COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-4

PART 4
RULES REGULATING GAS UTILITIES

BASIS, PURPOSE, AND STATUTORY AUTHORITY.

The basis and purpose of these rules is to set forth the manner of regulation over jurisdictional gas utilities, the services they provide, and their actions to maintain just and reasonable rates, ensure system safety, reliability, and resiliency, protect disproportionately impacted communities, and reduce greenhouse gas emissions from the use of gas by their customers and from leaks in their facilities. These rules also set forth the manner of regulation over master meter operators. These rules address a wide variety of subject areas including, but not limited to, planning, expenditure and demand forecasting, cost and rate impacts, system safety and integrity planning, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, transportation service, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, gas service low-income programs, cost allocation between regulated and unregulated operations, recovery of gas costs, appeals regarding local government land use decisions, demand side management programs, the reduction of greenhouse gas emissions from the distribution and end-use consumption of gas, and authority of the Commission to impose civil penalties on public utilities. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-3-101, 40-3.2-103, 40-3.2-106, 40-3.2-107, 40-3.2-108, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-117, 40-7-113.5, 40-7-116.5; and 40-8.7-105(5), C.R.S.

GENERAL PROVISIONS

4000. Scope and Applicability.

(a) Absent a specific statute, rule, or Commission order which provides otherwise, all rules in this Part 4 (the 4000 series) shall apply to all jurisdictional gas utilities, gas master meter operators, and to all Commission proceedings concerning gas utilities and gas master meter operators.

(b) The scope and applicability rules regarding appeals of local government land use decisions are as stated in rule 4700.

4001. Definitions.

The following definitions apply throughout this Part 4, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

(a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.

(b) "Aggregated data" means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) or a compilation of customer data of one or more customers from which and personal information has been removed.

(c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.

(d) "Air Pollution Control Division" means the Air Pollution Control Division of the Colorado Department of Public Health and Environment established by § 25-1-102(2)(a), C.R.S.

(e) "Air Quality Control Commission" means the decision-making body within the Colorado Department of Public Health and Environment established by § 25-7-104, C.R.S., to oversee and promulgate the rules to administer Colorado's air quality programs.

(f) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).

(g) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.

(h) "Best value employment metrics" means additional labor metrics required to be obtained by a utility from bidders and contractors for a utility construction contract, specifically, the length and type of training and apprenticeship programs available to the workforce, the percentage of labor estimated to be Colorado residents as compared to out of-state workers, the number and type of long-term careers supported by the project, whether the workforce will be covered by a labor agreement, and the wage rates and health care and pension benefits, including employer pension contribution rates, provided to protect labor.

(i) "Biomethane" means:

(I) 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

(II) includes biomethane recovered from manure management systems or anaerobic digesters that has been processed to meet pipeline quality gas standards.

(j) "Commission" means the Colorado Public Utilities Commission.

(k) "Contracted agent" means any person that has contracted with a utility in compliance with rule 4030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).

(l) "Cubic foot" means, as the context requires.

(I) At Local Pressure Conditions. For the purpose of measuring gas to a customer at local pressure conditions, a cubic foot is that amount of gas which occupies a volume of one cubic foot under the conditions existing in the customer's meter as and where installed. When gas is metered at a pressure in excess of eight inches of water column gauge pressure, a suitable correction factor shall be applied to provide for measurement of gas as if delivered and metered at a pressure of six inches of water column gauge pressure. A utility may also apply appropriate factors to correct local pressure measurement to standard conditions.

(II) At Standard Conditions. For all other purposes, including testing gas, a standard cubic foot is that amount of gas at standard conditions which occupies a volume of one cubic foot.

(m) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.

(n) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility's service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.

(o) "Customer data" means customer specific information, excluding personal information as defined in paragraph 1004(x), that is:

(I) collected from the gas meter by the utility and stored in its data systems;

(II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or

(III) about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.

(p) "Dekatherm" (Dth) means a measurement of gas commodity heat content. One Dekatherm is the energy equivalent of 1,000,000 British Thermal Units (1 MMBtu).

(q) "Dedicated recovered methane 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 geologic gas supplied by a gas distribution utility or small gas distribution utility.

(r) "Design peak demand" refers to the maximum gas flow rate projected for a utility system, or a portion thereof, which is utilized by a utility for gas infrastructure capacity planning.

(s) "Disproportionately impacted community" means a geographic area defined pursuant to § 40-2-108(3)(d), C.R.S., and as may be further modified by Commission rule or order. Mapping of such geographic areas shall be conducted in accordance with the best available mapping tool developed by the Colorado Department of Public Health and Environment, until such time as a different practice is adopted by Commission rule or order.

(t) "Distribution system" means the utility-owned piping and associated facilities used to deliver gas to customers, excluding facilities owned by a utility that are classified on the books and records of the utility as production, storage, or transmission facilities.

(u) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(v) "Gas" means natural or geological gas; hydrogen, or recovered methane, or any mixture thereof transported by a common carrier or dedicated pipeline; flammable gas; manufactured gas; petroleum or other hydrocarbon gases including propane; or any mixture of gases injected into a pipeline and transmitted, distributed, or furnished by any utility.

(w) "Income-qualified utility customer" or "low-income customer" is a customer meeting the requirements of § 40-3-106(1)(d)(II), C.R.S.

(x) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure, 4 CCR 723-1.

(y) "Interruption" means a utility's inability to provide transportation to a transportation customer, or its inability to serve a sales customer, due to constraints on the utility's pipeline system.

(z) "Intrastate transmission pipeline" or "ITP" means generally any person that provides gas transportation service for compensation to or for another person in the State of Colorado using transmission facilities rather than distribution facilities and is exempt from FERC jurisdiction.

(aa) "Local distribution company" (LDC) means any person, other than an interstate pipeline or an intrastate transmission pipeline, engaged in the sale and distribution of gas for end-user consumption. A LDC may also perform transportation services for its end-use customers, for another LDC or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.

(bb) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.

(cc) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.

(dd) "Mandatory relocation" means a project to relocate the utility's gas infrastructure as required by a federal, tribal, state, county, or local governmental body.

(ee) "Main" means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service lateral.

(ff) "Mcf" means 1,000 standard cubic feet.

(gg) "MMBtu" means 1,000,000 British Thermal Units, or one Dekatherm.

(hh) “Natural gas” or “geological gas” means methane or other hydrocarbons that occur underground without human intervention and may be used as fuel.

