DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 22

COLORADO GREENHOUSE GAS REPORTING AND EMISSION REDUCTION REQUIREMENTS

5 CCR 1001-26

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

Outline of Regulation

Pursuant to Colorado Revised Statutes § 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.gpo.gov/fdsys. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

Unless otherwise indicated, any incorporation by reference of provisions of Title 40, Part 98, of the Code of Federal Regulations (CFR) are to the edition effective as of July 1, 2019.

PART A Greenhouse Gas Reporting

I. General Provisions

I.A. This regulation establishes mandatory greenhouse gas (GHG) monitoring, recordkeeping and reporting requirements for owners and operators of certain facilities that directly emit GHGs, and retail or wholesale electric service providers.

I.B. Suppliers will be required to report GHGs based upon the quantity that would be associated with combustion or use of the products supplied.

II. Definitions

II.A. “Anaerobic Process” means a procedure in which organic matter in wastewater, wastewater treatment sludge, or other material is degraded by microorganisms in the absence of oxygen, resulting in the generation of carbon dioxide (CO_2) and methane (CH_4). This source category consists of the following: anaerobic reactors, anaerobic lagoons, anaerobic sludge digesters, and biogas destruction devices (for example, burners, boilers, turbines, flares, or other devices).

II.B. “Carbon Dioxide Equivalent (CO_2e)” means a metric measure used to compare the emissions from various GHG based upon their global warming potential (GWP). CO_2e is determined by multiplying the mass amount of emissions (metric tons per year), for each GHG constituent by that gas’s GWP, and summing the resultant values to determine CO_2e (metric tons per year).

II.C. “CFR” means Code of Federal Regulations.

II.D. “Counterparty” means a marketer, utility, or other entity with whom an energy transaction occurs or a market operator responsible for settlement in an organized market.

II.E. “Designated Representative” means an individual selected by an agreement binding on the owners and operators of such facility or supplier and acting in accordance with the certification statement in Section IV.B.6.

II.F. “Domestic Wastewater Treatment Plant” has the same meaning as defined by the Water Quality Control Commission in 5 Code of Colo. Regs. (CCR) 1002-22 (September 30, 2009).

II.G. “Electric Service Provider” or “Electric Utility” means any corporation, agency, or other legal entity that generates electricity for sale through combustion of fossil fuels or sells electricity for retail or wholesale use, including imported, exported, or in-state electricity, in the State of Colorado. Electric service provider or electric utility does not include an entity that generates electricity which is consumed solely at the facility or complex where the generation occurs

II.H. “Emergency Generator” means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance is not considered an emergency generator.

II.I “Energy Transaction” means a specified quantity of electricity purchased or sold at a known transaction point or through an organized market.

II.J. “Exported Electricity” means electricity generated inside the State of Colorado and delivered to serve load located outside the State of Colorado. Exported electricity does not include electricity that is generated outside the State of Colorado, is transmitted through the State of Colorado, and with the final point of delivery outside the State of Colorado.

II.K. "Facility" means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right of way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

II.L. "Food Processing" means an operation used to manufacture or process meat, poultry, fruits, and/or vegetables as defined under NAICS 3116 (Meat Product Manufacturing) or NAICS 3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing). For information on NAICS codes, see http://www.census.gov/eos/www/naics/ (as published January 30, 2020).

II.M. "Global Warming Potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., (CO_2). For the GHG emissions calculations requirements of this rule, the GWP values that must be used are as specified in Table A-1 to Subpart A of Title 40 CFR Part 98.

II.N. "Greenhouse Gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6) and Nitrogen Trifluoride (NF_3).

II.O. "Hydrofluorocarbons (HFCs)" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

II.P. "In-State Electricity" means electricity generated inside the State of Colorado and delivered to serve load within the State of Colorado. In-state electricity does not include electricity that is generated outside the State of Colorado, is transmitted through the State of Colorado, and with the final point of delivery outside the State of Colorado.

II.Q. "Industrial Waste Landfill" means a landfill other than a municipal solid waste landfill, a Resource Conservation and Recovery Act (RCRA) Subtitle C hazardous waste landfill, or a Toxic Substance Control Act (TSCA) hazardous waste landfill, in which industrial solid waste, such as RCRA Subtitle D wastes (non-hazardous industrial solid waste, defined in 40 CFR § 257.2 (May 30, 2017)), commercial solid wastes, or conditionally exempt small quantity generator wastes, is placed. An industrial waste landfill includes all disposal areas at the facility.

II.R. "Industrial Wastewater Treatment" means use of anaerobic processes to treat industrial wastewater and industrial wastewater treatment sludge at pulp and paper manufacturing, food processing, ethanol production and petroleum refining facilities. Industrial wastewater treatment does not include municipal wastewater treatment plants or separate treatment of sanitary wastewater at industrial sites.

II.S. "Imported Electricity" means electricity generated outside the State of Colorado and delivered to serve load within the State of Colorado. Imported electricity does not include electricity that is generated outside the State of Colorado, is transmitted through the State of Colorado, and with the final point of delivery outside the State of Colorado.

II.T. “Local Distribution Company” or “LDC” means a company that owns or operates distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are within a single state that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems. LDCs do not include pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

II.U. “Metric Ton” means a common international measurement for mass equal to 1,000 kilograms, which is equivalent to 2204.6 pounds or 1.1 short tons.

II.V. “Municipal Solid Waste Landfill” or “MSW Landfill” means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (40 CFR § 257.2 (May 30, 2017)) such as commercial solid waste, non-hazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads, public roadways, or other public right-of-ways. An MSW landfill may be publicly or privately owned.

II.W. “Natural Gas Transmission and Storage” has the same meaning as “natural gas transmission and storage segment” as defined in Air Commission Regulation Number 7, Part D, Section IV.A. (effective February 14, 2020).

II.X. “North American Industry Classification System (NAICS) Code(s)” means the six-digit code(s) that represents the product(s)/activity(s)/service(s) at a facility or supplier as listed in the Federal Register and defined in “North American Industrial Classification System Manual 2007,” available from the U.S. Department of Commerce, National Technical Information Service, Alexandria, VA 22312 and http://www.census.gov/eos/www/naics/ (as published January 30, 2020).

II.Y. “Oil and Natural Gas Operations and Equipment” means the equipment and activities listed in AQCC Regulation Number 7, Part D, Section V.C. (effective February 14, 2020).

II.Z. “Perfluorocarbons (PFCs)” means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

II.AA. “Research and Development” means those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a de minimis manner.

II.BB. “Responsible Official” means the definition of that term found in the Air Quality Control Commission’s Common Provisions Regulation (effective January 14, 2016).

II.CC. “Retail Utility” means an electric service provider or electric utility that sells electricity to end-use customers or ratepayers.

II.DD. “Supplier” means a producer, importer, or exporter in any supply category included in Table A-5 of Subpart A, 40 CFR Part 98, as defined by the appropriate subpart in 40 CFR Part 98.

II.EE “Transaction Point” means a recognized electrical location where seller agrees to deliver energy and purchaser agrees to receive energy for bilateral trades or settlement schedules regardless of market type or an identified settlement location or settlement area in an organized market.

II.FF. "Unspecified Energy" is electricity that is not traceable to a specific generating facility, such as electricity traded through open market transactions. This electricity is typically a mix of resource types, and may include renewables.

II.GG. "Wholesale Utility" means an electric service provider or electric utility that sells electricity or energy to a retail utility or other wholesale utility.

II.HH. "Year" means calendar year.

III. Applicability and Emissions Quantification for Affected Sources

III.A. The GHG monitoring, recordkeeping, and reporting requirements of this rule apply to the owners and operators of any facility or entity that is located in the State of Colorado and that meets any of the following requirements:

III.A.1. Any electric service provider or electric utility, regardless of annual GHG emission quantities. GHGs reported must include all emissions from electricity generation and transmission and distribution equipment, not including emergency generators.

III.A.2. Any local distribution company distributing natural gas in the State of Colorado, regardless of annual GHG emission quantities.

III.A.3. Any industrial waste landfill active at any point during the year, regardless of annual GHG emission quantities. Inert material facilities as defined under 6 CCR 1007-2, Part 1 (November 30, 2019), are exempt from the requirements of this regulation. The GHGs reported must include emissions from the landfill, landfill gas collection systems, and destruction devices for landfill gases

III.A.4. Any industrial wastewater treatment, regardless of annual GHG emission quantities.

III.A.5. Any underground coal mine meeting the source category definition for an underground coal mine in Subpart FF of 40 CFR, Part 98 at any point during the year and regardless of annual GHG emission quantities.

III.A.6. Any facility or supplier not covered under Sections III.A.1. through III.A.5. or III.C. that is required to report under 40 CFR Part 98 as incorporated herein must report GHGs directly to the State of Colorado to the same extent as reported under 40 CFR Part 98. The requirement to report pursuant to 40 CFR, Part 98 as incorporated herein continues to apply regardless of future revisions to 40 CFR, Part 98.

III.A.7. Any municipal solid waste landfill not required to report under 40 CFR Part 98 may voluntarily report GHGs. The GHGs reported must include emissions from the landfill, landfill gas collection systems, and destruction devices for landfill gases.

III.A.8 Any domestic wastewater treatment plant may voluntarily report GHGs.

III.A.9. Any agricultural operation may voluntarily report GHGs or operational information sufficient to allow the Division to determine GHGs.

III.A.10. Research and development activities are excluded from GHG reporting requirements.

III.B. To quantify GHG emissions for the reporting purposes of this rule, the owner or operator of a facility or an entity identified in Section III.A. must calculate GHG emissions by year as described, and any reporting requirement under 40 CFR, Part 98 and its Subparts as incorporated herein continue to apply regardless of future revisions to 40 CFR, Part 98.

III.B.1. For an electric service provider or electric utility identified in Section III.A.1, GHG emissions must be calculated using the applicable calculation methodologies and appropriate equations specified in Subparts C, D, and DD of 40 CFR, Part 98.

III.B.2. For a local distribution company identified in Section III.A.2., GHG emissions must be calculated using the applicable calculation methodologies specified in Subparts W and NN of 40 CFR, Part 98.

III.B.3. For an industrial waste landfill identified in Section III.A.3., GHG emissions must be calculated according to Subpart C, if applicable, and Subpart TT of 40 CFR, Part 98.

III.B.4. For industrial wastewater treatment identified in Section III.A.4., GHG emissions must be calculated according to Subpart C, if applicable, and Subpart II of 40 CFR, Part 98.

III.B.5. For an underground coal mine identified in Section III.A.5., GHG emissions must be calculated according to Subpart C, if applicable, and Subpart FF of 40 CFR, Part 98.

III.B.6. For a facility or supplier included pursuant to Section III.A.6., GHG emissions must be calculated using the calculation methodologies specified in each applicable Subpart of 40 CFR, Part 98.

III.B.7. For a municipal solid waste landfill identified in Section III.A.7., GHG emissions must be calculated according to Subpart C, if applicable, and Subpart HH of 40 CFR, Part 98.

III.B.8. For a domestic wastewater treatment plant identified in Section III.A.8., GHG emissions must be calculated using GHG emission estimating protocols acceptable to the Division.

III.B.9. For an agricultural operation identified in Section III.A.9., reported GHG emissions or operational information must utilize emission calculation protocols that are acceptable to the Division and applicable to the specific activities or types of operations in the agricultural sector.

III.C. Oil and Natural Gas Reporting Requirements:

III.C.1. Oil and natural gas operations and equipment at or upstream of a natural gas processing plant are not subject to Sections III.A, III.B, IV, and V of this regulation and must report GHG emissions to the State of Colorado according to the requirements of AQCC Regulation Number 7, Part D, Section V. (effective February 14, 2020). Records of information included in reports submitted pursuant to AQCC Regulation Number 7, Part D, Section V. (effective February 14, 2020) must be maintained for a period of two (2) years and made available to the Division upon request.

III.C.2. Natural gas transmission and storage are not subject to Sections III.A, III.B, IV and V of this regulation and must report GHG emissions according to the requirements of AQCC Regulation Number 7, Part D, Section IV. (effective February 14, 2020).

IV. Reporting Requirements

IV.A. Owners and operators of facilities or entities identified in Section III.A. must submit a report of all GHG emissions or supply in the previous calendar year. GHG emissions or supply must be reported utilizing Division-approved format or forms.

IV.A.1. The first report for owners and operators of facilities or entities required to report for calendar year 2020 pursuant to 40 CFR, Part 98 is due on or before March 31, 2021 (and by March 31 every year thereafter).

IV.A.2. Owners and operators of facilities or entities covered by Sections III.A.1 through III.A.5 must report to the Division even if their emissions are below the reporting thresholds of 40 CFR, Part 98. The first report for owners and operators of facilities or entities under Sections III.A.1. through III.A.5. that were not required to submit a federal report for calendar year 2020 pursuant to 40 CFR, Part 98 is due on or before March 31, 2022 for calendar year 2021 (and by March 31 every year thereafter).

IV.A.3. Owners and operators of facilities or entities under Sections III.A.7. through III.A.9. may report for any year. GHG emissions reported under this Section IV.A.3. must be submitted by March 31 for the prior year.

IV.B. GHG reports submitted must include the following:

IV.B.1. Individual GHG constituents (in metric tons per year) and aggregated CO2e emissions.

IV.B.2. AIRS ID if assigned to a subject facility, along with the facility name, entity name or supplier name (as appropriate), and physical street address of the facility, entity or supplier, including the city, State, and zip code. If the facility does not have a physical street address, then the facility must provide the latitude and longitude representing the geographic centroid or center point of facility operations in decimal degree format. This must be provided in a comma-delimited “latitude, longitude” coordinate pair reported in decimal degrees to at least four digits to the right of the decimal point.

IV.B.3. NAICS code(s) that apply to the facility or supplier, including the primary NAICS code and any additional NAICS code(s).

IV.B.4. Year and months covered by the report.

IV.B.5. Date of submission.

IV.B.6. Certification statement signed and dated by a responsible official, or their designated representative, that identifies the individual’s title and contact information and attests that the report being submitted is true, accurate and complete to the best of the certifying individual’s knowledge.

IV.C. In addition to the information required under Section IV.B., electric service providers and electric utilities must also report the following information for the prior year using Division-approved forms by no later than June 30 of each year:

IV.C.1. Beginning June 30, 2022, data elements necessary for the Division to determine GHG emissions attributable to imported and exported electricity. The reporting requirements in Section IV.C.1. track emissions associated with imports and exports in order to attribute GHG emissions from electricity delivered to customers in the State of Colorado, and determine GHG emissions from electricity exported out of the state. Emissions from imports and exports also informs the development, assessment, and refinement of strategies to achieve the statewide greenhouse gas targets and may assist local organizations with GHG planning efforts.

IV.C.1.a. In reporting the requirements of this Section IV.C.1., the electric service provider or electric utility will:

IV.C.1.a.(i) Use the reporting form published by the Division to report annualized data in a consistent format.

IV.C.1.a.(ii) Use the most detailed data readily available for business purposes when determining the annual reported values including, but not limited to, short or long term contracts, internal tracking systems for energy transactions between counterparties or through organized markets, or for other regulatory reporting requirements to the Colorado Public Utilities Commission, US EPA, Energy Information Administration, or Federal Energy Regulatory Commission.

IV.C.1.a.(iii) Use the most specific data sources in the published form for assigning GHG emissions to imports and exports of unspecified energy, electricity acquired through contract obligations, market electricity purchased or sold from a pooled group of resources, or renewable energy for which a renewable energy credit is not included with the purchase or sale. Data sources may include defined contractual requirements, facility specific or portfolio GHG emissions factors, published balancing authority or regional emissions intensity factors, or other data sources approved in advance by the Division.

IV.C.1.a.(iv) Not be required to report duplicative information from generation facilities, wholesale utilities, and retail utilities under common ownership of an electric service provider or electric utility.

IV.C.1.b. The annual data elements to be reported pursuant to Section IV.C.1. include but are not limited to:

IV.C.1.b.(i) For each fossil fuel fired generation facility, the Total Gross Megawatt-hours (MWh) generated at the facility and Net MWh received by each entity with an ownership stake in the facility, which must be reported by the entity with operational control.

IV.C.1.b.(ii) For each electric utility or electric service provider, the following information, aggregated by Counterparty, where applicable:

IV.C.1.b.(ii)(A) For all imported electricity, the quantity of electricity, and associated GHG emissions, including the emissions factors and emissions-factor basis, imported directly from owned generation or contracted generation located outside the State of Colorado, the quantity of electricity and associated GHG emissions, including the emissions factors and emissions-factor basis, purchased at Transaction Points located outside the State of Colorado and imported into Colorado, and the quantity of electricity and associated GHG emissions, including the emissions factors and emissions-factor basis, sold from out of state generation at Transaction Points within the State of Colorado;

IV.C.1.b.(ii)(B) For all exported electricity, the quantity of electricity, and associated GHG emissions, including the emissions factors and emissions-factor basis, delivered to Transaction Points outside the State of Colorado; and

IV.C.1.b.(iii) For each wholesale or retail utility, the quantity of renewable energy credits including vintage year acquired and transferred through energy transactions, sold, or retired to meet Colorado renewable energy standards.

IV.C.2. The data elements necessary for the Division to track the progress of GHG reductions from plans that have been approved by the Public Utilities Commission, including but not limited to Clean Energy Plans filed in accordance with § 40-2-125.5, C.R.S. (May 30, 2019). Progress tracking after a plan has been approved will inform development, assessment, and refinement of strategies to achieve the statewide greenhouse gas targets. Data collection pursuant to this Section IV.C.2. begins on January 1 of the year following approval of a plan, and the first report is due no later than June 30 of the year following the first year of data collection and annually thereafter.

IV.C.2.a. In reporting the requirements of this Section IV.C.2., the electric service provider or electric utility will:

IV.C.2.a.(i) Use the annual reporting form published by the Division, which is to be consistent with the methods, forms, or reports used for filings to the Public Utilities Commission.

IV.C.2.a.(ii) Use references to information submitted to the Public Utilities Commission as support for data elements reported on the form in lieu of submitting duplicative information to the Division.

IV.C.2.b. The data elements that must be reported pursuant to Section IV.C.2. include, but are not limited to:

IV.C.2.b.(i) Calculations of percent CO2 and percent GHG reductions from the 2005 baseline emissions approved in the plan. For utilities that conduct both retail and wholesale sales, percent reduction calculations must be provided based on retail sales only as well as for total combined retail and wholesale sales.

IV.C.2.b.(ii) A statement of the GHG accounting methodology used in the approved plan and percent reduction calculations, and any changes to that methodology if they occur for the reporting year. If methodology changes occur, supporting data for both the reporting year and baseline year must be provided to verify the percent reduction calculations.

IV.C.2.b.(iii) Changes in service territory from that identified in the approved plan that may impact the baseline values and percent reduction calculations.

IV.C.2.b.(iv) Plan Revisions filed with the Public Utilities Commission that are awaiting approval.

IV.C.2.b.(v) The number of renewable energy credits used for compliance with a Clean Energy Plan with the same vintage as the reporting year, that are generated and retired during the year.

IV.D. Report Revisions Due to Substantive Errors

IV.D.1. A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.

IV.D.2. If one or more substantive errors as defined in Section IV.D.1. are discovered in a previously submitted GHG report by an entity responsible for preparing or submitting the report, or providing data for the report, the Division must be notified in writing of the errors within five (5) business days of discovery of the errors and a revised report that corrects the substantive errors must be submitted within forty-five (45) days of the discovery of the errors.

IV.D.3. If the Division identifies substantive errors in a submitted report, the Division may notify the entity responsible for the report of the errors and a revised report that corrects the substantive errors must be submitted within forty-five (45) days of the notification.

IV.D.4. The Division may provide reasonable extensions of the forty-five day (45) period for submission of a revised report on a case-by-case basis when requested in writing by the reporting entity. The extension request must include details on why the request is being made and the additional requested time needed to submit the revised report.

V. Recordkeeping Requirements

V.A. All data elements and reports listed must be retained by the owners and operators of facilities or entities reporting under Section III.A. and be provided to the Division upon request:

V.A.1. All records of supporting documentation used to prepare and submit the GHG report, including but not limited to:

V.A.1.a. All units, operations, processes, and activities for which GHG emissions were calculated.

V.A.1.b. Operating data, fuel use records, or process information used for GHG emissions calculations.

V.A.1.c. GHG emissions calculations and methods used, including a written explanation if emission calculation methodologies used during the reporting period are changed.

V.A.1.d. Any records required to be retained pursuant to Subpart A of 40 CFR, Part 98 and the applicable Subparts of 40 CFR, Part 98 identified in Section III.B.

V.A.2. Reports submitted pursuant to the requirements of Section IV.

V.B. Records required under this Section V. must be maintained for five (5) years from the date of submission of the annual GHG report.

PART B Greenhouse Gas Emission Reduction Requirements

I. Prohibitions on Use of Certain Hydrofluorocarbons in Aerosol Propellants, Chillers, Foam, and Stationary Refrigeration End-Uses

I.A. Purpose and Applicability

I.A.1. The purpose of this regulation is to reduce hydrofluorocarbon (HFC) emissions in the State of Colorado by adopting United States Environmental Protection Agency (EPA) Significant New Alternatives Policy (SNAP) Program prohibitions for certain HFCs in air conditioning and refrigeration equipment, aerosol propellants, and foam end-uses. This regulation is designed to support greenhouse gas emission reductions identified in Colorado Revised Statutes, § 25-7-102(2)(g).

I.A.2. This regulation applies to any person, who on or after June 1, 2020, sells, offers for sale, leases, rents, installs, uses, or manufacturers in the State of Colorado any product or equipment that uses or will use a substance listed as prohibited in the end-uses listed in Section I.E.1.

I.B. Definitions

I.B.1. “Aerosol Propellant” means a liquefied or compressed gas that is used in whole or in part, such as a cosolvent, to expel a liquid or other material from the same self-pressurized container or from a separate container.

I.B.2. “Air Conditioning Equipment” means chillers, both centrifugal chillers and positive displacement chillers, intended for comfort cooling of occupied spaces.

I.B.3. “Bunstock” or “Bun Stock” means a large solid box-like structure formed during the production of polyurethane, polyisocyanurate, phenolic, or polystyrene insulation.

I.B.4. “Capital Cost” means an expense incurred in the production of goods or in rendering services including but not limited to the cost of engineering, purchase, and installation of components and/or systems, and instrumentation, and contractor and construction fees.

I.B.5. “Centrifugal Chiller” means air conditioning equipment that utilizes a centrifugal compressor in a vapor-compression refrigeration cycle typically used for commercial comfort air conditioning. Centrifugal chiller in this definition is a chiller intended for comfort cooling and does not include cooling for industrial process cooling and refrigeration.

I.B.6. “Cold Storage Warehouse” means a cooled facility designed to store meat, produce, dairy products, and other products that are delivered to other locations for sale to the ultimate consumer.

I.B.7. “Component” means a part of a refrigeration system, including but not limited to condensing units, compressors, condensers, evaporators, and receivers; and all of its connections and subassemblies, without which the refrigeration system will not properly function or will be subject to failures.

I.B.8. “Cumulatively Replaced” means the addition of, or change in, multiple components within a three-year period.

I.B.9. “Date of Prohibition” means the applicable date after which the prohibition for use of HFCs in a specific end-use provided in Section I.E. goes into effect.

I.B.10. ‘‘End-Use’’ means processes or classes of specific applications within industry sectors, including but not limited to those listed in Section I.E.

I.B.11. “Flexible Polyurethane” means a non-rigid synthetic foam containing polymers created by the reaction of isocyanate and polyol, including but not limited to that used in furniture, bedding, and chair cushions.

I.B.12. “Foam” means a product with a cellular structure formed via a foaming process in a variety of materials that undergo hardening via a chemical reaction or phase transition.

I.B.13. “Foam Blowing Agent” means a substance used to produce foam.

I.B.14. “Household Refrigerators and Freezers” means refrigerators, refrigerator-freezers, freezers, and miscellaneous household refrigeration appliances intended for residential use. For the purposes of this regulation, “household refrigerators and freezers” does not include “household refrigerators and freezers - compact”, or “household refrigerators and freezers - built-in.”

I.B.15. “Household Refrigerators and Freezers - Compact” means any refrigerator, refrigerator-freezer or freezer intended for residential use with a total refrigerated volume of less than 7.75 cubic feet (220 liters).

I.B.16. “Household Refrigerators and Freezers - Built-In” means any refrigerator, refrigerator-freezer or freezer intended for residential use with 7.75 cubic feet or greater total volume and 24 inches or less depth not including doors, handles, and custom front panels; with sides which are not finished and not designed to be visible after installation; and that is designed, intended, and marketed exclusively to be: installed totally encased by cabinetry or panels that are attached during installation; securely fastened to adjacent cabinetry, walls or floor; and equipped with an integral factory-finished face or accept a custom front panel.

I.B.17. “Hydrofluorocarbons” or “HFC” means a class of greenhouse gases (GHGs) consisting of hydrogen, fluorine, and carbon.

I.B.18. “Integral Skin Polyurethane” means a synthetic self-skinning foam containing polyurethane polymers formed by the reaction of an isocyanate and a polyol, including but not limited to that used in car steering wheels and dashboards.

I.B.19. “Manufacturer” means any person, firm, association, partnership, corporation, governmental entity, organization, or joint venture that produces any product that contains or uses HFCs or is an importer or domestic distributor of such a product.

I.B.20. “Metered Dose Inhaler,” or “Medical Dose Inhaler,” or “MDI” means a device that delivers a measured amount of medication as a mist that a patient can inhale, typically used for bronchodilation to treat symptoms of asthma, chronic obstructive pulmonary disease (COPD), chronic bronchitis, emphysema, and other respiratory illnesses. An MDI consists of a pressurized canister of medication in a case with a mouthpiece.

I.B.23. “Motor-Bearing” means refrigeration equipment containing motorized parts, including compressors, condensers, and evaporators.

I.B.24. “New” means products or equipment that are manufactured after the date of prohibition or equipment first installed for an intended purpose with new or used components after the date of prohibition, expanded by the addition of components to increase system capacity after the date of prohibition, or replaced or cumulatively replaced such that the cumulative capital cost of replacement after the date of prohibition exceeds 50% of the capital cost of replacing the whole system. For the purposes of this rule, a supermarket system is considered manufactured on the date upon which the refrigerant circuit is complete, the system can function, the system holds a full refrigerant charge, and the system is ready for use for its intended purposes.

I.B.25. “Phenolic Insulation Board” means phenolic insulation including but not limited to that used for roofing and wall insulation.

I.B.26. “Polyolefin” means foam sheets and tubes made of polyolefin.

I.B.27. “Polystyrene Extruded Boardstock and Billet (XPS)” means a foam formed from predominantly styrene monomer and produced on extruding machines in the form of continuous foam slabs which can be cut and shaped into panels used for roofing, walls, and flooring.

I.B.28. “Polystyrene Extruded Sheet” means polystyrene foam including that used for packaging. It is also made into food-service items, including hinged polystyrene containers (for “take-out” from restaurants); food trays (meat and poultry) plates, bowls, and retail egg containers.

I.B.29. “Positive Displacement Chiller” means vapor compression cycle chillers that use positive displacement compressors, typically used for commercial comfort air conditioning. Positive displacement chiller in this definition is a chiller intended for comfort cooling and does not include cooling for industrial process cooling and refrigeration.

I.B.30. “Refrigerant” or “Refrigerant Gas” means any substance, including blends and mixtures, which is used for heat transfer purposes.

I.B.31. “Refrigerated Food Processing and Dispensing Equipment” means retail food refrigeration equipment that is designed to process food and beverages dispensed via a nozzle that are intended for immediate or near-immediate consumption, including but not limited to chilled and frozen beverages, ice cream, and whipped cream. This end-use excludes water coolers, or units designed solely to cool and dispense water.

I.B.32. “Refrigeration Equipment” means any stationary device that is designed to contain and use refrigerant gas, including but not limited to retail or commercial refrigeration equipment, household refrigerators and freezers, and cold storage warehouses.

I.B.33. “Remote Condensing Units” means retail refrigeration equipment or units that have a central condensing portion and may consist of compressor(s), condenser(s), and receiver(s) assembled into a single unit, which may be located external to the sales area. The condensing portion (and often other parts of the system) is located outside the space or area cooled by the evaporator. Remote condensing units are commonly installed in convenience stores, specialty shops (e.g., bakeries, butcher shops), supermarkets, restaurants, and other locations where food is stored, served, or sold.

I.B.34. “Residential Use” means use by a private individual of a substance, or a product containing the substance, in or around a permanent or temporary household, during recreation, or for any personal use or enjoyment. Use within a household for commercial or medical applications is not included in this definition, nor is use in automobiles, watercraft, or aircraft.

I.B.35. “Retail Food Refrigeration” or “Commercial Refrigeration” means equipment designed to store and display chilled or frozen goods for commercial sale including but not limited to stand-alone units, refrigerated food processing and dispensing equipment, remote condensing units, supermarket systems, and vending machines.

I.B.36. “Retrofit” means to convert a system from one refrigerant to another refrigerant. Retrofitting includes the conversion of the system to achieve system compatibility with the new refrigerant and may include, but is not limited to, changes in lubricants, gaskets, filters, driers, valves, O-rings, or system components.

I.B.37. “Rigid Polyurethane and Polyisocyanurate Laminated Boardstock” means laminated board insulation made with polyurethane or polyisocyanurate foam, including that used for roofing and wall insulation.

I.B.38. “Rigid Polyurethane Appliance Foam” means polyurethane insulation foam in household appliances.

I.B.39. “Rigid Polyurethane Commercial Refrigeration and Sandwich Panels” means polyurethane insulation for use in walls and doors, including that used for commercial refrigeration equipment, and used in doors, including garage doors.

I.B.40. “Rigid Polyurethane High-Pressure Two-component Spray Foam” means a foam product that is sold in pressurized containers as two parts (i.e., A-side and B-side) in non-pressurized containers that are blown and applied in situ using high-pressure pumps at 800-1600 pounds per square inch (psi) and an application gun to propel the foam components, and may use liquid blowing agents without an additional propellant.

I.B.41. “Rigid Polyurethane Low-Pressure Two-Component Spray Foam” means a foam product that is sold as two parts (i.e., A-side and B-side) in containers that are pressurized to less than 250 psi that is typically applied in situ relying upon a gaseous foam blowing agent that also serves as a propellant so pumps typically are not needed.

I.B.42. “Rigid Polyurethane Marine Flotation Foam” means buoyancy or flotation foam used in boat and ship manufacturing for both structural and flotation purposes.

I.B.43. “Rigid Polyurethane Slabstock and Other” means a rigid closed-cell foam containing urethane polymers produced by the reaction of an isocyanate and a polyol and formed into slabstock insulation for panels and fabricated shapes for pipes and vessels.

I.B.44. “Stand-Alone Unit” means retail refrigerators, freezers, and reach-in coolers (either open or with doors) where all refrigeration components are integrated and the refrigeration circuit may be entirely brazed or welded. These systems are fully charged with refrigerant at the factory and typically require only an electricity supply to begin operation.

I.B.45. “Stand-Alone Low-Temperature Unit” means a stand-alone unit that maintains food or beverages at temperatures at or below 32°F (0 °C).

I.B.46. “Stand-Alone Medium-Temperature Unit” means a stand-alone unit that maintains food or beverages at temperatures above 32°F (0 °C).

I.B.47. “Substance” means any chemical intended for use in the end-uses listed in Section I.E of this regulation.

I.B.48. “Supermarket Systems” means multiplex or centralized retail food refrigeration equipment systems designed to cool or refrigerate, which typically operate with racks of compressors installed in a machinery room and which includes both direct and indirect systems.

I.B.49. “Use” means any utilization of any substance, including but not limited to utilization in a manufacturing process or product in the State of Colorado, consumption by the end-user in the State of Colorado, or in intermediate applications in the State of Colorado, such as formulation or packaging for other subsequent applications. For the purposes of this regulation, use excludes residential use, but it does not exclude manufacturing for the purpose of residential use.

I.B.50. “Vending Machine” means a self-contained unit that dispenses goods that must be kept cold or frozen.

I.C. Requirements

I.C.1. Prohibitions

I.C.1.a. No person may sell, lease, rent, install, use, or manufacture in the State of Colorado, any product or equipment using a prohibited substance for any air-conditioning, refrigeration, foam, or aerosol propellant end-use listed in Section I.E.1.

I.C.2. Exemptions.

I.C.2.a. Except where an existing system is retrofit after the date of prohibition, nothing in this regulation requires a person that acquired a product or equipment containing a prohibited substance prior to the applicable date of prohibition in Section I.E.1. to cease use of that product or equipment. Products or equipment manufactured prior to the applicable date of prohibition specified in Table 1 of Section I.E.1 (including spray foam systems not yet applied on site) may be sold, imported, exported, distributed, installed, serviced, and used after the specified date of prohibition.

I.C.2.b. End-uses that are exempted from Part B, Section I. of this regulation are provided for in Section I.E.2.

I.C.3. Alternative Compliance

I.C.3.a. This regulation does not prohibit a manufacturer of positive displacement chillers in the State of Colorado from the use of prohibited substances in Section I.E.1. provided that the manufacturer meets the following requirements:

I.C.3.a.(i) The manufacturer otherwise meets all other applicable requirements of Section I.D.

I.C.3.a.(ii) The manufacturer only uses the prohibited substances to manufacture or test positive displacement chillers designated for installation outside the State of Colorado.

I.C.3.a.(iii) The manufacturer submits a mitigation plan for emissions from prohibited substances from the manufacturing facility (including testing) to the Division no later than December 31, 2021 or prior to manufacturing or testing positive displacement chillers that use prohibited substances in the State of Colorado if no manufacturing or testing occurred on or before December 31, 2021. The plan must be approved by the Division and include:

I.C.3.a.(iii)(A) Details of emission mitigation efforts whether planned or implemented at the manufacturing facility, including dates of completion for any planned efforts.

I.C.3.a.(iii)(B) Projections of annual emissions from prohibited substances from the manufacturing facility, including emissions associated with manufacturing and testing, covering at least ten (10) calendar years from the date the plan is submitted.

I.C.3.a.(iv) The manufacturer must report actual emissions from prohibited substances to the Division on an annual basis for the prior calendar year no later than March 31 after the calendar year ends.

I.C.3.a.(iv)(A) For manufacturers producing or testing positive displacement chillers in the State of Colorado on or before December 31, 2021, the first emissions report is due March 31, 2023 for calendar year 2022.

I.C.3.a.(iv)(B) For manufacturers that first produce or test positive displacement chillers in the State of Colorado after December 31, 2021, the first emissions report is due March 31 following the first calendar year during which any emissions from prohibited substances occurred.

I.C.3.a.(iv)(C) Annual emissions reporting must continue until the manufacturer has fully transitioned from use of prohibited substances for positive displacement chillers listed in Section I.E.1.

I.C.3.a.(iv)(D) Emissions must be reported in metric tons for each prohibited substance.

I.C.3.a.(v) The manufacturer must complete project(s) within the State of Colorado that reduce greenhouse gas emissions by an amount equal to or greater than any projected annual carbon dioxide equivalent (CO2e) emissions not reduced for calendar years 2024 and beyond as part of the emissions mitigation plan identified in Section I.C.3.a.(iii).

I.C.3.a.(v)(A) Proposals for projects required under this section may be submitted as part of the emissions mitigation plan but must be submitted no later than one (1) year after approval of the mitigation plan and must be approved by the Division prior to execution.

I.C.3.a.(v)(B) Emission reductions from approved project(s) may be applied to multiple calendar years of unmitigated emissions when the projected reductions are greater than the projected unmitigated emissions on a CO2e basis.

I.C.3.a.(v)(C) A completion report for each project must be submitted to the Division no later than ninety (90) days after the project is completed and must include the details of project work completed, the amount of CO2e emissions reduced or avoided over the lifetime of the project, and any estimated benefits or co-benefits to the environment and community in which the project is located.

I.D. Disclosure Statement and Recordkeeping

I.D.1. Disclosure Statement

I.D.1.a. Any person who manufactures or sells in the State of Colorado a product or equipment in the air-conditioning, refrigeration, foam, or aerosol propellant end-uses listed in Section I.E.1., must provide a written disclosure to the buyer as part of the sales transaction and invoice or a label on the product or equipment as of the applicable date of prohibition for the end-use in Section I.E.1.

I.D.1.a.(i) For motor-bearing refrigeration and air-conditioning equipment that is not factory-charged or pre-charged with refrigerant, the disclosure or label must state:

"This equipment is prohibited from using any substance on the "List of Prohibited Substances" for that specific end-use, in accordance with State regulations for hydrofluorocarbons."

I.D.1.a.(ii) Except for products and equipment with existing labeling required by state or local building codes and safety standards which contain the information required in this Section I.D.2.a.ii., the disclosure or label for refrigeration and air-conditioning equipment that are factory-charged or pre-charged with an HFC or HFC blend must include the date of manufacture and the refrigerant and foam blowing agent the product or equipment contains.

I.D.1.a.(iii) For foam, the disclosure or label must include the date of manufacture and hydrofluorocarbon the product contains or the hydrofluorocarbon used to make the product. Alternatively, the disclosure or label may state: "Where sold, compliant with State HFC regulations."

I.D.1.a.(iv) For aerosol propellant products, the disclosure or label must include the date of manufacture and the hydrofluorocarbon the product contains or the hydrofluorocarbon used to make the product. Alternatively, the disclosure requirement may be met if the hydrofluorocarbon the product contains or the hydrofluorocarbon used to make the product is listed in a Safety Data Sheet for the product that complies with the requirements of 29 CFR 1910.1200 (effective February 8, 2013).

I.D.2. Recordkeeping

I.D.2.a. Any person who manufactures any product or equipment in the end uses listed in Section I.E.1. for sale or entry into commerce in the State of Colorado must maintain records sufficient to demonstrate that the product or equipment does not contain applicable prohibited substances listed in Section I.E.1. as of the date of prohibition for that end-use or that the product or equipment is exempt in accordance with Section I.E.2.

