles (e.g., trucks). These requirements do not apply to produced water loadout. The Commission has determined to prohibit the venting of hydrocarbons during loadout activities, because the venting is not reasonably necessary within the meaning of Section II.C.2.a.; however, the Commission notes that some thief hatches may be "open" during loadout but are not emitting and are instead operating only as vacuum relief for the storage tank. An "open" pressure relief device that does not emit, but instead creates a vacuum, would not be a violation of the prohibition on venting during loadout, though the burden will remain on operators to demonstrate that any open pressure relief devices are not venting.

These requirements will apply to well production facilities, natural gas compressor stations, and natural gas processing plants constructed before and after May 1, 2020, with annual hydrocarbon liquid loadout throughput equal to or greater than 5,000 barrels per year, on a 12-month rolling basis. Throughput is based on the throughput of liquids loaded out to transport vehicles and does not include liquids loaded out to pipeline. Facilities constructed after May 1, 2020, must control emissions from loadout upon commencement of operation if they anticipate having a loadout throughput over 5,000 barrels per year. Facilities that are modified (e.g., new well drilled, well re-fracked or recompleted) that expect to have throughput over 5,000 barrels per year must also control loadout operations upon commencement of operation following the modification. Facilities that increase throughput such that loadout throughput reaches 5,000 barrels must control the emissions from loadout upon reaching 5,000 barrels. The Commission does not intend that operators may loadout more than 4,999 barrels of hydrocarbon liquids without controls. Thus, if an operator currently loads out to pipeline, and is not subject to this requirement, but the pipeline becomes unavailable (e.g., due to maintenance, whether scheduled or unscheduled) and the operator has 6,000 barrels stored in tanks, the operator must control the emissions from the loadout to transport vehicles or wait to loadout to transport vehicles until it can arrange for controls.

The Commission recognizes that compliance may be more cost effective at newly constructed facilities for several reasons. Operators may account for the vapors associated with loadout in the initial evaluation of air pollution control equipment required. Operators may also design the facility to make compliance easier, with both these requirements and Section II.C.4. However, the Commission has determined that it is also cost-effective and technically feasible to retrofit existing facilities to control loadout emissions. Operators using air pollution control equipment to control loadout emissions must also comply with other Regulation Number 7 requirements applicable to air pollution control equipment (e.g., inspections, recordkeeping). Further, if operators employ vapor collection and return systems, operators should include this vapor source in the engineering evaluation of their storage tanks and vapor control systems to avoid over-pressurizing the tanks.

The Commission has also established additional requirements to ensure the effective control of loadout emissions, including many requirements that the Division has previously established as permit RACT (under Regulation Number 3 and not as categorical RACT used for ozone SIP purposes) in loadout permits. The Commission determined that observation of and/or training and signage related to the loadout process by operators will help ensure that new staff and third parties are effectively implementing these requirements. The Commission directed the Division to develop a template and/or guidance regarding expectations for signage. However, if tanks are loaded out less frequently than monthly, the observation needs to take place during loadout when it does occur, unless observation is not feasible. If observation is not feasible (e.g., the operator did not receive notice of the loadout, which occurred during the middle of the night when no operator personnel was on site), the operator must inspect the facility within 24 hours to ensure that loadout equipment was properly stored and that thief hatches were closed. The Commission encourages the Division to work with operators to better understand when observation is, or is not, feasible.

Leak Detection and Repair (Section II.E)

In SB 19-181, the Legislature directed the Commission to minimize emissions from the oil and gas sector, including the gathering and boosting segment (i.e., compression). In conjunction with this directive, SB 19-181 further instructed the Commission to consider semi-annual monitoring for leaks at well production facilities. Therefore, the Commission has revised the LDAR program of Section II.E. (formerly Section XVII.F.) to increase the frequency of approved instrument monitoring method (AIMM) inspections to semi-annual at compressor stations with emissions between 0 and 12 tpy VOC and at well production facilities with emissions between 2 and 12 tpy VOC. Phase-in of these new inspections begins in 2020, and the Commission expects that operators will conduct the first semi-annual inspection prior to the start of the summer ozone season (i.e., May 1, 2020). Current requirements in place for larger facilities to inspect on a more frequent basis remain unchanged.

The Commission adopted a proposal to require enhanced leak detection and repair requirements for facilities within 1,000 feet of an occupied structure. The commission also directed the Division to work on a proposal that would speed up repair times in these areas and bring forward for the Commission's consideration in a future rulemaking hearing as soon as possible.

There are no other substantive changes to the existing LDAR program.

Emissions Associated with Well Maintenance, Unloading, and Plugging Activities (Section II.G)

In 2014, the Commission adopted a requirement that operators use best management practices (BMPs) to minimize hydrocarbon emissions and the need for well venting associated with well liquids unloading and well maintenance. The Commission is replacing the term "venting" with "emissions" or "emitting" to ensure consistency with the Common Provisions definition of "emission" and to avoid any confusion with the new definition of "venting" that was added to Section II.C.2.a.(i) (formerly Section XVII.C.2.a.(i)) in 2017, though no change in meaning or applicability is intended. The Commission has determined that BMPs should also be employed to reduce emissions from the well associated with well plugging activities. These activities have been increasing in frequency in the DMNFR in recent years, and the Commission finds that BMPs are a cost-effective and flexible proactive strategy to address this emerging emissions source. BMPs include both practices that reduce the need for well liquids unloading or well maintenance activities and practices that reduce or control emissions resulting from the well maintenance, well liquids unloading, and well plugging activities.

The Commission has also clarified and strengthened the recordkeeping and reporting requirements associated with the well emissions and BMPs. The inventories that will be required to demonstrate attainment with the ozone NAAQS in future SIPs necessitate detailed information on the emissions associated with these activities. Further, understanding BMPs employed to reduce or eliminate these emissions will assist the Commission in developing both voluntary and regulatory strategies to make further progress towards attainment. In an effort to minimize duplication with the new emissions inventory in Section V., the Commission intends that all information associated with activities covered by this Section II.G. will be reported on a separate form and not as part of the Section V. inventory. While recordkeeping is to begin in July 2020, the Commission understands that current methods of reporting emissions from these activities may need to be updated or improved in the future, and the Commission directs the Division to work with stakeholders to update emission factors and/or calculation methods as necessary.