(ii) “Non-pipeline alternative” means programs, equipment, or actions that avoid, reduce, or delay the need for investment in certain types of new gas infrastructure and may include energy efficiency, demand response, and beneficial electrification.

(jj) “Non-standard customer data” means all customer data that are not standard customer data.

(kk) "Past due" means the point at which a utility can affect a customer’s account for regulated service due to non-payment of charges for regulated service.

(ll) "Pipeline system" means the utility-owned piping and associated facilities used in the transmission or distribution of gas.

(mm) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.

(nn) “Pressure district” means a localized area within a utility’s service territory whereby an established minimum and maximum pressure range is intended to be maintained and is distinct from neighboring regions.

(oo) “Property owner” means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of real property is located to determine ownership of government record.

(pp) “Pyrolysis” means the thermochemical decomposition of material at elevated temperatures without the participation of oxygen.

(qq) “Recovered methane” means any of the following that are located in the State of Colorado and meet the recovered methane protocol approved by the Air Quality Control Commission: biomethane; methane derived from municipal solid waste, the pyrolysis of municipal solid waste, biomass pyrolysis or enzymatic biomass, or wastewater treatment; coal mine methane as defined in § 40-2-124(1)(a)(II), C.R.S, the capture of which is not otherwise required by law; or methane that would have leaked without repairs of the gas distribution or service pipelines from the city gate to customer end use.

(rr) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission, presented on a tariff sheet, or contained in a tariff of the utility.

(ss) "Sales customer" or “full service customer” means a customer who receives sales service from a utility and is not served under a utility’s gas transportation service at that same meter.

(tt) "Sales service" means a bundled gas utility service in which the utility both purchases gas commodity for resale to the customer and delivers the gas to the customer.

(uu) "Security" includes any stock, bond, note, or other evidence of indebtedness.

(vv) "Service lateral" means that part of a distribution system from the utility’s main to the entrance to a customer’s physical location.

(ww) "Standard conditions" means gas at a temperature of 60 degrees Fahrenheit and subject to an absolute pressure equal to 14.73 pounds per square inch absolute.

(xx) “Standard customer data” means customer data maintained by a utility in its systems in the ordinary course of business.

(yy) "Standby capacity" means the maximum daily volumetric amount of capacity reserved in the utility's system for use by a transportation customer, if the customer purchased optional standby service.

(zz) "Standby supply" means the daily volumetric amount of gas reserved by a utility for the use by a transportation customer should that customer's supply fail, if the customer purchased optional standby service.

(aaa) “Third party” means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting on the customer’s behalf, a regulated utility serving the customer, or a contracted agent of the utility.

(bbb) "Transportation" means the exchange, forward-haul, backhaul, flow reversal, or displacement of gas between a utility and a transportation customer through a pipeline system.

(ccc) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.

(ddd) “Unique identifier” means customer’s name, mailing address, telephone number, or email address that is displayed on a bill.

(eee) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff, and are for service or merchandise not required as a condition of receiving regulated utility service.

(fff) "Utility" means a public utility as defined in § 40-1-103, C.R.S., providing sales service or transportation service (or both) in Colorado. This term includes both an ITP and a LDC.

(ggg) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(hhh) “Whole building data” means the sum of the monthly gas use for either all service connections at a building on a parcel of real property or all buildings on a parcel of real property.

4002. Applications.

(a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):

(I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 4100;

(II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 4101;

(III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 4102;

(IV) amendment of a certificate of public convenience and necessity to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 4103;

(V) transfer a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 4104;

(VI) approval of the issuance or assumption of any security, or to create a lien pursuant to § 40-1-104, C.R.S., as provided in rule 4105;

(VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 4106;

(VIII) amendment of a tariff on less than statutory notice, as provided in rule 4109;

(IX) approval of a meter sampling program, as provided in rule 4304;

(X) approval of a refund plan, as provided in rule 4410;

(XI) approval of a Low-Income Energy Assistance Plan, as provided in rule 4411;

(XII) approval of a cost assignment and allocation manual, as provided in rule 4503;

(XIII) approval of a gas infrastructure plan, as provided in rule 4552;

(XIV) approval of a clean heat plan, as provided in rule 4729 or 4734;

(XV) approval of a gas demand side management plan, as provided in paragraph 4752(e) and rule 4753, or for determinations on demand side management strategic issues, as provided in rule 4761;

(XVI) appeal of a local government land use decision, as provided in rule 4703; or

(XVII) any other matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.

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[indicates omission of unaffected rules]

4005. Records.

(a) Except as a specific rule may require, every utility shall maintain, for a period of not less than four years, and shall make them available for inspection at its principal place of business in Colorado during regular business hours, the following:

(I) records concerning disputes, which records are created pursuant to rule 4004;

(II) complete records of tests to determine the heating value of gas, which records are created pursuant to rule 4202;

(III) records concerning interruptions and curtailments of service, which records are created pursuant to rule 4203;

(IV) transportation request logs, which records are created pursuant to paragraph 4205(e);

(V) notices of rejected transportation requests, which records are created pursuant to paragraph 4206(c);

(VI) transportation agreements created pursuant to rule 4206;

(VII) all distribution pressure records, and all records or charts made with respect to rule 4208, appropriately annotated;

(VIII) meter calibration records created pursuant to under rule 4303;

(IX) records concerning meters, which records are created pursuant to rules 4305 and 4306;

(X) customer billing records, which records are created pursuant to paragraph 4401(a);

(XI) customer deposit records, which records are created pursuant to rule 4403;

(XII) records and supporting documentation concerning its cost assignment and allocation manual and fully-distributed cost study pursuant to paragraphs 4503(g) and 4504(e), for so long as the manual and study are in effect or are the subject of a complaint or a proceeding before the Commission;

(XIII) the total gas transported under each transportation service in Mcf or MMBtu and the associated total revenue;

(XIV) records concerning gas infrastructure plans, pursuant to rules 4550 through 4555;

(XV) records concerning clean heat plans, pursuant to rules 4725 through 4734;

(XVI) records concerning demand side management, pursuant to rules 4750 through 4761; and

(XVII) as applicable, the records and documents required to be created pursuant to rules 4910 through 4920.

(b) A utility shall maintain at each of its local offices and at its principal place of business all tariffs filed with the Commission and applying to Colorado rate areas. Current and complete tariffs shall also be available on a utility's website in a section that is easily navigable and clearly marked.