I.D.2.b. Records must be maintained for five (5) years and made available to the Division upon request.

I.E. List of Prohibited Substances and Exemptions

I.E.1. Table 1 lists prohibited substances in specific end-uses and the date of prohibition for each end-use, unless an exemption is provided for in Section I.E.2.

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
End-Use Category: Aerosol Propellants		
End-Use	Prohibited Substances	Date of Prohibition
Aerosol Propellants	HFC-125, HFC-134a, HFC-227ea and blends of HFC-227ea and HFC-134a	January 1, 2021
End-Use Category: Air Conditioning		
End-Use	Prohibited Substances	Date of Prohibition
Centrifugal Chillers (New)	FOR12A, FOR12B, HFC-134a, HFC-227ea, HFC-236fa, HFC245fa, R-125/ 134a/ 600a (28.1/70/1.9), R-125/ 290/ 134a/ 600a (55.0/1.0/42.5/1.5), R-404A, R-407C, R-410A, R-410B, R-417A, R-421A, R-422B, R-422C, R-422D, R-423A, R-424A, R-434A, R438A, R-507A, RS-44 (2003 composition), THR-03	January 1, 2024
Positive Displacement Chillers (New)	FOR12A, FOR12B, HFC-134a, HFC-227ea, KDD6, R125/ 134a/ 600a (28.1/70/1.9), R-125/ 290/ 134a/ 600a (55.0/1.0/42.5/1.5), R-404A, R-407C, R-410A, R-410B, R-417A, R-421A, R-422B, R-422C, R-422D, R-424A, R-434A, R-437A, R438A, R-507A, RS-44 (2003 composition), SP34E, THR-03	January 1, 2024
End-Use Category: Refrigeration		
End-Use	Prohibited Substances	Date of Prohibition
Cold Storage Warehouses (New)	HFC-227ea, R-125/290/134a/600a (55.0/1.0/42.5/1.5), R404A, R-407A, R-407B, R-410A, R-410B, R-417A, R-421A, R421B, R-422A, R-422B, R-422C, R-422D, R-423A, R-424A, R428A, R-434A, R-438A, R-507A, RS-44 (2003 composition)	January 1, 2023

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
Household Refrigerators and Freezers (New)	FOR12A, FOR12B, HFC-134a, KDD6, R-125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R-407C, R-407F, R-410A, R-410B, R-417A, R-421A, R-421B, R-422A, R-422B, R-422C, R-422D, R424A, R-426A, R-428A, R-434A, R-437A, R-438A, R-507A, RS24 (2002 formulation), RS-44 (2003 formulation), SP34E, THR-03	January 1, 2022
Household Refrigerators and Freezers—Compact (New)	FOR12A, FOR12B, HFC-134a, KDD6, R-125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R-407C, R-407F, R-410A, R-410B, R-417A, R-421A, R-421B, R-422A, R-422B, R-422C, R-422D, R424A, R-426A, R-428A, R-434A, R-437A, R-438A, R-507A, RS24 (2002 formulation), RS-44 (2003 formulation), SP34E, THR-03	January 1, 2021
Household Refrigerators and Freezers—Built-in (New)	FOR12A, FOR12B, HFC-134a, KDD6, R-125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R-407C, R-407F, R-410A, R-410B, R-417A, R-421A, R-421B, R-422A, R-422B, R-422C, R-422D, R424A, R-426A, R-428A, R-434A, R-437A, R-438A, R-507A, RS24 (2002 formulation), RS-44 (2003 formulation), SP34E, THR-03	January 1, 2023
Supermarket Systems (Retrofit)	R-404A, R-407B, R-421B, R-422A, R-422C, R-422D, R428A, R-434A, R-507A	January 1, 2021
Supermarket Systems (New)	HFC-227ea, R-404A, R-407B, R-421B, R-422A, R-422C, R-422D, R-428A, R-434A, R-507A	January 1, 2021
Remote Condensing Units (Retrofit)	R-404A, R-407B, R-421B, R-422A, R-422C, R-422D, R428A, R-434A, R-507A	January 1, 2021
Remote Condensing Units (New)	HFC-227ea, R-404A, R-407B, R-421B, R-422A, R-422C, R-422D, R-428A, R-434A, R-507A	January 1, 2021
Stand-alone Units (Retrofit)	R-404A, R-507A	January 1, 2021
Stand-alone Medium-Temperature Units (New)	FOR12A, FOR12B, HFC-134a, HFC-227ea, KDD6, R125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R407A, R-407B, R-407C, R-407F, R-410A, R-410B, R417A, R-421A, R-421B, R-422A, R-422B, R-422C, R422D, R-424A, R-426A, R-428A, R-434A, R-437A, R438A, R-507A, RS-24 (2002 formulation), RS-44 (2003 formulation), SP34E, THR-03	January 1, 2021
Stand-alone Low-Temperature Units (New)	HFC-227ea, KDD6, R-125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R-407A, R-407B, R-407C, R-407F, R-410A, R-410B, R-417A, R-421A, R-421B, R422A, R-422B, R-422C, R-422D, R-424A, R-428A, R434A, R-437A, R-438A, R-507A, RS-44 (2003 formulation)	January 1, 2021

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
Refrigerated Food Processing and Dispensing Equipment (New)	HFC-227ea, KDD6, R-125/ 290/ 134a/ 600a (55.0/1.0/42.5/1.5), R-404A, R-407A, R-407B, R-407C, R-407F, R-410A, R-410B, R417A, R-421A, R-421B, R-422A, R-422B, R-422C, R-422D, R424A, R-428A, R-434A, R-437A, R-438A, R-507A, RS-44 (2003 formulation)	January 1, 2021
Vending Machines (New)	FOR12A, FOR12B, HFC-134a, KDD6, R125/290/134a/600a (55.0/1.0/42.5/1.5), R-404A, R407C, R-410A, R-410B, R-417A, R-421A, R-422B, R422C, R-422D, R-426A, R-437A, R-438A, R-507A, RS-24 (2002 formulation), SP34E	January 1, 2022
Vending Machines (Retrofit)	R-404A, R-507A	January 1, 2021
End-Use Category: Foams		
End-Use	Prohibited Substances	Date of Prohibition
Rigid Polyurethane and Polyisocyanurate Laminated Boardstock	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof	January 1, 2021
Flexible Polyurethane	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof	January 1, 2021
Integral Skin Polyurethane	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Polystyrene Extruded Sheet	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Phenolic Insulation Board and Bunstock	HFC-143a, HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof	January 1, 2021
Rigid Polyurethane Slabstock and Other	HFC-134a, HFC-245fa, HFC-365mfc and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Rigid Polyurethane Appliance Foam	HFC-134a, HFC-245fa, HFC-365mfc and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Rigid Polyurethane Commercial Refrigeration and Sandwich Panels	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Polyolefin	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
Rigid Polyurethane Marine Flotation Foam	HFC-134a, HFC-245fa, HFC-365mfc and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
Polystyrene Extruded Boardstock and Billet (XPS)	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel B, Formacel Z-6	January 1, 2021
Rigid Polyurethane High-pressure Two-component Spray Foam	HFC-134a, HFC-245fa, and blends thereof; blends of HFC365mfc with at least 4 percent HFC-245fa, and commercial blends of HFC-365mfc with 7 to 13 percent HFC-227ea and the remainder HFC-365mfc; Formacel TI	January 1, 2021
Rigid Polyurethane Low-pressure Two-component Spray Foam	HFC-134a, HFC-245fa, and blends thereof; blends of HFC365mfc with at least 4 percent HFC-245fa, and commercial blends of HFC-365mfc with 7 to 13 percent HFC-227ea and the remainder HFC-365mfc; Formacel TI	January 1, 2021
Rigid Polyurethane One-component foam sealants	HFC-134a, HFC-245fa, and blends thereof; blends of HFC365mfc with at least 4 percent HFC-245fa, and commercial blends of HFC-365mfc with 7 to 13 percent HFC-227ea and the remainder HFC-365mfc; Formacel TI	January 1, 2021

I.E.2. Table 2 lists exemptions to the prohibitions in Section I.E.1.

Table 2: Exemptions		
End-Use Category	Prohibited Substances	Acceptable Uses
Aerosol Propellants	HFC-134a	Cleaning products for removal of grease, flux and other soils from electrical equipment; refrigerant flushes; products for sensitivity testing of smoke detectors; lubricants and freeze sprays for electrical equipment or electronics; sprays for aircraft maintenance; sprays containing corrosion preventive compounds used in the maintenance of aircraft, electrical equipment or electronics, or military equipment; pesticides for use near electrical wires, in aircraft, in total release insecticide foggers, or in certified organic use pesticides for which EPA has specifically disallowed all other lower-GWP propellants; mold release agents and mold cleaners; lubricants and cleaners for spinnerettes for synthetic fabrics; duster sprays specifically for removal of dust from photographic negatives, semiconductor chips, specimens under electron microscopes, and energized electrical equipment; adhesives and sealants in large canisters; document preservation sprays; U.S. Food and Drug Administration (FDA)-approved MDIs for medical purposes; wound care sprays; topical coolant sprays for pain relief; products for removing bandage adhesives from skin; bear spray; and law enforcement pepper spray.
Aerosol Propellants	HFC-227ea and blends of HFC-227ea and HFC-134a	FDA-approved MDIs for medical purposes.
Air Conditioning	HFC–134a	Military marine vessels where reasonable efforts have been made to ascertain that other alternatives are not technically feasible due to performance or safety requirements.
Air Conditioning	HFC-134a and R-404A	Human-rated spacecraft and related support equipment where reasonable efforts have been made to ascertain that other alternatives are not technically feasible due to performance or safety requirements.
Foams – Except Rigid polyurethane spray foam	All substances	Military applications where reasonable efforts have been made to ascertain that other alternatives are not technically feasible due to performance or safety requirements until January 1, 2022.

Table 2: Exemptions		
Foams – Except Rigid polyurethane spray foam	All substances	Space- and aeronautics-related applications where reasonable efforts have been made to ascertain that other alternatives are not technically feasible due to performance or safety requirements until January 1, 2025.
Rigid polyurethane two-component spray foam	All substances	Military or space- and aeronautics-related applications where reasonable efforts have been made to ascertain that other alternatives are not technically feasible due to performance or safety requirements until January 1, 2025.

II. Greenhouse Gas Emissions and Energy Management for the Manufacturing Sector in Colorado

II.A. Purpose and Applicability

II.A.1. The purpose of this regulation is to evaluate greenhouse gas (GHG) emissions and energy efficiency from certain stationary sources within Colorado’s industrial manufacturing sector and implement best practices for reducing GHG emissions and increasing energy efficiency.

II.A.2. This regulation applies to all energy-intensive, trade-exposed manufacturing stationary sources (EITE stationary sources) in Colorado, with reported direct GHG emissions equal to or greater than 50,000 metric tons of carbon dioxide equivalent per year.

II.A.3. The final audit shall be completed in year 2037, with reductions sustained thereafter.

II.B. Definitions

II.B.1. “Additional” means GHG emission reductions that exceed any GHG emission reductions otherwise required by law, regulation or legally binding mandate.

II.B.2. “Annual emissions” means the EITE stationary source’s direct GHG emissions for a specific calendar year, reported under Regulation Number 22.

II.B.3. “Annual emissions limitation” means the number of metric tons CO2e an EITE stationary source may emit as calculated in Section II.E.

II.B.4. “Alternate account representative” means an individual designated pursuant to II.I.3 to take actions on an EITE stationary source’ accounts.

II.B.5. “Audit plan” means the proposed audit scope, timelines and team submitted by the EITE stationary source to the Division for approval.

II.B.6. “Audit report” means the resulting document from the audit containing all the information and data required under Section II.C.3.

II.B.7. “Audit scope” means the GHG emission units and the energy consumption sources included in the energy and emissions control audit and identified in the approved audit plan.

II.B.8. "Audit team" means one or more persons performing the audit. The audit team must consist of at least one qualified third-party auditor. Additional capabilities and knowledge of the audit team must include, but are not limited to, technical expertise with specific operating and maintenance practices for the industry being audited; expertise in conducting GHG and energy management system audits; and expertise of the EITE stationary source's domestic and international market. The audit team must include individual(s) with documented audit expertise in the relevant industrial sector.

II.B.8.a. A bachelor's level college degree or equivalent in science, technology, business, statistics, math, environmental policy, economic, or financial auditing; or evidence demonstrating completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical, and analytical skills to conduct audit; and

II.B.8.b. Sufficient workplace experience to act as an auditor, including a minimum two years of full-time experience in a professional role that involved emissions data management, emissions technology, emissions inventories, environmental auditing or other technical skills necessary to conduct the audit.

II.B.9. "Carbon dioxide equivalent" (CO2e) means a metric used to compare the emissions from various GHG classes based upon their global warming potential (GWP). The CO2e is determined by multiplying the mass amount of emissions (metric tons per year), for each GHG constituent by that gas's GWP, and summing the resultant values to determine CO2e (metric tons per year).

II.B.10. "Certification body" means a professional organization that has been accredited for a specific sector and can provide compliance certificates.

II.B.11. "Co-benefits" means the additional benefits associated with the reduction of harmful air pollutants to local communities, including localized air quality benefits.

II.B.12. "Compliance account" means an account created by the Division or its agent for an EITE stationary source to which the Division and/or the EITE stationary source transfers GHG credits to meet its compliance obligations.

II.B.13. "Direct GHG emissions" means GHG emissions from an EITE stationary source that are reported to the State of Colorado under Regulation Number 22, Part A and/or 40 CFR Part 98.

II.B.14. "Disproportionately impacted community" means those communities that meet the definition contained in § 24-4-109(2)(b)(II), C.R.S.

II.B.15. "Energy and GHG emission control audit" (the audit) means a rigorous examination of the GHG emissions and energy consumption of an EITE stationary source with the goal of analyzing and recommending GHG BAECT and energy BMPs, and identifying opportunities for reduction in GHG emissions and energy consumption for the facility, conducted consistent with the requirements set forth in this section.

II.B.16. “Energy best management practices” (energy BMPs) means the best energy efficiency practices available to the EITE stationary source, based on the maximum degree of energy efficiency that is achievable on a case-by-case basis, taking into account energy, environmental, and economic impacts, and is achievable for such facility through application of production process improvements and available equipment or process control methods, systems, and techniques, and includes incorporating all the key elements of SEM, such that the facility continually improves its energy performance, reduces energy costs, and reduces GHG emissions associated with energy use.

II.B.17. “Energy efficiency” means using less electricity or fuel to produce the same quantity of product or service.

II.B.18. “Energy-intensive, trade-exposed manufacturing stationary source” (EITE stationary source) means a source that principally engages in cement and concrete product manufacturing, NAICS code 3273; foundries, NAICS code 3315; iron and steel mills and ferroalloy manufacturing, NAICS code 3311; and/or pulp, paper, and paperboard mills, NAICS code 3221.

II.B.19. “Federal Energy Star Program” means the U.S. Environmental Protection Agency’s voluntary program for industrial manufacturers through which specific energy performance indicators are measured and compared across industries and to which facilities are certified if they are achieving an Energy Star scoring of 75 or greater.

II.B.20. “Greenhouse gas best available emission control technology” (GHG BAECT) means a GHG emission control technology for a GHG emission unit based on the maximum degree of GHG reductions achievable on a case-by-case basis, taking into account energy, environmental, and economic impacts, employment of which is demonstrated by compliance with the GHG BAECT and energy BMP intensity rate determination.

II.B.21 “GHG BAECT and energy BMP intensity rate” means the total direct GHG emissions per unit of production from the emissions units within the audit scope after GHG BAECT and energy BMPs are operational as determined in Section II.D.1.b.(iv).

II.B.22. “GHG credit” means a tradable compliance instrument issued pursuant to Sections II.F.1.a.(ii) that represents a GHG emission reduction from an EITE stationary source of one metric ton of CO2e. The GHG credit must be real, additional, quantifiable, permanent, verifiable and enforceable. When issuing a GHG credit, the Division shall assign each credit an identifier that is unique.

II.B.23. “Harmful air pollutant” as used in this section means pollutants designated by EPA as criteria air pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate pollution (PM) (PM2.5 and PM10) and sulfur dioxide) or hazardous air pollutants.

II.B.24. “International Organization of Standardization” (ISO) means the independent, non-governmental international standard-setting body composed of representatives from various national standards organizations.

II.B.25. "ISO 50001: Energy Management Systems – Requirements with guidance for use" (ISO 50001) means the internationally accepted standard which specifies the requirements for an organization to demonstrate that it has a sustainable energy management system in place, has completed the energy planning process, and has a commitment to continual improvement of its energy performance.

II.B.26. "Lead auditor" means an individual who has met the requirements of and is certified as a lead auditor through a professional certification body.

II.B.27. "Management system" means the policies, processes, and procedures used by an organization to ensure that it can fulfill the tasks required to achieve its GHG emissions or energy management objectives.

II.B.28. "Net meter" means a renewable energy resource or renewable energy storage on the EITE stationary source's property which supply energy directly to the EITE stationary source's energy provider in exchange for a Power Purchase Agreement where the customer receives credit for the energy production.

II.B.29. "Non-GHG BAECT emissions" means the GHG mass emissions from an EITE stationary source that are not covered by the audit.

II.B.30. "North American industry classification system (NAICS) code(s)" means the six-digit code(s) that represents the product(s)/activity(s)/service(s) at a facility or supplier as listed in the Federal Register and defined in "North American Industrial Classification System Manual 2007," available from the U.S. Department of Commerce, National Technical Information Service, Alexandria, VA 22312 (as published August, 2021).

II.B.31. "Permanent" means the GHG emission reductions are not reversible, or, when the GHG emission reductions are reversible, that mechanisms are in place to replace any reversed emission reductions to ensure that all reductions that are awarded GHG credits endure.

II.B.32. "Plain-language" means writing that is clear, concise, well-organized, and follows other best practices appropriate to the subject or field and is easily understandable.

II.B.33. "Primary account representative" means an individual authorized by an EITE stationary source to make submissions to the Division or its agent in all matters pertaining to this Part that legally bind the authorizing source.

II.B.34. "Process" means a specific operation at an EITE stationary source comprising a series of actions or steps which are carried out in a specific order to complete a particular stage in the manufacturing process.

II.B.35. "Product" means the quantifiable material output of an individual manufacturing process or manufacturing facility.

II.B.36. "Proof of certification" means an official document issued by the formal registrar or certifying body stating the scope of certification, the expiration date and the standards to which the stationary source is certified.

II.B.37. "Qualified third-party auditor" means one or more individuals who hold a valid lead auditor certification in greenhouse gas and/or energy management systems and have demonstrated capabilities to evaluate GHG reduction opportunities for large, energy-intensive, industrial manufacturing processes and facilities. Qualified third-party auditors must have worked as an auditor for at least two years, or must have worked as a project manager or lead person for not less than four years (two of which may be graduate level work) in: (1) the development of GHG or other air emission inventories, or (2) as a lead environmental data or financial auditor.

The individual must not be affiliated with the EITE stationary source, its subsidiaries, or related entities; there can be no common ownership between the EITE stationary source and the third-party auditor. Capabilities and knowledge of the auditor include, but are not limited to, background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation and experience lead auditing GHG or energy management systems for the industry subject to this section.

II.B.38. "RACT/BACT/LAER Clearinghouse" (RBLC) means EPA's central database of air pollution technology information, including past RACT, BACT, and LAER decisions contained in New Source Review (NSR) permits, to promote the sharing of information among permitting agencies and to aid in future case-by-case determinations.

II.B.39. "Real" means that GHG emission reductions result from a demonstrable action or set of actions and are quantified using appropriate, accurate, and conservative methodologies that account for all GHG emission sources within the boundary of the regulated source generating GHG credits and account for uncertainty and activity-shifting leakage and market-shifting leakage.

II.B.40. "Regulated source" means a source of greenhouse gas that is subject to a rule adopted by the Commission under Section 105(1)(e) of the Act that imposes specific and quantifiable greenhouse gas reduction obligations upon that source or group of sources.

II.B.41. "Retail distributed generation" means a renewable energy resource or renewable energy storage that directly supply building or process energy needs at a metered location, where surplus energy is supplied to the location's energy provider when energy production is greater than on-site demand and grid energy is supplied through a customer meter to the location during times when on-site production is less than demand.

II.B.42. "Social cost of greenhouse gases" means the monetized damages associated with an incremental increase in carbon emissions in a given year. The social cost of greenhouse gases must include use of a discount rate of not more than two and a half percent; except that the social cost of greenhouse gases that is used may not be lower than that established in 2016, using a two and one-half percent discount rate, by the Federal Interagency Working Group on the social cost of greenhouse gases or than the final social cost of greenhouse gases, using a two and one-half percent or lower effective discount rate, established by the Federal Interagency Working Group on the social cost of greenhouse gases pursuant to Federal Executive Order 13990, dated January 20, 2021, whichever is higher.

II.B.43. "Strategic energy management" (SEM) means a management system-based, continuous improvement approach to energy management that seeks to improve an organization's energy performance, reduce energy costs, and reduce GHG emissions associated with energy use; drives improvement in facility energy efficiency through equipment upgrades and through operations and maintenance improvements and behavioral changes.

II.B.44. "Tracking and accounting system" means a GHG credit tracking system designated by the Division where GHG credits are issued, traded and retired by the Division or its agent.

II.B.45. "Transfer" of a GHG credit means the removal of a GHG credit from one account and placement into another account.

II.B.46. "Transfer request" means the communication by an authorized account representative or an alternate authorized account representative to the Division or its agent to transfer allowances between accounts.

II.B.47. "Verifiable" means that a reported emission reduction resulting from a GHG credit at a regulated source is well documented and transparent such that it lends itself to an objective review by the Division to verify the emission reduction is real, using monitoring of emissions reductions relative to the baseline.

II.C. Energy-Intensive Trade-Exposed Stationary Source Audit Requirements

II.C.1. Energy and GHG Emission Control Audits

II.C.1.a. By December 31, 2022, and December 31 every five years thereafter, owners or operators of each EITE stationary source must conduct energy and GHG emission control audits to establish greenhouse gas best available emission control technology (GHG BAECT) and energy best management practices (energy BMPs) and determine whether the stationary source is employing GHG BAECT and energy BMPs at the EITE stationary source, and submit the audit report to the Division.

II.C.1.b. Each EITE stationary source must conduct an audit within twelve (12) months of reporting direct GHG emissions of 50,000 metrics tons CO2e per year under Regulation Number 22, Part A and/or 40 CFR Part 98 and every five years thereafter.

II.C.1.c. Audits must be conducted by a qualified third party auditor and meet or exceed nationally or internationally accepted energy and GHG accounting and management audit standards or protocols.

II.C.2. Audit Plan

II.C.2.a. Each EITE stationary source must submit an audit plan to the Division for approval at least 120 days prior to beginning the audit as required in Section II.C.1. The Division will review the audit plan and notify the EITE stationary source within 60 days of submission of any deficiencies. If notified of deficiencies, the EITE stationary source must submit a revised audit plan for final approval no later than 30 days prior to beginning the audit. The EITE stationary source must receive approval from the Division of the audit plan prior to beginning the audit. Such approval shall not be unreasonably withheld. The audit plan must include:

II.C.2.a.(i) A description of all the emission units at the EITE stationary source that directly release one or more GHGs, ordered from largest emitting to smallest emitting emission units averaged over the past 5 years, quantified in CO2e as well as broken out by GHG type. Using this list, the emission units that comprise at least the top 80% of the EITE stationary source’s direct GHG emissions shall be identified, documented and included in the GHG emissions audit scope. Additionally, any individual emissions unit that comprises 2% or more of the EITE stationary source’s direct GHG emissions shall be identified, documented and included in the GHG emissions audit scope.

II.C.2.a.(ii) Unless the EITE stationary source is utilizing Section II.C.2.a.(iii) to show employment of energy BMPs, a description of all the emission units at the EITE stationary source that consume energy, averaged over the past five (5) years and ordered from largest consuming to smallest consuming. Using this list, the energy consumption sources that comprise the top 80% of the EITE stationary source’s energy consumption shall be identified, documented and included in the energy audit scope.

II.C.2.a.(iii) If an EITE stationary source is certified to the Federal Energy Star Program or ISO 50001, the EITE stationary source will be determined to be employing energy BMPs and the energy audit will be limited in scope. Proof of certification of the EITE stationary source to one or more of these existing standards must be included in the audit plan to utilize this option.

II.C.2.a.(iii)(1) If an EITE stationary source is planning on becoming certified to one of these standards, the EITE stationary source must submit the certification or registration timeline or plan, including key milestones towards certification or registration with certification scheduled for no more than 12 months after the audit date.

II.C.2.a.(iv) Records of any previous third-party audit results that the EITE stationary source proposes to use to support the audit on a supplementary basis or to avoid duplication of data collection efforts that have been performed within three (3) years prior to the planned audit date. To be accepted, supplementary audit data must be verified and validated by a third party and result from an audit that meets or exceeds nationally or internationally accepted energy and GHG accounting audit standards or protocols.

II.C.2.a.(v) A description of the audit team members, including experience, qualifications, and role in the audit, and existing or previous business relationship, and the nature of such relationship with the owner or operator of the EITE stationary source. If there is an existing or previous business relationship, a list and description of work done for the owner or operator of the EITE stationary source.

II.C.2.a.(v)(A) The Division may reject a proposed qualified third-party auditor or audit team if it does not meet the qualifications in Sections II.B.8. and II.B.37., failed to conduct a previous audit to the satisfaction of the Division, or is deemed to have a previous or existing relationship with the source that is so pervasive that the auditor would be unable to conduct the audit in an unbiased and independent manner.

II.C.2.a.(vi) The specific GHG and/or energy audit standards, protocols or procedures to be used for conducting the audit, if applicable.

II.C.3. Audit Reports

II.C.3.a. Each EITE stationary source must complete the audit report in accordance with Sections II.C.3.a.(i). through II.C.3.a.(v) and submit the audit report to the Division by December 31 of the audit year that includes the following elements for all GHG emission units listed in accordance with Section II.C.2.a. and specified in the Division-approved audit plan, at a minimum.

II.C.3.a.(i) The GHG BAECT analysis. The audit team must analyze GHG BAECT as follows:

II.C.3.a.(i)(A) Identify all available control technologies and strategies with practical potential for application to reduce GHG emissions from the GHG emission units included in the audit scope. Identify the current GHG emissions rate of each audited emission unit at the time of the audit.

II.C.3.a.(i)(A)(1) Control technologies and strategies must include, but are not limited to, fuel use, raw material use, energy efficiency improvements, preheating/heat reuse and strategic energy management options), and carbon capture and underground storage or utilization.

II.C.3.a.(i)(B) Eliminate technically infeasible control technologies and strategies.

II.C.3.a.(i)(B)(1) Notwithstanding Section II.C.3.a.(i)(B), the audit team must perform a feasibility assessment of carbon capture and underground storage or utilization technology for any single emissions unit evaluated with direct emissions of 100,000 tons per year or greater CO2e in any of the previous five years as reported under Regulation Number 22, Part A and/or 40 CFR Part 98. The audit team shall include this analysis in the audit report.

II.C.3.a.(i)(C) Rank remaining emission unit control technologies and strategies in descending order based on the reduction in direct GHG emissions per ton of product or output.

II.C.3.a.(i)(D) Perform a cost-effectiveness analysis on all control technologies and strategies for the emissions unit considering the full lifetime of the equipment. The cost-effectiveness analysis must include an estimate of the net levelized cost per ton of GHG emission reductions ($/ton CO2e) over the life of each proposed control method. The audit team must document in the audit report the discount rate, which is of no more than 8%, used for the cost-effectiveness analysis. The net levelized cost analysis should include, but is not necessarily limited to, the following costs and benefits:

II.C.3.a.(i)(D)(1) Engineering and design costs;

II.C.3.a.(i)(D)(2) Equipment costs, including installation;

II.C.3.a.(i)(D)(3) Available tax credits and/or incentive programs; and

II.C.3.a.(i)(D)(4) Changes in the annual costs resulting from the control technology/method including energy costs, operations and maintenance costs, and changes to productivity and/or product quality.

II.C.3.a.(i)(E) Eliminate cost-prohibitive GHG reduction measures considered. GHG reduction measures with a cost-effectiveness of equal to or less than the social cost of GHGs cannot be eliminated as cost-prohibitive, except for a demonstrated, unreasonable burden on competitiveness as analyzed in Section II.C.3.a.(i)(F).

II.C.3.a.(i)(F) Consider the economic, energy, and environmental impacts arising from each option under consideration. In this case, economic reasonableness includes an analysis of the economic impact of the emission unit control option on the EITE stationary source's competitiveness within the marketplace. The audit team must document these determinations and associated analyses in the audit report.

II.C.3.a.(i)(G) Additional required documentation for all control technologies and strategies must include, but are not limited to, overall implementation cost, control efficiency, remaining useful life of the equipment, impacts to land use approvals, and a quantification of any co-benefits. The level of analysis conducted and documented shall consider the nature of the GHG BAECT measure and potential impacts of these additional criteria.

II.C.3.a.(i)(H) The GHG BAECT analysis may reference recently permitted GHG best available control technologies (BACT), operational or process limits in the EITE stationary source's air pollution permits or in the RACT/BACT/LAER Clearinghouse for similar operations as applicable.

II.C.3.a.(ii) The energy BMP analysis.

II.C.3.a.(ii)(A) Unless the EITE stationary source successfully demonstrates that it currently employs energy BMPs pursuant to Section II.C.3.a.(ii)(B) or (C) and provides the requisite supporting information pursuant to Sections II.C.3.a.(ii)(B)(1) and (2) or II.C.3.a.(ii)(C)(1) to II.C.3.a.(ii)(C)(3), the audit team must analyze energy BMPs as follows:

II.C.3.a.(ii)(A)(1) Identify all available energy efficiency measures for the specific energy consumption sources included in the audit scope. Any energy efficiency measure considered to be a GHG BAECT option but not recommended as GHG BAECT must be included in the energy BMP analysis for that GHG emission unit, as applicable. This analysis can exclude any control technologies that redefine the stationary source.

II.C.3.a.(ii)(A)(2) Eliminate technically infeasible energy efficiency measures.

II.C.3.a.(ii)(A)(3) Rank remaining energy efficiency measures based on the reduction in energy use per ton of final product manufactured at the facility.

II.C.3.a.(ii)(A)(4) Perform a cost-effectiveness analysis on all energy efficiency measures considering the full lifetime of the measure. The cost-effectiveness analysis must include an estimate of the net levelized cost per energy consumption reduction over the life of the equipment. The audit team must document in the audit report the discount rate, which is of no more than 8%, used for the cost-effectiveness analysis. The net levelized cost analysis should include, but is not necessarily limited to, the following costs and benefits:

II.C.3.a.(ii)(A)(4)(a) Engineering and design costs;

II.C.3.a.(ii)(A)(4)(b) Equipment costs including installation;

II.C.3.a.(ii)(A)(4)(c) Available tax credits and/or incentive programs; and

II.C.3.a.(ii)(A)(4)(d) Changes in the following annual costs resulting from the control technology/method including energy costs, operations and maintenance costs, and changes to productivity and/or product quality.

II.C.3.a.(ii)(A)(5) Eliminate cost-prohibitive energy efficiency measures considered. Energy efficiency measures with a cost-effectiveness equal to or under the social cost of GHGs cannot be eliminated as cost-prohibitive, except for a demonstrated, unreasonable burden on competitiveness shown in Section II.C.3.a.(ii)(A)(6).

II.C.3.a.(ii)(A)(6) Consider the economic, energy, and environmental impacts arising from each measure remaining under consideration. In this case, economic reasonableness includes an analysis of the economic impact of the measure on the EITE stationary source’s competitiveness within the marketplace. The audit team must document these determinations and associated analyses in the audit report.

II.C.3.a.(ii)(A)(7) Additional required documentation for all analyzed measures include, but are not limited to, cost-effectiveness, remaining useful life of the equipment, impacts to land use approvals and any co-benefits. The level of analysis conducted and documented shall consider the nature of the energy efficiency measure and potential impacts of these additional criteria.

II.C.3.a.(ii)(B) In lieu of performing the energy BMP analysis, certification within 12 months of the audit date under the annual Federal Energy Star Program will be determined as employment of energy BMPs for the EITE stationary source. Annual Energy Star certification documentation for all years subsequent to the previous audit as well as the current certification must be included in the audit report and contain:

II.C.3.a.(ii)(B)(1) Specific BMP energy efficiency measures the EITE stationary source used to achieve the Federal Energy Star Program certification; and

II.C.3.a.(ii)(B)(2) The annual Energy Performance Indicator (EPI) benchmarking spreadsheet demonstrating a score of 75 or higher submitted with the Energy Star application.

II.C.3.a.(ii)(C) In lieu of performing the energy BMP analysis, registration to ISO 50001 within 12 months of the audit date will be determined as employment of energy BMPs for the EITE stationary source. Management system documentation must be included in the audit report and contain:

II.C.3.a.(ii)(C)(1) Specific BMP energy efficiency measures the EITE stationary source used to achieve the ISO 50001 Program certification;

II.C.3.a.(ii)(C)(2) Information on the energy management system including the Manual, Objectives and Goals, Energy Policy and results of the most recent energy management system audit; and

II.C.3.a.(ii)(C)(3) The valid registration certificate.

II.C.3.a.(ii)(D). If an EITE stationary source fails to achieve the annual certification by the EPA Energy Star Program or registration to ISO 50001, the source must submit a compliance action plan to the Division within 90 days of the certification or registration expiration. The plan must include the EITE stationary source's plan and timeline to implement energy BMPs to either reacquire certification in the EPA Energy Star Program, reacquire ISO 50001 registration, or comply with the requirements in Section II.C.3.a.(ii)(A). The energy BMPs must be achieved within twelve months after the compliance action plan is approved by the Division.

II.C.3.a.(iii) The GHG BAECT and energy BMP recommendation.

II.C.3.a.(iii)(A) The GHG BAECT recommendation will include:

II.C.3.a.(iii)(A)(1) Recommendations on the most effective direct GHG emissions control technology and strategy, or suite of technologies and strategies, for the GHG emissions unit analyzed as GHG BAECT;

II.C.3.a.(iii)(A)(2) A list of emissions control measures with a levelized cost less than or equal to $0; and

II.C.3.a.(iii)(A)(3) Recommendations on GHG BAECT options that provide greater co-benefits to the surrounding communities where the top emission unit control technologies or strategies are comparable in terms of cost-effectiveness.

II.C.3.a.(iii)(A)(4) A calculation of the Non-GHG BAECT emissions. Non-GHG BAECT emissions are calculated by subtracting the reported emissions from units evaluated for GHG BAECT from the facility annual emissions at the time of the first audit. This shall be calculated as follows:

Non-GHG BAECT Emissions = Total direct emissions from the most recent year reported – (reported emissions from the units evaluated for GHG BAECT)

II.C.3.a.(iii)(B) The energy BMP recommendation will include:

II.C.3.a.(iii)(B)(1) Recommendations on the most effective energy efficiency measures for the energy consumption sources analyzed to be set as Energy BMPs.

II.C.3.a.(iii)(B)(2) A list of energy efficiency measures with a levelized cost less than or equal to $0;

II.C.3.a.(iii)(B)(3) Recommendations on Energy BMP options that provide greater co-benefits to the surrounding communities where the top emissions unit control technologies or strategies are comparable in terms of cost effectiveness.

II.C.3.a.(iv) A plain-language summary of the audit findings, determinations, and recommendations in the top two languages spoken by the community surrounding the EITE stationary source. This summary shall include the list of GHG BAECT options for the emission units analyzed, how they were ranked and why they are being recommended.

II.C.3.a.(v) Confidential business information must be clearly identified and be submitted in a separate, supplementary document to the audit report.

II.D. GHG BAECT and Energy BMP Determination

II.D.1. Within 60 days of receipt of the audit report, the Division will determine GHG BAECT and energy BMPs for the EITE stationary sources as follows:

II.D.1.a. The GHG BAECT determination may be based on the top-ranked control technology for the emission units in the audit report, or a suite of control technologies, at the Division's discretion, so long as:

II.D.1.a.(i) The cost of the suite of control measures, combined, would not be unduly burdensome to the facility; and

II.D.1.a.(ii) The total annual CO2 emissions reductions generated by the suite of measures is equal to or greater than the annual CO2 emissions reductions generated by the top-ranked control technology according to the audit report.

II.D.1.b. A GHG BAECT determination will be issued for each GHG emissions unit in the audit scope and include:

II.D.1.b.(i) The Division's determination of specific control technologies and/or measures for that emission unit, including the current GHG emissions rate of each audited emission unit at the time of the audit;

II.D.1.b.(ii) All control technologies found under Section II.C.3.a.(i) to have a net levelized cost less than or equal to $0, where cost neutrality can be achieved no more than 5 years from operational date of the technology, except where the auditor has established that doing so would pose an unreasonable burden to the facility; and

II.D.1.b.(iii) The GHG emission rate per unit of final product at the EITE stationary source for the individual emissions units after implementation of the prescribed measures.

II.D.1.b.(iv) The final GHG BAECT and energy BMP intensity rate determination shall be issued for the EITE stationary source as a rate of total GHG emission (CO_2e) for the emissions units included in the audit scope per final product of the facility. This calculation shall be based on the determination(s) in Sections II.D.1.a. and II.D.1.c. (as applicable) and shall be calculated as follows:

GHG BAECT & Energy BMP Intensity Rate Determination = Σ (CO_2e per tons of facility product for each emission unit in audit scope).

II.D.1.b.(iv)(1) The Division may adjust the final GHG BAECT and energy BMP intensity determination based on a change to the GHG emission rate for any GHG BAECT measure after the GHG reduction measure is fully operational and tuned.

II.D.1.c. The energy BMP determination will be issued for each energy consumption source in the audit scope and include:

II.D.1.c.(i) The Division's determination of energy BMPs for the specific energy consuming equipment; and

II.D.1.c.(ii) Any energy efficiency measures found under Section II.C.3.a.(ii) to have a net levelized cost less than or equal to $0 that are not included in the BAECT determination, unless the auditor has established that doing so would pose an unreasonable burden to the facility.