Miscellaneous

Section II.C.2.a. prohibits the venting of hydrocarbons, unless reasonably required for maintenance, gauging, or safety. The Commission now clarifies that venting during gauging is expressly prohibited under this requirement where a storage tank measurement system is required under Section II.C.4. If Section II.C.4. allows for the opening of the thief hatch, that activity will not be considered venting within the meaning of Section II.C.2.a.

The Commission has revised Section II.C.2.b.(i), to reflect its intention in adopting the STEM provisions in 2014. The Commission intended in 2014, and specifically noted in the Statement of Basis and Purpose at that time, that STEM plans should include an analysis of the engineering design of the storage tank and associated air pollution control equipment (i.e., the vapor control system) to ensure that storage tanks are not overpressurized, causing excess emissions. The Commission believes that operators now largely understand and comply with this requirement, but has clarified the language in the rule itself principally to aid operators that may be new to the control program as a result of the new, lower control threshold. The Commission notes that this requirement does not require that operators maintain a site-specific design analysis for each facility. Worst-case design analyses or like-kind design analyses for similarly configured facilities may be utilized; however, the burden remains with the operator to show that the design analysis provided for the facility demonstrates adequacy of design. Further, the Commission acknowledges that closed-loop tank pressure control systems designed to maintain tank pressures below a specified point can be, if designed and operated property, indicative of adequate design. The Commission also acknowledges that design analyses do not need to be maintained within the STEM plan itself, so long as the STEM plan contains a description of the design analysis method employed and specifies the name and location of the design analysis for each facility covered by that STEM plan.

Pneumatic Controllers (Part D, Section III.)

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.

Downstream transmission (Part D, Section IV.)

SB 19-181 also directed the Commission to consider adopting a requirement that owners and operators of oil and gas transmission pipeline and compressor stations inspect and maintain all equipment and pipelines. The Commission's Regulation Number 7 has not historically regulated the transmission and storage segment, which includes pipeline, compressor stations, and other equipment transporting and storing natural gas downstream of the natural gas processing plant and prior to the distribution segment. Transmission pipelines, however, have been subject to federal and state pipeline safety regulations.

To address the new directive to minimize emissions from the transmission segment, the Commission adopted an innovative program that directs the setting of a methane intensity target and associated programmatic framework. This approach is the second recommendation from the SHER team, and again comes before the January 2020 deadline established by the Commission in November 2017. SHER team stakeholders involved in developing this program include trade associations, transmission segment operators, environmental and citizen groups, local governments, and the Division. The Division will approve a steering committee charter that will detail the purpose, responsibilities, and deliverables of the steering committee. The steering committee will develop an emissions protocol detailing the calculation and reporting of VOC, CO, NOx, ethane, and methane emissions and any associated program guidance documents or templates by September 30, 2020, determine a segment methane emissions intensity target by October 1, 2023, and certify initial target compliance based on the 2024 data. Each owner or operator in the segment will develop a company-specific best management practice (BMP) plan, the elements of which are enforceable by the Division. A goal of this program is continual improvement over time through review of BMPs, assessment of reported emissions and emissions intensity, and analysis of other data and best practices. In furtherance of this goal, the steering committee will periodically reassess the emissions intensity target and may consider, among other factors, the potential to reduce emissions from events beyond the control of the owner or operator.

The Division will provide an update on the development of the program to the Commission in 2021 as well as periodic updates regarding the progress of the program. The program will include a reporting element to demonstrate compliance and continual improvement. The steering committee will develop the criteria by which the industry participants will select a third-party contractor to collect and aggregate the company-wide reports into the segment-wide report prior to the first report due date of September 30, 2022. The third-party contractor, with involvement from the transmission segment owners or operators, may also provide VOC, NOx, and CO emissions data from the annual company-wide reports to the Division related to ozone modeling as needed and requested. Each year after the segment-wide emissions intensity target is established, the steering committee will submit a compliance certification to the Division that the transmission segment achieved the target. If such certification cannot be made, the steering committee will develop a plan for the segment to achieve compliance with the target. This plan, if needed, may include amendments to the program guidance documents, prescriptive control requirements, or other strategies to reduce methane emissions such that the transmission segment achieves the segment-wide emissions intensity target.

The inventory protocol may be based on existing EPA estimation and reporting mechanisms, specifically the EPA's Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). The emission estimation mechanisms may be updated as emission factors or calculation methods are revised. The inventory protocol will include the method(s) by which the transmission segment owners or operators will quantify and report emissions. The findings of the Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems (MAC) report (May 2016), among other data sources, may be used to develop the segment-specific methane emission reduction goals that, when combined, will achieve the transmission segment's emission intensity target in a cost-effective manner.

Annual inventory (Part D, Section V)

The Commission established an annual emissions reporting requirement to regularly update the Division's emissions inventory for equipment and activities in oil and gas operations. This inventory is intended to assist Colorado in ozone planning and the creation of emission inventories for use in ozone attainment modeling, as well as to comply with the directives in SB 19-181 to minimize emissions from the oil and gas sector. This inventory will provide missing information about oil and gas operations and will supplement the limited information provided on other aspects of those operations to assist the Commission in identifying emission sources appropriate for further emission reduction strategies. Additionally, this inventory will also help Colorado move forward in beginning to address the broad greenhouse gas directives in SB 19-096 (Concerning the collection of greenhouse gas emissions data to facilitate the implementation of measures that would most cost-effectively allow the state to meet its greenhouse gas emissions reductions goals) and HB 19-1261 (Concerning the reduction of greenhouse gas pollution, and, in connection therewith stablishing statewide greenhouse gas pollution reduction goals). This inventory is separate and apart from the APEN reporting and fee structure in Regulation Number 3, though the Commission expects that the Division, in consultation with stakeholders, will consider ways to align the reporting programs in the future to minimize duplication.