(c) A utility shall maintain its books of account and records in accordance with the provisions of 18 C.F.R. Part 201, the Uniform System of Accounts. A utility shall maintain its books of accounts and records separately and apart from those of its affiliates.

(d) A utility shall preserve its records in accordance with the provisions of 18 C.F.R. Part 225, the Preservation of Records of Public Utilities and Licensees.

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[indicates omission of unaffected rules]

OPERATING AUTHORITY

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[indicates omission of unaffected rules]

4102. Certificate of Public Convenience and Necessity for Facilities.

(a) A utility seeking authority to construct and to operate a facility, or an extension or expansion of a facility, pursuant to § 40-5-101, C.R.S., shall file an application in accordance with this rule. The utility shall apply to the Commission for issuance of a certificate of public convenience and necessity for approval of construction and operation of a facility, or an extension or expansion of a facility, which is not in the ordinary course of business.

(b) For a utility with 500,000 full-service customers or more, the utility shall apply to the Commission for issuance of a certificate of public convenience and necessity for construction and operation of a facility, or an extension or expansion of a facility, where the total utility capital investment value is greater than $12 million in 2020 dollars, unless the utility has already received approval by the Commission pursuant to paragraph 4555(c).

(c) For a utility with more than 50,000 full-service customers but less than 500,000 customers, the utility shall apply to the Commission for issuance of a certificate of public convenience and necessity for construction and operation of a facility, or an extension or expansion of a facility where the total utility capital investment value is greater than $10 million in 2020 dollars, unless the utility has already received approval by the Commission pursuant to paragraph 4555(c).

(d) For any utility with less than 50,000 full-service customers, the utility shall apply to the Commission for issuance of a certificate of public convenience and necessity for construction and operation of a facility, or an extension or expansion of a facility where the total utility capital investment value is greater than $5 million in 2020 dollars, unless the utility has already received approval by the Commission pursuant to paragraph 4555(c).

(e) The cost thresholds set forth in paragraphs (b) through (d) above shall be adjusted for inflation annually on March 1 of each year, based upon the annual percentage change in the United States Bureau of Labor Statistics Consumer Price Index – Denver-Aurora-Lakewood as published by the Colorado Department of Local Affairs for the immediately preceding calendar year. These adjustments shall be compounded annually. For reference, the Commission will post a notice on its website, https://puc.colorado.gov/, by March 15 of each year reporting the annual inflation adjustments applicable pursuant to this paragraph.

(f) An application for issuance of a certificate of public convenience and necessity to construct and to operate facilities, or an extension or expansion of a facility, pursuant to § 40-5-101, C.R.S., shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the information required in rule 4002;

(II) a statement of the facts (not conclusory statements) relied upon by the applying utility to show that the public convenience and necessity require the granting of the application or citation to any Commission decision that is relevant to the proposed facilities;

(III) the project category, consistent with the categories defined in subparagraph 4553(a)(III), or otherwise identified and justified by the utility;

(IV) a description of the general scope of work and an explanation of the need for the proposed facilities, including any applicable U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration code requirements for the facilities;

(V) the projected life of the proposed facilities;

(VI) the anticipated construction start date, construction period, with any phases indicated, and the expected in-service date for the proposed facilities;

(VII) relevant technical details, such as physical equipment characteristics of the proposed facilities, pipeline length, pipeline diameter, project material(s), and maximum allowable operating pressure;

(VIII) the estimated total cost and annual incremental revenue requirements of the proposed facilities, assuming both conventional depreciation and accelerated depreciation as applicable;

(IX) a cost estimate classification using the utility's or an industry-accepted cost estimate classification index, and explanation and support of methodology;

(X) the project location and an illustrative map of the proposed facilities that shows (subject to necessary and appropriate confidentiality provisions), which includes:

(A) the pressure district or geographic area that requires the proposed facilities;

(B) the existing and proposed regulator stations and existing and proposed distribution piping and higher capacity pipelines served by or representing the proposed facilities;

(C) whether the facilities will be located in any disproportionately impacted community;

(D) identification of the electric utility service provider(s); and

(E) any other information necessary to allow the Commission to make a thorough evaluation of the application.

(XI) to the extent practicable, the number of customers, annual sales, and design peak demand requirements, by customer class, directly impacted or served by the proposed facilities;

(XII) if the proposed facilities are located in a disproportionately impacted community, a description of:

(A) the nature of the utility's outreach to members of that disproportionately impacted community, as appropriate to the filing;

(B) the communications and materials employed; and

(C) the findings from those outreach efforts.

(XIII) identification of any permit(s) required to begin work;

(XIV) a description of the environmental requirements associated with completion of the proposed facilities, if any;

(XV) the change in projected utility-wide greenhouse gas emissions due to the proposed facilities, as calculated relative to the utility's most recently approved clean heat plan greenhouse gas emission forecast or subsequent interim-year update, in accordance with subparagraphs 4731(a)(I) and 4731(c)(I) or 4733(a)(VI), as applicable; and

(XVI) for proposed facilities meeting the definition of a new business project or a capacity expansion project, as defined in subparagraphs 4553(a)(III)(B) and (C), the utility shall also present an analysis of alternatives including non-pipeline alternatives, costs for those alternatives, and criteria used to rank or eliminate such alternatives.

(A) An analysis of alternatives shall consider, at a minimum:

(i) one or more applicable clean heat resources consistent with the utility's most recently approved clean heat plan, pursuant to rule 4732, demand side management plan, pursuant to rule 4753, or beneficial electrification plan, as applicable;

(ii) a cost-benefit analysis including the costs of direct investment and the social costs of carbon and methane for emissions due to or avoided by the alternative, and other costs determined appropriate by the Commission; and

(iii) available best value employment metrics associated with each alternative, as defined in paragraph 4001(h), including a projection of gas distribution jobs affected by the alternative and jobs made available through the alternative, opportunities to transition any affected gas distribution jobs to the alternative, pay and benefit levels of the affected gas distribution jobs and the jobs available through a transition opportunity, and how employment impacts associated with each alternative could affect disproportionately impacted communities.

(B) An analysis of alternatives shall include, at a minimum:

(i) the technologies or approaches evaluated;

(ii) the technologies or approaches proposed, if applicable;

(iii) the projected timeline and annual implementation rate for the technology or approaches evaluated;

(iv) the technical feasibility of the alternative assuming full adoption of the technologies and approaches evaluated; and

(v) the utility's strategy to implement the technologies or approaches evaluated.