II.D.2. The Division will hold one or more public meetings on the results of the final GHG BAECT and energy BMP determinations.

II.D.3. Within 45 days of making its final GHG BAECT and energy BMP determinations, the division will present the determinations at a regular meeting of the Commission. The Commission may approve the determinations or return them to the Division for further analysis. The Division will return to the Commission for final approval at its next regular meeting or as soon as practical.

II.E. Emission Reduction Requirements

II.E.1. All EITE stationary sources subject to this rule must reduce facility-wide GHG emissions by 5 percent.

II.E.1.a. EITE stationary sources annual emissions limitation shall be calculated as described in this Section II.E.1.a. Multiply the EITE stationary source's prescribed final GHG BAECT and energy BMP intensity rate determination, as determined by the Division under Section II.D. by the number of units produced in the calendar year, to result in a GHG BAECT mass emission number. If an EITE stationary source produces more than one product and, as a result, has more than one final GHG BAECT determination, the GHG BAECT mass emissions is calculated by multiplying the intensity rate for each product by the amount of product produced in the previous year, to calculate the GHG BAECT mass emissions for each product, and then adding the mass emissions for each product to calculate the GHG BAECT mass emissions. Add the Non-GHG BAECT emissions calculated under Section II.C.3.a.(iii)(A)(5) to the GHG BAECT emissions number, resulting in a mass-based emissions representing the facility-wide total GHG emissions (CO2e), which serves as the baseline for the 5 percent mass-based reduction. Subtract the five (5) percent mass emissions reduction as required under Section II.E. This shall be calculated as follows:

Annual Emission Limit for Compliance Year in tons CO2e = (((GHG BAECT & Energy BMP Intensity Rate Determination) * (Compliance Year Facility Product)) + Non-GHG BAECT determination) * 0.95

II.E.1.b. Beginning no later than the third year after each audit year, EITE stationary sources must demonstrate the additional mass-based five (5) percent GHG emission reduction and continued compliance with the reduction described in this section, by comparing the total mass GHG emissions limitation to the direct reported GHG emissions for the previous year. This is demonstrated through the annual compliance certification in Section II.G.1.a.

II.E.1.c. Where an EITE stationary source's approved compliance action plan requires that the plan be completed and operational after the third year after each audit year, the EITE stationary source must meet an interim annual mass emission limit achieving the required mass-based five (5) percent GHG emission reduction.

II.E.1.c.(i) This interim annual five (5) percent mass reduction shall be calculated by multiplying the EITE stationary source's GHG BAECT and energy BMP intensity rate, as determined by the Division under Section II.D. by the number of units produced in the third calendar year, to result in a GHG BAECT mass emission number. Add the Non-GHG BAECT emissions to this number. Five (5) percent of this mass emissions total represents the mass GHG emissions reduction required in tons of CO2e. The calculation is as follows:

((((GHG BAECT & Energy BMP Intensity Rate Determination) * (Compliance Year Facility Product)) + Non-GHG BAECT determination) * 5%)

II.E.1.c.(ii) The interim annual emissions limitation is calculated by multiplying the current GHG emissions intensity rate as documented in the most recent audit by the compliance year facility product to result in a mass GHG emissions total. Add the Non-GHG BAECT emissions to this total, and then subtract the 5% reduction calculated in Section II.E.1.c.(i). The calculation is as follows:

((Current GHG Emissions Intensity Rate as documented in the audit report * Compliance Year Facility Product) + Non-GHG BAECT determination) – ((((GHG BAECT & Energy BMP Intensity Rate Determination) * (Compliance Year Facility Product)) + Non-GHG BAECT Determination) * 5%)

II.E.2. If, at any point after the 2022 audit cycle and before 2030 an EITE stationary source achieves mass based GHG emission reductions equal to or greater than 20% below the source's 2015 GHG emissions baseline, the 5% emission reduction required under Section II.E.1. is considered satisfied through the year 2030, provided the 20% mass-based reductions are sustained as demonstrated through annual compliance certifications under Section II.G.1.a. An EITE stationary source meeting this requirement must continue to conduct the annual audits and otherwise comply with the requirements of this rule.

II.F. Emission Reduction Requirement Compliance

II.F.1. The EITE stationary source must submit a compliance action plan within 120 days of the Commission's approval of the GHG BAECT, energy BMPs, and GHG BAECT and energy BMP intensity rate determination that includes the EITE stationary source's plan and timeline to comply with the annual mass emission limit, and interim mass emission limit in Section II.D.1.b.(iv) as applicable and the energy BMPs determination.

II.F.1.a. The EITE stationary source may use the following emission reduction mechanisms to comply with the annual and interim emission limits:

II.F.1.a.(i) Actual, direct emissions reductions onsite at the EITE stationary source; or

II.F.1.a.(ii) Actual direct GHG emission reductions submitted in the form of GHG credits awarded by the Division. In order to produce GHG credits, the emissions reductions must be real, additional, verifiable, permanent and enforceable. GHG credits will only be issued in the tracking system after emission reduction have been demonstrated; or

II.F.1.a.(iii) Installation and utilization at the facility of a retail distributed generation or net meter renewable energy project that reduces the GHG emissions from the EITE stationary source's electrical energy use, and for which the EITE stationary source has retired Renewable Energy Credits in Colorado generated that year, which demonstrate emissions reductions to comply with Section II.F.1. Utilization of Renewable Energy Credits for compliance cannot exceed the annual generation of the distributed generation system and it can only be used to satisfy the five (5) percent GHG emission reduction associated with Section II.E.1. and shall not be used for any other component of the annual emission limitation.

II.F.1.b. If the measure(s) determined to be GHG BAECT and/or energy BMPs for an emission unit also are anticipated to result in significant co-benefits, then the EITE stationary source must demonstrate in its compliance action plan that the co-benefits will be achieved through comparable reductions of the relevant harmful air pollutant(s) at the EITE stationary source. If an EITE stationary source demonstrates there are no material co-benefits from the implementation of the measure(s) determined to be GHG BAECT and/or energy BMPs, these requirements do not apply.

II.F.2. Beginning no later than the third year after each audit year, EITE stationary sources must demonstrate the additional mass-based five (5) percent GHG emission reduction described in this section II.E. through the annual compliance certification in Section II.G.1.a.

II.F.3. When considering compliance options with similar or the same cost-effectiveness, the EITE entity must give increased priority to GHG reduction initiatives that would produce co-benefits to the neighboring communities surrounding the EITE stationary source.

II.F.4. The Division will review the compliance action plan for approval.

II.F.5. EITE stationary sources must comply with the compliance action plan once approved by the Division.

II.F.6. If in any calendar year an EITE stationary source achieves reported emissions lower than the annual emissions limitation, the Division will award the EITE stationary source GHG credits equal to the difference between the annual emissions limitation and reported emissions. GHG credits will only be issued after emission reductions have been demonstrated.

II.F.7. If in any calendar year an EITE stationary source fails to achieve the annual emissions limitation, the owners and operators may remedy this noncompliance by surrendering in the EITE entity's compliance account sufficient GHG credits so as to reduce the actual emissions to the EITE annual emissions limitation.

II.G. Reporting

II.G.1. Owners or operators of EITE stationary sources must submit an annual report to the Division by May 1 of each year (beginning May 1, 2026) that includes:

II.G.1.a. Annual Compliance Certification Requirements. The account representative of each EITE stationary source must submit a compliance certification to the Division or its agent that certifies:

II.G.1.a.(i) The EITE stationary source's annual GHG emissions, in metric tons, for the previous calendar year;

II.G.1.a.(ii) The total production at the EITE stationary source, in units that are consistent with the GHG BAECT and energy BMP intensity rate determination, for the previous year;

II.G.1.a.(iii) The EITE stationary source's GHG emissions rate per product for the previous calendar year and the GHG BAECT and energy BMP intensity rate determination.

II.G.1.a.(iv) The EITE stationary source's annual emissions limitation for the previous year;

II.G.1.a.(v) The difference, if any, between the EITE stationary source's actual total direct GHG emissions for the previous year and the EITE stationary source's annual emissions limitation for the previous year.

II.G.1.a.(vi) For EITE stationary sources that are complying through GHG credits pursuant to Section II.F.1.a.(ii):

II.G.1.a.(vi)(A) In the event that the EITE stationary source has actual total emissions that exceed its annual emissions limitation, the compliance certification shall specify the GHG credits that are to be surrendered from the EITE stationary source's compliance account sufficient to meet the EITE stationary source's annual emissions limitation.

II.G.1.b. Current project status to implement GHG BAECT or energy BMPs contained in a compliance action plan under Section II.F.1.;

II.G.1.b.(i) The current status of measures to achieve comparable co-benefits required under Section II.F.1.b.

II.G.1.c. If the EITE stationary source is determined to be employing energy BMPs through certification to the Federal Energy Star Program or the ISO 50001 standard, the EITE stationary source must submit the information in accordance with Section II.C.3.a.(ii);

II.G.1.d. Instances of noncompliance with the Division's approved GHG BAECT and energy BMPs determination, compliance action plan, reason(s) for noncompliance, and actions taken or planned to return to compliance; and

II.G.1.e. All information necessary for the Division to confirm the EITE stationary source's emission rate in the prior year.

II.G.2. In addition to the annual report, owners and operators of EITE stationary sources must submit a final audit update to the Division within 60 days of the operation of GHG BAECT and/or energy BMPs, which includes verification that all GHG BAECT and energy BMP measures established in section II.D. are operational.

II.H. Recordkeeping

II.H.1. EITE stationary sources must maintain records for a period of ten (10) years and make records available to the Division upon request, including:

II.H.1.a. Division approved audit plan.

II.H.1.b. Final audit reports.

II.H.1.c. Commission approved GHG BAECT and energy BMP determinations.

II.H.1.d. Annual Compliance Certificate

II.H.1.e. Approved compliance action plans and records reasonably necessary to demonstrate compliance with the approved plan.

II.H.1.f. Current certification or registration documentation to applicable standards to show continued compliance with Section II.C.3.a.(ii)(B) or (C).

II.H.1.g. If the final GHG BAECT is determined to have an operation date that is beyond the next 5-year audit, the EITE stationary source must maintain records of project management documentation related to the implementation of the GHG BAECT measure including project status, timeline, expected operational date as proposed and approved in the compliance action plan.

II.I. Accounting and Tracking System and Account Establishment and Registration Requirements

II.I.1. Establishment of accounting and tracking system and accounts.

II.I.1.a. The Division or its agent will establish an accounting and tracking system for EITE GHG credits.

II.I.1.a.(i) EITE GHG credits can only be used by EITE sources.

II.I.1.b. Upon receipt of the application required under Section II.I.2, the Division or its agent will establish one compliance account for each EITE stationary source in the accounting system.

II.I.1.c. If Division determines that a regulated source adversely affects a disproportionately impacted community through emissions of locally harmful air pollutants, the Division shall assign an identifier.

II.I.2. All EITE stationary sources must complete an application to register with the Division or its agent for a compliance account in the accounting system within 30 days after the Commission approves its GHG BAECT and Energy BMP determination, or within 30 days after the EITE stationary source first reports annual GHG emissions exceeding the 50,000-metric-ton threshold, whichever occurs later. Applicants must provide such information as the Division deems necessary in connection with the application, including but not limited to the following information:

II.I.2.a. Name, physical and mailing addresses, contact information, date and place of incorporation, and any ID number assigned by the incorporating agency;

II.I.2.b. Names and addresses of the entity's directors and officers with authority to make legally binding decisions on behalf of the entity, and partners with over 10 percent control over the partnership, including any individual or entity doing business as the limited partner or the general partner;

II.I.2.c. Names and contact information for person controlling over 10 percent of the voting rights attached to all the outstanding voting securities of the entity;

II.I.2.d. A business number, if one has been assigned to the entity by a Colorado state agency; and

II.I.2.e. A government-issued taxpayer or Employer Identification Number or for entities located in the United States, a U.S. Federal Tax Employer Identification Number, if assigned.

II.I.3. An EITE stationary source must designate a primary account representative and at least one, and up to four, alternate account representative. Any individual who requires access to the accounting system must register as a user in the accounting system.

II.I.4. Each authorized representative shall represent, and by his or her representations, actions, inactions, or submissions, legally bind the EITE stationary source in all matters relating to this part. Any representation, action, inaction, or submission by any authorized account representative shall be deemed to be a representation, action, inaction, or submission by the source.

II.J. Division Action on Compliance Certifications and Submittals

II.J.1. The Division may review and conduct independent audits of any compliance certification or other submission to the Division under this regulation.

II.J.2. If any submission contains false or fraudulent information, that is considered a violation of this regulation, subject to enforcement under § 25-7-115, C.R.S.

II.K. Noncompliance

II.K.1. In the event that an EITE stationary source fails to meet its annual emissions limitation, the EITE stationary source shall be deemed in noncompliance and must surrender three GHG credits for every ton emitted by the EITE stationary source in excess of the annual emissions limitation or be subject to a civil penalty or other enforcement action by the Division.

II.K.2. Nothing in Section II.K.1 shall limit the enforcement powers of the Division to remedy noncompliance with this Part, including but not limited to the Division's ability to seek additional penalties or fines, and compel actual reductions at any EITE stationary source in noncompliance.

III. Reduction of Emissions from Oil and Natural Gas Midstream Segment Fuel Combustion Equipment

III.A. Definitions

III.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

III.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.

III.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.

III.A.2. "Co-benefits" for purposes of Section III. means the reduction of harmful air pollutants in disproportionately impacted communities.

III.A.3. "Company emission reduction plan" or "company ERP" means a plan prepared by a midstream segment owner or operator, consistent with the guidance issued by the midstream steering committee, to achieve that owner or operator's proportionate reductions of greenhouse gas emissions to meet the requirements of Section III.

III.A.4. "Disproportionately impacted community" (DI community) means census block groups designated as DI communities in CDPHE's draft Data Viewer for Disproportionately Impacted Communities in Colorado (as of December 17, 2021, at: https://cohealthviz.dphe.state.co.us/t/EnvironmentalEpidemiologyPublic/views/EJActDICommunities-Public/HB21-1266DICommunities?%3AshowAppBanner=false&%3Adisplay_count=n&%3AshowVizHome=n&%3Aorigin=viz_share_link&%3AisGuestRedirectFromVizportal=y&%3Aembed=y) consistent with 24-4-109(2)(b)(II), C.R.S. (2021). A complete list of these census block groups by 12-digit FIPS code will be maintained by the Division and made publicly available.

III.A.5. "Harmful air pollutants" for purposes of Section III. means pollutants designated by EPA as criteria pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate pollution (PM) (PM2.5 and PM10) and sulfur dioxide) or hazardous air pollutants.

III.A.6. "Midstream fuel combustion equipment" means engines, turbines, process and other heaters, boilers, and reboilers in the midstream segment.

III.A.7. "Midstream segment" means the oil and natural gas compression segment and the natural gas processing segment that are physically located in Colorado and that are upstream of the natural gas transmission and storage segment.

III.A.8. "Midstream segment emission reduction plan" or "segment ERP" means a plan establishing the process and timelines for the midstream segment to achieve twenty percent (20%) reduction in greenhouse gas emissions (in CO2e) from midstream segment fuel combustion equipment by no later than December 31, 2030.

III.A.9. "Midstream steering committee" means a committee comprised of members approved by the Division to serve as a technical working group tasked with developing program guidance documents and developing a midstream segment emission reduction plan. To the extent practicable, the committee members will include two members representing the electric utility sector; three members representing the midstream segment (at least one representing the oil and natural gas compression segment and one representing the natural gas processing segment), or industry trade organizations representing owners or operators; at least three local government representatives (one from inside the 8-hour ozone control area and northern Weld County and one from outside the 8-hour ozone control area and northern Weld County); at least three members representing the general public (including a representative of an environmental organization and a representative of a disproportionately impacted community); and at least one Division staff person. The steering committee may also include two additional members: a representative from the Colorado Energy Office and a representative from the Public Utilities Commission.

III.A.10. "Natural gas processing segment" means the operations engaged in the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant.

III.A.11. "Natural gas transmission and storage 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.

III.A.12. "Northern Weld County" means the portion of the county that does not lie 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.

III.A.13. "Oil and natural gas compression segment" means the oil and natural gas compression, midstream pipelines, and other equipment used to collect oil and/or natural gas from gas or oil wells and used to compress, dehydrate, sweeten, or transport the oil and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or to a natural gas distribution pipeline. For purposes of Section III., equipment located at a well production facility, including but not limited to compressors, is excluded from the oil and natural gas compression segment.

III.A.14. "Residue gas" and "residue gas compression" mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

III.B. Beginning January 1, 2022, each midstream segment owner or operator must participate in this Section III. program to reduce greenhouse gas emissions from midstream fuel combustion equipment by twenty percent (20%) over the 2015 baseline as determined by § 25-7-140(2)(a)(II), C.R.S.

III.C. Creation of the Midstream Steering Committee and Initial Information Collection

III.C.1. By February 28, 2022, the midstream steering committee members will be approved by the Division. The first midstream steering committee meeting will be held no later than March 31, 2022, and thereafter at least monthly at a time and place determined by the midstream steering committee.

III.C.2. By no later than April 30, 2022, the midstream steering committee will initiate an information and data collection process through which it will seek and obtain information in addition to the reports provided pursuant to Section III.C.3. necessary to inform its technical analyses and policy considerations and comply with its duties under Section III.

III.C.2.a. The midstream steering committee will seek publicly available information concerning most recently filed electric utility Electric Resource Plans and Clean Energy Plans; regarding the forecast timing of upcoming Electric Resource Plan filings, electric utility energy sales and demand forecasts for 2023 through 2030; and regarding existing and contracted electric generation units, and approved future transmission lines in Colorado.

III.C.2.b. The Division will provide the midstream steering committee with the 2015 baseline CO2e emissions from the industrial sector identified in § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.C.3. By no later than July 31, 2022, each midstream segment owner or operator must provide the following information to the midstream steering committee on a Division-approved form to inform the guidance document that will be developed pursuant to Section III.D.1.

III.C.3.a. The facility name, AIRS ID (if applicable), and location (with coordinates) of each of the owner or operator's natural gas processing plants and natural gas compressor stations.

III.C.3.b. An inventory of all midstream fuel combustion equipment owned or operated by the midstream segment owner or operator including midstream fuel combustion equipment not located at a natural gas processing plant or natural gas compressor station. The inventory must identify which equipment is located within a disproportionately impacted community. The inventory must include the type of equipment (e.g., engine, boiler) and the total CO_2, methane, and CO_2e emissions from each piece of equipment in calendar years 2020 and 2021 as reported to the Division in accordance with Regulation Number 7, Part D, Section V. If different calculation methods were used to report emissions from midstream fuel combustion equipment to the U.S. EPA under the federal Greenhouse Gas Reporting Program, 40 C.F.R. Part 98, the inventory must include the emissions reported to the U.S. EPA for the equipment included in this inventory and an explanation of the changed method of calculation.

III.C.3.c. An estimate of the total annual power demand, along with total instantaneous power demand in kilowatt hours, or horsepower demand required for use of the midstream fuel combustion equipment identified in Section III.C.3.b.

III.C.3.d. An inventory of all electric motors driving gas compressors or electric heaters owned or operated by the midstream segment owner or operator including the facility where located (as applicable) and the date the electric equipment commenced operation.

III.C.3.e. An estimate of the total annual kilowatt hours and heat rate demand, along with total instantaneous power demand, being supplied by electric motors and electric heaters identified in Section III.C.3.d.

III.C.3.f. An estimate of existing transmission and distribution capacity to serve estimated load in a specific location as supplied by the applicable electric, transmission, or distribution service provider.

III.D. Midstream Steering Committee Duties, Guidance, Company ERPs, and Segment ERPs

III.D.1. The midstream steering committee will develop and issue one or more guidance documents for midstream segment owners and operators to submit company ERPs to the steering committee. The guidance will

III.D.1.a. Identify the sources that a midstream segment owner or operator must include in its company ERP, including the facilities, activities, and midstream fuel combustion equipment.

III.D.1.b. Identify the total tons of CO_2e reduction to be achieved by the segment ERP, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.D.1.c. Provide a methodology by which each midstream segment owner or operator will determine the total tons of CO2e reduction from midstream fuel combustion equipment to be achieved by that owner or operator. The methodology should take into account, without limitation, the emission reductions from midstream fuel combustion equipment achieved by the owner or operator from 2015 midstream fuel combustion equipment emission levels and the amount of emissions reduced by electrification of midstream fuel combustion equipment achieved by the midstream segment owner or operator.

III.D.1.d. Prescribe how CO2e emissions and emission reductions will be calculated in the company ERP, consistent with, to the extent feasible, the requirements of §§ 25-7-105(1)(e) and -140, C.R.S. (2021) and Regulation Number 7, Part D, Section V. The Division must approve of emission calculation methodologies before they can be included in the midstream steering committee guidance document(s).

III.D.1.e. To aid midstream owners and operators in ensuring CO2e emission reductions and co-benefits, identify and describe environmental justice considerations for midstream segment fuel combustion equipment affecting disproportionately impacted communities, including potential air quality impacts or improvements, other non-air environmental benefits or detriments, employment opportunities, and regional economic impacts that must be considered by midstream segment owners or operators in their company ERPs.

III.D.1.f. Identify and describe methods by which midstream segment owners or operators can achieve the emission reductions necessary to comply with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021), including, but not limited to, equipment replacement, equipment retrofit, equipment shutdown, or electrification. The guidance should also seek to identify and describe issues that must be addressed by operators considering electrification as an emission reduction strategy

III.D.1.g. Describe how midstream segment owners or operators can account for changes in and avoid increases to NOx or VOC emissions in securing the CO2e emission reductions necessary to meet the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.D.1.h. Describe how midstream segment owners or operators should account for costs associated with achieving required emission reductions from midstream segment fuel combustion equipment in their company ERPs, including capital costs, annualized equipment costs, annual operating costs, and costs in dollars per ton of CO2e reduced.

III.D.1.i. Describe how midstream segment owners or operators should incorporate midstream segment fuel combustion equipment that commences operation after September 30, 2023, into their company ERPs.

III.D.2. No later than December 31, 2022, the Division will make the draft midstream steering committee guidance document(s) available for at least 30 days of public comment.

III.D.3. By March 31, 2023, the midstream steering committee will publish its final guidance document(s) for the development of company ERPs.

III.D.4. By September 30, 2023, each midstream segment owner or operator must submit to the midstream steering committee its company ERP, consistent with and containing all the information identified in the guidance issued by the midstream steering committee, to achieve CO2e reductions from the owner or operator's midstream segment fuel combustion equipment, prioritizing greenhouse gas emission reductions that have co-benefits. The Division will develop emission reduction requirements for an owner or operator that fails to submit a company ERP.

III.D.5. By March 31, 2024, the midstream steering committee will develop a midstream segment ERP, and provide the proposed midstream segment ERP to the Division for review. The proposed midstream segment ERP will

III.D.5.a. Identify the total tons of CO2e reduction from midstream segment fuel combustion equipment to be achieved by the midstream segment ERP, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.D.5.b. Identify the total tons of CO2e reduction from midstream segment fuel combustion equipment to be achieved by each midstream segment owner or operator, consistent with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.D.5.c. Identify the midstream segment facilities and fuel combustion equipment addressed by the midstream segment ERP.

III.D.5.d. Prescribe the process and timing for midstream segment owners or operators to implement CO2e emission reduction strategies for midstream fuel combustion equipment, including, but not limited to, electrification, retrofit, shut-down, or replacement.

III.D.5.e. Describe how the implementation of the midstream segment ERP will affect disproportionately impacted communities within which midstream fuel combustion equipment is located, including a description of the percentage of CO2e emission reductions in disproportionately impacted communities that will be achieved by the midstream segment ERP as a percentage of total emission reductions to be achieved by the midstream segment ERP. The midstream segment ERP must ensure and prioritize CO2e reductions with co-benefits in disproportionately impacted communities, identify the disproportionately impacted communities in which the co-benefits will be achieved, and must attempt to quantify the co-benefits associated with the midstream segment ERP.

III.D.5.f. Prescribe how emission reductions will be achieved for midstream segment fuel combustion equipment that is modified, constructed, or relocated to Colorado on or after September 30, 2023.

III.D.5.g. Prescribe any additional recordkeeping and reporting requirements over and above existing provisions of Regulation Number 7, sufficient to ensure enforceability and verification of the midstream segment ERP.

III.D.5.h. To the extent feasible, the midstream segment ERP will report the total estimated cost to midstream segment owners and operators to achieve the CO2e reductions in the midstream segment ERP and the impact on CO2e emissions from electrical generating units in Colorado resulting from electrification of midstream fuel combustion equipment as set forth in the midstream segment ERP.

III.D.6. Following receipt of the midstream segment ERP from the midstream steering committee, the Division will make the draft midstream segment ERP available for at least 30 days of public comment.

III.D.7. By no later than August 31, 2024, the Division will submit a regulatory proposal based upon the midstream segment ERP to the Air Quality Control Commission and request a rulemaking hearing for no later than December 31, 2024.

III.E. Recordkeeping and Reporting. This Section III.E will be repealed upon adoption by the Air Quality Control Commission of regulations addressing midstream fuel combustion equipment to meet the requirements of § 25-7-105(1)(e)(XIII), C.R.S. (2021).

III.E.1. Midstream segment owners or operators must retain records of information submitted to the Division or midstream steering committee, including information supporting the company ERP, for three (3) years and make them available for inspection by the Division upon request.

III.E.2. Midstream segment owners or operators must retain records of actions taken after January 1, 2022, to reduce CO2e emissions from their midstream fuel combustion equipment.

III.E.3. 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 Air Quality Control Commission meeting in or after July 2023.

IV. Greenhouse Gas Intensity Program for the Oil and Natural Gas Upstream Segment

IV.A. Definitions

IV.A.1. “Calendar year” means January 1 up through and including December 31 of the year.

IV.A.2. “Co-benefits” for this Section IV. means the reduction of harmful air pollutants in disproportionately impacted communities.

IV.A.3. “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).

IV.A.4. “Controlling interest” for this Section IV. means an interest that provides a person, either directly or indirectly, the power to direct or cause the direction of the management and policies of another person, whether through ownership or voting securities, by contract, or otherwise.

IV.A.5. "Disproportionately impacted community" (DI community) means census block groups designated as DI communities in CDPHE's draft Data Viewer for Disproportionately Impacted Communities in Colorado (as of December 17, 2021, at: https://cohealthviz.dphe.state.co.us/t/EnvironmentalEpidemiologyPublic/views/EJActDICommunities-Public/HB21-1266DICommunities?%3AshowAppBanner=false&%3Adisplay_count=n&%3AshowVizHome=n&%3Aorigin=viz_share_link&%3AisGuestRedirectFromVizportal=y&%3Aembed=y) consistent with 24-4-109(2)(b)(II), C.R.S. (2021). A complete list of these census block groups by 12-digit FIPS code will be maintained by the Division and made publicly available.

IV.A.6. "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.

IV.A.7. "Drilling" or "drilled" means the process to bore a hole to create a well for oil and/or natural gas production.

IV.A.8. "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.

IV.A.9. "Greenhouse gas intensity" means the sum of preproduction emissions and production emissions in a calendar year in mtCO2e divided by the kBOE for that calendar year, calculated pursuant to Section IV.D.

IV.A.10. "Harmful air pollutants" for purposes of Section IV. means pollutants designated by EPA as criteria pollutants (carbon monoxide, lead, nitrogen dioxide, ozone, particulate pollution (PM) (PM2.5 and PM10) and sulfur dioxide) or hazardous air pollutants.

IV.A.11. "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.

IV.A.12. "Hydraulic refracturing" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

IV.A.13. "Intensity operator" means a person or entity that operates upstream segment activities or equipment. For purposes of Section IV., where a person or entity holds a controlling interest in more than one intensity operator, that person or entity is the intensity operator of all upstream segment activities and equipment in which that person or entity has a controlling interest.

IV.A.14. "kBOE" means production of hydrocarbon liquids and natural gas, measured in thousands of barrels of oil equivalent.

IV.A.15. "mtCO2e" means metric tons (mt) of carbon dioxide equivalent, using global warming potential values from the IPCC Fifth Assessment Report, 2014 (AR5).

IV.A.16. "Majority operator" means (1) an intensity operator with company-wide production in Colorado in calendar year 2022 of greater than or equal to 10,000 kBOE; (2) a new to market operator whose first transaction(s) in Colorado is to purchase the assets of a majority operator; (3) a new to market operator for which the total level of production from all assets acquired or developed in that calendar year exceeds 10,000 kBOE; (4) a new to market operator who has not purchased assets from a majority or minority operator and who commences operation of a well production facility after January 1, 2023; and (5) a minority operator that becomes a majority operator pursuant to Section IV.B.6.

IV.A.17. "Midstream segment" means the oil and natural gas compression segment and the natural gas processing segment that are physically located in Colorado and that are upstream of the natural gas transmission and storage segment.

IV.A.18. "Minority operator" means an intensity operator with company-wide production of hydrocarbon liquids and natural gas in Colorado in calendar year 2022 of less than 10,000 kBOE. Minority operator also means a new to market operator whose first transaction(s) in Colorado is to purchase the assets of a minority operator, as long as the total level of production from all assets acquired or developed by (in the case of new well production facilities) of the new to market operator in that calendar year does not exceed 10,000 kBOE.

IV.A.19. "New to market operator" means an owner or operator that did not produce any oil or natural gas in Colorado in calendar years 2021 or 2022 or own or operate any well production facility in Colorado as of December 31, 2022. A new to market operator that becomes a majority operator as defined in Section IV.A.16. or a minority operator as defined in Section IV.A.18. is no longer a new to market operator.

IV.A.20. "Preproduction emissions" means the greenhouse gas emitted from an oil or natural gas well and associated equipment and activities during the construction and operation of the oil or natural gas well until the well commences operation, including from the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of the oil and/or natural gas well.

IV.A.21. "Production emissions" means the greenhouse gas emitted from an oil or natural gas well and associated equipment and activities after the well commences operation.

IV.A.22. "Upstream segment" means oil and natural gas exploration and production operations physically located in Colorado upstream of the midstream segment.

IV.A.23. "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.

IV.B. Greenhouse gas intensity targets for the upstream segment.

IV.B.1. Beginning January 1, 2023, intensity operators must participate in this greenhouse gas intensity program to reduce preproduction and production emissions in Colorado. An intensity operator that fails to achieve any of the applicable targets in Section IV.B. must achieve additional reductions in preproduction and/or production emissions in the subsequent calendar year to address the difference between the intensity operator's reported greenhouse gas intensity for that calendar year and the applicable target.

IV.B.2. For calendar year 2025, intensity operators subject to Section IV.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

IV.B.2.a. Majority Operator: 10.94 mtCO2e/kBOE.

IV.B.2.b. Minority Operator: 34.39 mtCO2e/kBOE.

IV.B.3. For calendar year 2027, intensity operators subject to Section IV.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

IV.B.3.a. Majority Operator: 8.46 mtCO2e/kBOE.

IV.B.3.b. Minority Operator: 26.60 mtCO2e/kBOE.

IV.B.4. For calendar year 2030, intensity operators subject to Section IV.B.1. must achieve the following greenhouse gas intensity targets for preproduction and production emissions.

IV.B.4.a. Majority Operator: 6.80 mtCO2e/kBOE.

IV.B.4.b. Minority Operator: 21.38 mtCO2e/kBOE.

IV.B.5. In calendar years 2026, 2028, and 2029, intensity operators subject to Section IV.B.1. must achieve a greenhouse gas intensity less than or equal to the applicable preceding year target in Sections IV.B.2. and IV.B.3. (e.g., for calendar year 2026 achieve at least the target for calendar year 2025).

IV.B.6. If, in any calendar year beginning 2023, a minority operator

IV.B.6.a. Has production of greater than or equal to 10,000 kBOE or

IV.B.6.b. Has production that represents an increase over production in the prior calendar year by greater than or equal to 2,500 kBOE (e.g., if production is 2,500 kBOE higher in 2023 than it was in 2022), then

IV.B.6.c. Beginning the calendar year after the applicable circumstances under Sections IV.B.6.a. or IV.B.6.b., unless otherwise approved by the Division, the minority operator becomes a majority operator and must comply with the applicable majority operator greenhouse gas intensity targets for all its upstream segment operations for that year and all remaining years through 2030.

IV.B.7. Acquisitions. Except as provided, if an owner or operator acquires or takes over operation of an oil or natural gas well in Colorado after January 1, 2025, that owner or operator must meet the greenhouse gas intensity targets in Sections IV.B.2. through IV.B.5. applicable to the intensity operator acquiring the assets.

IV.B.7.a. If a majority operator merges with, acquires, or takes over operation of an oil or natural gas well in Colorado from a minority operator on or after January 1, 2025, the majority operator (or surviving entity) must at least comply with the applicable minority operator greenhouse gas intensity target for the preproduction and production emissions from the acquired well(s) for the calendar year of the acquisition. Beginning with the calendar year after the acquisition, the applicable majority owner or operator must comply with the applicable majority operator greenhouse gas intensity targets for the preproduction and production emissions from all its upstream segment operations, including the acquired well(s).

IV.B.7.b. If a minority operator acquires or takes over operation of an oil or natural gas well in Colorado from a majority operator on or after January 1, 2025, the minority operator must at least comply with the applicable minority operator greenhouse gas intensity target for the preproduction and production emissions from the acquired well(s) for the calendar years of and after the acquisition, after which the minority operator greenhouse gas intensity targets apply to all assets of the minority operator, including the acquired assets (unless the minority operator has become a majority operator).

IV.C. New facility intensity targets.

IV.C.1. Beginning January 1, 2023, intensity operators of well production facilities that commence operation after December 31, 2022, must also meet the new facility intensity target(s) for those facilities as set forth in Sections IV.C.2. through IV.C.4. in the calendar year of and the calendar year after the well production facility commences operation. These targets are in addition to the targets applicable to all of the intensity operator’s upstream segment operations as specified in Section IV.B.

IV.C.1.a. For purposes of Section IV.C., “new facility intensity” means the production emissions in CO2e from all well production facilities commencing operation in a calendar year divided by the production of hydrocarbon liquid and natural gas from those facilities in kBOE for that calendar year.

IV.C.2. For calendar years 2023 through 2025, the new facility intensity target is 8.59 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 7.7 mtCO2e/kBOE.

IV.C.3. For calendar years 2026 through 2027, the new facility intensity target is 6.64 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 6.0 mtCO2e/kBOE.

IV.C.4. For calendar years 2028 through 2030, the new facility intensity target is 5.34 mtCO2e/kBOE, unless the well production facility is located in the 8-hour Ozone Control Area and in a disproportionately impacted community, then the new facility intensity target is 4.8 mtCO2e/kBOE.

IV.D. Accounting for production kBOE, preproduction emissions, and production emissions.

IV.D.1. Production can only be allocated to one intensity operator for the same time period. Intensity operators must account for production from all oil or natural gas wells and well production facilities in which the intensity operator holds the controlling interest. Intensity operators must account for production during the time in which the intensity operator holds that controlling interest.

IV.D.2. Intensity operators must calculate kBOE by adding the production of hydrocarbon liquids in thousand barrels to the proportion of natural gas (calculated by dividing the million standard cubic feet (MMscf) volume of natural gas produced by the conversion rate of 5.8 MMscf/kBOE).

IV.D.3. The intensity operator that reports the preproduction emissions and production emissions for upstream segment activities and equipment must report the kBOE associated with those activities and equipment.

IV.E. Intensity operator greenhouse gas intensity plans.

IV.E.1. Greenhouse gas intensity plans must be submitted on a Division-approved format and must contain, at a minimum

IV.E.1.a. An identification of all the intensity operator's well production facilities, including facility name; facility AIRS ID, or facility location if the facility does not have an AIRS ID; entity listed as the operator for all well production facilities covered by the greenhouse gas intensity plan for which production is included as specified under Section IV.D.1.; and an identification of which facilities are located within a disproportionately impacted community.

IV.E.1.b. The intensity operator's greenhouse gas intensity company-wide and per well production facility for the preceding calendar year, including intensity calculation methodology.

IV.E.1.c. A list and description of the best management practices (BMPs), control methods, emission reduction strategies, and technologies the intensity operator intends to use to meet the applicable targets in Section IV.B.2. on a site-specific basis.

IV.E.1.d. An estimate of the greenhouse gas emission reductions that each type of BMP, control method, emission reduction strategy, or technology is expected to achieve on a company-wide mass basis and on a company-wide greenhouse gas intensity basis, including calculation methods.

IV.E.1.e. A description of which BMPs, control methods, emission reduction strategies, and technologies will be deployed in disproportionately impacted communities, and a demonstration that intensity operators will prioritize co-benefits.

IV.E.2. Greenhouse gas intensity plan submittal deadlines.

IV.E.2.a. By August 31, 2023, each intensity operator subject to Section IV.B.1. must submit to the Division a proposed greenhouse gas intensity plan demonstrating how the intensity operator intends to meet the applicable greenhouse gas intensity targets in Section IV.B.2.

IV.E.2.b. By June 30, 2025, each intensity operator subject to Section IV.B.1. must submit to the Division a greenhouse gas intensity plan demonstrating how the intensity operator will meet the applicable greenhouse gas intensity targets in Section IV.B.3.

IV.E.2.c. By June 30, 2027, each intensity operator subject to Section IV.B.1. must submit to the Division a greenhouse gas intensity plan demonstrating how the intensity operator will meet the applicable greenhouse gas intensity targets in Section IV.B.4.

IV.E.3. Asset transfer updates.

IV.E.3.a. Section IV.E.3. applies whenever ownership or operation of an oil or natural gas well or well production facility is transferred after August 31, 2024. The operator taking over operation of the oil or natural gas well or well production facility is referred to herein as the “acquiring operator”. The intensity operator from whom ownership or operation is transferred is referred to as the “selling operator.”

IV.E.3.b. If the transaction involves any well production facility for which the selling operator’s greenhouse gas intensity plan submitted under Section IV.E.2. provides for implementation of any BMP, control method, emission reduction strategy, or technology, then within thirty (30) days of closing of the transaction.