Operators will be required to submit a company-wide report on June 30 of each year for the preceding year. The first report will be due on June 30, 2021, covering emissions from July 1, 2020, through December 31, 2020. Operators are required to use the Division-approved form. The Commission expects that the Division will consult with stakeholders in the development of this form (or forms). The Commission understands that some of the emissions source category activities and equipment are not currently well defined, nor is there necessarily a well understood method of calculation for emissions (e.g., downhole well maintenance). The Commission therefore directs the Division to work with stakeholders from the adoption of this regulation throughout 2020 to, among other things: (1) appropriately define each emissions source category, activity, and equipment; and (2) identify reasonable methods of calculation for each emissions source category activity and equipment. For some emissions source category activities and equipment, achieving both goals may not be realistic before recordkeeping must begin in July 2020. Therefore, for those limited categories, the Commission expects that the Division will identify parameters that may be reported (e.g., frequency and duration) until such time as the category can be well defined and an appropriate calculation method can be identified. The Commission's intent here applies also to the well emissions reported under Section II.G.

Operators will need to include actual emissions information for various air pollutants, specifically methane, ethane, VOC, CO and NOx, for each emissions source category activity and equipment, as well as company-wide. The Commission has determined that monthly emissions information should be submitted for the summer months (May through September), while emissions for the remaining months can be aggregated into the annual figures. The Commission recognizes that, over time, these emissions inventories are likely to reflect ongoing emission reductions from the industry resulting from both the continued implementation of emission reduction strategies and the refinement of emissions estimation techniques. The Commission also recognizes that the emission estimation techniques used for inventory purposes may differ from regulatory methods for calculating, recording, and reporting emissions under the APEN and permitting program, and intends that such differences will be considered in any enforcement matter. It is critical that these inventories be as accurate and complete as possible, and operators are expected to perform quality assurance on the data prior to submittal. However, these inventories will require the submittal of a large amount of information, so operators are provided with timeframes for correcting information found to contain substantive errors.

The Commission directed the Division to report back to the Commission in 2020 regarding the inventory and progress made.

Ozone State Implementation Plan Revisions for Serious Reclassification (Part C, Section II.F. (new section in former Section X.; Part E, Sections II. and III. (formerly Sections XVI.D. and XIX.)

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the CAA's Serious ozone nonattainment area requirements, as set forth in CAA Sections 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., major stationary sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, to address the CAA Serious RACT SIP requirements, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx (which became major sources as of the effective date of the reclassification to Serious). The revisions include expanding the applicability of the combustion equipment requirements, including the combustion process adjustment requirements, in Section II. to equipment located at facilities with NOx emissions greater than or equal to 50 tons per year; incorporating by reference NSPS and/or NESHAP requirements for specific points at some 50 tpy major sources in Section III.; requiring some sources submit RACT analyses to the Division in Section III.; and a new categorical rule regarding general solvent use in Part C, Section II.F.

Consistent with Senate Bill 19-181, House Bill 19-1261 and Senate Bill 19-096, the Commission directs the Division to propose regulatory recommendations to the Commission in 2020 regarding: pneumatic devices that do not vent gas; continuous emission monitoring; alternatives to combustion for emissions control; enhanced LDAR, especially near occupied dwellings; and other options to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain," Colo. Rev. Stat. Section 25-7-109(10)(a), including "pre-production activities, drilling, and completion," id. Section 25-7-109(10)(c).

To increase transparency and accountability, the Commission further directs that in 2020 the Division explore options for developing a publicly accessible and searchable oil and gas complaint filing and tracking tool, and to accept public input on the development of this tool. The Division will report back to the Commission on its progress in 2020.

<u>SIP streamlining (Part B, Sections IV. and VII. (formerly Sections VI. and XV.) and Appendices B, C, and E)</u>

As a SIP clean-up effort, the Commission adopted revisions to Regulation Number 7, Part B, Sections IV. and VII. and removed Appendix E so the requirements align with current EPA methods and requirements.

In 1980, the Commission adopted requirements in Regulation Number 7, Section IV. requiring an annual pressure test for gasoline transport trucks. Those requirements were based on EPA's Control Techniques Guidelines (CTG) Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (December 1978) and included the test procedures for annual pressure and vacuum testing of gasoline transport trucks, as outlined in Appendix E. In 1980, The Commission also adopted Appendix B which specifies the criteria for controlling vapors from gasoline transfer to storage tanks. Those requirements are based on EPA's CTG Design Criteria for Stage I Vapor Control Systems Gasoline Service Stations (November 1975). EPA approved these provisions into Colorado's SIP in 1995.

Since the publication of EPA's CTGs, EPA has published similar requirements for gasoline transport trucks in EPA's NSPS Subpart XX Standards of Performance for Bulk Gasoline Terminals (40 CFR Part 60, Subpart XX (August 18, 1983, last revised December 19, 2003)); NESHAP R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR Part 63 Subpart R (December 14, 1994, last revised April 6, 2006)); NESHAP Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR Part 63, Subpart BBBBBB (January 10, 2008, last revised January 24, 2011)); and NESHAP Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC (January 10, 2008, last revised January 24, 2011)). These federal standards reference EPA's Method 27, Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test, in contrast to the CTG's pressure-vacuum test.

The Commission adopted provisions to replace the outdated vacuum-pressure test in Regulation Number 7 with the more current EPA Method 27. The Commission also updated the test values in Regulation Number 7, which are based on EPA's CTG but also correspond to the EPA Method 27 test values in EPA's NSPS XX, NESHAP R, NESHAP BBBBBB, and NESHAP CCCCCC. The Commission also revised the recordkeeping and certification requirements in Section IV. to correspond to EPA's Method 27 and federal standards. Lastly, the Commission clarified the requirements for owners or operators using vapor collection systems that such systems must be leak-tight and properly maintained and operated.

These revisions will update Colorado's SIP and align the gasoline transport truck, terminal, and service station control and testing requirements with current EPA NSPS and NESHAP standards.