(XVII) For proposed facilities meeting the definition of a system safety and integrity project, as defined in subparagraph 4553(a)(III)(A), the utility shall provide the risk ranking and detailed information regarding the utility's risk ranking methodology including, but not limited to, the material, age, maximum allowable operating pressure, density of surrounding residences and businesses, and any other physical and operating characteristics relevant to the risk ranking of the proposed facilities and the risk ranking methodology. The utility must also identify, explain, and provide the output to any risk-related models developed or employed by the utility in conducting risk analyses to support planned system safety and integrity projects.

(g) A separate certificate of public convenience and necessity is not required for mandatory relocations of a utility's gas infrastructure.

(h) In accordance with subparagraph 4552(d)(II), the utility may satisfy the requirements of rule 4210 in an application submitted pursuant to the Gas Infrastructure Planning Rules.

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[indicates omission of unaffected rules]

FACILITIES

4200. Construction, Installation, Maintenance, and Operation.

The gas plant, equipment, and facilities of a utility shall be constructed, installed, inspected, maintained, and operated in accordance with accepted engineering and gas industry practices to assure continuity of service, uniformity in the quality of service, and the safety of persons and property.

4201. Instrumentation.

A utility purchasing or receiving gas for transportation services shall install, or shall require the interconnecting pipeline to provide, such instruments or meters as may be necessary to furnish information detailing the quantity and quality of gas received into its system as necessary to maintain measurement accuracy and acceptable gas quality.

4202. Heating Value, Purity, and Pressure.

(a) A utility shall establish and maintain in its tariffs a minimum heating value for its gas, expressed in British Thermal Units per standard cubic foot. The minimum heating value shall be no less than the monthly average gross heating value of gas supplied by the utility in any given service area. No deviation below this minimum shall be permitted. The utility shall determine the heating value of gas by testing gas taken from such points on the utility's system and at such test frequencies as are reasonably necessary for a proper determination. The utility shall maintain records of tests conducted to determine the heating value of gas. The results of these tests shall be stated in terms of standard conditions.

(b) A change in minimum heating value shall require an appropriate adjustment, if any, to rates.

(c) The utility shall ensure that the gas it supplies, if from multiple sources or if the supply from a single source changes in composition, is interchangeable for safe and efficient use. The utility shall ensure that gas from new supply sources or from supply sources which the gas composition has changed is interchangeable with the gas it currently supplies. The utility shall evaluate interchangeability by means of one of the following:

(I) use of test results which establish that the gas supplied to the end-user falls within an acceptable range and which take into account the heating value, specific gravity, and composition of the gas;

(II) use of actual appliances to determine acceptability; or

(III) use of a standard in the natural gas industry.

(d) A utility shall promptly readjust its customers' appliances and devices as necessary to render proper service if the readjustment is required for safe and efficient use in accordance with paragraph (c) of this rule. Unless otherwise ordered by the Commission, a readjustment made pursuant to this paragraph shall be done at no charge to the customer. If a utility determines that a readjustment pursuant to this paragraph is necessary, the utility shall notify the Commission, in writing, of the readjustment and of the reason for the readjustment.

(e) A utility whose gas delivery exceeds 20 million cubic feet per annum shall test the heating value of gas at least once each week, unless the utility purchases or receives gas on a heat value basis or unless the interconnecting pipeline provides the utility with a record of the heating value of the gas delivered and the interconnecting pipeline's tests are made at least once each week.

(f) All gas supplied to customers shall be substantially free of impurities which may cause corrosion of facilities or which may form corrosive or harmful fumes when burned in a properly-designed and properly-adjusted burner.

(g) A LDC shall deliver gas at a pressure of six inches water column, plus or minus two inches water column, measured at the meter outlet, unless operating conditions require a higher delivery pressure. If a higher pressure is required, the utility shall require the customer to install appropriate pressure regulating equipment in the customer's lines, if necessary.

(h) A utility shall monitor distribution pressure as follows.

(I) In a distribution system serving 100 or fewer customers, the utility shall semi-annually check distribution pressures by indicating gauges at the district regulator station or other appropriate point in the distribution system.

(II) In distribution system serving more than 100 and fewer than 500 customers, the utility shall provide at least one recording pressure gauge or telemetering pressure device at the pressure regulating station or at some other appropriate point in the distribution system.

(III) In a distribution system serving 500 or more customers, the utility shall maintain one or more additional recording pressure gauges or telemetering pressure devices and shall make frequent 24-hour records of the gas pressure prevailing at appropriate points in the system.

(i) In its tariff, a utility shall include a description of test methods, equipment, and frequency of testing used to determine the quality and pressure of gas service furnished.

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[indicates omission of unaffected rules]

4210. Line Extension.

(a) A utility shall have tariffs which set out its line extension policies, procedures, and conditions.

(b) In its tariff a utility shall include the following provisions for gas main extensions and service lateral extensions from its distribution system:

(I) the terms and conditions, by customer class, under which an extension will be made;

(II) provisions requiring the utility to provide to a customer or to a potential customer, upon request, service lateral connection information necessary to allow the customer's or potential customer's facilities to be connected to the utility's system;

(III) provisions requiring the utility to exercise due diligence in providing the customer or potential customer with an estimate of the anticipated cost of a connection or extension; and

(IV) provisions addressing steps to ameliorate the rate and service impact upon existing customers, including stating in the tariff the procedures by which future customers would share costs incurred by the initial or existing customers served by a connection or extension (as, for example, by including the procedures by which a refund of customer connection or extension payments would be made when appropriate).

(c) Line extension policies, procedures, and conditions shall be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, including any costs associated with increases in design peak demand.

(d) Line extension allowances shall be updated pursuant to paragraph 4210(c) in a base rate proceeding, or in a separately filed application, as required, but should be implemented no later than December 31, 2024. If a utility utilizes standardized costs in calculating one or more portions of its line extension policies, the standardized costs must be updated in a base rate proceeding, utilizing the average actual cost across the applicable customer class and line extension type for the most recent consecutive 12-month period for which compiled cost data is available at the time it initiates a base rate proceeding. Exemptions from updated line extension allowances and standardized costs shall not extend to applications for line extensions submitted after May 1,2023, unless otherwise ordered by the Commission.

(e) Line extension policies, procedures, and conditions shall generally align with the greenhouse gas emission reduction goals established in § 25-7-102(2)(g), C.R.S.