IV.E.3.b.(i) The selling operator must submit an update to its greenhouse gas intensity plan that:

IV.E.3.b.(i)(A) Identifies each well production facility transferred (name and AIRS ID, if applicable), the name of the acquiring operator, and the date of closing of the transaction.

IV.E.3.b.(i)(B) Includes a quantification of the emission reductions that would have been achieved at each well production facility involved in the transaction under the greenhouse gas intensity plan consistent with the calculation methods used in Section IV.E.1.d.

IV.E.3.b.(i)(C) Includes a demonstration that the selling operator will still meet its greenhouse gas intensity targets and identifies any additional BMPs, control method, emission reduction strategy, and technologies consistent with Section IV.E.1.

IV.E.3.b.(ii) The acquiring operator must submit an update to its greenhouse gas intensity plan (or, in the event the acquiring operator is also a new to market operator, the acquiring operator must submit a new greenhouse gas intensity plan) that, for each well production facility involved in the transaction

IV.E.3.b.(ii)(A) Identifies the well production facility transferred (name and AIRS ID, if applicable), the name of the selling operator, and the date of closing of the transaction.

IV.E.3.b.(ii)(B) Commits to implementing the same BMP, control method, emission reduction strategy, and technology provided for in the selling operator's plan on the same schedule; or

IV.E.3.b.(ii)(C) Quantifies the emission reductions that would have been achieved under the selling operator's greenhouse gas intensity plan consistent with the calculation methods used in Section IV.E.1.d. and identifies how the acquiring operator will achieve equal or greater emission reductions at the same or other well production facilities involved in the transaction (or, if approved by the Division, at other of the acquiring operator's well production facilities) on the same schedule.

IV.E.4. Annual verifications.

By June 30 of 2024 through 2031, intensity operators must submit annual verifications on a Division-approved form to the Division summarizing the intensity operator's greenhouse gas intensity plan implementation during the preceding calendar year. The annual verification must include, at a minimum

IV.E.4.a. The intensity operator's implementation of the types of BMPs, control measures, emission reduction strategies, and technologies in its greenhouse gas intensity plan, on a site-specific basis (by location name and AIRS ID, if applicable, and whether the site is located within a disproportionately impacted community) for each BMP, control method, emission reduction strategy, and technology implemented.

IV.E.4.b. If applicable, an identification of new well production facilities subject to Section IV.C. commencing operation in that calendar year.

IV.E.4.c. If applicable, the intensity operator's implementation of BMPs, control measures, emission reduction strategies, and technologies to achieve the new facility intensity target at all sites subject to Section IV.C. on a site-specific basis (by location name and AIRS ID, if applicable.

IV.E.4.d. Instances of departure from the intensity operator's greenhouse gas intensity plan, reason(s) for departure, and any modifications of the applicable element(s) of the BMP plan.

IV.E.4.e. Use of any alternative emission reduction approaches not specified in the intensity operator's greenhouse gas intensity plan.

IV.E.4.f. A demonstration that emission reductions were prioritized in disproportionately impacted communities, including a quantification of co-benefits achieved.

IV.E.4.g. Identification by location name, AIRS ID (if applicable), well API number, and COGCC location ID (if applicable) of any oil or natural gas wells acquired or divested during the previous calendar year; the date of acquisition or divestment; and the name of the operator from which the well(s) were acquired or to whom the well(s) were divested.

IV.E.4.h. A certification by a company representative with oversight over the operator's greenhouse gas intensity program that the annual verification is accurate and complete, to the best of the representative's knowledge and, if applicable, that measures identified in an asset transfer update submitted under Section IV.E.3 have been implemented as described therein.

IV.F. Verification.

IV.F.1. By no later than March 2023, the Division will submit a petition for rulemaking with a proposed verification plan for how intensity operators will demonstrate compliance with applicable greenhouse gas intensity targets in Sections IV.B. and IV.C. to the Air Quality Control Commission. In preparing the proposal, the Division must

IV.F.1.a. Propose appropriate calculation and emission quantification methodologies for the emissions categories to be included in a demonstration of compliance with the greenhouse gas intensity targets in Section IV., taking into account the relative accuracy, reliability, and feasibility of the methodologies.

IV.F.1.b. Ensure the proposal addresses the relative completeness and reliability of the annual emission reports submitted pursuant to Regulation Numbers 7, Part D, Sections II.G. and V.

IV.F.1.c. Ensure the proposal addresses the results of the aerial and ground-based method surveys, including those conducted by the Division in 2021, and how those surveys should be used to ensure abnormal operating conditions and other large hydrocarbon emission events are accounted for in the demonstration of compliance with the greenhouse gas intensity and new facility intensity targets.

IV.F.1.d. Include recommendations for provisions the Division determines are necessary to ensure the enforceability of the greenhouse gas intensity and new facility targets, such as additional monitoring.

IV.F.1.e. Include recommendations to evaluate total greenhouse gas emissions relative to the applicable baseline and progress towards statewide greenhouse gas emission reduction goals for oil and gas emissions in § 25-7-105(1)(e)(XII) and (XIII), CRS.

PART C Recovered Methane

I. Recovered Methane Protocols and Crediting and Tracking System

I.A. Applicability

I.A.1. This Part C applies to projects for the generation of recovered methane credits used in clean heat plans for gas distribution utilities, municipal gas distribution utilities, or small gas distribution utilities.

I.A.2. Only recovered methane produced on or after the effective date of this rule shall be eligible for recovered methane credits.

I.B. Definitions

I.B.1. "Active Coal Mine" means a coal mine where any one of the following five conditions apply.

I.B.1.a. Mine development is underway.

I.B.1.b. Coal has been produced within the last 90 days.

I.B.1.c. Mine personnel are present in the mine workings.

I.B.1.d. Mine ventilation fans are operative.

I.B.1.e. The mine is designated as an “intermittent” mine by the Mine Safety and Health Administration (MSHA).

I.B.2. “Anaerobic digester” means a system where wastes are collected in containment vessels or covered lagoons where organic material is broken down by bacterial microorganisms in an oxygen-free environment. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to carbon dioxide and methane.

I.B.3. “Biomethane” means a mixture of carbon dioxide and hydrocarbons released from the biological decomposition of organic materials that is primarily methane and provides a net reduction in greenhouse gas emissions and includes biomethane recovered from manure management systems or anaerobic digesters that has been processed to meet pipeline quality.

I.B.4. “Clean heat plan” means a comprehensive plan submitted by a gas distribution utility or small gas distribution utility to the Colorado Public Utilities Commission, or by a municipal gas distribution utility to the Division, that demonstrates projected reductions in methane and carbon dioxide emissions that, together, meet the required reductions for gas distribution utilities under § 40-3.2-108, C.R.S. or for municipal gas distribution utilities under § 25-7-105(1)(e)(X.8), C.R.S., or the proposed reductions in the plan for small gas distribution utilities, at the lowest reasonable cost.

I.B.5. “Coal mine methane” means methane captured from active and inactive coal mines where the methane is escaping to the atmosphere. In the case of methane escaping from active mines, only methane vented in the normal course of mine operations that is naturally escaping to the atmosphere is coal mine methane.

I.B.6. "Credit generation date" means the earliest date that a recovered methane credit is first issued on any carbon offset registry, such as the American Carbon Registry or the Climate Action Reserve Offset Program, or the Division's recovered methane crediting and tracking system.

I.B.7. "Dedicated pipeline" means a conveyance of recovered methane that is not a part of a common carrier pipeline system, and which conveys recovered methane from where it is generated to a common carrier pipeline or to the end user in Colorado for which the recovered methane was produced so long as the recovered methane replaces geological gas supplied by a gas distribution utility, small gas distribution utility, or municipal gas distribution utility.

I.B.8. "Domestic Wastewater Treatment Plant" has the same meaning as defined by the Water Quality Control Commission in 5 Code of Colo. Regs. (CCR) 1002-22 (June 14, 2020).

I.B.9. "Gas distribution utility" means a public utility providing gas service to more than ninety thousand retail customers. Gas distribution utility does not include a municipal gas distribution utility.

I.B.10. "Gas system leaks" means methane that would have leaked without repairs of the gas distribution and service pipelines from the city gate to customer end use.

I.B.11. "Geological gas" means methane and other hydrocarbons that occur underground without human intervention and are used as fuel.

I.B.12. "Inactive Coal Mine" means a coal mine where none of the conditions in Section I.B.1. apply.

I.B.13. "Municipal gas distribution utility" means a municipally owned utility that provides gas service to more than ninety thousand customers.

I.B.14. "Pyrolysis" means the thermochemical decomposition of material at elevated temperatures without the participation of oxygen.

I.B.15. "Recovered methane" means any of the following that are located in Colorado, and meet a recovered methane protocol in Section I.C., and is delivered to or within Colorado through a dedicated pipeline or through a common carrier pipeline if the source of the recovered methane injects the recovered methane into a common carrier pipeline that physically flows within Colorado or toward the end user in Colorado for which the recovered methane was produced.

I.B.15.a. Biomethane

I.B.15.b. Coal mine methane where capture is not otherwise required by state or federal law.

I.B.15.c. Gas system leaks

I.B.15.d. Methane derived from:

I.B.15.d.(i) Municipal solid waste

I.B.15.d.(ii) Pyrolysis of municipal solid waste.

I.B.15.d.(iii) Biomass pyrolysis or enzymatic biomass.

I.B.15.d.(iv) Wastewater treatment.

I.B.16. "Recovered methane credit" means a tradable instrument that represents a greenhouse gas emission reduction or greenhouse gas removal enhancement of one metric ton of carbon dioxide equivalent (CO2e) that is real, additional, quantifiable, permanent, verifiable, and enforceable. Recovered methane credits do not include emission reductions or removal enhancements required or accounted for by a proposed or final federal, state, or local rule or regulation.

I.B.17. "Recovered methane protocol" means a documented set of procedures and requirements that quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements achieved by a recovered methane project and that calculate the project baseline.

I.B.18. "Small gas distribution utility" mean a public utility providing gas service to ninety thousand retail customers or fewer. Small gas distribution utility does not include a municipal gas distribution utility.

I.C. Recovered Methane Protocols

I.C.1. Recovered methane must be represented by a recovered methane credit generated pursuant to any of the recovered methane protocols in Part C, Sections I.C.2. through I.C.6. in order to count toward greenhouse gas emission reductions or removal enhancements in a clean heat plan for a gas distribution utility, municipal gas distribution utility, or a small gas distribution utility.

I.C.2. Biomethane from manure management systems

I.C.2.a. The "Compliance Offset Protocol Livestock Projects" adopted by the California Air Resources Board (CARB) on November 14, 2014, shall be used to quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements for biomethane recovered from manure management systems through a recovered methane project eligible under the protocol and to calculate the project baseline.

I.C.2.b. Greenhouse gas emissions resulting from vehicle transportation for the delivery of biomethane recovered from a manure management system to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado for which the recovered methane was produced shall be accounted for by tracking fuel use attributed to that transportation for both pick-up and delivery of the recovered methane and applying the appropriate emission factor for the fuel type as found in Table MM-1 or Table MM-2 of Subpart MM of 40 CFR, Part 98.

I.C.2.c. A manure management system subject to a proposed or final federal, state, or local rule or regulation that applies to the destruction of methane from the manure management system, such as through flaring, is only eligible for recovered methane credits issued by the Division for greenhouse gas or methane emission reductions achieved above and beyond the reductions required by such proposed or final federal, state, or local rule or regulation when using the CARB "Compliance Offset Protocol Livestock Projects".

I.C.3. Methane derived from municipal solid waste

I.C.3.a. Version 2.0 of the "Landfill Gas Destruction and Beneficial Use Projects" methodology (April 2021; Errata & Clarification October 25, 2022), issued by the American Carbon Registry (ACR) shall be used to quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements for methane derived from a municipal solid waste landfill through a recovered methane project eligible under the methodology or protocol and to calculate the project baseline.

I.C.3.b. Greenhouse gas emissions resulting from vehicle transportation for the delivery of methane recovered from a municipal solid waste landfill to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado for which the recovered methane was produced shall be accounted for by tracking fuel use attributed to that transportation for both pick-up and delivery of the recovered methane and applying the appropriate emission factor for the fuel type as found in Table MM-1 or Table MM-2 of Subpart MM of 40 CFR, Part 98.

I.C.3.c. A municipal solid waste landfill subject to a proposed or final federal, state, or local rule or regulation that applies to the destruction of methane from the landfill, such as through flaring, is only eligible for recovered methane credits issued by the Division for greenhouse gas or methane emission reductions achieved above and beyond the reductions required by such proposed or final federal, state, or local rule or regulation when using the ACR "Landfill Gas Destruction and Beneficial Use Projects" methodology.

I.C.4. Methane derived from wastewater treatment

I.C.4.a. Version 2.1 of the "Organic Waste Digestion Protocol" (January 16, 2014; Errata and Clarifications November 1, 2018) issued by the Climate Action Reserve (CAR) shall be used to quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements for methane derived from wastewater treatment through a recovered methane project eligible under the protocol and to calculate the project baseline. Projects that exclusively accept or rely on livestock manure cannot use the CAR "Organic Waste Digestion Protocol" and must utilize the "Compliance Offset Protocol Livestock Projects" adopted by CARB on November 14, 2014.

I.C.4.b. Domestic wastewater treatment plants with anaerobic digesters that will be installed or are in operation may apply for recovered methane credits using the protocol in this Section I.C.4.b.

I.C.4.b.(i) The project baseline for a domestic wastewater treatment plant (DWWTP) with anaerobic digesters is established by the process design report (PDR) for the construction or expansion of the plant that includes the anaerobic digesters submitted to and approved by the Colorado Water Quality Control Division (WQCD). If the PDR does not specify the final use or treatment of the methane from the anaerobic digesters, the DWWTP must submit documentation such as air permits, emissions recordkeeping, or facility schematics (signed by Colorado Professional Engineer), to establish the baseline. The PDR for the DWWTP and the approval issued by the WQCD for the design, or other documentation used to establish the baseline, must be included in the information provided pursuant to Section I.D.1.c.

I.C.4.b.(ii) If the PDR approved by the WQCD, or the other supporting documentation identified in Section I.C.4.b.(i), specifies that methane from the anaerobic digesters will be routed to a flare for combustion or otherwise captured and utilized, that will be included in the project baseline and be used to determine what is additional for recovered methane credit eligibility.

I.C.4.b.(iii) Where the project baseline includes existing control or capture and utilization of recovered methane, credits for the recovered methane will only be issued for emission reductions resulting from the recovered methane displacing geological gas for an end use that would otherwise be serviced by a gas distribution utility, municipal gas distribution utility, or small gas distribution utility according to the methodology in Section I.C.4.b.(iv).

I.C.4.b.(iv) Emission reductions shall be calculated using the applicable calculation methodology for local distribution companies (LDCs) described in Subpart NN of 40 CFR Part 98 at Section 98.403(a), and the volume of natural gas supplied in the calculation will be the volume of recovered methane that has displaced geological gas.

I.C.4.b.(v) As used in Section I.C.4.b.(iv), the volume of recovered methane shall be measured at the point of delivery of the recovered methane to a dedicated pipeline or common carrier pipeline, at which point the recovered methane is determined to be replacing geological gas. The measurement location must be specified in the information provided pursuant to Section I.D.1.a.

I.C.4.b.(vi) The monitoring and quality assurance and quality control (QA/QC) requirements in Section 98.404, procedures for estimating missing data in Section 98.405, data reporting requirements in Section 98.406(b)(11), and records that must be retained in Section 98.407 of Subpart NN of 40 CFR Part 98 must be followed as applicable to the calculation methodology in Section 98.403(a) of Subpart NN that is used and the results of that calculation. The point of measurement requirements in Section 98.404 do not have to be followed because the point of measurement for the recovered methane is specified in Section I.C.4.b.(v) of this Regulation Number 22, Part C.

I.C.4.b.(vii) Use of this protocol does not obligate any owner or operator of a domestic wastewater treatment plant to comply with Sarbanes Oxley regulations.

I.C.4.c. Greenhouse gas emissions resulting from vehicle transportation for the delivery of methane recovered from wastewater treatment or a domestic wastewater treatment plant to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado for which the recovered methane was produced shall be accounted for by tracking fuel use attributed to that transportation for both pick-up and delivery of the recovered methane and applying the appropriate emission factor for the fuel type as found in Table MM-1 or Table MM-2 of Subpart MM of 40 CFR, Part 98.

I.C.4.d. A wastewater treatment facility or operation subject to a proposed or final federal, state, or local rule or regulation that applies to the destruction of methane generated from wastewater treatment, such as through flaring, is only eligible for recovered methane credits issued by the Division for greenhouse gas or methane emission reductions achieved above and beyond the reductions required by such proposed or final federal, state, or local rule or regulation when using the CAR “Organic Waste Digestion Protocol” in Section I.C.4.a. or the domestic wastewater treatment plant protocol in Section I.C.4.b.

I.C.5. Coal mine methane

I.C.5.a. Version 1.1 of the “Capturing and Destroying Methane from Coal and Trona Mines in North America” methodology issued by the American Carbon Registry (ACR) in August 2022, shall be used to quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements for coal mine methane through a recovered methane project eligible under the methodology or protocol and to calculate the project baseline.

I.C.5.b. Greenhouse gas emissions resulting from vehicle transportation for the delivery of methane recovered from a coal mine to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado for which the recovered methane was produced shall be accounted for by tracking fuel use attributed to that transportation for both pick-up and delivery of the recovered methane and applying the appropriate emission factor for the fuel type as found in Table MM-1 or Table MM-2 of Subpart MM of 40 CFR, Part 98.

I.C.5.c. An active or inactive coal mine subject to a proposed or final federal, state, or local rule or regulation that applies to the destruction of methane from the coal mine, such as through flaring, is only eligible for recovered methane credits issued by the Division for greenhouse gas or methane emission reductions achieved above and beyond the reductions required by such proposed or final federal, state, or local rule or regulation when using the ACR “Capturing and Destroying Methane from Coal and Trona Mines in North America” methodology.

I.C.6. Gas system leaks

I.C.6.a. Recovered methane credits for gas system leak mitigation may only be issued where direct quantification of the leak occurs. To be eligible for recovered methane credits, leak mitigation projects must:

I.C.6.a.(i) Occur at a location within the gas distribution system between the city gate and the customer meter.

I.C.6.a.(ii) Have leaks quantified following written company procedures and calculation methods meeting each of the following requirements.

I.C.6.a.(ii)(A) The written procedures must specify each category or type of equipment (i.e. underground main, underground service, meter, flange, etc.) that is part of the leak detection and repair project for which recovered methane credits will be requested.

I.C.6.a.(ii)(B) The written procedures must specify how the gas flow rate of the leak will be measured or calculated for each equipment type or category, including quality assurance requirements, estimated uncertainty of measurement device(s) used, and data to be collected. Examples of measurement techniques include, but are not limited to, pipeline pressure and physical parameters, flow rate meters, high flow samplers, and bag sampling.

I.C.6.a.(ii)(C) The written procedures must specify how the post-repair verification that gas is no longer leaking at the repaired location will be measured or calculated.

I.C.6.a.(ii)(C)(1) Where the equipment or technique used for the post-repair inspection is not the same as that used for the initial leak rate determination, the written procedures must specify the records to be collected and provided to the verifying entity for certification for the post-repair demonstration.

I.C.6.a.(ii)(C)(2) For leaks that are mitigated by repairing existing equipment or components, the equipment or technique used to verify the leak has been repaired must have a detection sensitivity equal to or higher than the equipment or technique used for initially measuring the leak rate.

I.C.6.a.(ii)(C)(3) For leaks that are mitigated by permanently removing the equipment or components from the gas distribution system, a post-repair leak rate determination is not required. Documentation of the permanent removal of the equipment or components shall be provided to the verifying entity.

I.C.6.a.(ii)(D) The written procedures must include a methodology for determining methane concentration of the leak. Methods for determining methane concentration include, but are not limited to, system gas chromatographs, bag sampling and lab analysis, portable gas chromatographs, and combustible gas instruments (CGI) that are capable of determining concentrations of methane either in ppm or percent gas measurements.

I.C.6.a.(ii)(E) The written procedures must specify the survey frequency for each category or type of equipment. Survey frequencies may include one-time studies to find large emission sources, annual, or shorter frequencies.

I.C.6.a.(ii)(F) The written procedures must use the following time durations to calculate the methane leakage mitigated from the project.

I.C.6.a.(ii)(F)(1) For one-time studies, the time duration shall be six months from the date and hour that the leak was verified to be repaired.

I.C.6.a.(ii)(F)(2) For surveys conducted annually or less frequently, the time duration shall be six months.

I.C.6.a.(ii)(F)(3) For survey frequencies shorter than annual, the time duration shall be one-half the time interval between surveys, not to exceed six months.

I.C.6.a.(ii)(G) The baseline for the leak repair project is determined by multiplying the gas flow rate of the leak, methane concentration, and time duration allowed by Section I.C.6.a.(ii)(F), and converting to carbon dioxide equivalent emissions. The amount of recovered methane eligible for recovered methane credit from the project is equal to the baseline.

I.C.6.a.(iii) Each applicant must submit its written procedures to the Division for approval. The Division will review the written procedures and notify the applicant of any deficiencies. If notified of deficiencies, the applicant may submit revised written procedures for final approval. The applicant must receive Division approval in writing before any recovered methane credits can be generated under this Section I.C.6.

I.C.6.a.(iv) Quantification of emissions following the written procedures specified in Part C, Section I.C.6.a.(ii) shall be verified by an accredited body or organization as specified in Part C, Section I.C.7.a.

I.C.6.b. Gas system leaks subject to a proposed or final federal, state, or local rule or regulation that requires the detection and repair of the leaks are not eligible for recovered methane credits.

I.C.7. Entity accreditation for verifying greenhouse gas reductions or removal enhancements from recovered methane projects

I.C.7.a. All greenhouse gas emission reductions or greenhouse gas removal enhancements demonstrated through the use of an approved recovered methane protocol under this Part C, Section I.C. to an applicable recovered methane project, except projects for biomethane from manure management systems, must be verified by a body or organization that is accredited to conduct verification for the specific project type under the Accreditation Program for Greenhouse Gas Validation/Verification Bodies (GHGVVB) of the ANSI National Accreditation Board (ANAB), part of the American National Standards Institute (ANSI), and in accordance with the most current version(s) of International Organization for Standardization (ISO) 14065 required by ANAB for accreditation and to conduct verification.

I.C.7.b. Greenhouse gas emission reductions or greenhouse gas removal enhancements from recovered methane projects for biomethane from manure management systems must be verified by a CARB-accredited offset verification body that is accredited to conduct verification for livestock projects.

I.D. Recovered Methane Crediting and Tracking System

I.D.1. An entity seeking issuance of credits to it in the Division’s recovered methane crediting and tracking system must submit the following information to the Division no more than twelve months from the date methane was recovered from a project in order for that methane to be eligible for credits:

I.D.1.a. The name and a detailed description of the recovered methane project; the start date and, if applicable, end date of the project; the date(s) methane was recovered from the project for which credit issuance is being sought, and; the amount of recovered methane in standard cubic feet for which credit issuance is being sought.

I.D.1.a.(i) If a detailed description of the project has been provided to the Division in a prior application for credits from the project and there has been no change in how the project operates, then the description of the project may be excluded from subsequent application(s) for credits from the project.

I.D.1.b. The credit generation date of any credits being transferred from an outside carbon offset registry under Sections I.D.3., I.D.4. or I.D.5. as applicable, to the Division's recovered methane crediting and tracking system.

I.D.1.c. Proof that the applicable approved recovered methane protocol under Part C, Section I.C. has been used to establish the credits being sought from the recovered methane project. This must include all data and information specified in the protocol that is used for the quantification of emissions and monitoring requirements as it relates to the credits being sought.

I.D.1.d. Proof that the recovered methane project is located in Colorado, which must include:

I.D.1.d.(i) Physical street address of the project including the city and zip code. If the project does not have a physical street address, then the project must provide the latitude and longitude representing the geographic centroid or center point of facility operations in decimal degree format. This must be provided in a comma-delimited "latitude, longitude" coordinate pair reported in decimal degrees to at least four digits to the right of the decimal point; and

I.D.1.d.(ii) The AIRS ID associated with the project or facility where the project is located if an AIRS ID has been assigned to the project or facility by the Division.

I.D.1.e. Proof that the recovered methane derived from the project for which credit issuance is being sought has been delivered to or within Colorado through a dedicated pipeline or through a common carrier pipeline that physically flows within Colorado or toward an end user in Colorado for which the recovered methane was produced.

I.D.1.e.(i) If the recovered methane is delivered from a project directly to an end user, then the name and address of the end user must be provided along with proof that the recovered methane replaced geological gas otherwise supplied to that end user by a gas distribution, small gas distribution, or municipal gas distribution utility.

I.D.1.e.(ii) If vehicle transportation was used for the delivery of recovered methane from a project to a dedicated pipeline, common carrier pipeline, or directly to an end user, then the greenhouse gas emissions attributed to that transportation as calculated per Sections I.C.2.b., I.C.3.b., I.C.4.c. or 1.C.5.b., and the underlying data used in the calculation, must also be provided.

I.D.1.f. Proof that a body or organization that is accredited pursuant to Part C, Section I.C.7, was used to verify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements for recovered methane derived from a recovered methane project, including the results of that verification from the entity or organization accredited pursuant to Part C, Section I.C.7.

I.D.1.g. Proof that the requirements of Part C, Sections I.D.3., I.D.4. or I.D.5. have been met if applicable to the recovered methane project. If Section I.D.5. is applicable to a manure management system project, then notification of the offset registry the project is registered in and the date it was registered must also be provided. If Section I.D.5. is not applicable to a manure management system project, then notification of that must be provided.

I.D.1.h. Certification that the greenhouse gas or methane emission reductions or removal enhancements for which credit issuance is being sought are not required or accounted for by any proposed or final federal, state, or local rule or regulation outside of this Part C or a clean heat plan, including to meet any regulatory greenhouse gas offset or cap and trade requirements.

I.D.1.h.(i) If any proposed or final federal, state, or local rule or regulation for greenhouse gas or methane emission reductions or removal enhancements applies to a source of recovered methane, each rule or regulation shall be identified, along with the specific requirements of the rule or regulation concerning the greenhouse gas or methane emission reductions or removal enhancements.

I.D.1.i. Certification that the greenhouse gas or methane emission reductions or removal enhancements for which credit issuance is being sought will not also be used to meet any voluntary greenhouse gas reduction or offset requirements outside of this Part C or a clean heat plan.

I.D.2. The Division's recovered methane crediting and tracking system will:

I.D.2.a. Limit participation to recovered methane project developers and gas distribution, small gas distribution, or municipal gas distribution utilities, and require such entities to register and apply for a user account in the system with the following requirements.

I.D.2.a.(i) Only one account will be allowed per entity registered in the crediting and tracking system.

I.D.2.a.(ii) An entity must provide such information as the Division deems necessary in connection with the user account application, including but not limited to the information identified in Air Quality Control Commission Regulation Number 22, Part B, Sections II.I.2.a. through II.I.2.e.

I.D.2.a.(iii) One primary account representative must be designated, and up to four alternate account representatives may be designated, under the entity's user account. All account representatives will be considered authorized representatives of the entity registered in the crediting and tracking system.

I.D.2.a.(iv) An authorized representative shall represent, and by his or her representations, actions, inactions, or submissions, legally bind the entity in all matters relating to the crediting and tracking system. Any representation, action, inaction, or submission by any authorized representative of an entity registered in the crediting and tracking system shall be deemed to be a representation, action, inaction, or submission by the entity.

I.D.2.b. Allow for the trading of recovered methane credits among entities registered in the crediting and tracking system.

I.D.2.c. Allow for each recovered methane credit in the crediting and tracking system to be active or available for twelve months from the credit generation date.

I.D.2.c.(i) Credits in the Division's crediting and tracking system will expire after twelve months from the credit generation date unless retired.

I.D.2.c.(ii) Credits first generated in a carbon offset registry as specified in Sections I.D.3., I.D.4., and I.D.5. become ineligible for transfer to the Division's crediting and tracking system after twelve months from the credit generation date.

I.D.2.c.(iii) All expired or retired credits in the crediting and tracking system may no longer be sold or traded.

I.D.2.c.(iv) All expired or retired credits in the account of a gas distribution utility, small gas distribution utility, or municipal gas distribution utility in the crediting and tracking system may be applied toward that utility's approved clean heat plan within the limits that apply to the use of recovered methane in the plan.

I.D.2.d. Allow for each recovered methane credit generated in the crediting and tracking system to be uniquely identifiable and trackable within the system.

I.D.2.e. Allow all transactions in the crediting and tracking system to be auditable and traceable by the Division.

I.D.2.f. Allow data to be reported from the crediting and tracking system and be made publicly available by the Division. This data will include whether the credit was generated from a project located in a Disproportionately Impacted Community, as defined in § 24-4-109(2)(b)(II), C.R.S.

I.D.2.g. Allow the Division to purge unused accounts from the crediting and tracking system after eighteen months of inactivity and written notice to the account representative(s) if no objection is provided by an account representative in response to the notification.

I.D.3. Recovered methane projects for municipal solid waste and coal mine methane and their associated greenhouse gas reduction or removal credits must initially be registered in the American Carbon Registry (ACR) by the project developer or operator.

I.D.3.a. Any greenhouse gas reduction or removal credits from the project that are to be used for purposes of recovered methane under this Part C must be canceled or retired from ACR for transfer to and use in the Division's recovered methane crediting and tracking system.

I.D.3.b. Confirmation from ACR of credit cancellation in the ACR must be provided to the Division in order for the credit to be made available in the Division's recovered methane crediting and tracking system. The canceled ACR credit must be associated with the applicable recovered methane project for municipal solid waste or coal mine methane.

I.D.4. Recovered methane projects for wastewater treatment subject to Section I.C.4.a. and their associated greenhouse gas reduction or removal credits must initially be registered in the Climate Action Reserve's (CAR) Reserve Offset Program by the project developer or operator.

I.D.4.a. Any greenhouse gas reduction or removal credits from the project that are to be used for purposes of recovered methane under this Part C must be canceled or retired from the CAR Reserve Offset Program for transfer to and use in the Division's recovered methane crediting and tracking system.

I.D.4.b. Confirmation from CAR of credit cancellation in the CAR Reserve Offset Program must be provided to the Division in order for the credit to be made available in the Division's recovered methane crediting and tracking system. The canceled CAR Reserve Offset Program credit must be associated with the recovered methane project for wastewater treatment.

I.D.5. If a recovered methane project for biomethane from a manure management system is registered by the project developer or operator in a CARB-approved offset project registry, which includes ACR, CAR, and Verra, then any greenhouse gas reduction or removal credits from the project that are to be used for purposes of recovered methane under this Part C must be canceled or retired from the applicable CARB-approved offset project registry for transfer to and use in the Division's recovered methane crediting and tracking system.

I.D.5.a. Confirmation from the applicable CARB-approved offset project registry of credit cancellation in the registry must be provided to the Division in order for the credit to be made available in the Division's recovered methane crediting and tracking system. The canceled offset registry credit must be associated with the recovered methane project for biomethane from a manure management system.

I.E. Recordkeeping

I.E.1. Records of all information required under Section I.D.1. must be maintained by the entity submitting the information for five (5) years from the date of submission, and be provided to the Division upon request.

PART D General Provisions

I. Severability

If any section, clause, phrase, or standard contained in these regulations is for any reason held to be inoperative, unconstitutional, void, or invalid, the validity of the remaining portions thereof will not be affected and the Commission declares that it severally passed and adopted these provisions separately and apart.

PART E Statements of Basis, Specific Statutory Authority and Purpose

I. Adopted: May 22, 2020

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-110 and 25-7-110.5., C.R.S., and the Air Quality Control Commission's ("Commission") Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted House Bill 2019-1261 (concerning the reduction of greenhouse gas pollution) (HB 19-1261) amending the legislative declaration in §25-7-102 of the Act, and Senate Bill 2019-096 (concerning the collection of greenhouse gas emissions data) (SB 19-096) creating §25-7-140 of the Act. HB 19-1261 and SB 19-096 both define greenhouse gas pollution (GHG) as including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF6) and nitrogen trifluoride (NF_3). In HB 19-1261, now codified in part at §§25-7-102(2) and -105(1)(e), C.R.S., the General Assembly declared that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "many of these impacts disproportionately affect" certain disadvantaged communities. § 25-7-102(2), C.R.S.

Consequently, the General Assembly updated Colorado's statewide greenhouse gas pollution (GHG) reduction goals requiring the Commission to implement regulations to achieve a 26% reduction of statewide GHG by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. § 25-7-102(2) (g), C.R.S. To accomplish these important goals the legislature also passed SB 19-096, now codified as §25-7-140, C.R.S., directing the Air Quality Control Commission (Commission) to undertake two phases of rulemaking aimed first at requiring GHG emitters to monitor and report GHG emissions, § 25-7-140(2)(a)(I), C.R.S., and second to implement measures allowing the state to cost-effectively meet its GHG reduction goals. § 25-7-140(2)(a)(III), C.R.S. With respect to GHG reporting and the statewide inventory, §25-7-140(2)(a)(I), C.R.S., requires the Commission to adopt rules by June 1, 2020, "requiring greenhouse gas-emitting entities to monitor and publicly report their emissions as the Commission deems appropriate to support Colorado's [GHG] inventory efforts and to facilitate implementation of rules that will timely achieve Colorado's greenhouse gas emission reduction goals." Further, §25-7-140(2)(a), C.R.S., requires the Commission to consider what information is already being reported for Colorado under the United States Environmental Protection Agency's (EPA) current federal GHG reporting rule, otherwise known as the Mandatory Greenhouse Gas Reporting Rule codified in Title 40 CFR Part 98 (Part 98), and tailor new reporting requirements to fill any gaps in data as determined to be appropriate to allow for a comprehensive and robust state GHG inventory.

§ 25-7-140(2)(a)(I), C.R.S., also requires these rules to "include requirements for providers of retail or wholesale electric service in the state of Colorado to track and report emissions from all generation sources within the state and elsewhere that electricity consumption by their customers in this state causes to be emitted." § 25-7-105, C.R.S, setting forth the duties of the Commission, also directs development of rules for evaluating how public utilities are meeting obligations under Clean Energy Plans with the Public Utility Commission through considerations of facility ownership and purchased power. § 25-7-1051(e)(VIII)(E), C.R.S.

§§ 25-7-105(1)(e) and 140(2)(a)(III), C.R.S., further requires the Commission to implement GHG reduction strategies to achieve the reduction goals set forth in §25-7-102(2)(g), C.R.S. HFCs are highly potent GHGs generally used in aerosols, refrigeration and air conditioning, and foam blowing. Phasing out HFCs from most manufacturing processes and end-uses is adopted as a strategy towards accomplishing the mandated GHG reductions.

Regulation Number 22, Parts A and B, Section I. are intended to satisfy the requirements set forth by the General Assembly in §25-7-140(2)(a)(I), C.R.S., with respect to statewide GHG reporting and an initial GHG reduction strategy towards addressing statewide reductions required by §25-7-140(2)(a)(III), C.R.S., and § 25-7-105(1)(e), C.R.S., by implementing the phase-out of HFCs in manufacturing and end-use products in Colorado.

Specific Statutory Authority

The Act, specifically §25-7-105(1), C.R.S., directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102, C.R.S., and that are necessary for the proper implementation and administration of the Act.

§ 25-7-102(2), C.R.S., declares that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life" that reducing GHG is necessary "to limit the increase in the global average temperature" and that "reducing [GHG], Colorado will also reduce other harmful air pollutants, which will, in turn, improve public health, reduce health care costs, improve air quality, and help sustain the environment[.]" Further, §25-7-102(2), C.R.S., declares that reducing GHG will result in economic benefits to Colorado by creating new markets, spurring innovation, and driving investment in low-carbon technologies thus positioning Colorado's "economy, technology centers, financial institutions, and businesses to benefit from national and international efforts to reduce [GHG.]" § 25-7-102(2)(f), C.R.S.

§ 25-7-106, C.R.S., provides the Commission maximum flexibility in developing an effective air quality program and promulgating such a combination of regulations as may be necessary or desirable to carry out that program. §25-7-106(6), C.R.S., further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report emission data and other information as the Commission may require.

§ 25-7-140(2)(a)(I), C.R.S., specifically directs the Commission to, by June 1, 2020, "adopt rules requiring [GHG]-emitting entities to monitor and publicly report their emissions as the commission deems appropriate to support Colorado's greenhouse gas emission inventory efforts and to facilitate implementation of rules that will timely achieve Colorado's greenhouse gas emission reduction goals. The commission shall consider what information is already being publicly reported by the federal environmental protection agency and tailor new reporting requirements to fill any gaps in data, as it determines is appropriate, to allow for maintaining and updating state inventories that are sufficiently comprehensive and robust. The rules must include requirements for providers of retail or wholesale electric service in the state of Colorado to track and report emissions from all generation sources within the state and elsewhere that electricity consumption by their customers in this state causes to be emitted. The commission may require emitting entities to report the amount of emissions of each of the seven individual components of greenhouse gases as well as the carbon dioxide equivalent of those emissions."

§ 25-7-140(2)(a)(III), C.R.S., requires the Commission to implement measures to cost-effectively allow the state to meet its GHG emission reduction goals, which includes reduction of HFCs as potent GHGs. §25-7-105(e), C.R.S., authorizes the Commission to promulgate implementing rules and regulations to achieve statewide GHG emission reduction goals, including emission reduction strategies that have been deployed by another jurisdiction to reduce multi-sector GHG emissions. § 25-7-109(2), C.R.S., authorizes the Commission to adopt emission control regulations to reduce emissions of various pollutants, including chemical substances such as HFCs.