Miscellaneous

The Commission has also adopted revisions to provisions not discussed in detail above in order to facilitate and align the substantive revisions identified, including revisions to the Applicability in Part A, Section I.A., and exemptions in Part A, Section II.B.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 that are unrelated to the reclassification to serious to update and streamline requirements for gasoline transport trucks, terminals, and service stations to align with current federal requirements; therefore, these revisions do not exceed or differ from the federal act or rules thereunder. Further, the Commission adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Sections II. (except II.C.1.b.(ii) and II.F.), III.F., IV., and V. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including storage tanks, storage tank loadout, fugitive emissions from components, pneumatic controllers, and downstream transmission operations. The proposed revisions also include an annual oil and gas sector emissions inventory report. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, the Greenhouse Gas Reporting Program (GHGRP), and Pipeline and Hazardous Materials Safety Administration (PHMSA) may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks and fugitive emissions components then the NSPS and NESHAP and more facilities and operations than the GHGRP and PHMSA.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part E, Sections II. and III. to include categorical RACT requirements for combustion equipment at major sources of NOx and incorporate by reference federal standards for specific sources or points. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment. The Commission also revised Regulation Number 7 to include categorical RACT requirements for general solvent use and is not aware of federal rules applicable to general solvent use.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of more costly retrofits.

(V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 Part D, Sections I. through IV. strengthen Colorado's SIP state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections II.F. recognize practices currently utilized by solvent operations. The revisions to Regulation Number 7, Part E, Sections II. and III. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

(VII) The revisions to Regulation Number 7 Part D, Sections I. through V. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C, Sections II. and Part E, Section II. similarly establish the categorical RACT requirements for similarly situated and sized sources.

(VIII) If EPA does not approve Colorado's SIP, or if Colorado continues to fail to achieve the NAAQS, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing an annual oil and gas inventory report are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for storage tanks and component leaks. Other revisions reflect changes in industry practice, such as for solvent use. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.

(XI) The revisions adopted will reduce significant amounts of VOC and methane, addressing both Colorado's ozone problems and making strides to reduce the impact of climate change. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19-181 specifically directs the Commission to “consider” revising its rules to adopt more stringent requirements related to LDAR, pneumatic devices, monitoring, and the transmission segment. The Commission determined that the Division’s proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

Colorado must revise Colorado’s ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 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 methane, VOCs, and other hydrocarbons.

(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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 17-18 & 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission’s (Commission) Procedural Rules.

Basis

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

The Commission also revised Part D, Sections II.G., IV., and V. to include annual reporting of carbon dioxide (CO2) and nitrous oxide (N2O) and Section V. to include additional emissions reporting from class II disposal well facilities. The Commission adopted a new Part D, Section VI. requiring owners and operators of pre-production oil and gas operations to monitor pollution during pre-production (i.e., drilling through flowback) and early-production and to control emissions from pre-production tanks and vessels (i.e., flowback vessels). Lastly, the Commission expanded the requirements in Part D, Section II. to control emissions from hydrocarbon liquids loadout at class II disposal well facilities. These proposed revisions are a next step in addressing the directives of SB 19-181, SB 19-096, and HB 19-1261, building upon revisions adopted by the Commission in December 2019.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, et seq. (Act), specifically § 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations. Sections 25-7-109(1)(a), (2), and (3) authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources; emission control regulations pertaining to NOx, hydrocarbons, and hazardous air pollutants; and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane, and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Purpose

To address SB 19-181, SB 19-096, HB 19-1261, ozone, visibility, and nitrogen deposition, the Commission adopted revisions to Regulation Number 7 that limit emissions from engines, limit emissions from pre-production tanks, reduce emissions from hydrocarbon liquids loadout at class II disposal well facilities, require reporting of emissions from class II disposal well facilities, expand annual reporting to include additional greenhouse gases, and require monitoring at pre-production and early production oil and gas operations. These revisions are all adopted on a state-wide and state-only basis.

Engines (Part E)

The Commission adopted requirements in Part E, Section I. to minimize emissions from natural gas fired RICE. The requirements apply to natural gas fired RICE greater than or equal to 1,000 HP. The requirements are responsive to SB 19-181 as it applies to engines used in the oil and gas sector, as well as securing NOx reductions that will also reduce ozone, visibility, and nitrogen deposition at RMNP.

Except for the combustion process adjustment requirements for engines at major sources, the Commission has not revised the requirements pertaining to engines since 2010, and emissions from engines associated with oil and gas production in Colorado have continued to increase. While the Commission recognizes the twin challenges currently faced by the oil and gas industry in Colorado - the COVID-19 pandemic and low oil prices - this regulation's provisions for phasing in compliance over time and, particularly, the unique characteristics of the Alternative Company-Wide Compliance Plan (Company-Wide Plan, affords the industry the flexibility necessary to achieve emission reductions necessary to protect public health and the environment in a cost effective manner.

Applicability (Section I.D.5.a.)

The Commission adopted a new subpart, Section I.D.5., to establish state-only standards to reduce emissions from a subset of existing stationary engines operating over or equal to 1,000 HP and those placed in service, modified, or relocated after November 14, 2020. As defined in the rule, "placed in service" addresses when an engine is brought to a site for utilization. "Placed in service" is a new term that deviates from the Division and industry's traditional reliance on the defined term "commence construction" or NSPS JJJJ's reliance upon manufacture date.

The Commission is clarifying when replacement of an engine under an authorized alternative operating scenario (AOS) would not trigger the engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. Subsequent replacements under an authorized AOS also would not trigger the replacement engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. If an engine is replaced under an AOS, while it may not trigger the lower standards based on "placed in service," it may nonetheless trigger the lower standards if it is "relocated" – i.e. if the replacement engine is brought into Colorado from outside Colorado, or brought into the nonattainment area from outside the nonattainment area. The return of an engine to the same site from which it was removed for the sole purpose of repair or maintenance is not considered "placed in service" or "relocated" for purposes of this Section I.D.5.