4211. – 4299. [Reserved].

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[indicates omission of unaffected rules]

BILLING AND SERVICE

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[indicates omission of unaffected rules]

4409. Restoration of Service.

(a) Unless prevented from doing so by safety concerns, a utility shall restore, without additional fee or charge, any discontinued service which was not properly discontinued or restored as provided in rules 4407, 4408, and 4409.

(b) A utility shall restore service if the customer does any of the following:

(I) pays in full the amount for regulated charges shown on the notice and any deposit or fees as may be specifically required by the utility's tariff in the event of discontinuance of service;

(II) pays any reconnection and collection charges specifically required by the utility's tariff, enters into an installment payment plan, and makes the first installment payment, unless the cause for discontinuance was the customer's breach of such an arrangement;

(III) presents a medical certification, as provided in subparagraph 4407(e)(IV);

(IV) demonstrates to the utility that the cause for discontinuance, if other than non-payment, has been cured.

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[indicates omission of unaffected rules]

4411. Low-Income Energy Assistance Act.

(a) Scope and applicability.

(I) Rule 4411 is applicable to gas and combined gas and electric utility providers except those exempted under subparagraph (II) or (III) of this rule. Pursuant to §§ 40-8.7-101 through 111, C.R.S., utilities are required to provide an opportunity for their customers to contribute an optional amount through the customers' monthly billing statement.

(II) Municipally owned gas or gas and electric utilities are exempt if:

(A) the utility operates an alternative energy assistance program to support its eligible customers with their energy needs and self-certifies to the Organization through written statement that its program meets the following criteria:

(i) the amount and method for funding of the program has been determined by the utility's governing body; and

(ii) the program monies will be collected and distributed in a manner and under eligibility criteria determined by the governing body for the purpose of residential energy assistance to customers who are challenged with paying energy bills for financial reasons, including seniors on fixed incomes, individuals with disabilities, and low-income individuals, or,

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[indicates omission of unaffected rules]

(IV) A municipal gas or gas and electric utility that is exempt under subparagraph (a)(III) of this rule shall be entitled to participate in the Organization's low-income assistance program.

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[indicates omission of unaffected rules]

4412. Gas Service Low-Income Program.

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[indicates omission of unaffected rules]

(e) Payment plan.

(I) Participant payments for gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which gas is the primary heating fuel, participant payments shall be no lower than two percent and not greater than three percent of the participant's household income. For accounts for which electricity is the primary heating fuel but the participant also has gas service, utility participant payments for gas service shall not be greater than one percent of the participant's household income.

(II) In the event that a primary heating fuel for any particular participant has been identified by LEAP, that determination shall be final.

(III) Notwithstanding the percentage of income limits established in subparagraph 4412(e)(I), a utility may establish minimum monthly payment amounts for participants with household income of $0, provided that the participant's minimum payment for a gas account shall be no more than $10.00 a month.

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[indicates omission of unaffected rules]

(i) Energy efficiency and weatherization.

(I) The utility shall provide all program participants with information on energy efficiency programs offered by the utility or other entities and existing weatherization programs offered by the State of Colorado or other entities.

(II) The utility shall provide the Colorado Energy Office with the name and service address of participant households for which annual gas usage exceeds 600 therms annually.

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[indicates omission of unaffected rules]

(l) Annual report. No later than December 31 of each year, each utility shall file a report in the most recent miscellaneous proceeding established by the Commission to receive annual low-income filings using the form available on the Commission's website, based on the 12-month period ending October 31 and containing the following information below:

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[indicates omission of unaffected rules]

(XI) the average monthly and annual total gas consumption in PIPP participants' homes;

(XII) the average monthly and annual total gas consumption in the utility's residential customer's homes;

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[indicates omission of unaffected rules]

4506. – 4524. [Reserved].

GREENHOUSE GAS EMISSIONS

4525. Overview and Purpose.

These rules implement §§ 40-3.2-106, 40-3.2-107, 40-3.2-108, C.R.S., for the purpose of evaluating greenhouse gas emissions in utility demand side management, gas infrastructure plan, and clean heat plan proceedings.

4526. Definitions.

(a) "Federal technical support document" shall mean the 2016 technical support document of the Federal Interagency Working Group on Social Cost of Greenhouse Gases, entitled "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" or the most recently available successor of the 2016 federal technical support document, where the recommended discount rate and the starting values are consistent with §§ 40-3.2-106(4) and 40-3.2-107(2)(a), C.R.S. The addendum to the federal technical support document is entitled "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide."

4527. Measurement and Accounting.

(a) Greenhouse gas emissions shall include methane and carbon dioxide emissions measured separately in metric tons and presented in carbon dioxide equivalent. Baseline emissions, system-wide emissions, and reductions in emissions shall be based on the most recent clean heat workbook published by the Air Pollution Control Division, and approved by the Commission through rule or order, to guide the proper calculation and reporting of both carbon dioxide and methane emissions.

(I) For any utility that establishes its baseline emissions using default emission rate factors, the utility may petition the Commission as part of its application to approve a clean heat plan, filed pursuant to rule 4729 or 4734, to adjust its baseline emissions based on empirical data of distribution system methane leakage emissions, provided that:

(A) the measured leakage data utilizes advanced leak detection technologies and approaches, consistent with directives from the Air Pollution Control Division or the Commission; and

(B) the utility continues to use advanced leak detection technologies and approaches for all future measurement years.

(b) The utility shall calculate greenhouse gas emission projections and baselines to include the following components:

(I) methane leaked from the transportation and delivery of gas from the gas distribution and service pipelines from the city gate to its customer's end-use;

(II) carbon dioxide emissions resulting from the combustion of gas by residential, commercial, and industrial customers who themselves are not otherwise subject to federal greenhouse gas emission reporting and excluding all transportation customers; and

(III) emissions of methane resulting from leakage from delivery of gas to other LDCs.

4528. Social Cost of Carbon and Social Cost of Methane.

(a) The cost of carbon dioxide emissions shall be established by the Commission based on the most recent social cost of carbon dioxide developed by the federal government, in accordance with the following:

(I) the cost of carbon dioxide emissions starting in 2020, shall not be less than the base cost of $68.00 per metric ton in 2020 dollars;

(II) the Commission shall update the social cost of carbon values to the present dollar year for each year after 2020 by applying an escalation rate equal to or greater than the escalation rates established in the federal technical support document.