<u>Purpose</u>

The following section sets forth the Commission's purpose in adopting Regulation Number 22, and includes the technological and scientific rationale for the adoption of Regulation Number 22:

Part A: Greenhouse Gas Reporting

Part A has been developed to allow the reporters and the Division to leverage existing EPA reporting tools that are currently used by the majority of sources covered by this regulation, as well as for consistency with other U.S. Climate Alliance states that have implemented GHG reporting regulations. The Division intends to develop a mechanism to receive XML files that are exported from EPA's electronic GHG reporting tool, known as e-GGRT. The EPA tool can be used by entities with emissions below the federal reporting thresholds to compile, summarize, and export GHG emissions data in the XML file. The information contained in the XML files will then be uploaded into a database for use in future inventories and planning activities. Use of existing EPA reporting tools will allow for the GHG data reporting program in Colorado to begin as expeditiously as possible and minimize the burden on the regulated sources.

Additionally, consistency with EPA and other state data collection programs will be necessary if Colorado joins a regional program at some point in the future and will allow for a smooth transition if additional federal legislation or regulation is adopted for GHGs. To ensure consistency and allow for comparison with other states, GHG data reporting by the affected sources under Part A, will be performed using the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report, 100-year time horizon GWP values. Part A covers the collection of the GHG data pursuant to §25-7-140(2)(a)(I), C.R.S., and does not address how that data will be used in the Colorado GHG Inventory or other planning activities. Because the data will be collected for each individual GHG pollutant, the Division will be capable of converting and comparing reported data to CO2e using other IPCC Assessment Reports' GWP values and/or time horizons.

In the statewide GHG inventory, the Division will publish data by the mass and GWP value of each GHG pollutant pursuant to the IPCC's 4th and 5th Assessment Reports as well as, at the direction of the Commission, future IPSS Assessment Reports. The use of the 100-year time frame IPCC 4th Assessment report in these regulations is not intended to convey that those values should be used for planning purposes or are otherwise more appropriate than more recent analysis.

Consistent with the Federal Mandatory Reporting Rule (Part 98), emissions of each GHG constituent, as required and defined in §25-7-140, C.R.S., will be reported in metric tons of CO2e. Where existing emissions reporting under Colorado regulations is used to meet the obligations of this regulation, emissions will be reported by the source in the unit of measure required by the referenced regulation. In addition, each GHG constituent will be reported individually, enabling the Division to convert reported data using more updated GWP values and/or time horizons, as appropriate, for developing the Colorado GHG inventory or other planning activities. The Division will convert the emissions to metric tons for use in the GHG inventory or other planning activities. While Part A utilizes the reporting tools and protocols of Part 98, the Division is requiring reporting from certain source categories in Colorado regardless of the related federal reporting threshold in order to obtain a more complete and granular data set to inform the inventory and planning processes.

More detailed data will also inform local governments as they pursue their own climate change goals. Source categories required to report all GHG emissions, regardless of reporting thresholds under Part 98, include all electricity generation and distribution (whether subject to PUC jurisdiction under § 40-1-103, C.R.S., or not), local distribution companies, industrial waste landfills, active underground coal mines, and industrial wastewater facilities.

GHG emissions reporting for oil and natural gas operations and equipment at or upstream of a natural gas processing plant and natural gas transmission and storage covered under Section III.C. will be gathered in accordance with Commission Regulation Number 7. These reporting requirements and protocols fill gaps in the federal reporting requirements by expanding the facilities required to report as well as the data reported under Regulation Number 7, Part D, Sections IV. and V. As such, the Commission recognizes that information reported under Regulation Number 7 may differ from that reported under Part 98 as the inventory required under Regulation Number 7 is more comprehensive, detailed and takes into account information relevant to Colorado operators.

Under Part A, suppliers engaged in activities covered by Subparts LL, MM, NN, OO, PP, and QQ of Part 98 are required to report GHGs based upon the quantity that would be associated with combustion or use of the products supplied. This differs from other reporting under Part 98 since the reported data does not always reflect a direct emission. Suppliers covered by Subparts LL (coal-to-liquid suppliers), MM (petroleum product suppliers), and NN (natural gas and natural gas liquids) report the GHGs that would result from total combustion or release of the product being supplied. The information obtained through these reports is important to developing a comprehensive statewide GHG inventory, however the nature of the data requires special attention to account for the type of supply and locus of GHG emissions, if any. For instance, under Subpart PP, carbon dioxide suppliers report carbon dioxide that is produced by mass, and not as emissions. The Commission acknowledges that carbon dioxide supply may not always equate directly to GHG emissions because it is not combusted by an end user and may not be released into the atmosphere depending on its end use. Likewise, Subpart NN suppliers are required to assume that all fractionated products are combusted as fuel despite the fact that a substantial quantity of those products are not combusted but used as chemical feedstocks. In fact, EPA’s technical support document for Subpart NN indicates that fuel uses make up just under 30% of total natural gas liquids (NGL) product sales. As a result, the reporting under Subpart NN does not necessarily equate entirely to GHG emissions as provided in a Part 98 report. Thus, the Division will be required to analyze if and how GHGs reported from these source categories are properly included in the statewide GHG inventory and reduction efforts.

EPA made advance determinations that certain elements of Part 98 reports are subject to federal Confidential Business Information (CBI) protections and has published those determinations at https://www.epa.gov/ghgreporting/confidential-business-information-ghg-reporting (updated April 8, 2020). As part of submissions pursuant to Part A, Section IV.B., a statement that the entity is following EPA’s guidelines for Part 98 with respect to designation of information as CBI in the certification statement under Section IV.B.6. shall satisfy the company’s obligation to identify information in the report as CBI. The Commission does not, however, intend that such statements be determinative of whether the information is CBI under Colorado law, but expects that information will be made available as required and permitted by the Colorado Open Records Act.

A significant gap in GHG reporting that is imperfectly captured by Part 98 relates to fuel supplied, consumed, and combusted in the state. While reporting from local distribution companies and suppliers required to report under Part A provide important pieces of the fuel supply chain, end-uses including where the fuel is actually combusted, such as in-state or out-of-state, are more difficult to accurately account for. Thus, the Division will utilize other sources of information to fill gaps necessary to fully inform the statewide GHG inventory related to the end use and combustion location of fuels.

To accomplish this, the Division may use sources including, but not limited to, the Energy Information Administration's "prime supplier" reporting through its EIA-782C form and information obtained from the Colorado Department of Revenue regarding fuel distributors. Having considered all relevant factors, including but not limited to, current federal GHG reporting under Part 98, statutory requirements under §§24-4-103(2.7) and 29-1-304.5, C.R.S., and feedback from stakeholders, the Commission has decided to provide for optional GHG reporting from domestic wastewater plants and active municipal solid waste landfills not otherwise required to report under Part 98.

Any facilities or operations for which GHG reporting is optional should report in accordance with the protocols and deadlines set forth in Part A, Sections III and IV. In doing so, these facilities and operations will enable the Commission to establish a more robust statewide GHG inventory and better inform future reduction strategies. The Commission recognizes the lack of universally accepted GHG calculation or reporting protocols for some voluntary reporting source categories, such as domestic wastewater treatment plants and agricultural operations. The Division will continue to consult with potential voluntary reporters in these categories to reach consensus on appropriate and acceptable protocols for reporting purposes. For domestic wastewater treatment plants at Part A, Section III.B.8., examples of such protocols may include the "U.S. Community Protocol for Accounting and Reporting of Greenhouse Gas Emissions" (Version 1.2, July 2019), at Appendix F: Wastewater and Water Emission Activities and Sources, published by ICLEI: Local Governments for Sustainability, and protocols developed by the IPCC or based on IPCC protocols. The Division expects that all direct GHG emissions from a domestic wastewater treatments plant will be calculated and reported by a voluntary reporter. For an agricultural operation identified in Part A, Section III.A.9., examples of such protocols may include those specified in Subpart JJ of 40 CFR, Part 98 and developed by the IPCC and the U.S. Department of Agriculture (USDA) for the sector.

Part A will also quantify the GHG emissions associated with electricity imported and consumed in Colorado, as required by §25-7-140(2)(a)(I), C.R.S., and which is not covered by the federal mandatory reporting under Part 98 data submissions. Attribution of GHG emissions to statewide electricity consumption will be accomplished by requiring subject entities to submit supplemental data including generation, wholesale and retail sales, and emissions information to the Division, as appropriate for the business activities conducted in Colorado by the entity. The supplemental data form will be developed through a stakeholder process led by the Division. The supplemental data form is intended to report annual consolidated data from detailed sources already collected by or available to the entities for business or other regulatory purposes (i.e. contracts, internal tracking systems for energy transactions with counterparties or through organized markets, Energy Information Administration reporting, Public Utility Commission reporting, US EPA, Federal Energy Regulatory Commission, etc.) into a single process and standard report format so that the Division can document emissions associated with total electricity consumption in Colorado.

The reporting form will include calculation methodologies and data sources, prioritizing more specific sources over less specific sources for determining GHG emissions from imported electricity when the generation source of the energy is unknown, which can occur through various market transaction mechanisms. Quantification of GHG emissions associated with electricity exported from Colorado will also be accomplished through the use of the supplemental data form because understanding the complete energy flow through the transmission and distribution systems is necessary to determine energy consumed in Colorado. Direct reporting of this annual summary information using a consistent form, rather than relying on summaries provided through the Department of Energy or other sources, will provide necessary completeness and granularity of the data for state and local GHG strategy development. Additionally, direct reporting to the Division will also allow for more timely incorporation into the Colorado GHG Inventory process and more detailed analysis and trending to assess the progress toward achieving the statewide GHG reduction goals.

In adopting the reporting requirements of this Regulation No. 22, Part A, IV.C.2 the Commission does not take a position on what information should be utilized to determine GHG emission reductions as part of a Clean Energy Plan. The requirements for submitting data associated with Clean Energy Plans, and the process by which the Division will evaluate the emissions reduction projections and provide recommendations to the Public Utilities Commission, will be developed and published through a separate process from this Regulation Number 22 rulemaking. Subpart A will also establish ongoing reporting for utilities that have received approval of a Clean Energy Plan by the Public Utilities Commission. Tracking of GHG reduction progress achieved by these plans will inform development, assessment, and refinement of strategies to achieve the statewide GHG targets.

Sources of Sulfur Hexafluoride (SF6) owning or operating electrical transmission and distribution equipment facilities located in more than one state that calculate SF6 emissions on a system-wide basis for recordkeeping and reporting under EPA's Part 98 may determine its Colorado SF6 emissions by estimating the Colorado portion of its system-wide emissions based on the percentage of its total transmission line miles that exist in Colorado.

Given recent and ongoing deregulation efforts by the federal government, and especially those focused on air quality and climate change, the Commission finds it necessary to protect Colorado's regulatory regime in these areas from potential federal deregulation or rollbacks. This must be balanced with the legislative directive in § 25-7-140(2)(a)(I), C.R.S., to "consider what information is already being publicly reported by the [EPA,]" which the Commission is doing by leveraging Part 98 reporting and tools available thereunder, including e-GGRT. In doing so, the Commission is cognizant that these programs and tools are subject to change in ways that may either improve or diminish their utility for Colorado's GHG emission reporting and inventory efforts.

By incorporating by reference Part 98 and its related subparts as they are effective July 1, 2019, and by referencing applicable provisions of Part 98 in Part A, Sections III.A. and B of this Regulation Number 22, the Commission intends to protect against potential federal rollbacks by specifying those currently subject to federal GHG reporting will continue to report under the federal requirements as they currently stand in the event the federal GHG reporting rules are revised or rescinded. Should the EPA indicate, through public notice or otherwise, an intent in any way diminish or rollback the requirements of Part 98, its related subparts, or associated tools, including but not limited to e-GGRT, the Commission and Division will endeavor to promptly establish reporting requirements and tools necessary to maintain the GHG reporting and inventory regime adopted in this Regulation Number 22, Part A. However, the Commission also recognizes that some future changes might enhance GHG reporting, so the Commission may also choose to update the incorporation date if those future revisions align with and advance Colorado's goals

Part B, Section I.: Prohibitions on Use of Certain Hydrofluorocarbons in Aerosol Propellants, Chillers, Foam, and Stationary Refrigeration End-Uses

The federal EPA adopted two rules under its Significant New Alternatives Policy (SNAP), Rule 20 in July 2015, and Rule 21 in December 2016, which require phasing out the use of high-GWP HFCs in retail and residential refrigeration and air conditioning (AC), aerosol products, and rigid and spray foam end-uses. Under SNAP Rule 20, the compliance dates for eliminating unacceptable HFCs ranged from July 2016 to January 2022, depending on the application. The compliance dates under SNAP Rule 21 ranged from January 2017 to January 2025. In August 2017, the D.C. Circuit of the United States Court of Appeals vacated SNAP Rule 20 to the extent it requires manufacturers to replace HFCs with a substitute substance finding the EPA had exceeded its authority under Section 612 of the Clean Air Act (42 U.S.C. § 7671k). However, the D.C. Circuit found that EPA's removal of HFCs from the list of safe substitutes under SNAP was lawful thus enabling the EPA to prohibit or limit prospective use of HFCs in manufacturing and end uses. Yet, in 2018, EPA guidance advised that it would not be enforcing SNAP Rule 20 until it developed new rules based on the D.C. Circuit's ruling, which has not occured. In April 2019, the D.C Circuit vacated SNAP Rule 21 to the same extent and on the same grounds as SNAP 20.

Absent federal enforcement regulating use of these highly potent GHGs, individual states have adopted, or are in the process of adopting, statutes and regulations phasing out the use of HFCs in manufacturing and end-use products. The U.S. Climate Alliance has drafted a model framework to promote uniformity of HFC regulation across member states. Part B., Section I. is based upon the U.S. Climate Alliance's model framework as are proposed HFC rules under consideration in other states. Based on stakeholder feedback and significant economic impacts, the Commission adopted an alternative requirement for positive displacement chillers that differs from the U.S. Climate Alliance's model framework. The purpose of this provision is to address GHG emissions associated with use of prohibited high-GWP HFCs in the manufacture of positive displacement chillers in lieu of phasing out the use of these HFCs in chillers destined for sale or installation outside of Colorado or other states with similar HFC prohibitions.

This alternative approach requires GHGs associated with the use of prohibited high-GWP HFCs in this specific manufacturing process to be mitigated through best management practices at the manufacturing facility and any remaining emissions to be addressed through GHG reduction projects completed in the State of Colorado. Positive displacement chillers manufactured for sale or installation in Colorado after the January 1, 2024 prohibition date will still be restricted from using prohibited HFCs.

The Division, in considering emission reduction projects under Section I.C.3.a.(v), will give preference to projects that have environmental co-benefits or benefits to the local community. While projects can include those developed or owned by the manufacturer, such projects must be additional to any efforts planned or undertaken as part of an overall GHG emissions reduction program the manufacturer may have and must not be projects or activities that would be carried out in the ordinary course of business. Additionally, based on public comment and stakeholder feedback, Part B., Section I. differs from the U.S. Climate Alliance's model framework in the treatment of bear spray and law enforcement pepper spray. These two products in the aerosol-propellant category have been exempted in Part B., Section I.

Additional Considerations

The following are additional findings of the Commission made in accordance with the Act:

§ 25-7-110.5(5)(b), C.R.S.

As these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) Any federal requirements that are applicable to this situation with a commentary on those requirements;

Part A: In order to improve the nationwide inventory of GHG emissions, Part 98 sets forth the federal GHG reporting requirements for qualifying source categories in accordance with the Federal Clean Air Act. The Subparts to Part 98 establish the reporting protocols and methodologies for each source category. Part 98 effectively establishes three groups of source categories required to report annual GHG emissions: sources required to report regardless of emission volumes; sources only required to report if emissions meet or exceed specified thresholds (generally 25,000 metric tons of CO2e in combined emissions from stationary sources); and fuel suppliers that import or export product equivalent to 25,000 metric tons of CO2e or more. Through Part A the Commission builds upon established federal reporting requirements and closes reporting gaps by eliminating reporting thresholds for certain sources and expanding certain other source categories to report GHG emissions in order to establish a more robust and accurate GHG inventory for Colorado.

Part B., Section I.: To the extent Part B., Section I. requires manufacturers to replace HFCs, there are no applicable federal requirements as a result of the D.C. Circuit Court's vacature of SNAP Rules 20 and 21 and EPA's lack of progress in further regulating HFCs. To the extent that Part B., Section I. prohibits or restricts prospective uses of prohibited HFCs (phases out), it does not conflict with any applicable current federal regulations.

(II) Whether the applicable federal requirements are performance-based or technology-based and whether there is any flexibility in those requirements, and if not, why not;

Part A: There are no control requirements associated with the Part A GHG reporting rule.

Part B., Section I.: To the extent SNAP Rules 20 and 21 remain in effect and are enforceable, the federal HFC rules are primarily technology-based in that the rules largely proscribe or severely limit the use of HFCs in certain manufacturing processes and end-uses thus requiring substitution or replacement with lower GWP substances.

(III) Whether the applicable federal requirements specifically address the issues that are of concern to Colorado and whether data or information that would reasonably reflect Colorado's concern and situation was considered in the federal process that established the federal requirements;

Part A: Colorado's General Assembly has determined that climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life and that reducing statewide GHG emissions can mitigate these impacts. § 25-7-102, C.R.S. While the EPA also indicated that its "mandatory GHG reporting program [set forth in Part 98] will provide EPA, other government agencies, and outside stakeholders with economy-wide data on facility-level (and in some cases corporate-level) GHG emissions," § 25-7-140, C.R.S. explicitly requires the Commission to adopt GHG reporting requirements to fill any gaps in the federal reporting requirements.

To the extent that reporting under 40 CFR Part 98 establishes adequate GHG reporting to satisfy this legislative directive, those requirements and reporting protocols have been adopted. To the extent that the Commission has determined certain source categories may be underreporting due to reporting thresholds or exemptions of certain source categories, those thresholds or exemptions have been eliminated. Additionally, Part A establishes new reporting requirements for certain source categories for which there are no federal reporting requirements.

Part B., Section I.: To the extent Part B., Section I. requires manufacturers to replace HFCs, there are no current applicable federal requirements as contemplated in this regulation. As a result of the D.C. Circuit Court's vacature of SNAP Rules 20 and 21 and EPA's lack of progress in further regulating HFCs, there are no current applicable federal requirements relating to the phase-out of HFCs as contemplated in this regulation. To the extent that Part B., Section I. prohibits or restricts prospective uses of prohibited HFCs (phases out), it does not conflict with any current applicable federal regulations.

(IV) Whether the proposed requirement will improve the ability of the regulated community to comply in a more cost-effective way by clarifying confusing or potentially conflicting requirements (within or cross-media), increasing certainty, or preventing or reducing the need for costly retrofit to meet more stringent requirements later;

Part A: Part A will maintain reporting requirements for facilities already required to report under Part 98 and will require additional facilities to report under reporting protocols either set forth in Part 98 and related subparts or under state reporting requirements already in place (i.e. oil and natural gas operations reporting under Regulation Number 7). By leveraging existing protocols and reporting procedures, Part A minimizes inefficiencies while still accomplishing the legislative mandate set forth in § 25-7-140, C.R.S.

Part B., Section I: To the extent Part B., Section I. requires manufacturers to replace HFCs, there are no applicable federal requirements as contemplated in this regulation. As a result of the D.C. Circuit Court's partial vacature of SNAP Rules 20 and 21 and EPA's lack of progress in further regulating HFCs, there are no current applicable federal requirements relating to the phase-out of HFCs as contemplated in this regulation However, Part B., Section I imposes restrictions on the same substances as those restricted under SNAP Rules 20 and 21 with which the regulated community had already started to comply before those rules were vacated. Absent federal progress in regulating use of these highly potent GHGs, individual states have adopted, or are in the process of adopting, statutes and regulations phasing out the use of HFCs in manufacturing and end-use products. The U.S. Climate Alliance has drafted a model framework to promote uniformity of HFC regulation. Part B., Section I. is based upon the U.S. Climate Alliance's model framework as are proposed HFC rules under consideration in other states. This consistency is intended to improve the regulated community's ability to comply in a more cost-effective manner.

(V) Whether there is a timing issue which might justify changing the time frame for implementation of federal requirements;

Part A: The March 31 annual reporting deadline is the same under Regulation Number 22 and Part 98 for all reporters. Regulation Number 22 does not affect federal GHG reporting requirements for those sources subject to federal reporting requirements. With respect to any sources required to report under Regulation Number 22 but not under federal requirements, there is no timing issue related to implementation of any federal requirements.

Part B., Section I.: To the extent Regulation Number 22, Part B., Section I., requires manufacturers to replace HFCs, there are no applicable federal requirements as a result of the D.C. Circuit Court's vacature of SNAP Rules 20 and 21 and EPA's lack of progress in further regulating HFCs. To the extent that Regulation Number 22, Part B., Section I., prohibits or restricts prospective uses of prohibited HFCs (phases out), there are no timing issues that justify changing the time frame for implementation of any federal requirements.

(VI) Whether the proposed requirement will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth;

Part A: Part A's annual GHG reporting requirements are retrospective in that they are a report of past emissions and therefore are not subject to uncertainty and do not hinder or negatively affect future growth of facilities required to report past emissions.

Part B., Section I.: The HFC phase-out in Part B., Section I. allows a reasonable time to comply and permits the substitution of lower-GWP substances or retrofit of components. As such, affected businesses or industrial sectors are afforded a reasonable margin for accommodation of uncertainty and future growth.

(VII) Whether the proposed requirement establishes or maintains reasonable equity in the requirements for various sources;

Part A: With respect to any sources already required to report GHG emissions under the federal reporting requirements, Part A, maintains reasonable equity as reporting requirements are the same for each source type. With respect to any sources newly required to report GHG emissions under Part A, the rule establishes reasonable equity as reporting requirements are the same for each source type.

Part B., Section I.: Part B., Section I., phases-out the use of HFCs across specific end-uses and manufacturing processes, with only limited exemptions or alternative compliance requirements. Reasonable equity is established among these end-uses and processes by use of phase-out dates that are the same as those determined to be achievable with industry input in the development of the SNAP rules and the U.S. Climate Alliance's model framework. Part B., Section I. was also based upon the U.S. Climate Alliance's model framework to allow those subject to the rule to avoid varying requirements across states to the extent possible while still addressing the serious climate change impacts these substances present.

(VIII) Whether others would face increased costs if a more stringent rule is not enacted;

Part A: No, it is not anticipated there would be increased direct costs to others if a more stringent rule is not enacted.

Part B., Section I.: The legislature has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals. A more stringent HFC rule could achieve additional GHG reductions. Reductions not achieved in one sector will require measures in other sectors of the economy to achieve the state's GHG reduction goals. The HFC rule is drafted to strike a balance between the costs to the entities impacted under the rule and further measures that will need to be utilized in other sectors of the economy.

(IX) Whether the proposed requirement includes procedural, reporting, or monitoring requirements that are different from applicable federal requirements and, if so, why and what the "compelling reason" is for different procedural, reporting, or monitoring requirements;

Part A: Reporting requirements beyond those required under federal Part 98 are necessary to effectively quantify and measure Colorado's progress toward statewide GHG reductions and to achieve the public health, safety and welfare goals set forth in § 25-7-102, C.R.S., § 25-7-140(2)(a)(I), C.R.S., dictates that the Commission tailor new [GHG] reporting requirements to fill any gaps in the existing federal reporting requirements and "allow for maintaining and updating state inventories that are sufficiently comprehensive and robust."

Through Part A, the Division proposes building upon established federal reporting requirements and closes reporting gaps by lowering or eliminating reporting thresholds for certain sources, expanding certain other source categories, and requiring new source categories to report GHG emissions in order to establish a more robust and accurate GHG inventory for Colorado. Filling gaps in emission data from those select sources not otherwise required to report under Part 98 in order to more accurately determine statewide GHG emissions and develop reduction strategies is a compelling reason to expand the reporting requirements. Additionally, under Part A, Section IV.C., electric service providers and electric utilities will be required to submit supplemental data necessary to verify GHG emissions attributable to imported and exported electricity and to verify plans submitted to the Public Utilities Commission. Under this requirement, owners and operators of these sources will be required to compile and report directly to the Division information collected by or available to them for business or other regulatory purposes. While this may overlap with some other federal reporting requirements, it is expected there will be reporting beyond what is required federally.

Part B., Section I: To the extent Part B., Section I., requires manufacturers to replace HFCs, there are no current applicable federal requirements as a result of the D.C. Circuit Court's vacature of SNAP Rules 20 and 21 and EPA's lack of progress in further regulating HFCs.

(X) Whether demonstrated technology is available to comply with the proposed requirement;

Part A: Part A maintains reporting requirements for facilities already required to report under Part 98 and will require additional facilities to report under reporting protocols either set forth in Part 98 and related subparts or under state reporting requirements already in place (i.e. oil and gas operations). Demonstrated technology exists to enable compliance with the reporting requirements of Regulation Number 22.

Part B., Section I.: Yes, non-HFC replacements with significantly lower GWP are generally available and widely used in manufacturing processes and end-uses phased out in Part B., Section I.

(XI) Whether the proposed requirement will contribute to the prevention of pollution or address a potential problem and represent a more cost-effective environmental gain;

Part A: Under Part A the Commission will develop a sufficiently comprehensive and robust GHG inventory to enable and inform future implementation strategies to cost-effectively reduce statewide GHG emissions to meet the legislative directive of § 25-7-102(2)(g), C.R.S.

Part B., Section I: The General Assembly has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals. HFCs are a highly potent GHG such that small volumes of reduction can affect significant reductions of GHG emissions measured in CO2e. A more stringent HFC rule could achieve additional GHG reductions. Reductions not achieved in one sector will require compensating measures in other sectors of the economy to achieve the state's GHG reduction goals. Part B., Section I. is drafted to strike a balance between the costs to the entities impacted under the rule and further measures that will need to be utilized in other sectors of the economy.

(XII) Whether an alternative rule, including a no-action alternative, would address the required standard.

Part A: § 25-7-140, C.R.S., does not permit a no-action alternative and requires the Commission to adopt GHG reporting regulations "to allow for maintaining and updating state inventories that are sufficiently comprehensive and robust." Further, the statute requires the rules "include requirements for providers of retail and wholesale electric service in the state of Colorado to track and report emissions from all generation sources within the state and elsewhere that electricity consumption by their customers in this state causes to be emitted." While alternative requirements could address these mandates, the Commission has determined that the proposed reporting requirements are appropriate to establish statewide progress towards the GHG emission reduction goals mandated by the General Assembly in § 25-7-102, C.R.S. To the extent alternative reporting thresholds and source categories were considered, they were determined to be inadequate to satisfy the directives set forth in § 25-7-140, C.R.S.

Part B., Section I.: §§ 25-7-105(1)(e) and -140(2)(a)(III), C.R.S., require the Commission to implement GHG emission reduction strategies in order to accomplish the statewide GHG emission reduction goals set forth in § 25-7-102(g), C.R.S. HFCs are a highly potent GHG such that small volumes of reduction can affect significant reductions of GHG emissions measured in CO2e. A more stringent HFC rule could achieve additional GHG reductions. Reductions not achieved in one sector will require compensating measures in other sectors of the economy to achieve the state's GHG reduction goals.

Part B, Section I. rule is drafted to strike a balance between the costs to the entities impacted under the rule and further measures that will need to be utilized in other sectors of the economy. While the General Assembly has not explicitly required implementation of an HFC phase-out as a reduction strategy and therefore a no-action alternative is possible, given the statewide reduction goals and the potency of HFCs, no action on HFCs would require more stringent measures in other sectors in order to achieve the same GHG reductions.

§ 25-7-110.8, C.R.S.

To the extent that the § 25-7-110.8, C.R.S., requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(a) These rules are based on reasonably available, validated, reviewed, and sound scientific methodologies and all validated, reviewed, and sound scientific methodologies and information made available by interested parties has been considered.

(b) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in emission of HFCs and will enable the Commission to establish sufficiently comprehensive and robust inventories of GHGs as required by § 25-7-140, C.R.S.

(c) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health and the environment that will justify the costs to government, the regulated community, and to the public to implement and comply with the rule.

(d) The rules are the most cost-effective to achieve the necessary and desired results and reduction in air pollution.

(e) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

§ 25-7-105(1)(e), C.R.S. - Statewide GHG Pollution Abatement

To the extent that the § 25-7-105(1)(e), C.R.S., requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

Any impacts to disproportionately impacted communities and (IV) Coordination with other state agencies, stakeholders, and the public:

The Commission carefully considered the concerns of and potential impacts on communities disproportionately impacted by climate change in the following ways:

Stakeholder engagement: 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. Opportunities for input included email, remote stakeholder meeting participation, and in-person meeting participation. Public stakeholder meetings were held from early afternoon until after 6pm in both Denver and Glenwood Springs, to maximize access for working and busy individuals. Language interpretation services for stakeholder meetings were made available (though none were requested during this process).

Potential economic impacts: The Division conducted outreach to determine potential impacts to disproportionately impacted communities for Parts A and B., Section I. With respect to Part A, impacts on local governments and small rural operations were significant considerations in determining whether to require mandatory GHG reporting from domestic wastewater treatment facilities and municipal solid waste landfills with emissions below the reporting threshold in 40 CFR Part 98.

Ultimately, in this rulemaking the Commission elected against mandatory reporting from these source categories, but to allow voluntary reporting. While more robust GHG data has the potential to enhance local climate efforts and ultimately reduce a variety of negative impacts on Colorado’s communities, the Division recognizes that providing data can represent an administrative burden, particularly for small operations with fewer staff and serving smaller communities.

For both domestic wastewater treatment and municipal solid waste landfill emissions (below the 40 CFR Part 98 threshold) reporting, the Division identified available reporting protocols to minimize the burden of the reporting process for any sources wishing to report voluntarily. In addition to public comments, the Division considered stakeholder comments from organizations representing local governments, local wastewater districts and the Wastewater Utility Council, and conducted outreach to the Solid Waste Association of North America's Colorado Chapter in the drafting of the proposed GHG reporting rule.

For Part B., Section I., Division outreach efforts sought to determine if any manufacturers (large or small) of equipment or small niche end-uses that might be impacted by the proposed HFC reduction rule exist in the state. Based on discussions with industry partners and trade groups, as well as online research and communication with the Colorado Department of Labor & Employment (CDLE), the Division was able to confirm that Trane has a chiller manufacturing facility in Pueblo, Colorado that employs approximately 500 individuals. The potential impacts of Part B., Section I. on this facility and area jobs was carefully considered in the development of Part B, Section I. and the Commission has adopted an innovative solution to protect these important jobs while also achieving necessary climate benefits. Accordingly, the Commission has determined that the HFC-phase out in Part B., Section I. will not result in an accumulation of negative or lack of positive environmental, health, economic, or social conditions in a manner that disproportionately impacts certain communities within the state.

Coordination with other jurisdictions:

Absent federal enforcement regulating HFCs, individual states have adopted, or are in the process of adopting, statutes and regulations phasing out the use of HFCs in manufacturing and end-use products. The U.S. Climate Alliance has drafted a model framework to promote uniformity of HFC regulation. Part B., Section I. is based upon the U.S. Climate Alliance's model framework as are draft rules under consideration in other states.

Additional Considerations:

Having considered all relevant information in the record and those factors set forth in § 25-7-105(1)(e)(VI), C.R.S., the Commission has determined that Parts A and B., Section I. are appropriate measures necessary to implement statewide GHG pollution abatement. The Commission concludes that GHG reporting in Part A and the HFC phase-out in Part B., Section I. will either directly result in health, environmental, and air quality benefits or otherwise enable the Commission and General Assembly to better regulate GHG emissions in the future through a more robust inventory.

Furthermore, based on the Division's Final Economic Impact Analysis, the costs of compliance with Parts A and B., Section I. and any negative impacts to Colorado's jobs and economy are considerably outweighed by these benefits. Based on the Division's analysis, Part B., Section I. is anticipated to result in statewide GHG reductions in Colorado of about 560 thousand metric tons CO_2e in 2025 and 1.15 million metric tons CO_2e in 2030. Additionally, as these regulations will lower GHG emissions and the General Assembly has determined that reducing GHG emissions will result in economic and jobs growth by creating new markets, spurring innovation, and driving investments in low-carbon technologies. The time necessary for compliance under Parts A and B., Section I. reflect consideration of existing state and federal requirements as well as feedback from stakeholders. As described in significant detail, Part A will enable the Commission to better inventory analyze statewide GHG emission sources across diverse sectors and sources by utilizing existing federal reporting requirements in 40 CFR Part 98 and also expanding those requirements. Parts A and B., Section I. are therefore determined to be appropriate and cost-effective.

II. Adopted: August 19, 2021 (Revisions to Regulation Number 22, Part B, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-110 and -110.5, C.R.S., and the Air Quality Control Commission's ("Commission") Procedural Rules, 5 C.C.R. §1001-1.

Basis

The Commission is amending Regulation Number 22, Part B, Section I., to revise the definitions of "Rigid Polyurethane High-pressure Two-component Spray Foam" and "Rigid Polyurethane Low-pressure Two-component Spray Foam" found in the existing Hydrofluorocarbons (HFC) prohibitions rule (Part B, Sections I.B.40. and I.B.41.) to more accurately describe the noted products or end-uses.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act (Act), specifically § 25-7-105(1), C.R.S., directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102, C.R.S., and that are necessary for the proper implementation and administration of the Act.

§ 25-7-105(1)(e), C.R.S., authorizes the Commission to promulgate implementing rules and regulations consistent with the statewide GHG pollution reduction goals in § 25-7-102(2)(g), C.R.S. In adopting GHG abatement strategies and implementing rules, the Commission is authorized to take into account other relevant laws and rules to enhance efficiency and cost-effectiveness and solicit input from other state agencies and stakeholders on the advantages of different statewide GHG pollution mitigation measures. § 25-7-105(1)(e)(II), (IV), C.R.S. Implementing rules may include regulatory strategies that "enhance cost-effectiveness, compliance flexibility, and transparency around compliance costs." § 25-7-105(1)(e)(V), C.R.S.

Further, in promulgating such implementing rules, the Commission is to consider many factors, including, but not limited to: health, environmental, and air quality benefits and costs; the relative contribution of each source or source category to statewide GHG pollution; equitable distribution of the benefits of compliance; issues related to the beneficial use of electricity to reduce GHG emissions; and whether greater or more cost-effective emission reductions are available through program design. § 25-7-105(1)(e)(VI), C.R.S.

§ 25-7-106, C.R.S., provides the Commission "maximum flexibility in developing an effective air quality program and [promulgating] such [a] combination of regulations as may be necessary or desirable to carry out that program." § 25-7-109(1), C.R.S., authorizes the Commission to adopt and promulgate emission control regulations that require the use of effective practical air pollution controls for each type of facility, process, or activity which produces or might produce significant emissions of air pollutants. An "emission control regulation" may include "any regulation which by its terms is applicable to a specified type of facility, process, or activity for the purpose of controlling the extent, degree, or nature of pollution emitted from such type of facility, process, or activity. . . ." § 25-7-103(11), C.R.S. Emission control regulations may pertain to any chemical compound including GHG pollution and emissions of ozone precursors. See § 25-7-109(2)(c), C.R.S.

Purpose

The following section sets forth the Commission's purpose in amending Regulation Number 22, Part B, Section I, and includes the technological and scientific rationale for these amendments:

Part B.I: Amendments to definitions of certain HFC end-uses

The Commission amended the definitions of “Rigid Polyurethane High-pressure Two-component Spray Foam” and “Rigid Polyurethane Low-pressure Two-component Spray Foam” in Regulation Number 22, Part B, Section I to more accurately describe these products or end-uses. Because the definitions adopted in May 2020 were not technically accurate in describing the end-uses, there was concern the end-uses may not be actually covered under the rule as was intended. The definitions adopted in May 2020 came from the U.S. Climate Alliance’s model framework for HFC regulation and were based on language describing the noted end-uses in the preamble to the EPA Significant New Alternatives Policy (SNAP) Program, Rule 21.

Additional Considerations

The following are additional findings of the Commission made in accordance with the Act:

§ 25-7-110.5(5)(b), C.R.S.

As these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), C.R.S., the Commission determines:

Part B.I: The Commission amended two definitions in this rule in order to more accurately describe these products or end-uses. These amendments do not alter or change the analysis of these additional considerations under § 25-7-110.5, C.R.S., for Part B, Section I. that was conducted at the time of its original adoption in May 2020.

§ 25-7-110.8, C.R.S.

To the extent that the § 25-7-110.8, C.R.S., requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

(a) These rules are based on reasonably available, validated, reviewed, and sound scientific methodologies and all validated, reviewed, and sound scientific methodologies and information made available by interested parties has been considered.

(b) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in GHG pollution and/or ozone precursors as transportation co-pollutants and will enable the Commission to satisfy the requirements of §§ 25-7-102, -105(1)(e), -106, and/or -109, C.R.S., as applicable.

(c) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health and the environment that will justify the costs to government, the regulated community, and to the public to implement and comply with the rule.

(d) The rules are the most cost-effective to achieve the necessary and desired results and reduction in air pollution.

(e) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Further, these revisions will include any typographical, grammatical and formatting errors throughout the regulation.

III. Adopted: October 22, 2021

Revisions to Regulation Number 22, Part B, Section II.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-110 and -110.5, C.R.S., and the Air Quality Control Commission's ("Commission") Procedural Rules, 5 C.C.R. §1001-1.

Basis

In HB 19-1261, now codified in part at §§ 25-7-102(2) and -105(1)(e), C.R.S., the General Assembly declared that "[c]limate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "[m]any of these impacts disproportionately affect" certain disadvantaged communities. § 25-7-102(2), C.R.S. The General Assembly also recognized that "[b]y reducing greenhouse gas pollution, Colorado will also reduce other harmful air pollutants, which will, in turn, improve public health, reduce health care costs, improve air quality, and help sustain the environment." § 25-7-102(2)(d), C.R.S.