The Commission also adopted a different framework for "relocated" engines in Regulation Number 7, Part E, then in Regulation Number 6, Part B, which provides that engines brought to a site from another location in Colorado are not considered "new" and are not subject to the more stringent standards of the applicable NSPS. Under Regulation Number 7, there are only two exceptions to when an engine is considered new: when an engine is replaced under an alternative operating scenario (AOS) in an existing permit, which requires the engine to meet the same standards as the engine replaced, or when an engine subject to a Company-Wide Plan is moved from one site to another site with the same owner or operator. When an engine is subject to a Company-Wide Plan, the operator will have more flexibility to move an engine as long as it achieves at least the same emission reductions under the plan. However, an engine brought into the 8-Hour Ozone Control Area is considered "relocated" and must meet or exceed the standards as of the date it begins operation, whether or not it is subject to a Company-Wide Plan.

Emission Standards (Section I.D.5.b.)

The Commission adopted different emission standards based on engine configuration and the date that the engine was placed in service, modified, or relocated. The Commission intends that the applicable engine configuration is determined by the most current Division-issued permit or APEN filed prior to November 14, 2020. If the engine configuration is not identified in a Division-issued permit or APEN, the owner or operator is required to submit an APEN with this information to the Division by May 1, 2021. After November 14, 2020, any change to the identified configuration that results in an emissions increase is considered a modification.

The Commission adopted, generally, more stringent NOx standards applicable to engines placed in service, modified, or relocated after November 14, 2020. However, for 2-stroke lean burn engines, the NOx standard is the same whether the engine is currently in use at a site or brought on at a later date. The Commission also intends that any engines subject to a more stringent standard under a permit or other rule, such as Section I.D.2.b. of Regulation Number 7, must still comply with that more stringent limit.

The Commission adopted varying timing requirements for owners or operators to meet the emission standards, based on the location of subject engines inside and outside of the 8-Hour Ozone Control Area. Owners or operators with any engines in the 8-Hour Ozone Control Area are subject to a more aggressive timeline, which requires 100% of engines inside the 8-Hour Ozone Control Area to meet the emission standards by May 1, 2024, and 100% of engines outside the 8-Hour Ozone Control Area meet the emission standards by May 1, 2026. Operators with no engines inside the 8-Hour Ozone Control Area must follow the second timeline and meet the standards of at least 20% of engines each year from 2022 to 2026.

The Commission intends that the emission standards in Table 2 are a gram per horsepower-hour limit based on appropriate averaging times. The Commission also intends that operators demonstrate compliance with the certification and recordkeeping requirements through the performance testing results required by Section I.D.5.d and the portable analyzer results obtained in accordance with Section I.D.5.e., using the appropriate averaging times.

The Commission requests that the Division consider evaluating strategies to increase the electrification of engines, lower emissions standards for engines, and possible controls applicable to smaller engines.

Notification to Division (Section I.D.5.b.(iii))

If an owner or operator has subject engines, the owner or operator must submit a notice to the Division no later than May 1, 2021. However, the owner or operator of engines covered by a Company-Wide Plan will not need to submit the information required by Section I.D.5.b.(iii) for all engines.

Permit Modification (Section I.D.5.b.(iv))

The Commission adopted two deadlines for when a permit modification application is required. If the engine can meet the standards through only a permit modification, the application is due May 1, 2021. If the engine cannot meet the standards through only a permit modification, the application is due 365 days prior to that engine’s compliance deadline. An example of the first scenario is where an engine currently permitted with a high emission rate can meet the standards if operated at a lower emission rate and it is, in fact, already operating as of November 14, 2020, at that lower emission rate. In contrast, an example of the second scenario is where an engine is permitted at an emission rate above the applicable standard and operates at its permitted level, which would require the operator to change the operation of the engine in order to comply. This engine, therefore, would have a compliance date in accordance with Section I.D.5.b.(v)(B), and the permit application would be due 365 days prior to that engine’s compliance deadline. Stakeholders expressed concerns that the Division may not be able to timely process all of the permit modifications. Therefore, the Commission determined that the flexibility outlined in the rule was necessary for both industry and the Division. In the case of a pending permit modification, the Commission intends that the most current APEN requested limits will be used to determine compliance with the rule.

Industry stakeholders have expressed that the rules need to be more accommodating for Division delays in permit issuance for those situations where owners and operators cannot take action to comply with the emission standards without a permit in hand. Industry notes that without a revised permit, owners and operators would be out of compliance with federal and state permit requirements, leaving the operator with the choice of what standards to comply with. Based on information provided by these stakeholders, the Division believes that there are only 15 such permits. Additionally, the vast majority of engine upgrades do not necessitate a permit modification prior to completing the upgrade. The Division has indicated that it has enough dedicated staff to complete the required permit modifications in a timely fashion so long as the operator submits the permit application at least one year in advance of the compliance deadline. To address stakeholder concerns, the Commission expects the Division to work with operators that require a permit prior to commencing upgrades and create a process to give these permit applications priority. Should any permits push up against the one-year issuance deadline, the Division, in its discretion, will evaluate any potential operator compliance deadline extensions on a case-by-case basis.

Alternative Company-Wide Compliance Plan (Company-Wide Plan) *(Section I.D.5.c)*

The Commission adopted a Company-Wide Plan option to allow flexibility for each owner or operator to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emission reductions than would be achieved through compliance with the emission standards on an individual engine basis.

The Company-Wide Plan requires an overall emissions percentage reduction based on company-wide engine operations. Owners or operators using this option must demonstrate that the total NOx emissions allowed under the Company-Wide Plan are less than or equal to the total NOx emissions allowed through compliance with the emission standards on an individual engine basis. Engines included in a Company-Wide Plan remain subject to the performance testing, monitoring, recordkeeping, and reporting requirements.