(b) For net present value calculations of the social cost of carbon dioxide emissions, the utility shall use a discount rate equal to the lesser of 2.5 percent or the discount rate established by the federal technical support document.

(c) The cost of methane emissions shall be established by the Commission based on the values set forth in the federal technical support document or on the federal government's most recent assessment of the global cost of methane as updated to reflect the latest available values derived from peer-reviewed, published studies, in accordance with the following:

(I) the social cost of methane emissions, starting in 2020, shall not be less than the base cost of $1,756 per metric ton in 2020 dollars;

(II) the Commission shall update the annual social cost of methane emissions values to the present dollar year for each year after 2020 by applying an escalation rate equal to or greater than the escalation rates established in the federal technical support document or the addendum to the 2016 federal technical support document if the social cost of methane is not included in the federal technical support document; and

(III) the social cost of methane emissions shall use the best available leakage rates to determine the methane emissions from fossil gas extraction and processing, in addition to the greenhouse gas emissions identified in rule 4527, and consistent with § 40-3.2-107(2)(b), C.R.S.

(d) For net present value calculations of the social cost of methane emissions, the utility shall use a discount rate equal to the lesser of 2.5 percent or the discount rate established in the federal technical support document.

(e) For net present value calculations of portfolios of resources presented pursuant to rules governing clean heat plans or any type of DSM plan, the utility shall also present net present value calculations using the utility's weighted average cost of capital universally on all costs included within the relevant portfolio.

4529. – 4549. [Reserved].

GAS INFRASTRUCTURE PLANNING

4550. Overview and Purpose.

These rules foster the examination of capital investment of jurisdictional utilities that are subject to the Commission's regulatory authority through the development and approval of gas infrastructure plans, planned projects, and alternatives to planned projects. The purpose of these rules is to establish a process to determine the need for, and potential alternatives to, capital investment, consistent with the objectives of maintaining just and reasonable rates, ensuring system safety, reliability, and resiliency, protecting income-qualified utility customers and disproportionately impacted communities, and supporting utility efforts to meet applicable clean heat targets pursuant to rule 4728, as established in § 40-3.2-108, C.R.S.

4551. Definitions.

(a) "Customer-owned yard line" means any customer-owned gas line running underground from the utility meter to a customer's home, business, or other customer end use.

(b) "Defined programmatic expense" means a programmatic expense that, in the aggregate, falls within the oversight of a utility's application for issuance of a certificate of public convenience and necessity or approval of a gas infrastructure plan. Defined programmatic expense means company-wide programmatic investment in activities related to relocation or replacement of meters and customer-owned yard lines, or as otherwise ordered by the Commission.

(c) "Gas infrastructure plan action period" means a three-year period beginning January 1st of the year in which the gas infrastructure plan application filing is made.

(d) “Gas infrastructure plan informational period” means the three-year period following the gas infrastructure plan action period.

(e) “Gas infrastructure plan total period” means the gas infrastructure plan action period and the gas infrastructure plan informational period.

(f) “Planned project” means any planned facility or an extension of an existing facility, or a defined programmatic expense with a defined scope of work and associated cost estimate that exceeds $3 million in utility capital investment in 2020 dollars, or $2 million in utility capital investment in 2020 dollars for gas utilities with less than 50,000 full-service customers, as adjusted annually for inflation.

(I) The dollar thresholds in paragraph (f) shall be adjusted for inflation annually on March 1 of each year, based upon the annual percentage change in the United States Bureau of Labor Statistics Consumer Price Index – Denver-Aurora-Lakewood as published by the Colorado Department of Local Affairs for the immediately preceding calendar year. These adjustments shall be compounded annually. For reference, the Commission will post a notice on its website, https://puc.colorado.gov/, by March 15 of each year reporting the annual inflation adjustments applicable pursuant to this rule.

4552. Filing Form and Schedule.

(a) The utility shall file a gas infrastructure plan every two years unless otherwise required by the Commission through rule or order.

(I) The largest gas distribution utility in Colorado, as determined by the volume of gas sold in Colorado, shall file a gas infrastructure plan by May 1, 2023.

(II) All other utilities shall file a gas infrastructure plan by March 1, 2024.

(b) The utility shall file a gas infrastructure plan pursuant to this paragraph 4552(b) in accordance with paragraph 4552(c), for which the following requirements shall apply:

(I) The filing shall include the elements required by rule 4553, except the utility shall be allowed to present an analysis of alternatives pursuant to subparagraph 4553(c)(I)(P) for the following number of new business and capacity expansion projects unless that number exceeds the total number of planned new business and capacity expansion projects presented in the gas infrastructure plan.

(A) For utilities with 500,000 customers or more, the utility shall provide an analysis of alternatives for at least five projects classified as either new business or capacity expansion projects.

(B) For utilities with more than 50,000 full-service customers and less than 500,000 customers, the utility shall provide an analysis of alternatives for at least two projects classified as either new business or capacity expansion projects.

(C) For utilities with less than 50,000 full-service customers, the utility shall provide an analysis of alternatives for at least one project classified as either new business or capacity expansion project.

(II) Upon receipt of the filing, the Commission will open a proceeding, notice the filing, and establish an intervention period for the purpose of establishing parties and set a calendar for written comments from parties to the proceeding. Parties may conduct discovery on the filing and on any prefiled testimony submitted with the filing.

(III) The Commission will establish procedures for the proceeding that shall include one or more public comment hearings.

(IV) The Commission, on its own motion or at the request of others, may request additional supporting information from the utility or the parties to the proceeding.

(V) The Commission will issue a written decision, within 150 days of filing if practicable, regarding the adequacy of the utility's filed gas infrastructure plan and the methods and processes the utility used in formulating the gas infrastructure plan and providing guidance to be used in the preparation of the biennial filings required pursuant to paragraph 4552(d).

(c) For utilities with 500,000 full-service customers or more, a utility's first gas infrastructure plan shall be eligible to be filed pursuant to paragraph 4552(b) in a miscellaneous proceeding to be opened by the Commission for each utility. For utilities with less than 500,000 customers, a utility's first two gas infrastructure plans shall be eligible to be filed pursuant to paragraph 4552(b). All subsequent gas infrastructure plans shall be filed pursuant to paragraph 4552(d). A utility, at its own discretion, may voluntarily file a gas infrastructure plan it is eligible to file under paragraph 4552(b) instead as an application under paragraph 4552(d).