Consequently, the General Assembly updated Colorado's statewide greenhouse gas (GHG) pollution reduction goals so as to achieve a 26% reduction of statewide GHG by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. § 25-7-102(2)(g), C.R.S. Statewide GHG pollution is defined as "the total net statewide anthropogenic emissions of carbon dioxide [(CO_2)], methane [(CH_4)], nitrous oxide [(N_2O)], hydrofluorocarbons [(HFCs)], perfluorocarbons [(PFCs)], nitrogen trifluoride [(NF_3)], and sulfur hexafluoride [(SF_6)] expressed as carbon dioxide equivalent [(CO_2e)] calculated using a methodology and data on radiative forcing and atmospheric persistence deemed appropriate by the commission." § 25-7-103(22.5), C.R.S.

§ 25-7-105(1)(e), C.R.S., sets forth the framework for developing GHG abatement rules consistent with the statewide GHG pollution reduction goals in § 25-7-102(2)(g), C.R.S. This provision grants the Commission broad authority to regulate GHG emissions in order to accomplish these goals.

In order to evaluate the utilization of, and potential emissions reductions from, GHG best available emission control technologies (BAECT) and best available energy efficiency practices (referred to as best management practices or Energy BMP) in energy-intensive trade-exposed (EITE) stationary sources, the Commission adopted in Regulation Number 22, Part B, Section II, rules governing emission control and energy audits from these sources and requiring a five percent reduction in GHG emissions therefrom.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act (Act), specifically § 25-7-105(1), C.R.S., directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102, C.R.S., and that are necessary for the proper implementation and administration of the Act.

§ 25-7-105(1)(e), C.R.S., authorizes the Commission to promulgate implementing rules and regulations consistent with the statewide GHG pollution reduction goals in § 25-7-102(2)(g), C.R.S. In adopting GHG abatement strategies and implementing rules, the Commission is authorized to take into account other relevant laws and rules to enhance efficiency and cost-effectiveness and solicit input from other state agencies and stakeholders on the advantages of different statewide GHG pollution mitigation measures. § 25-7-105(1)(e)(II) and (IV), C.R.S.

Implementing rules may include regulatory strategies that incentivize development of renewable resources and “enhance cost-effectiveness, compliance flexibility, and transparency around compliance costs.” § 25-7-105(1)(e)(V), C.R.S. Further, in promulgating such implementing rules, the Commission is to consider many factors, including, but not limited to: health, environmental, and air quality benefits and costs; the relative contribution of each source or source category to statewide GHG pollution; equitable distribution of the benefits of compliance; issues related to the beneficial use of electricity to reduce GHG emissions; and whether greater or more cost-effective emission reductions are available through program design. § 25-7-105(1)(e)(VI), C.R.S.

§ 25-7-105(1)(e)(IX), C.R.S., authorizes the Commission to require energy-intensive, trade-exposed [(EITE)] stationary sources, “to execute an energy and emission control audit, according to criteria established by the [C]ommission, of the source’s operations every five years through at least 2035.” The intent of the audit is to determine whether covered sources are employing “best available emission control technologies for [GHG] emissions [(GHG BAECT)] and best available energy efficiency practices [(Energy BMP)]”.

§ 25-7-105(1)(e)(XIII), C.R.S., adopted in House Bill 21-1266, directs the Commission to “require a five percent reduction in the [GHG] emissions associated with [EITE] stationary sources that currently employ [GHG BAECT and Energy BMPs], as determined by the Commission, pursuant to [§ 25-7-105(1)(e)(IX), C.R.S.].”

§ 25-7-106, C.R.S., provides the Commission “maximum flexibility in developing an effective air quality program and [promulgating] such [a] combination of regulations as may be necessary or desirable to carry out that program.” § 25-7-109(1), C.R.S., authorizes the Commission to adopt and promulgate emission control regulations that require the use of effective practical air pollution controls for each type of facility, process, or activity which produces or might produce significant emissions of air pollutants. An “emission control regulation” may include “any regulation which by its terms is applicable to a specified type of facility, process, or activity for the purpose of controlling the extent, degree, or nature of pollution emitted from such type of facility, process, or activity. . . .” § 25-7-103(11), C.R.S. Emission control regulations may pertain to any chemical compound including GHG pollution. See § 25-7-109(2)(c), C.R.S.

<u>Purpose</u>

The Commission adopted Regulation Number 22, Part B, Section II to give effect to the requirements of §§ 25-7-105(1)(e)(IX) and (XII)(B), C.R.S., and to further the reduction of statewide GHG pollution consistent with § 25-7-102(2)(g), C.R.S., as applicable to EITE stationary sources.

§ 25-7-105(1)(e)(IX), C.R.S., authorizes the Commission to require EITE stationary sources, “to execute an energy and emission control audit, according to criteria established by the [C]ommission, of the source’s operations every five years through at least 2035.” The intent of the audit is to determine whether covered sources are employing GHG BAECT and Energy BMPs. The last audit shall occur in the year 2037.

The audit and GHG emission reduction requirements contained in Part B, Section II are applicable only to stationary sources that principally engage in defined manufacturing activities and have direct GHG emissions equal to or greater than 50,000 tons CO2e per year as reported under 40 CFR, Part 98 and/or Part A of this Regulation Number 22. Based on 2019 data, there are only four stationary sources meeting these requirements: EVRAZ Rocky Mountain Steel’s mill in Pueblo, with reported GHG emissions of 305,674 tons CO2e; CEMEX Construction Materials South’s Lyons Cement Plant, with reported GHG emissions of 268,643 tons CO2e; GCC Rio Grande’s cement manufacturing plant in Pueblo, with reported GHG emissions of 743,403 tons CO2e; and Holcim-Lafarge’s cement plant in Florence, with reported GHG emissions of 985,222 tons CO2e.

The fifth highest GHG emission sources in one of these enumerated manufacturing activities reported GHG emissions of approximately 27,000 tons CO2e in 2019.The four EITE stationary sources over 50,000 tons CO2e per year in 2019 remained the only sources over this threshold in 2020 as well. It is notable that, based on 2019 reported data, these four stationary sources contribute approximately 54% of Colorado industrial and manufacturing sector's GHG emissions. Accordingly, this emissions threshold guarantees that the state's largest EITE sources of GHG emissions are employing GHG BAECT and Energy BMPs in their manufacturing processes while appropriately limiting the regulatory burden on smaller sources.

Critical to the success of the GHG BAECT and Energy BMP audit program is the selection of sufficiently rigorous audit protocols and qualified auditors. Accordingly, Section II.C.2. and the associated definitions in Section II.B. establish the minimum qualifications for the auditor and audit team and the criteria and processes by which the audits are to be performed. Under Section II.C.2.a.(v)(A), the Division can reject an auditor if the auditor has a previous or existing relationship with the source that is so pervasive that the auditor would be unable to conduct the audit in an unbiased and independent manner. The Division should consider the extent to which the auditor has advocated on behalf of the EITE stationary source before the Commission; whether the relationship is currently or recently pervasive, compared to a relationship primarily in the past; whether the auditor has primarily acted as an advocate for the EITE stationary source as opposed to a scientific or technical advisor; and whether the work conducted on behalf of the EITE stationary source would, in any way, inhibit the auditor's ability to conduct an independent and unbiased audit.

Prior to executing an audit, the EITE stationary source must submit to the Division for its review and approval of the audit plan, which identifies the audit scope, the audit team and any standards or protocols planned for use in the audit. The Division's review should ensure that the plan is sufficiently rigorous and meets or exceeds national and/or international standards for such audits. Examples of sufficiently rigorous accounting and audit protocols include, but are not necessarily limited to, the GHG Protocol's Corporate Accounting and Reporting Standard (more information available at https://ghgprotocol.org/corporate-standard) and the International Organization for Standardization's (ISO) 14064 and 50001 series (more information available at https://www.iso.org/home.htm).

As set forth in Section II.C.2., the energy and emissions control audit will analyze GHG BAECT for the EITE stationary source's emissions units that emit the top 80% of the stationary source's GHG emissions, and any individual emissions source that represents more than 2% of the emissions from the EITE stationary source. This audit scope is determined by the Division to be broad enough to capture all GHG emission sources at the EITE stationary source except for those considered "de minimis" and provide for a thorough audit of the emissions at the facility.

The Energy BMP audit will assess all emission units that account for 80% of the source's energy consumption. This scope ensures that the audit captures the largest emitting and energy consuming emissions units and that the majority of the EITE stationary source's emissions are examined. It is expected that there may be overlap between these two scopes, which is addressed in Section II.C.3.a.(ii)(A)(1).

Section II.C.3. establishes the audit reporting requirements and detailed steps for the GHG BAECT and Energy BMP analyses. These analyses are conducted on a case-by-case basis for the EITE stationary source under review and incorporate certain objective criteria for the auditor and Division to consider. The GHG BAECT analysis and prioritization process will consider technical feasibility of the control for the stationary source, the estimated emission reductions realized with each measure, cost-effectiveness and environmental, economic, and energy impacts. Additionally, consideration should be given to other factors such as existing facility permit limits, limits and emissions data available for similar operations, and air pollution co-benefits to local communities.

Under Section II.C.3.a.(i)., the control technologies and strategies considered during the GHG BAECT analysis should consider fuel switching, waste to heat options, strategic energy management (SEM) options and carbon capture and underground storage or utilization (CCUS). In evaluating fuel-switching as a control technology, the source should consider switching from coal and petroleum coke to a lower-carbon fuel. In evaluating waste to heat options, the source should consider changing raw material inputs in production processes. In evaluating waste to heat options, the source should consider preheating and heat re-use. The Commission understands that certain of these technologies may not yet be ready for employment as GHG BAECT or Energy BMPs at the stationary sources and expects them to be evaluated for technical feasibility if they are “available.”

The cost-effectiveness evaluation will include the full lifetime of the measure under consideration and all “net levelized” costs to account for costs and costs avoided—or benefits—that may result from adopting a particular control or efficiency measure. These factors are described in further detail at Section II.C.3.a.(i)(D) for GHG BAECT and II.C.3.a.(ii)(A)(4) for Energy BMPs and should include changes in the annual costs resulting from the control technology/method including energy costs, operations and maintenance costs, productivity (e.g. increased production rate or reduced down-time), product quality (e.g. improved quality or reduced rate of rejects/bad batches).

As detailed in Part B, Section II.C.3.a.(i)(E) for GHG BAECT and Section II.C.3.a.(ii)(A)(5) for Energy BMPs, measures identified in the audit as technically feasible cannot then be eliminated as cost-prohibitive if the cost-effectiveness of the measure is equal to or less than the avoided social cost of GHGs. Further, any direct or indirect energy, economic and environmental impacts for each potential GHG control measure is to be considered. Economic considerations may include a comparison to direct competitors and international markets for the EITE source’s final product (i.e. steel or cement). Environmental considerations should include any benefits or detriments that may result from a particular measure. Energy considerations should include direct and indirect energy efficiency benefits or detriments, including changes in demand for offsite electric generation.

The social cost of GHG’s cost-effectiveness comparison mechanism ensures that sufficient weight is afforded to the full spectrum of climate impacts from GHG emissions that could be controlled through technically feasible means. As set forth in Part B, Section II.B.41, the social cost of greenhouse gases to be used aligns with that established in § 25-7-110.5(4)(f), C.R.S., through the adoption of House Bill 21-1266. The social cost of GHGs to be used in each GHG BAECT and Energy BMP audit must be consistent with this definition and the Division will review the social cost of GHGs used in the audit recommendations to ensure the values are correctly calculated. Using the social cost of GHGs is an appropriate, objective measure for evaluating potential costs avoided when analyzing the “cost-prohibitiveness” of effective, technically feasible control measures and balancing that against other environmental, energy, or economic impacts, such as competitiveness.

This balancing serves to recognize the externalities resulting from GHG emissions that could be avoided through the use of potentially costly control measures and the limited ability of EITE sources to implement those measures if it would render them uncompetitive in the marketplace and therefore risk unintended consequences, including GHG leakage.

Further, Section II.C.3.a(i)(B)(1) sets forth the Commission’s intent that EITE stationary sources will consider and fully evaluate the possibility of employing CCUS or utilization as a control measure for any emissions unit with direct emissions of 100,000 tons CO_2e and provide that analysis to the Division at least every five-year audit cycle. The analysis must go beyond a superficial examination of whether other similar facilities have successfully employed these technologies and must look at the state of the technology and whether it can be successfully employed at the source under review. If it is technically possible to employ these technologies, they must then be evaluated for other factors such as cost-effectiveness and other direct or indirect impacts, like competitiveness in the marketplace.

The intent of this assessment is to objectively and rationally uncover the strengths and weaknesses of CCUS technology at the facility. The assessment should include economic and technical issues associated with carbon capture technology at the specific facility. A feasibility analysis is expressly not required by this rule, but if a facility has conducted a full feasibility analysis within the last 5 years, that information will satisfy the requirement to provide the information in Section II.C.3.a.(i)(B)(1). In subsequent audit cycles, these reports can be updated instead of recreated.

In the interest of regulatory efficiency, as an alternative to conducting an Energy BMP audit under Sections II.C.2. and 3, the EITE stationary source will be determined to have conducted a qualifying audit and be currently employing Energy BMPs if the stationary source is certified under the EPA Energy Star Program or is registered to the ISO 50001 - standard for energy management. This alternative pathway was adopted because the underlying programs examine and audit the facility's performance as a whole, and are equally or more rigorous and thorough than the Energy BMP audit contemplated in § 25-7-105(1)(e)(IX)(A), C.R.S. The Federal Energy Star Program is a widely accepted "benchmarking" program managed by EPA and requires annual certification that the facility is sufficiently efficient (reaches a score of 75 or higher out of 100).

More information available at: https://www.energystar.gov/industrial_plants/earn-recognition/plant-certification

ISO 50001 is the internationally recognized energy management system developed by the International Organization for Standards which requires certification every 3 years.

More information available at: https://www.iso.org/iso/iso_50001_energy_management_systems.pdf

Both certifications are appropriate alternative means of demonstrating Energy BMP employment as they require rigorous evaluation of an industrial facility's energy performance and the employment of best available energy practices through either benchmarking in the case of Energy Star or certification to a specific set of requirements for holistic energy management of the facility, in the case of ISO 50001.If the EITE stationary source is not certified under EPA's Energy Star Program or ISO 50001, the EITE stationary source must conduct an Energy BMP audit pursuant to Section II.C.2. and 3.

The GHG BAECT and Energy BMP Recommendation

As described in Section II.C.3.a.(iii), the auditor's recommendation must include: (1) The auditor's recommendation on the most effective technology or strategy or suite of control technologies as determined under Section II.C.3.a.; (2) a list of all control measures with levelized costs less than or equal to $0 as determined in Section II.C.3.a.(i)(D); and (3) recommendations on options that provide greater pollution reduction co-benefits to communities surrounding the EITE stationary source.

The GHG BAECT and Energy BMP recommendation in the audit report serves as the foundation for the GHG BAECT and Energy BMP determination to be made by the Division and ultimately finalized by the Commission. This recommendation consists of the technologies identified through the audit process that would be considered "best" to control and reduce GHG emissions from the emissions units included in the audit scope. The recommendation is documented in the audit report. The GHG BAECT recommendation may be a single technology or reduction measure for the emission unit or a suite of technologies or measures if multiple measures are able to achieve greater reductions and are the same or similar cost-effectiveness. This approach creates potential for a greater reduction at the same or similar cost to the EITE stationary source, as well as opportunities for increased consideration and inclusion of technologies or measures that have significant co-benefits. The energy BMP recommendation will be issued as a list of the most effective energy efficiency measures for the EITE stationary source for the energy consumption sources included in the audit scope. Both the GHG BAECT and energy BMP recommendations will include a list of measures that have a levelized cost of equal to or less than $0 for the Division's consideration.

The GHG BAECT and Energy BMP recommendation will document the total cumulative GHG emissions intensity rate for all emission units included in the audit scope. This will be calculated by identifying each emissions unit's annual GHG emissions per final product from the EITE source then summing all audited emission unit intensity rates for a total GHG BAECT and Energy BMP GHG emissions intensity rate for the EITE stationary source. If any energy efficiency measure achieves additional GHG reductions for the facility it shall be included in the GHG BAECT emission intensity rate per final product of the EITE stationary source.

The audit report must also show the calculations and recommendation for the total mass emissions from emission units that were not included in the audit scope. This number is integral to the annual emissions limit calculation for each EITE stationary source because the emissions limitation must include all emissions from the facility.

The GHG BAECT and Energy BMP Intensity Rate Determination

The Division will analyze and review the audit report's GHG BAECT and Energy BMP intensity rate recommendations and associated analyses for all emission units included in the audit scope and make a final recommendation to the Commission to establish the GHG BAECT and Energy BMP GHG emissions intensity rate for the EITE stationary source. The Commission may ask questions, require additional information, or grant approval to the Division-determined rate for the facility. The Division will strive to incorporate these briefings into existing briefings or proceedings before the Commission.

After receiving the audit report, the Division's determination will be based on the audit recommendation and the Division may select either the top control identified or a suite of controls that meet certain, enumerated criteria. The Division's GHG BAECT and Energy BMPs determination for each emissions unit or energy-consuming source within the audit scope will include: (1) The specific control or suite of controls selected as GHG BAECT (Section II.d.1.b.) and Energy BMPs (Section II.D.1.c.); (2) the final GHG BAECT and energy BMP intensity rate for the EITE stationary source (Section II.D.1.b.(iv)); and (3), in addition to any controls selected as GHG BAECT and/or Energy BMPs, all controls found to have a net levelized neutral cost over five (5) years from operational date, unless doing so would impose an unreasonable burden to the EITE stationary source as determined by the Division and based upon findings in the audit report (Sections II.D.1.b.(ii) and II.d.1.c.(ii)).

The GHG BAECT and Energy BMP intensity rate is determined from the GHG BAECT analysis for each piece of GHG emitting equipment to calculate a cumulative GHG BAECT and energy BMP Intensity Rate for the facility. This GHG BAECT and energy BMP intensity rate represents a single, cumulative rate for all GHG emitting equipment included in the audit scope, for both GHG BAECT and energy BMPs. This intensity rate does not include any GHG emitting equipment not included in the audit scope.

The calculation is as follows:

> GHG BAECT & Energy BMP Intensity Rate Determination = Σ (CO_2e per tons of facility product for each emission unit in audit scope)

Non-GHG BAECT Emissions Calculation

During the audit, the mass total of GHG emissions from the GHG emitting equipment that was not included in the audit scope, or "Non-GHG BAECT emissions," shall be determined. Non-GHG BAECT emissions are calculated by subtracting the reported emissions from units evaluated for GHG BAECT from the facility annual emissions at the time of the first audit. Once reviewed and approved by the Division and Commission, this mass total will remain fixed. This number will be used in calculating the annual emissions limitation for each EITE stationary source.

The calculation is as follows:

Non-GHG BAECT Emissions = Total direct emissions from the most recent year reported - (reported emissions from the units evaluated for GHG BAECT)

Annual Emissions Limitation Determination

The annual emissions limit must consider all GHG emissions from the EITE stationary source. The direct GHG emitting units that were not included in the audit scope must be included in calculating the limit. Therefore, the GHG BAECT and energy BMP intensity rate determined by the Division must be converted to mass by using the year's production total. *This is done by multiplying the units of production for the EITE stationary source for the year, by the GHG BAECT and energy BMP intensity rate. This results in a mass emissions total which represents the mass emissions from the facility operating all GHG BAECT and energy BMPs during that year. The Non-GHG BAECT emissions are then added to this total, resulting in a mass-based emission total for the EITE stationary source. This is then multiplied by 95% in order to affect the 5% reduction required by statute, the end result of which is the EITE stationary source's "annual emission limit" for the year under review.* Calculation of and compliance with this annual emissions limitation is required beginning in the third year after the audit year, onward. The five percent reduction must be achieved in addition to any subsequent lower GHG BAECT and Energy BMP intensity level determined for the EITE stationary source.

The calculation is as follows:

Annual Emission Limit for Compliance Year in tons CO2e = (((GHG BAECT & Energy BMP Intensity Rate Determination) * (Compliance Year Facility Product)) + (Non-GHG BAECT Determination))*0.95

Compliance Year Facility Product = tons of final product reported to Division by EITE Stationary Source

This calculation links the mass based number to total production and is appropriate for EITE industries. This is a unique set of industries, where there is the potential for "leakage"- that is, for production to move to other locations outside of Colorado, and because of this, state statute specifically treats EITE industries distinctly from other GHG emitting industries. This mass based approach to production may not be appropriate for the industrial sector as a whole or other sectors.

This approach gives effect to § 25-7-105(1)(e)(XIII)(B), C.R.S., because it would be consistent with the requirements of § 25-7-105(1)(e)(IX) and would affect a 5% reduction in GHG emissions "associated with [EITE] sources that currently employ [GHG BAECT] and [Energy BMPs], as determined by the [C]ommission...." Pertinent to these reduction requirements, where an EITE source is employing GHG BAECT and Energy BMPs, § 25-7-105(1)(e)(IX) limits the Commission's ability to "impose a direct non-administrative cost on the source directly associated with at least [95%] of the source's [GHG] emissions attributable to manufacturing a good in the state[.]" § 25-7-105(1)(e)(IX)(A), C.R.S. Thus, in order to give effect to this limitation and the emissions reduction required in § 25-7-105(1)(e)(XIII)(B), the 5% reduction requirements must apply to GHG emissions "associated with the [EITE] sources" and "attributable to manufacturing a good in the state."

Use of the emissions limitation approach set forth in GEMM for EITE sources accomplishes this suite of legislative directives. It requires EITE sources to reduce GHG emissions "attributable to manufacturing a good in the state by 5%." It does not impose non-administrative costs on the other 95% of GHG emissions from the source. This provides the EITE sources flexibility to mitigate the costs of the required reductions and provides an incentive to improve efficiency and reduce emissions. Importantly, it accomplishes all this while allowing EITE sources to adjust production levels based on market forces and meet demand with an annual mass emissions limitation at a GHG intensity of 5% below that accomplished through the employment of GHG BAECT and Energy BMPs without requiring the source to reduce production to accomplish these reductions. This balances the need for substantial and lasting GHG emissions reductions from EITE sources while recognizing the treatment afforded these particular sources by the General Assembly.

Annual Emission Limit Compliance

Pursuant to Sections II.E.1.b. and II.F.2., EITE stationary sources are required no later than the third year after each audit to achieve and maintain an additional mass-based five percent GHG emission reduction below emissions that would be achieved through the employment of GHG BAECT and Energy BMPs, unless an interim emission rate is established under Section II.E.1.c. To demonstrate compliance, EITE stationary sources must submit an annual compliance report with the information set forth in Section II.G.1., including the previous year's GHG emissions; units of product produced; and the GHG BAECT and energy BMP intensity rate determination. The EITE stationary sources must also maintain records for 10 years.

Compliance Pathways

To give effect to the legislative directive § 25-7-105(1)(e)(XIII)(B), C.R.S., and in accordance with the guidance concerning implementing rules in §§ 25-7-105(1)(e)(II), (V), and (VI), C.R.S., in Section II.F.1.c. the Commission provides three pathways to achieve the required emission intensity rate. This includes any one or combination of: direct on-site reductions (Section II.F.1.a.(i)); surrendering reduction credits created by GHG reductions at other regulated sources (Section II.F.1.a.(ii)); and utilization of retail distributed generation or net metering renewable projects that reduce GHG emissions from the facilities' energy use for which RECs have been retired (Section II.F.1.a.(iii)). For the utilization of renewable energy, the RECs retired must be from Colorado and retired in the year generated. Regardless of the compliance pathway utilized, the EITE stationary source must assure that any significant co-benefits are achieved at the EITE stationary source pursuant to Section II.F.1.b.

Utilization of Renewable Energy Credits for compliance cannot exceed the annual generation of the distributed generation system and cannot be used for compliance with the Annual Emissions Limitation for more than the required 5% reduction, nor can they be counted toward the 20% emissions reduction required to exempt the source from further 5% reduction requirements, as those are to be based on direct emissions reductions from the facility.

The megawatt hour (MWh) of distributed generation in avoided GHG emission value shall be based on the relevant electricity provider's reported annual system emissions, calculated in a manner consistent with the Division's AQCC-approved Clean Energy Plan guidance, and be adjusted annually to account for the changing emissions profile of the generation fleet of the source's electricity supplier. This is because a system MWh avoided today may be more emissions intensive than a system MWh avoided in the future.

The Commission recognizes that large capital-intensive emissions reduction projects such as large-scale carbon capture, utilization, and storage may take an extended time to complete. The Commission directs staff to develop a proposal to allow an alternative compliance pathway with an extended timeline, with sufficient guardrails to ensure that cumulative GHG emissions reductions will be greater than those achievable with short-term measures, and that communities near the facility will realize appropriate co-benefits.

Points of Compliance

There are a number of discrete requirements with which the covered sources must demonstrate compliance over the course of each audit cycle. These include:

- Submission of the Audit Plan at least 120 days prior to commencing the audit (Section II.C.2.);
- Submission of the Audit Report no later than December 31, 2022 and every five years thereafter (Section II.C.1.a.);

- Submission and execution of the Compliance action plan within 120 days of the Commission's approval of the GHG BAECT and Energy BMP determination (Section II.F.1.);

- Compliance with annual emission limits established in the GHG BAECT and Energy BMP determination by the third year after each audit year (Sections II.E.1.b. and II.F.2); and

- Submission of annual compliance certification by May 1 beginning in 2026 (Section II.G.1).

Mechanisms for Assuring Compliance

GEMM is generally enforceable as a provision of part 1 of the Act, see § 25-7-105(1)(e)(IX) (requiring EITE stationary sources to conduct GHG BAECT and Energy BMP audits), and as an emission control regulation promulgated by the Commission. See § 25-7-115(1)(a), C.R.S. Accordingly, noncompliance with GEMM is subject to the injunctive and civil penalty authority of the Division and Commission. See §§ 25-7-121 and -122, C.R.S. In addition to these general authorities, f § II.K.1.a. provides an alternative means of addressing noncompliance with the emission reduction requirements of GEMM where the EITE stationary source is utilizing GHG credits to comply. Section II.K.1.a. provides the source an opportunity to rectify any shortcomings in emission reduction requirements under GEMM by surrendering three GHG credits for every ton emitted by the source in excess of its annual emission limit.

Co-benefits

The treatment of co-benefits in the evaluation and determination of co-benefits in the audit and subsequent effects on the Section II.F. compliance pathways and is affected through three mechanisms:

1. In Section II.C.3.a.(i)(G) for BAECT and Section II.C.3.a.(ii)(A)(7) for BMPs, the auditor must evaluate and document expected air quality co-benefits of any BAECT or BMP measure assessed;

2. In Section II.C.3.a.(iii)(A)(4) for BAECT and Section II.C.3.a.(iii)(B)(3) for BMPs, the auditor's recommendation must include as a BAECT and/or BMP the option that provide greater co-benefits to the surrounding communities where the top options are otherwise comparable in terms of cost-effectiveness; and

3. In Section II.F.1.b., where an EITE source complies with the annual emission limit, it must also achieve the co-benefits to the local community where "the measure(s) determined to be GHG BAECT and/or energy BMPs for an emission unit also are anticipated to result in significant co-benefits[.]"

As to this final point, the express intent is to ensure that any localized co-benefits that would be realized through implementation of the specific BAECT or BMPs identified in the audit are still realized for the local community, regardless of which compliance pathway the source utilizes. This is explicitly intended to benefit local communities and particularly those disproportionately impacted by climate change and other air quality issues and is in response to input from communities and local governments.

The quantification of any co-benefits under Sections II.C.3.a.(i)(G) and II.C.3.a.(ii)(A)(7) must include establishment of a baseline for the relevant pollutant(s) and quantification of net co-benefits from the control technologies and strategies below or above the baseline. The baseline shall be determined based on the best available information, including monitored emissions, if available, or reported emissions of the relevant pollutant(s) at the time of the audit.

GHG Credit Accounting and Trading Program for EITE Stationary Sources

§ 25-7-105(1)(f)(I)(C), C.R.S., defines “trading program” as “a commission-adopted regulatory program that allows for regulated sources to meet their greenhouse gas compliance obligations under subsection (1)(e) of this section through the creation, purchase, acquisition, or exchange of, or other commercial-type transaction involving, a GHG credit with other regulated sources.” § 25-7-105(1)(f)(I)(A), C.R.S., defines “regulated source” as “a source of [GHG] that is subject to a rule adopted by the [C]ommission under [§ 25-7-105(1)(e)] that imposes specific and quantifiable [GHG] reduction obligations upon that source or group of sources.”

An accounting and “trading program” for GHG credits will be developed by the Division, which can be utilized by EITE sources covered by GEMM. The trading program will serve as one pathway to complying with GHG emissions limitations and will allow trading of GHG reductions while also ensuring co-benefits of reducing localized harmful air pollutants at the EITE sources. This is achieved by separately determining what reductions in harmful air pollutants will be achieved at the source through the use of GHG BAECT and requiring that these emission reductions are achieved regardless of how the EITE complies to reduce its GHG emissions.

GHG credits issued by the Division will serve as the mechanism for the trading program. These GHG credits must be utilized for the trading program and represent a GHG emission reduction of one metric ton of CO2e in Colorado, and be real, additional, quantifiable, permanent, verifiable and enforceable. The Act authorizes the Commission to adopt this program through its general rulemaking authority, its authority to adopt implementing rules for GHG pollution reduction, and specific authority to adopt an accounting and trading program as established under House Bill 21-1266.See §§ 25-7-106(1) (granting the Commission “maximum flexibility in developing an effective air quality control program and [the authority to] promulgate such combination of regulations as may be necessary or desirable to carry out that program”); -105(1)(e)(II) (granting the Commission broad authority to adopt implementing rules to affect GHG emissions reductions); -105(1)(e)(V) (implementing rules for GHG reductions should enhance cost-effectiveness and compliance flexibility and transparency around compliance costs); -105(1)(e)(IX)(A) (EITE sources should be provided “a pathway to obtain equivalent lower-cost emission reductions at other regulated sources to satisfy their compliance objectives”); and -105(1)(f) (granting the Commission authority to establish GHG credit trading program between “regulated sources,” and specifically to implement § 25-7-105(1)(e)(IX)).

The program accords with the Commission’s authority by allowing EITE sources pathways to accomplish reduction requirements at other regulated sources using an accounting and trading program through which the Division can track emission reductions and trades, prevent double-counting of GHG emission reductions, and identify EITE sources that adversely affect disproportionately impacted communities through emissions of locally harmful air pollutants.

Importantly, the accounting and trading program applies only to EITE stationary sources subject to the audit and GHG emission reductions in GEMM. However, given the authority granted to the Commission in § 25-7-105(1)(f), it is possible that this program may serve as a model for a future, more broadly applicable GHG credit trading program for the industrial manufacturing sector. Should that arise, the Commission may consider how EITE sources should be incorporated into the broader program at that time. The current approach recognizes the directive in statute that EITE sources be provided “a pathway to obtain equivalent lower-cost emission reductions at other regulated sources to satisfy their compliance obligations” while also recognizing EITE sources would initially be the only “regulated sources” as that term is defined, and therefore the only sources eligible to participate in the trading program until additional GHG sources in Colorado meet this definition.

Based on these tenets, Section II.I. sets out provisions establishing an accounting system to track GHG reduction credits. These provisions task the Division with establishing the accounting system. An EITE source seeking eligibility to trade credits must first apply and have the Division create a compliance account for the EITE source. This application for an account must be submitted to the Division within 30 days after approval of the EITE source’s BAECT and Energy BMP determination. Any EITE source the Division determines adversely affects disproportionately impacted communities through emission of locally harmful air pollutants must be identified by the Division in the accounting system.

Only GHG credits meeting the definition set forth in Section II.B.22 may be traded in the accounting system. Pursuant to this definition a “GHG credit” represents a GHG emission reduction of one metric ton of CO2e that is real, additional, quantifiable, permanent, verifiable and enforceable. To track such credits, the Division is directed to assign each credit a unique identifier (such as a serial number) and, as further directed in Section II.F.1.a.(ii), only issued in the tracking system after the underlying emission reduction has been demonstrated.

Sections II.G. and II.H. are designed to ensure that EITE stationary sources conduct regular reporting to demonstrate compliance with the audit requirements in Section II.C. and emissions reduction requirements in Section II.F. and maintain all pertinent records.

The Commission determined that the audit procedures and compliance requirements set out in Part B, Section II, establish the criteria by which the Commission can determine, on a five-year basis, whether EITE stationary sources are employing GHG BAECT and energy BMP. The Commission has determined the audit process is cost-effective and reasonable to achieve these ends.

<u>Additional Considerations</u>

The following are additional findings of the Commission made in accordance with the Act:

§ 25-7-110.5(5)(b), C.R.S.

As these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) Any federal requirements that are applicable to this situation with a commentary on those requirements;

EITE Entities are required to report GHG emissions under existing federal regulations. Some EITE stationary sources may be required to conduct a GHG “best available control technology” or “BACT” analysis as part of a Prevention of Significant Deterioration permitting action unrelated to the requirements of these rules. However, there are no current federal regulations requiring these entities to conduct GHG BAECT and energy audits or to reduce GHG emissions as required under this rule.

(II) Whether the applicable federal requirements are performance-based or technology-based and whether there is any flexibility in those requirements, and if not, why not;

EITE Entities are required to report GHG emissions under existing federal and state regulations. Some EITE stationary sources may be required to conduct a GHG “best available control technology” or “BACT” analysis as part of a Prevention of Significant Deterioration permitting action unrelated to the requirements of these rules. Those BACT evaluations are technology-based. However, there are no current federal regulations requiring these entities to conduct GHG BAECT and energy audits or reduce GHG emissions as required under this rule.

(III) Whether the applicable federal requirements specifically address the issues that are of concern to Colorado and whether data or information that would reasonably reflect Colorado's concern and situation was considered in the federal process that established the federal requirements;

Federal BACT analyses under PSD permitting are separate and distinct from the GHG BAECT analysis adopted in this Part B, Section II. in both its scope and purpose. Under federal PSD permitting, GHG emissions cannot alone trigger a BACT analysis, though the permitting authority may evaluate GHG controls for “anyway” sources that trigger PSD permitting requirements by exceeding other criteria pollutant thresholds. See Air Regul. Grp. v. E.P.A., 573 U.S. 302, 333–34 (2014). This Part B, Section II. in contrast is adopted pursuant to specific legislative directive to evaluate GHG BAECT and Energy BMPs; there are no applicable federal requirements in this regard.

(IV) Whether the proposed requirement will improve the ability of the regulated community to comply in a more cost-effective way by clarifying confusing or potentially conflicting requirements (within or cross-media), increasing certainty, or preventing or reducing the need for costly retrofit to meet more stringent requirements later;

This section gives meaningful effect to §§ 25-7-105(1)(e)(IX) and (XIII), C.R.S., and provides regulated entities flexibility to identify and cost-effectively employ emissions control technologies BAECT and energy efficiency measures to reduce GHG emissions so long as they constitute GHG BAECT and Energy BMPs. Regulated entities that demonstrate effective employment of BAECT and Energy BMPs are afforded certainty with respect to direct non-administrative costs associated with ninety-five percent of the source’s GHG emissions and control over the means of otherwise reducing GHG emissions to comply with § 25-7-105(1)(e)(XIII)(B), C.R.S.

(V) Whether there is a timing issue which might justify changing the time frame for implementation of federal requirements;

There are no applicable federal requirements that create any timing issues. Part B, Section II. allows regulated entities a reasonable time to comply with the audit, any resulting compliance action plan, and GHG emission reduction requirements and allows opportunities for alternative compliance.

(VI) Whether the proposed requirement will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth;

Part B, Section II. affords regulated entities significant flexibility for meeting GHG emission reduction requirements. Furthermore, EITE entities are afforded the ability to affect required reductions through alternative compliance measures where needed. As such, regulated entities are afforded a reasonable margin for accommodation of uncertainty and future growth. The three pathways provided for EITE stationary sources to accomplish the 5% emissions reductions in Sections II.E. and II.F. and as required under § 25-7-105(1)(e)(XII)(B), C.R.S., provide affected sources flexibility to accommodate uncertainty and future growth.

(VII) Whether the proposed requirement establishes or maintains reasonable equity in the requirements for various sources;

All qualifying EITE entities are equally subject to the audit and action plan requirements and the audits account for the specifics of the EITE stationary source in question. Likewise, all regulated entities are afforded opportunities to select and apply BAECT and energy BMPs that work for the specific source and account for environmental, economic, and energy concerns. Furthermore, the five percent GHG emission reduction requirements in Sections II.E. and II.F. are equally applied to all qualifying EITE stationary sources. Where available, opportunities to maximize co-benefits to communities near or around the stationary source should be prioritized.

(VIII) Whether others would face increased costs if a more stringent rule is not enacted;

The General Assembly has acknowledged that climate change impacts Colorado's economy and directed that GHG emissions should be reduced across all sectors of our economy. Colorado has established specific GHG reduction goals. Reductions not achieved in one sector will require measures in other sectors of the economy to achieve the state's GHG reduction goals. However, the General Assembly further provided requirements that energy-intensive and trade-exposed entities demonstrate use of BAECT and energy BMPs through an audit process and limited the Commission's ability to impose additional reductions on at least ninety-five percent of the source's GHG emissions where such measures are effectively employed. See § 25-7-105(1)(e)(IX), C.R.S. With respect to the 5 percent emission reductions required of EITE entities employing GHG BAECT and energy BMPs under § 25-7-105(1)(e)(XIII)(B), C.R.S., any emission reductions not timely realized from these entities would, in turn, require greater emission reductions from other sources in the industrial and manufacturing sector in order to achieve the twenty percent sector-wide requirements by 2030 set forth in § 25-7-105(1)(e)(XIII)(A), C.R.S.

(IX) Whether the proposed requirement includes procedural, reporting, or monitoring requirements that are different from applicable federal requirements and, if so, why and what the "compelling reason" is for different procedural, reporting, or monitoring requirements;

Part B, Section II. gives effect to the General Assembly's adoption of 25-7-105(1)(e)(IX), C.R.S., which includes a requirement for energy-intensive trade-exposed entities to execute energy and emission control audits that are not required under federal regulations. This is a compelling reason, as these audits will inform the state's strategies and future regulations to accomplish the statewide GHG pollution reduction goals and address the impacts of climate change set forth in § 25-7-102(2), C.R.S. and sector-specific emission reductions under § 25-7-105(1)(e)(XIII), C.R.S.