This Company-Wide Plan option is available only to owners or operators with five or more engines that are subject to Section I.D.5.b(v)(B). For purpose of the Company-Wide Plan only, the term owner/operator refers to owners or operators that are participating in a Company-Wide Plan and are owned or operated by the same parent company. Engines that already meet the emission standards of Table 2 but only need a permit modification to reflect compliance may not be part of a Company Wide Plan for which credit is claimed by the operator. However, if the operator makes a further retrofit to the engine, the operator may include that engine in the Company Wide Plan and claim credit for the reductions achieved by the further retrofit. For example, if Engine A, a 4-stroke lean burn engine, has a permit limit of 1.8 g/hp-hr, but currently operates at 1.2 g/hp-hr, Engine A would not be included in the Company Wide Plan. However, if the operator installs additional control technology such that Engine A can now operate at 1.0 g/hp-hr, the emission reductions associated with the drop in emissions from 1.2 g/hp-hr to 1.0 g/hp-hr can be included in the Company-Wide Plan. Only physical retrofits, and not operational changes, can be accounted for in this manner.

Owners or operators will submit a notification (referred to as a compliance plan) using a Division-approved form that will be developed with stakeholder input. Recognizing that the Company-Wide Plan is intended to afford flexibility only where it will achieve the same or better reductions, the Commission has provided for detailed information to be submitted to the Division for review. The information submitted will allow the Division to compare the emission standards and operating conditions that an engine is meeting before and after the Company-Wide plan as well as the maximum emissions permissible if all Company-Wide Plan engines complied individually with the standards versus the permissible emissions under the Company-Wide Plan.

Owners or operators must calculate “Plan Emission Reductions” - i.e. a summation of NOx emission reductions from all engines in the Company-Wide Plan. This figure is calculated by looking at the maximum amount of NOx emissions from the engines before November 14, 2020 (using the current permitted emission rate) and subtracting the maximum amount of NOx emissions that will be allowed from those engines under the Company-Wide Plan.

Owners or operators must also demonstrate that the Company-Wide Plan will result in real emission reductions, and the Division is directed to disapprove any Company-Wide Plan that the Division determines does not achieve those reductions. Owners or operators will calculate the estimated historic emissions from the plan’s engines in tons per year as a baseline, using the most stringent regulatory or permitted emission standards and operating conditions in conjunction with actual operating hours (averaged over 2017-2019). That baseline figure is then compared to the maximum amount of emissions permissible from the Company-Wide Plan engines to ensure that the Company-Wide Plan will result in emission reductions. The demonstration also includes a comparison of the emission reductions that would be achieved from the actual baseline figure if each engine complied with the emission standards on an individual basis to the reductions that will be achieved under the Company-Wide Plan. In this way, the Commission seeks to ensure that a Company-Wide Plan achieves demonstrable reductions in NOx emissions.

Owners or operators will not be allowed to utilize reductions in permitted operating hours to offset emission reductions that would otherwise be achieved where permitted hours are higher than actual hours of operation (on average over 2017, 2018, and 2019). For example, an operator with a permit to operate at 8,760 hours per year but that operated only at 5,000 hours per year (on average over 2017, 2018, and 2019) cannot modify its permit to lower the permitted hours of operation to 5,000 and thereby create NOx emissions for which it can take credit in its Company-Wide Plan.

Some stakeholders have expressed concerns over how engines that began operation during or after the averaging years will calculate “historic” emissions. For these types of engines, the Commission expects that the most recent year(s) of operation should be used to calculate “historic” emissions. If there is less than one year of operation during this time frame, the Commission expects that the operator should extrapolate the available operation emission data to one year to estimate “historic” emissions.

Owners or operators must also submit notice of relocated engines in the annual update to the Company-Wide Plan, beginning in 2022. A relocated engine will be categorized by its new location (inside or outside of the 8-Hour Ozone Control Area) for purposes of the engine’s compliance deadline.

To assist with implementation, the Commission directs the Division to provide timely guidance to the regulated community as to how to develop a Company-Wide Plan. The Commission recognizes that the Company-Wide Plan provisions are complicated, and believes providing the following examples of how the Commission intends the program to work will be helpful.

Example 1:

An engine in a Company-Wide Plan is located inside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), also within the 8-Hour Ozone Control Area. The engine was not “placed in service” or “relocated” within the meaning of this rule, and compliance deadlines would not change. The owner/operator just submits the new location in its annual update.

Example 2:

An engine in a Company-Wide Plan is located outside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), except that site B is located inside the 8-Hour Ozone Control Area. The engine is not “placed in service” within the meaning of this rule but it is “relocated.” The engine’s relocation into the 8-Hour Ozone Control impacts both the standard with which it must comply and the timing of when the new standard must be achieved.

If the engine was not proposed for retrofit or if it was proposed for retrofit but under the Company-Wide Plan it would not meet the standard, the engine will need to meet the emission standards as of its date of operation following relocation. If the engine was proposed for retrofit to achieve performance below the emission standards (retrofit/shut-down, etc.), the engine must meet the more stringent of either the applicable standard or the proposed Company-Wide Plan standard as of the date of operation following the relocation date.

Conversely, if an engine subject to a Company-Wide Plan located in the 8-Hour Ozone Control Area is moved to a different site (same owner/operator) outside of the 8-Hour Ozone Control Area, the engine is not “placed in service” or “relocated” within the meaning of this rule. The engine must meet the standard specified in the Company-Wide Plan consistent with the applicable compliance date.

Example 3:

Operator A has 20 engines and submits a Company-Wide Plan that includes modifying five engines (in 2022 and 2023) and shutting down two engines (in 2024). Operator A then transfers ownership of one of the engines (either the engine or the entire facility) to be shut down to Operator B; that shutdown would have achieved 20 tons per year (tpy) NOx reduction. Operator A must find an additional 20 tpy NOx reduction from the 19 engines remaining in its Company-Wide Plan.

