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.govinfo.gov. 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		

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
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
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

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
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
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

Table 1: End-Use, Prohibited Substances, and Date of Prohibition		
Polyolefin	HFC-134a, HFC-245fa, HFC-365mfc, and blends thereof; Formacel TI, Formacel Z-6	January 1, 2021
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.

Table 2: Exemptions		
End-Use Category	Prohibited Substances	Acceptable Uses
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.
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. Removed and placed in Regulation Number 27 April 20, 2023.

III. Removed and placed in Regulation Number 7, Part B, Section VII. April 20, 2023.

IV. Removed and placed in Regulation Number 7, Part B, Section VIII. April 20, 2023.

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 (CO_2e) 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 (SF_6) 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.

Purpose

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.

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 occurred. 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.

<u>Additional Considerations</u>

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

<u>§ *25-7-110.5(5)(b), C.R.S*</u>*.*

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 CO2e in 2025 and 1.15 million metric tons CO2e 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. (Removed and placed in Regulation Number 27 April 20, 2023)

IV. (Removed and placed in Regulation Number 7 April 20, 2023.)

V. (Removed and placed in Regulation Number 27 April 20, 2023)

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.

<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).

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.

<u>Purpose</u>

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.

VII. Adopted: April 20, 2023

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

To improve the readability and usability of Regulation Number 7 and Regulation Number 22, the Commission adopted revisions restructuring and reorganizing the parts and sections.

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 § 25-7-103.3, directs rule-making agencies, such as the Commission, to review their rules and consider whether the rule is necessary; whether the rule overlaps or duplicates other rules of the agency or with other federal, state, or local government rules; whether the rule is written in plain language and is easy to understand; whether the rule has achieved the desired intent and whether more or less regulation is necessary; whether the rule can be amended to give more flexibility, reduce regulatory burdens, or reduce unnecessary paperwork or steps while maintaining its benefits; whether the rule is implemented in an efficient and effective manner, including the requirements for the issuance of permits and licenses; whether a cost-benefit analysis was performed by the applicable rule-making agency; and whether the rule is adequate for the protection of the safety, health, and welfare of the state or its residents. Based on this review, the rule-making agency will determine whether the existing rules should be continued in their current form, amended, or repealed.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 22.

The Commission reorganized Regulation Number 7 into four regulations: Part B became Regulation Number 24; Part C became Regulation Number 25; Part D remained in Regulation Number 7; and Part E became Regulation Number 26. The upstream oil and gas intensity and midstream combustion program provisions currently in Regulation Number 22 moved to Regulation Number 7. The manufacturing sector greenhouse gas provisions in Regulation Number 22 became a new Regulation Number 27.

The Commission also made typographical, grammatical, and formatting corrections throughout the regulations.

Incorporation by Reference

The Commission will update regulatory references as needed as opportunities arrive.

Additional Considerations

These revisions are administrative in nature and, therefore, do not exceed or differ from the requirement of the federal act or rules. Therefore, § 25-7-110.5(5)(a) does not apply.

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.