(X) Whether demonstrated technology is available to comply with the proposed requirement;

Part B, Section II does not require the use of any specific technology but instead serves as a mechanism to evaluate the control technologies and energy efficiency practices regulated entities are employing and to determine the effectiveness of those measures already in use. The GHG BAECT and Energy BMP audits are used to conduct this evaluation and must include analyses of, but not necessarily implementation of, transformative technologies. All GHG BAECT and energy BMP determinations will be based on demonstrated and available technologies.

(XI) Whether the proposed requirement will contribute to the prevention of pollution or address a potential problem and represent a more cost-effective environmental gain;

This rule will enable the Commission to determine whether EITE stationary sources are employing GHG BAECT and Energy BMPs to effectively minimize GHG emissions from regulated facilities. EITE sources will be required to comply with the annual emission limits established pursuant to this audit process. The GHG emissions reductions from this rule are expected to help Colorado achieve the statewide GHG pollution reduction goals in § 25-7-102(2)(g), C.R.S., and the sector-specific GHG emission reductions set forth in § 25-7-105(1)(e)(XIII), C.R.S. Anticipated reductions in co-pollutants are expected to have positive health benefits for the people of Colorado.

(XII) Whether an alternative rule, including a no-action alternative, would address the required standard.

This rule implements the statutory requirements of §§ 25-7-105(1)(e)(IX) and (XIII)(B), C.R.S. Alternatives exist for how to accomplish these requirements, including different emission thresholds for qualifying entities, different standards for evaluating GHG BAECT and Energy BMPs, and the provision of no or differing means of alternative compliance as well as different timing requirements for emission reductions. The Commission determined that Part B, Section II. appropriately gives effect to the statutory requirements and is consistent with the statewide and sector-specific GHG pollution reduction goals. A no-action alternative is not available under § 25-7-105(1)(e), C.R.S.

Findings of Fact

To the extent that § 25-7-110.8, C.R.S., 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 on reasonably available, validated, reviewed, and sound scientific methodologies and all validated, reviewed, and sound scientific methodologies and information made available by interested parties has been considered.

(II) Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in GHG pollution and co-pollutants and will enable the Commission to satisfy the requirements of §§ 25-7-102, -105(1)(e), -106, and/or -109, C.R.S., as applicable.

(III) Evidence in the record supports the finding that the rule shall bring about reductions in risks to human health and the environment that will justify the costs to government, the regulated community, and to the public to implement and comply with the rule.

(IV) The rules are the most cost-effective to achieve the necessary and desired results and reduction in air pollution.

(V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

IV. Adopted: December 17, 2021

Revisions to Regulation Number 22, Part B, Sections III. and IV.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-101, C.R.S., et seq., the Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 C.C.R. §1001-1.

Basis

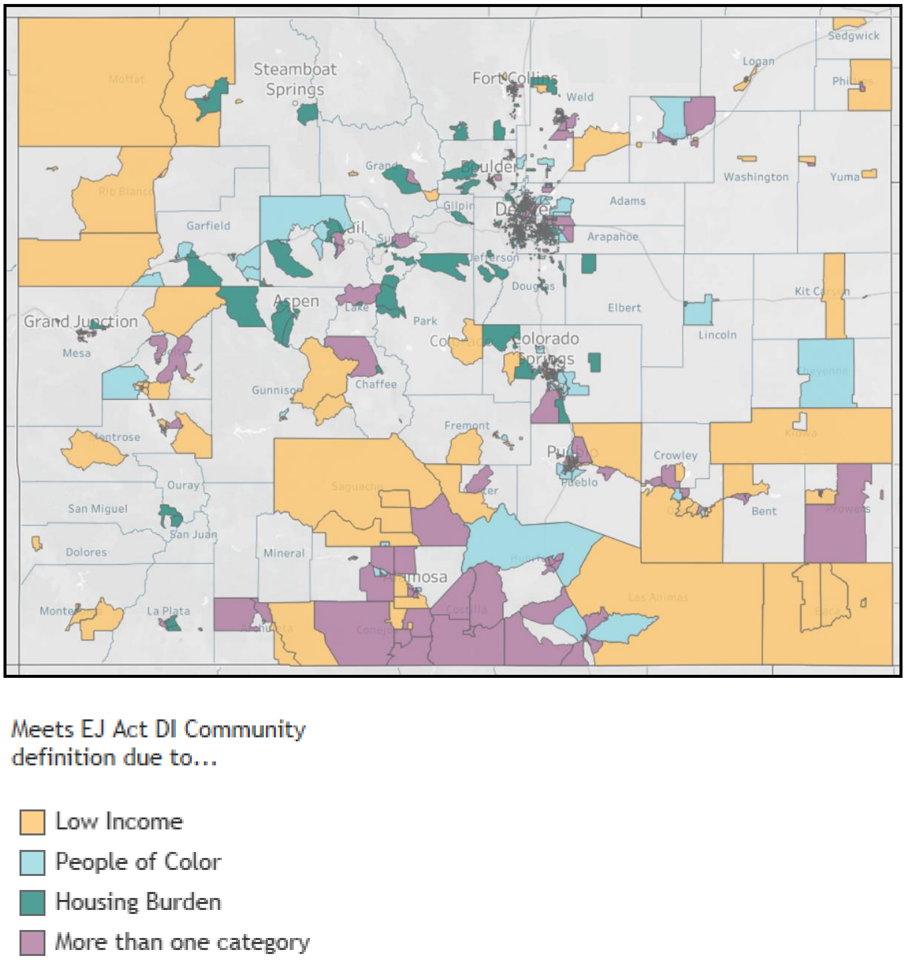
During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission (OGCC) and this Commission. In the same session, the General Assembly adopted House Bill 19-1261 (HB 19-1261), setting statewide greenhouse gas (GHG) reduction goals. The General Assembly declared in HB 19-1261 that "climate change adversely affects Colorado's economy, air quality and public health, ecosystems, natural resources, and quality of life[,]" acknowledged that "Colorado is already experiencing harmful climate impacts[,]" and that "many of these impacts disproportionately affect" certain disadvantaged communities. The goals set in HB 19-1261 seek a 26% reduction of statewide GHG emissions by 2025; 50% reduction by 2030; and 90% reduction by 2050 as compared to 2005 levels. The GHG Pollution Reduction Roadmap ("GHG Roadmap") developed by the Colorado Energy Office and CDPHE identifies the largest contributors to state GHG emissions and quantifies the baselines from which these reduction percentages are to be estimated.

In October 2020, the Commission established a target for the O&G Sector of a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030 (an estimated 13 million metric tons (MMT) CO2e by 2025 and 8 MMT CO2e by 2030). Commission targets for the sector including industrial combustion emissions (Industrial Sector) include a 20% reduction from 2015 numbers by 2030. House Bill 21-1266 (HB 21-1266), signed into law on July 2, 2021, memorializes these percentage reductions in statute, and provides additional requirements for the rulemakings to achieve these goals. The oil and gas industry is a large source of GHG emissions, and the largest anthropogenic source of methane in Colorado. For the oil and gas industry, not all of its emissions are found in the “O&G Sector”, also referred to as the “Oil & Gas Fugitive Emissions” category of the GHG Roadmap. Most methane emissions from upstream and midstream activities, along with estimates of methane “leakage” from pipelines in the transmission & storage and distribution segments, are in the O&G Sector. In contrast, the emissions from fuel combustion at oil and gas sources in the upstream and midstream segments are largely found in the “RCI Sector” of the GHG Roadmap (specifically in the “industrial” category, which is the subject of specific requirements in HB 21-1266).

In this rulemaking action, the Commission has adopted requirements for upstream and midstream segment operations, to reduce GHG emissions from those operations, sufficient - when taken in combination with other regulatory and voluntary actions across the state - to achieve the GHG reduction requirements of HB 21-1266. In this action, the Commission did not adopt regulations applicable to the transmission and storage segment or the distribution segment. With regard to the transmission and storage segment, the Commission adopted a performance-based program for this segment in 2019 designed to materially reduce greenhouse gas emissions from transmission and storage operations; reporting of progress has not yet begun under that program and the Commission believes it reasonable to evaluate the progress of that program before modifying it.

The Commission did not adopt regulations applicable to the distribution segment because legislation passed in the 2021 session invests the Colorado Public Utility Commission (PUC) with authority over this segment of the oil and gas industry. Senate Bill 21-264 (SB 21-264) requires that gas distribution utilities will submit a comprehensive clean heat plan that demonstrates projected reductions in methane and carbon dioxide emissions that meet prescribed reduction targets. Each clean heat plan must outline the utility’s proposal to reduce carbon dioxide and methane emission levels by 4% in 2025 and 22% in 2030. Gas distribution utilities, depending on their size, must submit clean heat plans to the PUC by August 1, 2023 and January 1, 2024. Thus, the Commission believes that the transmission & storage performance program and the clean heat plans are likely to achieve reductions of emissions necessary from these segments to achieve the goals of § 25-7-105(1)(e)(XII).

In the 2021 legislative session, in HB 21-1266, the General Assembly also determined that “state action to correct environmental injustice is imperative, and state policy can and should improve public health and the environment and improve the overall well-being of all communities… [and] efforts to right past wrongs and move toward environmental justice must focus on disproportionately impacted communities and the voices of their residents.” HB 21-1266 also requires the Commission to ensure additional protections for, and reductions of co-pollutants in, disproportionately impacted communities. CDPHE developed a map of the disproportionately impacted communities that meet the definition of HB 21-1266. While this map is expected to change over time, the disproportionately impacted communities that have been identified at the time of this program’s adoption are as set forth in the following map:



<u>Specific Statutory Authority</u>

The Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq. (the State Air Act or the 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 § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act provides the Commission broad authority to regulate air pollutants, including GHG and its constituent gasses (particularly carbon dioxide, methane, and nitrous oxide).

§ 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. § 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. § 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. § 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.

Pursuant to HB 21-1266, the Commission must, by January 1, 2022, adopt regulations to ensure that the state meets its greenhouse gas reduction targets for the oil and gas sector in the GHG Roadmap (36% by 2025 and 60% by 2030). The Commission must also ensure that industrial sector emissions (including those from oil and gas fuel combustion equipment) are reduced by 20% from the 2015 baseline by 2030. These revisions ensure that the state meets its statutory goals. These revisions to Regulation Number 22 will, taking into account other relevant laws and rules (including the revisions to Regulation Number 7 adopted as part of this rulemaking action), as well as voluntary actions taken by local communities and the private sector, achieve the state's GHG reduction goals through 2030 for the oil and gas industry. The revisions include protections for disproportionately impacted communities that ensure reductions of pollutants other than GHGs, additional requirements for monitoring and leak detection and repair, and improve the state's current emission inventory reporting program in Regulation Number 7, Part D.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 22, and includes the technological and scientific rationale for the adoption of the revisions.

The Commission recognizes that a task force on Carbon Capture, Utilization, and Storage (CCUS) has been convened as part of the GHG Roadmap implementation, with a report to the Governor due in January 2022. The Roadmap recognizes CCUS may play an important role over a longer time horizon in meeting the HB 19-1261 targets, but that uncertainties make modeling CCUS contributions difficult at this time. The Commission encourages the Division to evaluate ways to incorporate GHG emission reductions generated from CCUS projects into existing or contemplated regulatory programs such as the fuel combustion program or the GHG intensity program discussed.

Definitions: Sections III.A. and IV.A.

In Sections III.A. and IV.A., the Commission included several defined terms from Regulation Number 7 and intends that the same terms have the same meaning in both regulations unless otherwise specified (i.e., unless the regulation states that a term is defined specifically for purposes of that regulation). The Commission intends that terms used in Sections III. or IV., even if only defined in one of those Sections, have the same meaning.

The Commission defined both the midstream segment and the upstream segment of the oil and gas industry. The upstream segment is not intended to necessarily be co-extensive with the use of the term "exploration and production operations" in Regulation Number 7. The Commission recognizes that there is some "compression" undertaken at well production facilities, and intends that those operations are part of the upstream segment, not the midstream segment (even if they would otherwise fall under the gathering and boosting segment as that term is used in the EPA's Greenhouse Gas Reporting Program). The Commission directs the Division to consider how centralized oil facilities, such as those receiving hydrocarbon liquids from tankless well production facilities, should be classified for purposes of these programs. The Commission has also defined the oil and natural gas compression segment to reflect the above; to clarify, if equipment is operated by the upstream operator at a well production facility, the equipment is not part of the oil and natural gas compression segment.

However, if an emission point is located at a well production facility but operated by a midstream operator, that emission point is part of the oil and natural gas compression segment.

The Commission has defined “disproportionately impacted community” consistent with the definition in HB 21-1266. However, the statute does not call out which communities are considered disproportionately impacted. CDPHE is developing a tool, called “enviroscreen”, that will be utilized for members of the public and the regulated community to understand which communities in Colorado are disproportionately impacted. However, this tool was not ready at the time of this rulemaking. Therefore, the Commission has determined that the disproportionately impacted communities existing at the time of this program - and therefore the communities in which provisions of this program apply - are identified in the map. The Commission has included, in the definition of this term, a reference to the climate equity data map at which more detail can be seen of the boundaries of the disproportionately impacted communities addressed by this rulemaking. The Commission has also referenced a list of the census block groups by 12-digit FIPS code covered by the map incorporated into the definition, identifying what census blocks are disproportionately impacted communities as of the date of this rulemaking. The Commission intends that the Division will preserve a copy of the map and the accompanying list in place at the time of this rulemaking such that sources may use the map and list as a guide for understanding the applicability of requirements.

The Commission added the definition of natural gas processing segment, which is intended to mirror the applicability of sources reporting to EPA in the Greenhouse Gas Reporting Rule, 40 CFR Part 98, as the natural gas processing segment.

The Commission added a definition of “preproduction emissions” and “production emissions”. It is the intent of the Commission that all emissions from the well, wellhead equipment (both permanent and temporary), the well production facility, and the piping between the wellhead and the well production facility – everything “upstream” of the midstream segment – are accounted for in one of these two definitions.

Midstream Steering Committee for Fuel Combustion Equipment: Part B, Section III.

The Commission recognizes that emissions from midstream fuel combustion equipment are a significant portion of the midstream segment’s greenhouse gas emissions. Emissions from fuel combustion equipment covered by this program include not only the carbon dioxide emissions, but also the methane and other greenhouse gases from that same equipment. For example, “methane slip” from engines, meaning the methane that is not combusted and that escapes unburnt into the atmosphere, is included in this program. The Commission also recognizes that reducing emissions from fuel combustion equipment, particularly as it involves electrification of large combustion equipment, will need to be carefully coordinated to ensure the continued reliability of Colorado’s power grid. As a result, the Commission established the Midstream Steering Committee to develop guidance for operators on how to develop each operator’s company-specific emission reduction plan, addressing the mechanisms and timetable for reducing greenhouse gas from fuel combustion equipment.

The Commission adopted minimum requirements for participation on the steering committee. To the extent that more than one representative of a disproportionately impacted community participates on the steering committee, the Commission intends that more than one disproportionately impacted community would be represented. Recognizing that the Commission does not have the authority to require participation by the Colorado Energy Office or Public Utilities Commission staff but that their participation will be valuable, the Commission intends that the Division include them on the steering committee if they are willing.

The rules adopted by the Commission mandate that midstream segment owners and operators submit certain specified information to the steering committee by July 31, 2022. This information must include an identification of all fuel combustion equipment owned or operated by each midstream segment operator. There is no de minimis equipment that should not be identified, though not all equipment may end up in the operator’s ERP or the segment ERP.

This information should also allow the steering committee to easily understand what equipment - and how much emissions - are located within disproportionately impacted communities. Owners and operators must all include an estimate of the total annual power demand required for use of all midstream combustion equipment owned or operated by each midstream segment operator. When reporting this estimate, the owners and operators should identify whether such equipment is required to run continuously or whether operation of certain equipment is intermittent or interruptible. Owners and operators are also required to seek an estimate of existing transmission and/or distribution capacity to serve the estimated electric load (i.e. total power demand) at the specific locations of the midstream segment fuel combustion equipment, and provide that information to the steering committee. Transmission and/or distribution capacity should be obtained from the appropriate electric utility, transmission, or distribution service provider and reported to the steering committee when made available by the utility or utilities. Owners and operators should evaluate whether their midstream segment fuel combustion equipment operations require firm or non-firm transmission service. Should an owner or operator consider potential electrification, the Commission intends the owner or operator will continue to engage with the appropriate electric utility, transmission, or distribution service provider.

If the midstream steering committee determines that it needs additional information, it may request it from the midstream segment operators. The rules provide that such additional information should be requested by April 30, 2022; however, this does not limit the Division's authority to use existing statutes and regulatory authority to require the submittal of additional information to the Division. The Division must preserve trade secrets and other confidential business information, if provided to the Division, as required by the Colorado Open Records Act. The Commission intends that the midstream steering committee work with electric utilities as well as regulatory agencies that have the information in publically available files. To the extent the midstream steering committee seeks voluminous information available from the PUC, the Commission encourages the midstream steering committee to first seek to obtain such information from the PUC directly. The Commission intends the electric utilities work collaboratively with the midstream steering committee to assist the committee in locating and, if necessary, clarifying such information. The Commission does not intend that the Division will provide, or that the steering committee will seek confidential or trade secret information from utilities, such as pricing information. The Commission intends that the electric utilities will work collaboratively with the midstream steering committee to assist the steering committee in locating and, if necessary, clarifying requested information.

The Division will provide the steering committee with the 2015 baseline for industrial greenhouse gas emissions, from which the midstream segment needs to achieve a twenty-percent (20%) reduction by 2030. While the Commission intends that reductions should be achieved as quickly as possible, the Commission does not demand a linear reduction in emissions between 2025 and 2030. Further, the emissions reductions considered in this 20% reduction requirement include only emissions from the fuel combustion equipment in the Industrial Sector of the GHG Roadmap. Emissions from the power sector (generally referred to as "Scope 2 emissions") that could result from electrification of midstream fuel combustion equipment, are considered under another portion of the GHG Roadmap.

The midstream steering committee will prepare a guidance document (or series of documents) to help midstream segment owners and operators in preparing their own company-specific emission reduction plans. The guidance document is not intended to be an independent analysis of electric grid availability or a forecast of available resources; it is designed to assist operators in identifying the issues they must consider when preparing their company ERPs. The Commission has asked that utilities participate on the midstream steering committee to help inform the issues that must be addressed in considering electrification as an emission reduction strategy, but this committee is not designed to perform independent analysis such as that performed by individual operators, utilities, or the PUC. The Commission intends that the guidance document will specify methods for calculating emissions from fuel combustion equipment, and that the Division must approve of the calculation methods before they can be included in the guidance.

Specifically, the Commission directs the Division to evaluate calculation methods used in the annual emission reports to the Division under Regulation Number 7, Part D, Section V., compare those with methods used to report to the U.S. EPA under the greenhouse gas reporting program and other available calculation methods, and determine the appropriate methods to be used by operators. The Commission expects consistency in the calculation and reporting methods used by operators, as much as practicable. The Commission directs the Division to ensure that midstream steering committee work product, like the guidance document, is translated into Spanish and made available with the draft guidance. The Commission also intends that the Division hold public meetings to receive feedback on the midstream steering committee work production (both the guidance and the midstream segment ERP), and that notice of these meetings be made at least thirty (30) days prior and that the notice and agenda be translated into Spanish.

Operators must submit company emission reduction plans to the steering committee in accordance with the requirements of Section III.D.4. and containing the information specified in the guidance and regulation. The Commission intends that the Division will prepare emission reduction requirements for any midstream owner or operator that does not timely submit its company ERP; however, if a company ERP is submitted late, the Division may nonetheless approve of inclusion of that company ERP into the segment ERP.

The Commission structured the rule such that the midstream steering committee submits a proposed regulatory package - with supporting analysis - to the Division instead of directly to the Commission. The Commission intends that the Division will review the steering committee's proposal, and use its independent judgment as to whether the proposal will ensure compliance with the requirements of § 25-7-105(1)(e)(XIII), C.R.S. - i.e. achieves a 20% reduction in CO2e from the 2015 baseline - for the midstream segment. The midstream segment emission reduction plan submitted by the Division to the Commission will therefore be based on the segment-wide emission reduction plan developed by the midstream steering committee, but will consider the public comments received and the Division's evaluation of whether the steering committee's emission reduction plan will achieve the state's goals for CO2 reductions from midstream segment fuel combustion equipment.

Upstream Greenhouse Gas Intensity: Part B, Section IV.

In these revisions, the Commission has set targets for greenhouse gas intensity that step-down over time to achieve the GHG reductions required of upstream segment operations to meet the requirements of HB 21-1266. There is currently no regulatory greenhouse gas intensity program in the United States of which the Commission is aware. However, there are a number of voluntary programs, including ONE Future, the Natural Gas Sustainability Initiative, etc. Multiple Colorado operators are already participating in voluntary methane intensity programs.

While this program is new from a regulatory standpoint, the Commission feels it is an important program to guarantee - as much as possible - the emissions reductions needed from oil and gas upstream operations to meet the requirements of HB 21-1266. The Commission has adopted many regulations specific to oil and gas operations since 2005, including several since 2019 that are still in the process of being implemented. The regulations already adopted, in conjunction with other laws and regulations and the new direct regulations being adopted in this same rulemaking process in Regulation Number 7, Part D, will all provide the necessary emissions reductions. If existing and new measures are still not enough to ensure the emission reduction targets are met, this intensity program will require additional enforceable emission reduction actions from operators above their intensity targets. The Commission believes that the direct regulations adopted as part of this rulemaking along with those adopted and still being fully implemented will achieve or very nearly achieve the emission reductions required, and this intensity program will create an enforceable mechanism to ensure that any remaining required reductions are realized.

Notwithstanding the foregoing, in the event that the annual emissions inventories or other data collected by the Division reveals that the intensity program is not achieving the reductions necessary to achieve either the state's 2025 or 2030 greenhouse gas goals for these sectors, the Commission directs the Division to - consistently with the requirements of § 25-7-105(1)(e)(VII), C.R.S. - propose requirements that include additional direct regulation.

The Commission intends that the same operator that accounts, in the intensity program, for the production under Section IV.D. and the emissions in the intensity calculation, is the operator that accounts for the emissions under Regulation Number 7 reporting requirements. For the purposes of this intensity program, this operator is referred to as the “Intensity operator,” as defined in Regulation Number 22, Section IV.A.12.

Calculating Intensity

The Commission, for consistency across Colorado operations, determined that in converting natural gas production to barrels of oil equivalent, owners and operators should use the conversion factor of 5800 standard cubic feet of natural gas per barrel of oil equivalent. To clarify the calculation for intensity, which requires use of oil and natural gas production in thousand barrels of oil equivalent (kBOE), as well as the common units used for reporting natural gas production of million standard cubic feet (MMscf), operators should divide natural gas production reported in MMscf by 5.8 MMscf/kBOE. The equation for calculating total production in kBOE is:

TP (kBOE) = [NGP (MMscf)/5.8 (MMscf/kBOE)] + [OP (bbl)/1000 (bbl/kBOE)]

Where:

TP (kBOE) = total annual production of natural gas and oil in the units of kBOE

NGP(MMscf) = annual natural gas production in the units of million standard cubic feet

OP (bbl) = annual oil production in the units of barrels of oil

The Commission set greenhouse gas intensity targets to cover all preproduction emissions and production emissions from upstream oil and gas operations. The intensity program covers emissions in both the “Industrial” sector and the “Oil and Gas” sector in the GHG Roadmap. The Commission recognizes that these sectors have different statutory targets for GHG reductions; the “Industrial” sector must meet a 20% reduction from the 2015 baseline by 2030, and the “Oil and Gas” sector must meet a 36% reduction from the 2005 baseline by 2025 and a 60% reduction from the 2005 baseline by 2030. The Commission adopted the projected throughput from the GHG Roadmap inventory work for purposes of setting these targets. However, the Commission understands that some stakeholders may sponsor a study of production forecasts to further inform and refine the established intensity targets. The Commission is willing to consider the results of such a study, and directs that the Division consider the results of any such study in the 2023 verification rulemaking (as discussed) and propose updating targets as appropriate.

The Commission determined that it was appropriate to set more stringent intensity targets for the larger producers in the state (i.e., “majority producers”), than for the smaller producers (i.e., “minority producers”). The threshold set by the Commission for determining majority producers was based on accounting for the operators representing at least 80% of the state’s oil and natural gas production. The Commission recognizes that the smaller producers - that largely operate wells with declining production - have less opportunity to reduce intensity than the larger operators. However, the Commission does not intend that older facilities with declining production should just be permitted to operate with ever-increasing intensities, and directs the Division to study a potential facility-specific maximum allowable intensity and propose it as part of the 2023 verification rulemaking, if appropriate.

Acquisitions

The Commission adopted provisions providing how to adjust operator-specific reduction requirements upon the occurrence of asset transfer or other business realities. The Commission does not intend that operators may meet their greenhouse gas intensity targets simply by selling low-performing facilities, and the provisions for sales and acquisitions are designed to ensure both statewide emission reductions and greenhouse gas intensity targets are achieved. Generally, if an owner or operator sells its interest in a well or facility at some point during a calendar year, the owner or operator will report the production and emissions for the time period of its ownership, and the purchasing entity will report the production and emissions for the time period of its ownership, triggered by the closing date of the transaction. However, because majority and minority operators have different targets, the Commission clarifies how those situations should be addressed.

First, if a majority operator acquires assets from a minority operator, the majority operator would have some time before the acquired assets would be subject to the majority operator intensity targets. During the year of the acquisition, the majority operator need only demonstrate that the emissions and production from the acquired assets meet the minority operator targets – for the time period subsequent to the date of closing of the transaction. However, in the calendar year after the acquisition, the majority operator would include the emissions and production from the acquired assets in its company-wide intensity calculation and need to meet the majority operator targets. Second, if a minority operator acquires assets from a majority operator, for the year of and the year following the acquisition, those assets need to meet the minority operator target for the acquired assets and would be included in the company-wide intensity calculation subject to the minority operator target. Under these situations, the Commission recognizes that there may be limited reasons why some additional time could be necessary. The Commission encourages operators to timely reach out to the Division if more time is required, and for the Division to work with operators that demonstrate equivalent or better emission reductions would be achieved. However, the timing of the acquisition itself, or the failure to conduct environmental due diligence prior to the acquisition, are not such limited reasons that the Commission intends the Division use its discretion to accept.

If, at any point, a minority operator has production over 10,000 kBOE, or if a minority operator increases its production by 2,500 kBOE over the prior calendar year production - then in the calendar year after the acquisition, the minority operator would become a majority operator and be subject to those targets (and other rules applicable to majority operators). Otherwise, if a minority operator acquires assets (or merges with) a minority operator, the minority targets must be met in the year of the acquisition for all assets, including the acquired assets. If a majority operator sells assets, the majority operator targets must still be met, even if that operator’s production falls below 10,000 kBOE. If a new to market operator acquires the assets of a minority operator, the new to market operator becomes a minority operator and the minority operator targets apply; similarly, if a new to market operator acquires the assets of a majority operator, the majority operator targets apply.

New Facility Intensity

The Commission also determined that it was necessary to set a “new facility intensity” target, to recognize that operators of new well production facilities must continue to improve their performance, and reduce GHG emissions associated with new production. The Commission relied upon studies of intensity at oil and gas operations to determine that a new facility GHG intensity should be approximately 78.5% of the majority operator greenhouse gas intensity target. These new facility targets are in addition to the majority operator/minority operator targets in Section IV.B. So, a majority operator who constructs a new well production facility in 2027 must meet: (1) the greenhouse gas intensity target in Section IV.B.3.a. for all its upstream segment operations including the newly constructed well production facility (and subsequent majority operator targets in Section IV.B.); (2) the new facility intensity target in Section IV.C.3. for calendar year 2027 for the newly constructed well production facility; and (3) the new facility intensity target in Section IV.C.4. for calendar year 2028 for the newly constructed well production facility.

Greenhouse Gas Intensity Plans

In Section IV.E, the Commission requires that owners or operators submit greenhouse gas intensity plans. The primary purpose of these plans is for owners or operators to demonstrate to the Division how they intend to meet the 2025, 2027, and 2030 greenhouse gas intensity targets in Sections IV.B.2. through IV.B.4. The Commission determined to require submittal of site-specific plans that identify at which sites emission reductions will be achieved to ensure that the greenhouse gas intensity targets are met, all the way through the 2030 targets. The Commission intends that operators be permitted to update their plans after submittal, but the greenhouse gas intensity plan in effect must always demonstrate that the targets will be achieved. The Commission is also requiring annual verifications identifying what actions were taken, consistent with the plans. In addition to annual verifications to the intensity plans, the Commission has required submittal of asset transfer plan updates specific to any assets a company purchases. These assets transfer plans are to ensure that operators do not purchase high-intensity sites from another operator without making any improvements to those sites that would have been made if the sites had not been transferred. The Commission adopted this requirement to protect the integrity of the program and ensure emission reductions are realized as expected.

Verification

In Section IV.F., the Commission directs the Division to develop a mechanism to track progress towards meeting the state’s GHG reduction goals and to evaluate compliance with the greenhouse gas intensity targets and new facility intensity targets in Sections IV.B. and IV.C. The Commission determined that it was advisable to give the Division time in 2021 and 2022 (1) to evaluate the annual emission reports submitted in 2021 and 2022, (2) to evaluate different calculation and emission quantification methodologies for different emitting activities and equipment, and (3) to consider the impact and results of the aerial and ground-based survey work being conducted by the Division (and contractors) in 2021 (because this data will not be fully available until the spring of 2022) as well as other relevant surveys.

In 2023, the Commission expects that the Division will propose a verification plan after considering the current status of oil and gas GHG emissions, based on Regulation Number 7 reporting and top-down monitoring results, production increases or decreases based on data reported to the OGCC, the aerial and ground-based survey work, and other important considerations, such as the availability, reliability, and cost-effectiveness of direct measurement techniques as appropriate. This 2023 rulemaking may also address other aspects of the intensity program, including evaluating progress towards the reduction targets for oil and gas in § 25-7-105(1)(e)(XII).

<u>Disproportionately Impacted Communities</u>

The Commission recognizes the critical need for emission reductions - and in particular emission reductions of GHG co-pollutants - within disproportionately impacted communities. The Commission also included the definitions of “co-benefits” and “harmful air pollutants.” These terms are used in Sections III. and IV. to ensure that the midstream segment emission reduction plan and operators’ greenhouse gas intensity plans achieve and prioritize reductions of co-pollutants in disproportionately impacted communities. In Section III., the Commission has included a requirement that operators prioritize and quantify reductions of co-pollutants within disproportionately impacted communities in their ERPs. In Section IV, the Commission required that greenhouse gas intensity plans identify the facilities in disproportionately impacted communities and demonstrate how co-pollutant emission reductions will be prioritized therein. The Commission is further requiring that annual verifications to intensity plans demonstrate that emission reductions were prioritized in disproportionately impacted communities, and must quantify the reductions of harmful air pollutants. The Commission intends that where the same or similar technological and economic considerations apply to reductions that can be achieved in a disproportionately impacted community or elsewhere, as it pertains to determining at which facilities or which activities to reduce emission, reductions within disproportionately impacted communities must be prioritized over other GHG reduction options. The 2023 verification rulemaking may also include regulatory provisions addressing how the Division will evaluate compliance with the requirement to prioritize reductions in disproportionately impacted communities.

The Commission also directs the Division to work with the Environmental Justice Unit at CDPHE to ensure access to GHG Intensity Plan information – and the impact of GHG Intensity Plans on DI Communities – by the residents of those communities. The Commission has also included, in related revisions to Regulation Number 7, Part D, Section VI., a direction that the Division report out on these issues to the Commission on an annual basis.

Incorporation by Reference

The Commission will update regulatory references as needed as opportunities arrive.

Additional Considerations

The following are additional findings of the Commission made in accordance with the Act:

§ 25-7-110.5(5)(b), C.R.S.

As these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) Any federal requirements that are applicable to this situation with a commentary on those requirements;

There are no federal regulations applicable to the situations covered by the provisions of Part B, Sections III and IV. However, there are existing federal regulations that seek to identify and reduce methane emissions from the oil and gas industry, such as the Greenhouse Gas Reporting Program (40 CFR Part 98) and New Source Performance Standards (30 CFR Part 60) Subparts KKK, OOOO, and OOOOa. Part B, Sections III and IV do not conflict with any applicable current federal regulations. The EPA will soon release proposals to address greenhouse gas emissions from oil and gas equipment, but EPA's proposal does not address the particular situations addressed by the Commission's revisions here.

EPA also asks states to consider environmental justice as part of their actions, though there are no specific regulatory requirements at this time. In this revision, Part B, Sections III and IV expand on environmental justice considerations by incorporating the definition of "disproportionately impacted communities" (DI Community), and seeking to prioritize reductions in DI communities.

(II) Whether the applicable federal requirements are performance-based or technology-based and whether there is any flexibility in those requirements, and if not, why not;

The federal requirements addressing methane reductions from the oil and gas sector (though not applicable in this situation) as described are both performance-based and technology-based. Current federal requirements for methane reductions speak to achieving a control efficiency, with minimal flexibility. Some requirements also mandate the use of technology to detect methane emissions. However, EPA does provide some flexibility in the technology that can be used.

(III) Whether the applicable federal requirements specifically address the issues that are of concern to Colorado and whether data or information that would reasonably reflect Colorado's concern and situation was considered in the federal process that established the federal requirements;

There are federal requirements that seek to reduce greenhouse gas from oil and gas operations, though none that are addressed to the specific goals of Part B, Sections III and IV. The Commission's revisions address Colorado-specific requirements and needs, like those of HB 19-1261 and HB 21-1266, which were not considered in any federal process.

(IV) Whether the proposed requirement will improve the ability of the regulated community to comply in a more cost-effective way by clarifying confusing or potentially conflicting requirements (within or cross-media), increasing certainty, or preventing or reducing the need for costly retrofit to meet more stringent requirements later;

The proposed midstream and upstream programs will ensure that the regulated community can achieve required GHG emissions reductions in cost-effective ways by giving covered entities options to reduce emissions through direct regulation and development of company-specific plans to ensure compliance with state targets.

(V) Whether there is a timing issue which might justify changing the time frame for implementation of federal requirements;

This is a state-specific rule that is not implementing federal requirements. Thus, no timing issue exists.

(VI) Whether the proposed requirement will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth;

The regulatory provisions allow a reasonable amount of time for affected entities to comply with the new revisions. As such, affected businesses or industrial sectors are afforded a reasonable margin for accommodation of uncertainty and future growth.

The rules adopted by the Commission establish a new midstream steering committee to assist in analyzing the technical feasibility and economic reasonability of future means of reducing emissions in this segment. The midstream steering committee will prepare a guidance document (or series of documents) to help midstream segment owners and operators in preparing their own company-specific emission reduction plans, thus allowing for additional time to achieve compliance. The upstream intensity program also accommodates uncertainty, by allowing for an additional year (at least) to consider and develop a verification program.

(VII) Whether the proposed requirement establishes or maintains reasonable equity in the requirements for various sources;

With respect to any sources already operating within the upstream segment, the rule establishes reasonable equity because it takes into account the size of the operator, the percentage of ownership each operator claims, and the location of the facility. With respect to any new well production facilities subject to the upstream statewide intensity program requirements, the rule establishes reasonable equity as requirements are the same for each source type based on age of the production well. This is also demonstrated for the midstream segment with the establishment of the midstream steering committee to ensure equity across operators based on location and utility provider.

(VIII) Whether others would face increased costs if a more stringent rule is not enacted;

The Commission believes that the cost of inaction would be greater to industry and the public than the costs associated with the revisions to Part B, Sections III. and IV. Not only with respect to the social cost of climate change, but also more direct costs. These revisions are designed with the maximum flexibility for the regulated community. Under HB 21-1266, if the state is not on track to achieve the emission reduction goals, the Commission must adopt further regulations to achieve those goals. Future efforts are likely to be not as cost-effective as the flexible programs in these revisions.

(IX) Whether the proposed requirement includes procedural, reporting, or monitoring requirements that are different from applicable federal requirements and, if so, why and what the “compelling reason” is for different procedural, reporting, or monitoring requirements;

Reporting requirements beyond those required under federal Part 98 are necessary to effectively quantify and measure Colorado’s progress toward statewide GHG reductions and to achieve the public health, safety, and welfare goals set forth in § 25-7-102, C.R.S. Many of the reporting requirements associated with these programs are in existing Commission regulations, in Regulation Number 7, Part D. However, these revisions do require some additional reporting. Under these requirements, owners and operators of these sources will be required to compile and report directly to the Division information collected by or available to them for business or other regulatory purposes. While this may overlap with some other federal reporting requirements, it is expected there will be reporting beyond what is required federally.

(X) Whether demonstrated technology is available to comply with the proposed requirement;

Demonstrated technology exists to enable compliance with the requirements of these revisions.

(XI) Whether the proposed requirement will contribute to the prevention of pollution or address a potential problem and represent a more cost-effective environmental gain;

These revisions will cost-effectively reduce statewide GHG emissions to meet the legislative directive of the State Air Act, as revised by SB 19-181, HB 19-1261, and HB 21-1266. As noted, the General Assembly has acknowledged that climate change impacts Colorado’s economy and directed that GHG emissions should be reduced across the many sectors of our economy. Colorado has established specific GHG reduction goals within its statutes. Programs established in this rulemaking action - in both Regulation Numbers 7 and 22 - provide mechanisms for GHG reductions to occur cost-effectively across a specific, high-emitting sector of the state’s economy.

(XII) Whether an alternative rule, including a no-action alternative, would address the required standard.