Example 4:

A Company-Wide Plan includes shutting down an engine. The operator then realizes it needs a replacement engine at that same site. The operator has a few options. First, the operator can amend its Company-Wide Plan to no longer shut down the engine (assuming the engine’s compliance deadline has not yet passed) and can identify other actions to be taken to achieve the emission reductions that would have otherwise been realized from the shutdown of the engine. Second, the operator can shut down the engine as originally intended and bring on a new engine. The new engine will be subject to the emission standards as an engine “placed in service” after November 14, 2020, and cannot be a part of the operator’s Company-Wide Plan because an engine scheduled for shut down under a Company-Wide Plan cannot be replaced with a different engine subject to the Company-Wide Plan. Because the operator must comply with the Company-Wide Plan, the operator will still need to cancel the APEN and permit for the existing engine and permit the new engine as a new source.

Example 5:

An operator has ten engines subject to a Company-Wide Plan and intends to modify five of those engines to achieve the required Plan Emission Reductions. However, in order to meet the CO standards for one of the engines that will not be modified to achieve Plan Emission Reductions, the operator must make an adjustment that has the effect of increasing NOx emissions from that engine. In calculating the maximum allowable NOx emissions from engines in the compliance plan and Plan Emission Reductions required, the operator must account for the increase in NOx emissions from the engine.

Performance Testing, Monitoring, Recordkeeping, and Reporting (Sections I.D.5.d., I.D.5.e., I.D.5.f., and I.D.5.g.)

The Commission adopted performance testing requirements to establish a baseline for evaluating an engine’s performance – i.e. to enable an operator to know whether the engine was meeting the standards already or how much action might be required to meet the standards. To conserve the resources of both the Division and the operators, the Commission has allowed for operators to rely on existing ongoing semi-annual portable analyzer testing requirements, as well as performance testing conducted under NSPS JJJJ, a permit, or testing conducted voluntarily after January 1, 2020.

The Commission also adopted semi-annual portable analyzer testing requirements. The portable analyzer monitoring must commence within twelve (12) months of the initial performance test. The Commission intends that operators will conduct two portable analyzer tests in 2022, the first of which must be completed by June 30, 2022.

The Commission has also adopted new monitoring, recordkeeping and reporting requirements. With respect to oil and filter changes under Section I.D.5.e.(iv)(A), the Commission acknowledges that the development of an oil analysis program that tests to ensure that oil does not need to be changed meets the requirements of that section.

In the recordkeeping section, the Commission requires that for both performance tests and portable analyzer tests, the owner or operator retains records regarding the date, engine settings on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission acknowledges that maintaining the test reports (for performance tests) and maintaining records consistent with the Division's Portable Analyzer Monitoring Protocol (for portable analyzer test), is sufficient to demonstrate compliance with the requirements to maintain the date, engine setting on the date of the test, and documentation of the methods and results of the testing/monitoring.

The Commission has required the reporting of the results of performance tests (Section I.D.5.g.(i)) and semi-annual portable tests (Section I.D.5.g.(iv)). By "results," the Commission means that the owner/operator shall indicate whether the tests were passed or failed. Other, more detailed results are required to be maintained as part of the recordkeeping requirements and will be available to the Division upon request.

General provisions (Section I.D.2.)

In 2019, the Commission adopted a reorganization of Regulation Number 7 moving like-sections together, including engines. The Commission now completes the reorganization of the engine sections by duplicating the applicable general provisions that applied to engines in Part D, Section II. (formerly numbered Section XVII.) in Part E, Section I.D.2. These provisions will continue to apply to engines addressed in Part E, Sections I.D.3. and I.D.4. (formerly Sections XVII.E.) and will also apply to engines addressed under the new Part E, Section I.D.5.

<u>Oil and gas operations (Part D)</u>

The Commission expanded or adopted additional requirements in Part D to further minimize emissions of greenhouse gases, ozone precursors, and other hydrocarbons from the oil and gas sector.

Pre-production and early production monitoring

The Commission adopted a new Section IV. that requires owners or operators to monitor air quality at and/or around pre-production operations (i.e., drilling, fracturing, drill-out, flowback) and early production operations (i.e., six months). The purpose of this air quality monitoring is multi-faceted in that the Commission anticipates the monitoring program will gather information about the evolving oil and gas monitoring technologies, data about potential emissions during pre-production and early production operations (e.g., ozone precursor emissions, greenhouse gas emissions, hazardous air pollutants), and inform future monitoring efforts. Owners or operators will also monitor air quality for ten days prior to beginning pre-production operations. The Commission recognizes that ten days does not provide a comprehensive or long-term baseline but intends that it cover day-of-week variability in surrounding activities and short-term meteorological variability, in order to provide a reference point for interpreting subsequent data.

Owners or operators must submit an air quality monitoring plan to the Division for approval prior to monitoring air quality. The Commission created a flexible air quality monitoring program that allows the operator to specify what pollutant(s) representative of pre-production and early production hydrocarbon emissions will be monitored and by what monitoring technology. The Commission anticipates that the additional elements of the air quality monitoring plan, such as monitor siting, frequency of measurements, monitoring equipment limitations, and ability to trigger or collect speciated samples, will vary based on the monitoring objectives and technology utilized. The Commission also anticipates that the response level(s) will vary based on the monitoring technology, monitor placement, the pollutant(s) monitored, data collection and averaging times, and other factors. The response level may differ from a lower detection level established by the owner or operator that triggers an initial investigation of potential emissions at the facility. The Commission expects that the monitoring technology selected will have a detection ability sufficient to detect the pollutant(s) monitored at an appropriate level above area concentrations such that the monitoring objectives (e.g., detect ozone precursors, detect hazardous air pollutants, detect greenhouse gas emissions, associate elevated monitored values to an emission source within the monitored operations) are achieved. The Commission recognizes that not every elevated measurement constitutes a detection requiring a response but instead may be accompanied by analytics evaluating the measurements in comparison to an emission source or activity. The Commission also expects that placement of the monitors will be designed to be adequate to meet the objectives of the monitoring plan and that operators will select a monitoring technology that collects measurements at short-term intervals (e.g., 1 minute, 15 minutes, 1 hour) and appropriate sensitivity. For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division’s determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division’s website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners of operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

Class II disposal well facilities

The Commission added a new definition of class II disposal well facilities. This definition is based on EPA's Underground Injection Control Program: Criteria and Standard definition of class II well (see 40 CFR Section 146.5(b)(1)). The Commission did not include the element of EPA's definition concerning enhanced recovery of oil or natural gas as storage tanks related to those activities are considered part of the associated well production facility. The Commission recognizes that some class II disposal well facility operators interpret Part D, Section II.C. such that their storage tanks have not been subject to the storage tank control requirements. Although the Commission understands that the Division intended Part D, Section II.C. to apply to storage tanks serving class II disposal well facilities, the Commission also recognizes that a good faith argument existed under the prior rule language to support the alternative interpretation. The Commission intends for the Division to work with owners or operators to address implementation concerns that may arise including related to the May 1, 2021, state-wide compliance deadline for controlling emissions from storage tanks $\geq$ 2 tpy and associated monitoring requirements as well as concerns related to the need for supplemental fuel to control emissions.