(d) Pursuant to the schedule in paragraph 4552(a), and subject to the eligibility requirements in paragraph 4552(c), the utility shall file its gas infrastructure plan as an application administered pursuant to the Commission's Rules of Practice and Procedure, 4 CCR 723-1.

(I) A utility's gas infrastructure plan shall meet the requirements of rules 4002 and 4553.

(II) The utility shall identify in the application any planned projects within the gas infrastructure plan action period for which it seeks a certificate of public convenience and necessity pursuant to rule 4102, a declaratory order that the planned project is in the ordinary course of business, or other relief to be addressed by the Commission in its decision rendered pursuant to rule 4555. For planned projects exceeding the cost thresholds in rule 4102 for which the utility seeks relief pursuant to this subparagraph (d)(II), the utility may include the requirements of rule 4102 in an application submitted pursuant to the Gas Infrastructure Planning Rules.

(III) The Commission may hold a hearing for the purpose of reviewing and rendering a decision regarding the contents of the utility's gas infrastructure plan.

(IV) Prior to the filing of the application, the utility shall hold one or more public workshops to educate, and facilitate feedback from, stakeholders and potential intervenors on the projects selected, the utility's approach to alternatives analyses for the projects selected, and the results of the utility's alternatives analyses, pursuant to subparagraph 4553(c)(I)(P) with the goal of facilitating a robust and broadly supported set of alternatives analyses upon the filing of the application. Following each public workshop, the utility shall accept written comments for up to fourteen days from stakeholders and potential intervenors.

4553. Contents of a Gas Infrastructure Plan.

(a) General.

(I) The utility shall describe in each gas infrastructure plan the methodology, criteria, and assumptions used to develop the gas infrastructure plan. The utility shall specifically describe its system planning and infrastructure modeling process including the assumptions and variables that are inputs into the process.

(II) The utility shall describe its budget planning processes and the expected level of accuracy in its cost projections.

(III) The utility shall categorize planned projects, or explain any deviation of project categorization, based on the categories set forth below. A planned project may be included in more than one category or subcategory. The utility shall also explain the inter-relationship of planned projects, to the extent applicable.

(A) "System safety and integrity projects" shall include but are not limited to pipeline and storage integrity management programs; exposed pipe inspection and remediation; pipe or compressor station upgrades; projects undertaken to meet U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration requirements; and Supervisory Control and Data Acquisition (SCADA) upgrades.

(B) "New business projects" shall include utility investment and spending needed to provide gas service to new customers or customers requiring new gas service.

(C) "Capacity expansion projects" shall include both individual projects and sets of inter-related facilities needed to maintain system reliability and meet a specified capacity expansion need. Within the category of capacity expansion projects, the utility shall further separate appropriate projects into the following sub-categories:

(i) capacity expansion projects needed for reliability or growth in sales by existing customers, structures, and facilities; and

(ii) capacity expansion projects needed for growth in sales due to new customers, structures, and facilities, that are not otherwise new business planned projects.

(D) "Mandatory relocation projects" as defined in paragraph 4001(dd).

(E) "Defined programmatic expenses" as defined in paragraph 4551(b), means the following, or as otherwise ordered by the Commission:

(i) "relocation or replacement of meters" shall include the utility's investment and expenditure to replace or relocate customer meters, including at-risk meters, not otherwise covered by other projects; and

(ii) "replacement of customer-owned yard lines" shall include the investment and expenditure to replace customer-owned yard lines and associated infrastructure with utility-owned pipelines and associated infrastructure.

(IV) The utility shall provide, for each year of the gas infrastructure plan total period, and for each project category defined above in subparagraph 4553(a)(III), the following information:

(A) the total number of projects; and

(B) the total annual capital investment.

(V) The utility shall provide one or more maps indicating locations of individual planned projects, pressure district or geographic area served by the individual planned projects or that would otherwise lead to a foreseeable lack of system reliability, if applicable, and other distinct zones identified for planning purposes in the utility's most recently approved clean heat plan pursuant to subparagraph 4731(a)(I)(B) with sufficient geographical detail such that the Commission can evaluate and fully comprehend the extent and purpose of the overall gas infrastructure plan. The utility shall also indicate whether the planned projects are located within disproportionately impacted communities.

(VI) The utility shall provide a copy of its prior year's United States Department of Transportation Gas Distribution Annual Report, Form F7100.

(VII) The utility shall provide a summary of stakeholder participation and input and explain how this input was incorporated into the gas infrastructure plan. For each recommendation received by the utility prior to filing its plan, a utility shall summarize the recommendation and respond to it. If a project or projects are located in a disproportionately impacted community, the utility shall further provide a description of outreach to members of that community, including a description of the nature of the outreach as appropriate to the filing, including descriptions of communications and materials, and findings from those efforts. The utility shall also provide a summary of the public workshops on alternatives analyses as required by subparagraph 4552(d)(IV).

(VIII) The utility shall provide project-level information consistent with the requirements in paragraph 4553(c) for all projects with an expected construction start date during the gas infrastructure plan action period and the gas infrastructure plan informational period, where available. For planned projects in the gas infrastructure plan informational period where project-level information is not available, category-level specificity consistent with subparagraph 4553(a)(III) is acceptable.

(IX) The utility shall provide the then-current peak design temperature assigned to unique segments of the utility system used for capacity planning, and data to support such design temperature(s).

(b) Forecast requirements.

(I) The utility shall present reference, low, and high forecasts of design peak demand, customer count, sales and capacity requirements, gas content including expected mixtures by volume of hydrogen and recovered methane, and system-wide greenhouse gas emissions, consistent with the utility's approved portfolio of clean heat resources and in accordance with subparagraph 4731(b)(I), or any appropriate interim-year update to such forecasts in accordance with subparagraph 4733(a)(VI).

(II) If a utility filed a small utility clean heat plan in accordance with rule 4734, the utility shall justify and document the data, assumptions, models, and other inputs upon which it relied to develop this gas infrastructure plan. A utility filing under this rule shall indicate how its forecast incorporates, to the extent practicable, relevant external factors including, but not limited to:

(A) the effect of current or enacted state and local building codes;

(B) changes in the utility's line extension policies, and the associated impact on gas customer growth;

(C) building electrification programs or incentives offered by the local electric utility or local or federal entities that overlap with the utility's gas service territory; and

(D) the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).

(c) Planned project information.