The new regulatory requirements and amendments are needed to achieve the statutorily mandated emission reductions. As noted, the State Air Act requires the Commission to implement GHG emission reduction strategies in order to secure reductions of pollution consistent with the statewide GHG emission reduction goals. Currently emissions projections over the next decade demonstrate that a no-action alternative would fall short of achieving Colorado’s reduction goals. Additionally, no alternative combination of sector-specific regulations has been identified that is sufficient to meet the state’s GHG emissions reductions goals.

Findings of Fact

To the extent that § 25-7-110.8, C.R.S., 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 greenhouse gas and VOC emissions.

(III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

(IV) The rules are the most cost-effective alternative to achieve the necessary reduction in air pollution and provide the regulated entity flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

V. Adopted: July 21, 2022

Revisions to Regulation Number 22, Part B, Sections II.B.19. and II.B.25.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103, C.R.S., et seq., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-110 and 25-7-110.5, C.R.S., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

The Commission has incorporated by reference Regulation Number 22, Greenhouse Gas Emissions and Energy Management for Manufacturing in Colorado, Part B, Section II.B.19. and Part B, Section II.B.25. These sections shall be modified for the limited purpose of removing the incorporation by reference sentence in Part B, Section II.B.19. and Part B, Section II.B.25. This correction does not change or alter the requirements of the existing rule.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, §§ 25-7-105(1)(b) and 25-7-109, C.R.S. authorize the Commission to adopt emission control regulations, including emission control regulations relating to new stationary sources, for the development of an effective air quality control program.

Purpose

Updating citation references of 40 C.F.R. Part 60 allows the Division to implement and enforce the Emission Guidelines and Compliance Times for applicable source categories. Adoption of the rules will not impose additional requirements upon sources beyond the minimum required by federal law and may benefit the regulated community by providing sources with up-to-date information and regulatory certainty.

VI. Adopted: November 18, 2022

Revisions to Regulation Number 22, Part C.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-101, C.R.S., et seq., the Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 C.C.R. §1001-1.

Basis

During the 2021 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes through Senate Bill 21-264 (SB 21-264) (Concerning the adoption of programs by gas utilities to reduce greenhouse gas emissions, and, in connection therewith, making an appropriation) that directed, among other things, the Commission to adopt rules establishing recovered methane protocols for coal mines, biomethane, and gas system leaks. §§ 25-7-105(1)(e)(X.4)-(X.8), C.R.S.; *see also* § 40-3.2-108, C.R.S.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act, § 25-7-101, C.R.S., et seq. (the State Air Act or the 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 § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act provides the Commission broad authority to regulate air pollutants, including GHG and its constituent gasses (particularly carbon dioxide, methane, and nitrous oxide).

Pursuant to § 25-7-105(1)(e)(X.4), the Commission must, by February 1, 2023, adopt rules establishing recovered methane protocols for coal mines, biomethane, and gas system leaks and a crediting and tracking system for recovered methane.

Purpose

In response to SB 21-264, the Commission adopted recovered methane protocols for biomethane, coal mine methane, and gas system leaks. These protocols must be used for gas distribution utilities to take credit for the greenhouse gas emission reductions from the recovered methane projects in the utility's clean heat plan. Accordingly, the Commission also adopted a crediting and tracking system for recovered methane.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Clean Heat Plans

Through SB 21-264, the Colorado General Assembly required gas distribution utilities and municipal gas utilities to develop and implement clean heat plans that demonstrate projected reductions in methane and carbon dioxide emissions at the lowest reasonable cost. § 40-3.2-108(2)(b), C.R.S. Requirements for submission of clean heat plans differ between gas distribution utilities with more than ninety thousand retail customers, small gas distribution utilities with ninety thousand or fewer retail customers, and municipal gas distribution utilities with ninety thousand or more retail customers. *See* § 40-3.2-108, C.R.S.; and see § 25-7-105(1)(e)(X.8), C.R.S.

Gas distribution utilities with ninety thousand or more retail customers must file with the Public Utilities Commission (PUC) clean heat plans that will reduce carbon dioxide and methane emissions from the distribution and end-use combustion of gas to meet specified clean heat targets relative to a 2015 baseline. In 2025, the clean heat plans must reduce emissions at least four percent in 2025, of which no more than one percent can be from recovered methane, and twenty-two percent in 2030, of which no more than five percent can be from recovered methane. § 40-3.2-108(3)(b)(II), C.R.S. The largest gas distribution utility in the state, Xcel Energy, must file its clean heat plan with the PUC no later than August 1, 2023 and all other gas distribution utilities must file clean heat plans with the PUC no later than January 1, 2024. These first plans must demonstrate that the clean heat plan will accomplish the 2025 clean heat targets.

Small gas distribution utilities, those with ninety thousand or fewer retail customers, may elect to file with the PUC clean heat plans accomplishing the same clean heat targets as the larger gas distribution utilities or, alternatively, may submit a small utility emission reduction plan. *See* § 40-3.2-108(9), C.R.S. These clean heat plans would be subject to the same clean heat targets as those for larger gas distribution utilities. *Id*. In a small utility emission reduction plan, the utility can set its own emission reduction targets. *Id*.

The PUC has opened a rulemaking proceeding, No. 21R-0449G, to adopt rules governing clean heat plans gas distribution and small gas distribution utilities no later than December 1, 2022. § 40-3.2-108(5)(b), C.R.S.

A municipal gas distribution utility, being a municipally owned utility that provides gas service to more than ninety thousand customers, must submit its clean heat plan to the Division no later than August 1, 2023. § 25-7-105(1)(e)(X.8)(C), C.R.S. Like the other utilities, a municipal gas distribution utility's clean heat plan must reduce emissions at least four percent in 2025, of which no more than one percent can be from recovered methane, and twenty-two percent in 2030, of which no more than five percent can be from recovered methane. *Id*.

All clean heat plans, whether submitted to the PUC or Division and whether mandatory or voluntary, may incorporate clean heat resources that can include recovered methane in order to accomplish the emissions reductions needed for the pertinent clean heat target. *See* § 40-3.2-108(2)(c), C.R.S. (defining "clean heat resource" to include recovered methane); *see also* § 40-3.2-108(4)(c), C.R.S. (describing clean heat portfolio requirements). The use of recovered methane in these portfolios is a limited, but potentially critical aspect of utilities successfully accomplishing clean heat targets. Accordingly, the Commission through these regulations is adopting robust recovered methane protocols that will rigorously evaluate any recovered methane projects before awarding credits that can be used towards clean heat plan compliance and is establishing a crediting and tracking system that will enable efficient and effective accounting and exchange of recovered methane credits.

Recovered Methane Protocol Selection

The proposed recovered methane protocols were selected with input from the public as well as members of the recovered methane technical work group. The technical work group members were selected based on technical expertise for the specific subgroups (gas distribution system leaks, coal mine methane, and biomethane) and environmental justice expertise. Subgroups included representation from academia, industry, utilities, environmental groups, and local governments. Members of the public could also attend the technical work group meetings and provide written comments throughout the process. Technical work group meetings were held on ten occasions between January and July 2022. The technical work groups considered various project types and protocols to satisfy the statutory directives set forth in SB21-264, including international Clean Development Mechanism protocols, California Air Resource Board (CARB) protocols and American Carbon Registry (ACR) protocols, among others, before making recommendations on those to be proposed to this Commission. Public stakeholder meetings regarding the recovered methane protocols were also held on three occasions in June of 2022 along with a presentation to the Climate Equity Advisory Council.

The gas distribution system leaks subgroup consisted of representatives from Colorado State University, Geosyntec, Xcel Energy, Black Hills Energy, Atmos Energy, Colorado Springs Utilities, Summit Utilities, Radicle, Western Resource Advocates, Southwest Energy Efficiency Project, International Brotherhood of Electrical Workers, and the City and County of Denver.

The coal mine methane capture subgroup consisted of representatives from Geosyntec, Delta Brick, Environmental Commodities Corporation, Energy Smart Solutions, Radicle, Environmental Defense Fund, Colorado Springs Utilities, Colorado Mining Association, Peabody Energy, Colorado State University, Xcel Energy, and the City and County of Denver.

The biomethane subgroup consisted of representatives from Western Resource Advocates, Radicle, Natural Resource Defense Council, Colorado Dept of Agriculture, Sheldon Kye Energy, Metro Water Recovery, Black Hills Energy, Colorado Springs Utilities, Ramboll, Renewable Natural Gas Coalition, Camco International, Xcel Energy, City and County of Denver, and Summit Utilities.

Pursuant to § 40-3.2-108(2)(p), C.R.S., recovered methane protocols must: specify relevant data collection and monitoring procedures and emission factors; account for uncertainty, activity-shifting leakage risks, and market-shifting leakage risks associated with a type of recovered methane project; determine data verification requirements; and specify procedures for approving entities accredited for verification of ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements. In satisfaction of these requirements, the Commission has adopted the following recovered methane protocols:

Biomethane from manure management systems - The Commission has selected the “Compliance Offset Protocol Livestock Projects” adopted by CARB on November 14, 2014 to quantify GHG emission reductions or GHG removal enhancements for biomethane recovered from manure management systems. This protocol meets the requirements in the statutory definition of “recovered methane protocol” by clearly identifying data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture methane from manure management systems. Chapter 5 of the protocol lays out methods and equations to quantify greenhouse gas emission reductions from a project, including establishing the project baseline, and Appendix A has the emission factors to be used in the quantification methodology. Chapter 6 specifies the data collection and monitoring procedures of the protocol. The protocol also includes an additionality evaluation component found in Chapter 3 (Eligibility). The protocol addresses uncertainty by having rigorous data collection and monitoring procedures and includes a methodology for data substitution if necessary as found in Appendix B. The protocol also has a verification requirement in Chapter 8 that requires a CARB accredited offset verification body to verify all GHG reductions or GHG removal enhancements from a livestock manure management systems project.

Methane derived from municipal solid waste - The Commission has selected Version 2.0 of the “Landfill Gas Destruction and Beneficial Use Projects” methodology (April 2021; Errata & Clarification October 25, 2022) issued by ACR to quantify GHG emission reductions or GHG removal enhancements for methane derived from municipal solid waste. This protocol meets the requirements in the statutory definition of “recovered methane protocol” by clearly identifying data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture methane from municipal solid waste. Chapter 3 of the protocol summarizes how to make a baseline determination and perform an additionality assessment for the project. Chapter 4 lays out methods and equations to quantify greenhouse gas emission reductions from the project and addresses leakage issues, which the protocol indicates does not apply to landfill gas projects. Appendix B has the emission factors to be used in the application of the protocol. Chapter 5 specifies the data collection and monitoring procedures of the protocol. The protocol addresses uncertainty by having rigorous data collection and monitoring procedures. Validation and verification requirements for use of the protocol and confirming the GHG reductions or GHG removal enhancements from a municipal solid waste methane recovery project will be met by a body or organization accredited under the Accreditation Program for Greenhouse Gas Validation/Verification Bodies (GHGVVB) of the ANSI National Accreditation Board (ANAB) as required under Part C, Section I.C.7.a. All bodies accredited under GHGVVB to perform verification services for a specific project type utilizing an ACR protocol or methodology are acceptable to ACR so long as ACR’s requirements and approval to conduct verification for the specific project type have also been met (see exhibit “ACR VV Standard_V1.1_May 31 2018” and ACR Validation and Verification requirements at https://americancarbonregistry.org/carbon-accounting/verification/verification).

Methane derived from wastewater treatment - The Commission has selected Version 2.1 of the “Organic Waste Digestion Protocol” (January 16, 2014; Errata and Clarifications November 1, 2018) issued by the Climate Action Reserve (CAR) to quantify GHG emission reductions or GHG removal enhancements for methane derived from wastewater treatment. This protocol meets the requirements in the statutory definition of “recovered methane protocol” by clearly identifying data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture methane from wastewater treatment. Chapter 5 of the protocol lays out methods and equations to be used in order to quantify greenhouse gas emission reductions from a project, including establishing the project baseline, and Appendix B has emission factors to be used in the quantification methodology. Chapter 6 specifies the data collection and monitoring procedures of the protocol. The protocol addresses uncertainty by incorporating baseline and project uncertainty factors into its calculation methodologies. The protocol also includes an additionality evaluation component found in Chapter 3 (Eligibility Rules) and a verification requirement in Chapter 8. Verification requirements for use of the CAR protocol and confirming the GHG reductions or GHG removal enhancements from a wastewater treatment methane recovery project will be met by a body or organization accredited under the Accreditation Program for GHGVVB of the ANAB as required under Part C, Section I.C.7.a.

All bodies accredited under GHGVVB to perform verification services for a specific project type utilizing a CAR protocol are acceptable to CAR so long as CAR's requirements to conduct verification for the specific project type have also been met. CAR will conduct validation of projects that use its protocols. As the CAR protocol applies only to certain wastewater treatment facilities, Section I.C.4.a., also provides that Facilities or operations that exclusively accept or rely on livestock manure must use CARB's "Compliance Offset Protocol finalized on November 14, 2014 because this protocol is specific to that type of operation. Per Part C, Section I.C.7.b., verification under the CARB protocol must be completed by an entity accredited by CARB for this type of project.

The Commission also adopted a novel protocol for domestic wastewater treatment facilities using anaerobic digesters at Section I.C.4.b. This protocol is necessary because it is the practice and regulatory expectation in Colorado that such facilities capture and either control or use methane from anaerobic digesters, irrespective of any recovered methane program. However, to the extent that a facility elects to deliver methane it captures for use instead of on-site destruction, the Commission recognizes that there is an additional GHG emission reduction benefit that should qualify for a recovered methane credit based on the recovered methane not being destroyed on-site through flaring and instead displacing use of geological gas supplied by a gas utility. The protocol established in Section I.C.4.b. meets the requirements in the statutory definition of "recovered methane protocol" by clearly identifying data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture methane from domestic wastewater treatment facilities using anaerobic digesters. The protocol clearly establishes the project baseline, identifies data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture methane from domestic wastewater treatment facilities using anaerobic digesters. Project baselines are determined pursuant to Section I.C.4.b.(i) and Section I.C.4.b.(ii) sets out the means of assuring emissions reductions are additional. Data collection, monitoring procedures, and emission factors are addressed in Section I.C.4.b.(iii) through I.C.4.b.(vi). As the emissions savings from this type of project are based entirely on combusting recovered methane instead of geological gas in an end-use and therefore focused on methane combustion, the procedures and methodologies set forth in Subpart NN of 40 CFR Part 98, governing GHG emissions reporting from suppliers of natural gas and natural gas liquids, are sufficiently analogous to use for this protocol. Thus, the Commission incorporates by reference the applicable provisions of Subpart NN for this protocol. Data verification requirements and minimizing uncertainty in the emission reductions are addressed in Section I.C.4.b.(vi). There, the Division recommends incorporating the existing monitoring, quality assurance and quality control requirements, and data reporting in 40 CFR §§ 98.404-406 as appropriate means of quantifying emissions reductions from these facilities insofar as they are applicable to the emissions calculation provisions of 40 CFR § 98.403. The third-party verification process will confirm that the protocol requirements were followed to establish emission reductions. The Division will work with ANAB to establish validation standards to be followed for the protocol.

Coal mine methane - The Commission has selected Version 1.1 of the "Capturing and Destroying Methane from Coal and Trona Mines in North America" methodology (August 2022) issued by the American Carbon Registry (ACR) to quantify GHG emission reductions or GHG removal enhancements for coal mine methane. This protocol meets the requirements in the statutory definition of "recovered methane protocol" by clearly identifying data collection and monitoring procedures, emission factors, and data verification requirements for projects that capture coal mine methane. Chapter 5 of the protocol lays out methods and equations to quantify greenhouse gas emission reductions from a project, including establishing the project baseline, and Appendix A has the emission factors to be used in the quantification methodology. Chapter 6 specifies the data collection and monitoring procedures of the protocol. The protocol addresses uncertainty by having rigorous data collection and monitoring procedures. The protocol also includes an additionality evaluation component found in Chapter 3 (Eligibility) and has a verification requirement in Chapter 7.

Verification requirements for use of the protocol and confirming the GHG reductions or GHG removal enhancements from a coal mine methane project will be met by a body or organization accredited under the Accreditation Program for GHGVVB of the ANAB as required under Part C, Section I.C.7.a. All bodies accredited under GHGVVB to perform verification services for a specific project type utilizing an ACR protocol or methodology are acceptable to ACR so long as ACR's requirements and approval to conduct verification for the specific project type have also been met.

Gas distribution system leaks - The Division's review of available gas distribution system leak accounting approaches did not identify any published protocols that quantified system leakage for purposes of creating recovered methane credits as described in §§ 40-3.2-108 and 25-7-105(1)(e)(X.4), C.R.S. Hence, the Division proposes a novel protocol in Section I.C.6. In order to verify additionality and for recovered methane credits to be issued, individual repaired leaks must not be part of the utility's required leak detection and repair procedures and emissions reduced must be quantified following written procedures in Part C, Section I.C.6. The written procedures must identify the measurements and other data required to be collected in order to quantify the mass emissions of methane, the processes and instrumentation used to collect the data, and the quality assurance requirements necessary to ensure accurate measurements from the instrumentation for each leak. Section I.C.6.a.(ii)(C) sets out the requirements for confirming that a leak is repaired and no longer emitting gas. Section I.C.6.a.(ii)(C)(1) provides the parameters that an applicant's procedure must satisfy to confirm leak repairs and is intended to allow reasonable flexibility while ensuring certainty that emissions reductions from repaired leaks are real and verified. As used in Section I.C.6.a.(ii)(C)(2), the detection sensitivity of equipment or techniques used for post-repair verification must be at least as capable of detecting emissions from the repaired equipment as that which was used for initial measurement. As recognized in Section I.C.6.a.(ii)(C)(3), certain leaks may be mitigated by removing the equipment or component permanently from the gas distribution system, in which case a post mitigation measurement is not possible. The Division will review and approve the proposed methodologies in the written procedures submitted by the company and the third-party verification process will confirm that the written procedures were followed and that all data required in the procedures was collected. The Division will work with ANAB to establish validation standards to be followed for the protocol.

Double-counting of emissions reductions in a Clean Heat Plan filing is avoided because any referenced methods utilized in a gas utility's projected future emissions cannot also generate recovered methane credits under this program. Any utility applying for credits under Section I.C.6. must certify that any leak repairs for which credits are sought are not included as part of the system planning baseline and projected emissions in a proposed or approved Clean Heat Plan. The Division may confirm this by reviewing the applicant's Clean Heat Plan. Conversely, it is the Commission's understanding of the Public Utilities Commission's rules in 4 Colo. Code. Regs. 723-4 that emissions changes in a proposed or approved Clean Heat Plan resulting from revised federal reporting requirements or advanced leak detection and repair obligations enacted by the Colorado Public Utilities Commission or other regulatory agency are included as part of the Clean Heat Plan baseline and projected emissions and not as a clean heat resource for which recovered methane credits are required to be utilized. Finally, this recovered methane protocol does not have activity- or market-shifting leakage risks as the methane is already in the distribution pipeline.

Under Sections I.C.2.b., I.C.3.b., I.C.4.c., and I.C.5.b., project developers or operators are required to account for any vehicular emissions from the delivery of recovered methane to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado. Vehicle fuel use attributable to delivery under these provisions is to include any vehicle fuel consumed for travel to or from the project site to retrieve or gather the recovered methane, for any gathering or collection activities, and travel to or from a project site for delivery of recovered methane to a dedicated pipeline, common carrier pipeline, or directly to an end user in Colorado.

The Commission has determined the protocols selected will not have activity- or market-shifting leakage risks as the recovered methane protocols are intended to spur and assist in the development of projects that reduce greenhouse gas emissions in Colorado but do not create an incentive for those utilizing the protocols to then undertake activities that increase greenhouse gas emissions outside Colorado.

As the Commission is incorporating by reference a number of existing protocols, the Commission is cognizant that future rulemakings will be necessary to update these incorporations. Likewise, the Commission recognizes that the landscape of greenhouse gas accounting, including recovered methane protocols, is ever-evolving and that additional protocols for additional recovered methane project types may be appropriate for future amendments to this Part C. As such, the Commission encourages the Division and stakeholders alike to monitor and evaluate developments in this field to ensure Colorado continues to employ best practices for assessing emissions reductions and assigning corresponding recovered methane credits, and to incorporate these new or updated protocols into these rules by written comment only rulemaking as appropriate.

One area of particular interest expressed by stakeholders is the possibility of Colorado adopting a single recovered methane protocol for all project types and the possibility to use a “life-cycle analysis” approach for assessing emissions reductions. Hence, any person or entity may submit to the Division an assessment of the benefits and costs associated with development and implementation of a single combined recovered methane protocol for determining credits for recovered methane projects from manure management systems, municipal solid waste, wastewater treatment, coal mine methane, and any other projects contemplated in SB 21-264 as applicable. Such assessment should include, but is not necessarily limited to, an assessment of a single combined recovered protocol that considers the life-cycle emission impacts of the project to recover methane from manure management systems, municipal solid waste, wastewater treatment, coal methane, and any other projects contemplated in SB 21-264 as applicable, as well as a life-cycle emission evaluation or methodology for the geological gas the recovered methane would be replacing. Any assessment shall evaluate the anticipated costs to the Division for implementing such a protocol instead of those adopted in this proceeding, as well address all requirements that apply to recovered methane protocols in SB 21-264. In order to facilitate a full evaluation of any such assessment, the entity should provide the Division a proposed framework for the assessment, including an outline of the evaluation of the benefits and costs that will be conducted as part of the assessment. The Division will evaluate any such framework within a reasonable time (with a goal of completing such evaluation within 90 days of receipt) and work with the person or entity developing the assessment. The Division will also ensure that any calculation methodologies for emissions intensity are consistent with all relevant calculation methodologies under air quality regulations, guidance, or policy. The entity may also provide the Division a draft of the assessment prior to finalization and the Division will provide feedback on the proposed draft within a reasonable time (with a goal of responding within 90 days of receipt). The Division may elect to submit such a proposal for a single recovered methane protocol to the Commission for adoption. Within 180 days of receiving the final assessment, the Division must notify the entity of whether it will submit a proposal to the Commission.

Procedures for Approving Entities Verifying GHG Reductions or Removal Enhancements

Consistent with § 40-3.2-108(2)(p), C.R.S., recovered methane protocols must “[s]pecify procedures pursuant to which the air quality control commission must approve an entity that the division proposes to accredit for verification of ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements.” The Commission has therefore required that all greenhouse gas reduction or removal enhancements be verified by an accredited third-party. See Part C, Section I.C.7.

The Commission has determined that any entity engaged to verify ongoing GHG emission reductions must, itself, be accredited to conduct such verification through the Accreditation Program for Greenhouse Gas Validation/Verification Bodies of the ANSI National Accreditation Board (ANAB), or for manure management system projects, be accredited by CARB for that project type.

ANAB accreditation for Greenhouse Gas Validation/Verification is a rigorous and extensive process in which applying bodies must demonstrate technical competency and implementation of applicable verification standards specific to greenhouse gas emissions. Namely, ANAB requires a verifying body to faithfully implement the most current version(s) of ISO 14065 required by ANAB for accreditation and to conduct verification. Currently, this includes ISO 14065:2013, Greenhouse gases - Requirements for greenhouse gas validation and verification bodies for use in accreditation or other forms of recognition, and ISO 14065:2020, General principles and requirements for bodies validating and verifying environmental information. ANAB is requiring that verification bodies or entities transition accreditation to ISO 14065:2020 before the end of June 2024. ANAB also requires technical competency and implementation of ISO 14064-3:2019, Greenhouse gases - Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, and ISO 14066:2011, Greenhouse gases - Competence requirements for greenhouse gas validation teams and verification teams, for validation bodies or entities, with ISO 14064-3: 2019 and 14066 being incorporated into ISO 14065 as normative references.

The application and accreditation process is explained here https://anab.ansi.org/greenhouse-gas-validation-verification/how-to-apply.

Once accredited, ANAB further requires ongoing surveillance of accredited entities and reassessment every three years. ANAB maintains a current list of accredited entities, which can be found here: https://anabpd.ansi.org/Accreditation/environmental/greenhouse-gas-validation-verification/AllDirectoryListing?prgID=200&statusID=4.

Requiring that recovered methane projects be verified by entities accredited through this robust, pre-existing program, the Commission intends to guarantee that recovered methane credits generated and used for clean heat plan compliance are real, additional, quantifiable, and verifiable. As of July 2022, there are 20 verifying bodies accredited under this program.

For projects for biomethane from manure management systems, which must use the “Compliance Offset Protocol Livestock Projects” adopted by CARB on November 14, 2014, the verifying body must be accredited through CARB for that project type. CARB’s accreditation program for greenhouse gas emissions is found at California Code of Regulations, Title 17, § 95132, and the provisions specific to its offset protocols that are relevant here are at California Code of Regulations, Title 17, § 95978.

A list of CARB-accredited verification bodies is available at: https://ww2.arb.ca.gov/resources/documents/accredited-offset-verification-bodies.

Should the Division or other stakeholders identify accreditation bodies or third-party verification programs that are deemed sufficiently rigorous in addition to those identified in this proceeding, the Division or any person or entity may petition the Commission to amend these rules accordingly.

Crediting and Tracking System

In conjunction with the protocols in Part C, Section I.C., the Commission established in Part C, Section 1.D.a. crediting and tracking system for recovered methane credits consistent with § 25-7-105(1)(e)(X.4), C.R.S. This system is currently limited in scope to recovered methane credits and their limited use in clean heat plan compliance under § 40-3.2-108(3), C.R.S., for gas distribution utilities and small gas distribution utilities, and § 25-7-105(1)(e)(X.4), C.R.S., for municipal gas distribution utilities. Recovered methane credits are not general purpose “GHG credits” that can be traded or used to meet GHG compliance obligations by “regulated sources,” as that term is defined in § 25-7-105(1)(f)(B), C.R.S. The recovered methane crediting and tracking system established in Part C, Section I.D. provides the exclusive forum for the trading of recovered methane credits generated through qualifying projects, verified through approved protocols, and used by utilities for clean heat plan compliance.

It is critical that credits are rigorously tracked to ensure the environmental attributes are not double-counted since once credits are issued, they become fully tradable until they are retired or otherwise expire.

Accordingly, the system functions in four phases: (1) registration, (2) project submission, (3) Division review and credit generation, and (4) credit trading, use/retirement, and expiration.

Registration - Under Part C, Section I.D.1.a., entities wishing to participate in the recovered methane crediting and tracking system must register with the Division and identify authorized users. Through the registration process, it is necessary that authorized users bind the entities they represent as they will be able to request the transfer of credits in the system.

Project Submission - Under Part C, Sections I.D.1.b. through I.D.1.i., I.D.3., and I.D.4., prior to the generation of any recovered methane credits, the Division must receive information sufficient to demonstrate that the applicant's project satisfied all statutory requirements and guarantee all emissions reductions or removal enhancements are real, additional, quantifiable, permanent, verifiable, and enforceable.

As set forth in Part C, Sections I.D.1.g. and I.D.3, applicants seeking credits for recovered methane projects for municipal solid waste and coal methane must first register with the ACR and establish credits in that system for the project. Then, in order for ACR credits to be used in Colorado's recovered methane tracking system, the applicant must cancel the ACR credits without using them and provide such evidence to the Division as part of its project submission. Pursuant to American Carbon Registry, *Requirements and Specifications for the Quantifications, Monitoring, Reporting, Verification, and Registration of Project-Based GHG Emissions Reductions and Removals* (Dec. 2020), to be eligible under ACR, new projects must be validated within two years of the project Start Date, with limited exceptions defined in the Standard.

Under Part C, Sections I.D.1.g. and I.D.4., the same process applies for applicants seeking credits for recovered methane projects for wastewater treatment for which credits must first be established at the Climate Action Reserve (CAR) Reserve Offset Program. Pursuant to the Version 2.1 of the "Organic Waste Digestion Protocol" (January 16, 2014; Errata and Clarifications November 1, 2018) at Section 3.2, to be eligible for registration with CAR, projects must be submitted to CAR no more than six months after the project start date.

And, under Part C, Sections I.D.1.g. and I.D.5. the same process also applies for applicants seeking credits for recovered methane projects for manure management systems if those projects are first registered in a registry outside of the recovered methane system.

For all projects, the recovered methane credit in the Colorado system must represent the attribute of one metric ton of carbon dioxide equivalent reduced using the 100-yr value from the IPCC's Fourth Assessment Report (AR). In addition to the requirements of the protocols specified under Section I.C., applicants must provide information sufficient to demonstrate that any project for which credits are sought meet the particular requirements of SB21-264 and this Part C.

One such requirement is a demonstration that the recovered methane project where emissions reductions are credited be physically located in Colorado. Though the Commission is aware that certain parties to this proceeding have advocated for allowing recovered methane credits to be generated from projects located outside of Colorado, the Commission has determined that only projects located inside Colorado are eligible for generating recovered methane credits. The Commission makes this determination to remain consistent with the General Assembly's direction that recovered methane means biomethane and methane derived from specified sources "that are located in Colorado and meet a recovered methane protocol approved by [this Commission]." § 40-3.2-108(2)(n), C.R.S.

Further, requiring that recovered methane projects be in Colorado is necessary to ensure that the emissions reductions realized through such projects and that the credits then utilized by gas utilities for clean heat plan compliance reflect reductions in statewide greenhouse gas emissions. While it is possible that SB21-264 could be interpreted differently and that reductions in greenhouse gas emissions outside of Colorado will also have the effect of slowing climate change, such a reading would fail to further Colorado's interests in reducing statewide greenhouse gas pollution towards the goals established by the General Assembly in § 25-7-102(2), C.R.S. and would therefore be contrary to the clearly stated legislative intent of SB 21-264. See § 40-3.2-108(1)(a), C.R.S. (citing the need to reduce greenhouse gas emissions from the built environment "in order to achieve Colorado's science-based greenhouse gas emission reduction goals and maintain a healthy, livable climate for Coloradoans").

Section I.D.1.e. requires an applicant to provide proof that recovered methane has been delivered to or within Colorado through a "dedicated pipeline" or "common carrier pipeline." SB 21-264 does not define "dedicated pipeline." Pursuant to feedback from parties to this proceeding, the Commission adopted a definition of "dedicated pipeline" at Section I.B.7. that aligns with the legislative intent to reduce GHG emissions in Colorado by replacing geological gas with recovered methane while broadly accounting for the practical realities of potential recovered methane projects in Colorado. This approach, sometimes referred to as a "virtual pipeline" allows for recovered methane to be transported in point-to-point pipelines, but also through other conveyances such as trucks. It would also allow direct delivery of the gas from the recovered methane project to the end user, without requiring that it be injected into a utility's distribution system so long as the project developer can demonstrate that but for the recovered methane, the end-user would be consuming geologic gas from a utility. To this end, the proof that recovered methane is replacing geological gas required under Section I.D.1.e.(i) is not intended to be an engineering or technical showing but rather a demonstration that recovered methane is serving a demand that would otherwise be fulfilled with geological gas. This could be satisfied with proof of delivery of the recovered methane to its end use, gas utility bills showing that the end use was formerly served by a gas utility, or similar showings.

Division Review and Credit Generation- upon receipt and verification of a complete submission under Part C, Section I.D.1., the Division will generate recovered methane credits for the project in the system. Sections I.D.1.e. through I.D.1.i. detail how the credits will be entered and tracked in the system in a manner that will avoid double-counting of credits. Further, these sections provide for a system that requires that recovered methane credits generated and used in the system are directly traceable to the specific project from which they were created. The Division will retain the ability to audit and evaluate all credit balances and generate reports that will be made publicly available.

Credit Trading and Use/Retirement and Expiration - As indicated in Part C, Section I.D.2.c., recovered methane credits are active and tradable for twelve months after they are generated. This is consistent with treatment of these credits as a clean heat resource in clean heat plans. See § 40-3.2-108(2)(c), C.R.S. ("To qualify as a clean heat resource, all credits or severable, tradable mechanisms representing the emission reduction attributes of the clean heat resource must be retired in the year generated and may not be sold."); see also § 40-3.2-108(7)(b) ("If a utility includes recovered methane, the utility shall quantify actual emission reductions achieved on a project basis for each project for which it claims reductions in that year, based on any recovered methane credits generated."). During this period, the credits in the system are fully tradable between and amongst registered entities. Within twelve months from generation recovered methane credits must be used and retired as a clean heat resource for clean heat compliance, *see* § 40-3.2-108(2)(c), C.R.S., otherwise they will expire and can no longer be used or traded.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference a code, standard, guideline, or rule that has been adopted by an agency of the United States, this state, or another state, or adopted or published by a nationally recognized organization or association. The criteria of § 24-4-103(12.5), C.R.S., 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 protocols, standards and reference methods incorporated in Regulation Number 22.

Additional Considerations

Section 25-7-110.5(5)(b), C.R.S.

To the extent these revisions exceed and may differ from the federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), C.R.S., the Commission determines:

(I) Any federal requirements that are applicable to this situation with a commentary on those requirements;

There are no federal requirements applicable to this situation. Furthermore, Part C establishes a fully voluntary, opt-in program therefore any part of the rule that “exceeds the requirements of the federal act or differs from the federal act or rules thereunder” would be voluntarily submitted to and not mandated by this rule.

(II) Whether the applicable federal requirements are performance-based or technology-based and whether there is any flexibility in those requirements, and if not, why not;

There are no federal requirements applicable to this situation.

(III) Whether the applicable federal requirements specifically address the issues that are of concern to Colorado and whether data or information that would reasonably reflect Colorado's concern and situation was considered in the federal process that established the federal requirements;

In SB 21-264, Colorado’s General Assembly found that “a significant source of [GHG] pollution from the built environment comes from the use of gas to heat Colorado’s homes and businesses and to heat water in those buildings, from the use of gas in the commercial and industrial processes, and from gas leaks in the supply chain.” § 40-3.2-108(a)(II), C.R.S. Further, the General Assembly determined that “there is significant potential to reduce emissions of methane from active and inactive coal mines, landfills, wastewater treatment plants, agricultural operations, and other sources of methane pollution through development of methane recovery and biomethane projects…” § 40-3.2-108(1)(b)(I), C.R.S. Hence, the General Assembly established clean heat plan requirements, while providing an option for utilities to use recovered methane as a clean heat resource to accomplish certain amounts of emissions reductions in those plans.

There are no federal requirements applicable to this situation.

(IV) Whether the proposed requirement will improve the ability of the regulated community to comply in a more cost-effective way by clarifying confusing or potentially conflicting requirements (within or cross-media), increasing certainty, or preventing or reducing the need for costly retrofit to meet more stringent requirements later;

The allowance for meeting clean heat targets through the use of recovered methane credits is explicitly made available to utilities as a means of more cost-effectively meeting those targets. See § 40-3.2-108(1)(b), C.R.S. The protocols identified for these recovered methane projects are already in use in other jurisdictions and therefore allow project developers to utilize existing resources, including the American Carbon Registry and Climate Action Reserve's existing registry systems. Furthermore, utilization of these protocols and the crediting and tracking system is entirely voluntary for utilities.

There are no federal requirements applicable to this situation nor any conflicting regulatory regimes that require clarification.

(V) Whether there is a timing issue which might justify changing the time frame for implementation of federal requirements;

There are no federal requirements applicable to this situation.

(VI) Whether the proposed requirement will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth;

The proposed regulation does not impose any mandatory requirements. Rather, it provides a system for regulatory flexibility for utilities to comply with clean heat targets through the use of recovered methane credits. The protocols and recovered methane crediting and tracking system adopted in this Part C inherently provide accommodation for uncertainty and future growth for utilities by providing a mechanism for achieving a portion of their clean heat targets irrespective of customer demand. For recovered methane project developers, there is no mandatory compliance requirement but the protocols and trading system are entirely scalable and therefore accommodate uncertainty and future growth.

(VII) Whether the proposed requirement establishes or maintains reasonable equity in the requirements for various sources;

The recovered methane protocols and crediting and tracking system in this voluntary, opt-in program are equitable for both project developers seeking to generate credits on the system and for utilities seeking to acquire and utilize those credits. Notably, Colorado's General Assembly determined that reducing emissions through recovered methane and biomethane projects provides "significant economic development opportunities, especially in rural Colorado[.]" § 40-3.2-108(1)(b)(I), C.R.S.

(VIII) Whether others would face increased costs if a more stringent rule is not enacted;

Arguably, the more stringent the requirements for recovered methane protocols or the more restrictive the crediting and tracking system would impose higher barriers to entry and potentially limit participation where it is not cost-effective. However, this itself would not increase costs but limit the cost-effectiveness of this voluntary, opt-in program.

(IX) Whether the proposed requirement includes procedural, reporting, or monitoring requirements that are different from applicable federal requirements and, if so, why and what the "compelling reason" is for different procedural, reporting, or monitoring requirements;

There are no federal requirements applicable to this situation.

(X) Whether demonstrated technology is available to comply with the proposed requirement;

Yes, both the recovered methane protocols and the crediting and tracking system are based on demonstrated and available technology.

(XI) Whether the proposed requirement will contribute to the prevention of pollution or address a potential problem and represent a more cost-effective environmental gain;

See responses to Items *(III)* and *(IV)* of this section.

(XII) Whether an alternative rule, including a no-action alternative, would address the required standard.

While the Commission had options in which recovered methane protocols to select and how to design the crediting and tracking system, it has done so leveraging existing and tested options where available. These rules are required under § 25-7-105(1)(e)(X.4), C.R.S., and a no-action alternative is not available.

Findings of Fact

To the extent that § 25-7-110.8, C.R.S., 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 greenhouse gas and VOC emissions.

(III) Evidence in the record supports the finding that the rules will 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 alternative to achieve the necessary reduction in air pollution and provide the regulated entity flexibility.

(V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Editor's Notes

History

New rule eff. 07/15/2020.

Rules Part A III.B, IV.C.1, V.A, Part B I.B.40-41, I.D.1.a, I.D.1.a.(ii), Part D II eff. 10/15/2021.

Rules Part B II, Part D III eff. 12/15/2021.

Rules Part B III, IV, Part D IV eff. 01/30/2022.

Rules Part B II.B.19, II.B.25, Part D V eff. 09/14/2022.

Rules Parts C-E, Part E VI eff. 01/14/2023.