The Commission also expanded the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout at class II disposal well facilities. Operators inject fluids, primarily brines, associated with oil and natural gas production into class II wells. Current regulatory requirements in the Safe Drinking Water Act for class II wells relate to the construction, operation, and monitoring of the well. The Safe Drinking Water Act does not require emissions reporting or storage tank or loadout emissions controls at class II disposal well facilities. Therefore, the Commission expanded the hydrocarbon liquids loadout requirements to class II disposal well facilities to reduce emissions from these operations.

The Commission directs the division to evaluate potential emission issues associated with load ins at class II disposal facilities

Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of Senate Bill 19-096 and House Bill 19-1261, the Commission expanded the reporting requirements to include the reporting of CO2 and N2O emissions from Colorado's oil and gas sector.

As described above, the Safe Drinking Water Act does not require emissions reporting. Therefore, the Commission also clarified and expanded the annual emissions reporting requirements for class II disposal well facilities to better understand the emissions from these facilities and activities. Related to the fluids accepted for injection disposal, the Commission is requiring owners or operators to take periodic samples of the liquids to inform emission estimates. Acknowledging that fluid intake and facility designs may differ, the Commission expects the Division will work with owners and operators to develop sampling frequencies and protocols and to ensure accurate and consistent methods are used for emissions estimation and reporting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission includes reference dates to rules and reference methods incorporated in Regulation Number 7.

Community Engagement

Section 25-7-105(e) requires engagement with disproportionately impacted communities, other state agencies, stakeholders, and the public. The Division provided multiple ways for the public, local governments, industry, environmental groups, and other stakeholders to provide comment during the development of the proposed rules, including email and remote stakeholder meeting participation.

Additional Considerations

The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and Regional Haze Rule and requires Colorado to attain the NAAQS and reduce visibility. Therefore, the Commission adopted certain revisions to Regulation Number 7 to reduce VOC and NOx emissions in Colorado.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including engines, pre-production operations, and class II disposal well facilities storage tanks and storage tank loadout. The proposed revisions also revise the annual oil and gas sector emissions inventory report to include GHGs and class II disposal well facilities. NSPS JJJJ, NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, NESHAP ZZZZ, and the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR Part 98 may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks then the NSPS and NESHAP, more engines than NESHAP JJJJ, and more facilities and operations than the GHGRP.

(II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.

(III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. The Regional Haze Rule was also not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns.

(IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. And, Colorado must improve visibility in accordance with Regional Haze. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits. And, the current revisions will improve visibility across the state, in particular in Colorado's class I areas.

(V) Colorado must attain the 2008 ozone NAAQS by July 20, 2021, and the 2015 ozone NAAQS by August 3, 3021, or risk being reclassified. Colorado must make reasonable progress toward improving visibility or risk EPA establishing a federal regional haze plan for Colorado. EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. EPA has established a Regional Haze SIP submittal deadline of July 1, 2021. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

(VI) The revisions to Regulation Number 7 address emissions from engines and the oil and gas sector in a cost-effective manner, as detailed in the Economic Impact Analysis, allowing for continued growth of Colorado's industry.

(VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.

(VIII) If Colorado continues to fail to achieve the NAAQS or make progress to reduce visibility, EPA may promulgate Federal Implementation Plans; thus potentially determining requirements for Colorado's sources. This outcome may subject others to increased costs.

(IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing and revising annual oil and gas inventory reporting are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.

(X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for hydrocarbon liquid loadout. Other revisions reflect changes in industry practice, such as for controlling emissions from flowback vessels.

(XI) The revisions adopted will reduce NOx, VOC, and methane, addressing both Colorado's ozone problems, making strides to reduce the impact of climate change, and making progress to improve visibility. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

(XII) Alternative rules could also provide reductions in greenhouse gases, ozone, VOC, NOx, other hydrocarbons, impacts to visibility, and nitrogen deposition to address Regional Haze, SB 19-181, and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements for the oil and gas sector. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in the need for much more stringent requirements to reduce nitrogen deposition in RMNP, improve visibility in Colorado's Class I areas, and reduce ozone across the state but particularly in the DMNFR.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

To the extent that CRS Section 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 methane, VOCs, and other hydrocarbons.

(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 and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Editor's Notes

History

Entire rule eff. 01/30/2009.

Parts I.A.1, XVII, XIX.L eff. 02/14/2011

Parts II.D, XII.D XII.H, XVII.D, XIX.M eff. 02/15/2013.

Parts II.B, VI.B.2.a.(i)(E), IX.A.12.a.(x), XVII XVIII, XIX.B, XIX.N eff. 04/14/2014.

Parts I.A.1., X.A, X.E, XII.A.3, XII.C.1, XII.C.2.a(ii)(B), XII.E, XII.F.3.d, XII.F.5.a, XII.G, XII.H.3-6, XII.I, XIII, XVI, XIX, XX, XX.O eff. 01/14/2017.

Entire rule eff. 12/30/2017.

Parts XVI, XIX, XX.Q eff. 09/14/2018.

Entire rule eff. 01/14/2019.

Entire rule eff. 02/14/2020.

Part D rules II, IV-VI, Part E, Part F rule T eff. 11/14/2020.