(I) The utility shall present the following project-specific information for all planned projects in the gas infrastructure plan total period, with information provided to the extent practicable for projects in the gas infrastructure plan informational period:

(A) project name;

(B) project category, consistent with the categories defined in subparagraph 4553(a)(III), or otherwise identified and justified by the utility;

(C) general scope of work and explanation of need for the project, including any applicable U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration code requirements for the project;

(D) projected life of the project;

(E) if the project is presented as a gas infrastructure plan action period project or a gas infrastructure plan informational period project;

(F) anticipated construction start date, construction period, with any phases indicated, and expected in-service date;

(G) the cost estimate classification using the utility's or an industry-accepted cost estimate classification index, and support of the methodology;

(H) project technical details, such as physical equipment characteristics of proposed facilities, pipeline length, pipeline diameter, project material(s), and maximum allowable operating pressure;

(I) total project cost estimate and a presentation of the associated annual revenue requirements for the project during the gas infrastructure plan total period, assuming both conventional depreciation and accelerated depreciation in accordance with the forecasts submitted or developed pursuant to paragraph 4553(b);

(J) the project location and an illustrative map of the facilities (subject to necessary and appropriate confidentiality provisions) including:

(i) the pressure district or geographic area that requires the proposed facilities;

(ii) the existing and proposed regulator stations and existing and proposed distribution piping and higher capacity pipelines served by or representing the proposed facilities;

(iii) the locations of any disproportionately impacted community;

(iv) identification of the electric utility service provider(s) at that location; and

(v) any other information necessary to allow the Commission to make a thorough evaluation.

(K) to the extent practicable, the number of customers, annual sales, and design peak demand requirements, by customer class, directly impacted or served by the project;

(L) permit(s) required to begin work, if any;

(M) environmental requirements associated with completion of project, if any;

(N) the change in projected greenhouse gas emissions due to the planned project;

(O) the status of the planned projects as addressed in previous plans, as well as changes, additions or deletions in the current plan when compared with prior plans; and

(P) for a quantity of new business and capacity expansion projects, given the criteria established by the Commission in accordance with subparagraph 4552(b)(I)(A) through (C), the utility shall present an analysis of alternatives, including non-pipeline alternatives, costs for those alternatives, and criteria used to rank or eliminate such alternatives.

(i) An analysis of alternatives shall consider, at a minimum:

(1) one or more applicable clean heat resources consistent with the utility's most recently approved clean heat plan, pursuant to rule 4732, demand side management plan, pursuant to rule 4753, or beneficial electrification plan, as applicable;

(2) a cost-benefit analysis including the costs of direct investment and the social costs of carbon and methane for emissions due to or avoided by the alternative, and other costs determined appropriate by the Commission; and

(3) available best value employment metrics associated with each alternative, as defined in paragraph 4001(h), including a projection of gas distribution jobs affected by the alternative and jobs made available through the alternative, opportunities to transition any affected gas distribution jobs to the alternative, pay and benefit levels of the affected gas distribution jobs and the jobs available through a transition opportunity, and how employment impacts associated with each alternative could affect disproportionately impacted communities.

(ii) An analysis of alternatives shall include, at a minimum:

(1) the technologies or approaches evaluated;

(2) the technologies or approaches proposed, if applicable;

(3) the projected timeline and annual implementation rate for the technology or approaches evaluated;

(4) the technical feasibility of the alternative assuming full adoption of the technologies and approaches evaluated;

(5) the utility's strategy to facilitate the technologies or approaches evaluated; and

(6) an explanation of the methodology used to select which projects are presented with an alternative analysis, including discussion of the public review process required pursuant to subparagraph 4552(d)(IV).

(Q) For new business and capacity expansion projects, a utility shall provide an alternative analysis as set forth in subparagraph (c)(I)(P) above or justify why the new business and capacity expansion project is not suitable for an alternative analysis for which the utility seeks a certificate of public convenience and necessity or other relief, in accordance with subparagraph 4552(d)(II).

(R) For system safety and integrity projects, the utility shall provide the applicable federal regulation, the planned project's risk ranking and the utility's risk ranking methodology including but not limited to the material, age, maximum allowable operating pressure, density of surrounding residences and businesses, and any other physical and operating characteristics relevant to the risk ranking of the planned project and the risk ranking methodology. The utility should also identify, discuss in detail, and provide the output to any risk-related models developed or employed by the utility in conducting risk analyses to support planned system safety and integrity projects or other projects.

(II) With respect to the reference, low and high forecasts conducted pursuant to subparagraph 4553(b)(I):

(A) the total incremental investment that may be needed over the gas infrastructure plan action period and gas infrastructure plan informational period; and

(B) an identification of the primary individual new projects avoided in the low design peak demand forecast and an identification of the primary individual new projects and capital spend added in the high design peak demand forecast.

(d) Existing infrastructure assessment reporting. The utility shall report on the following in the gas infrastructure plan.

(I) The utility shall report the following information regarding customer-owned yard lines attached to its distribution system, if applicable:

(A) an estimate of the number of customer-owned yard lines by municipality served;

(B) the number of customer-owned yard lines replaced by the utility to date and capital investment incurred to do so; and

(C) the estimated gross and net rate-based investment needed to replace all customer-owned yard lines in present dollars through year 2030, through year 2040, and through year 2050.

(II) The utility shall report the following information regarding hydrogen compatibility throughout its distribution system, to the extent known:

(A) estimate the percentage of distribution system components known to be compatible with safely carrying varying concentrations of hydrogen, including but not limited to:

(i) piping;

(ii) fittings; and

(iii) non-pipe system components.

(B) The utility shall identify any areas of the system with unknown materials or materials known to be not compatible with hydrogen mixtures up to 20 percent by volume.

(III) The utility shall report the following information regarding advanced leak detection:

(A) identification of equipment, survey method, percentage of system surveyed in each year, and interval in which additional advanced leak detection occurred on the same areas of the system;

(B) any updates to anticipated system-wide methane emissions based on most recent advanced leak detection surveys; and

(C) extent to which leakage sources identified are within disproportionately impacted communities.

4554. Interim Gas Infrastructure Plan Reporting.

(a) In calendar years when no gas infrastructure plan is submitted, no later than May 1 in the year after the filing of the utility's last gas infrastructure plan proceeding, as applicable under paragraph 4552(a), the utility shall file an interim gas infrastructure plan report addressing the status of planned projects and approved alternatives from previous gas infrastructure plans.

(b) The utility shall provide the best available information on the status of each planned project consistent with the information listed in subparagraph 4553(c)(I). The utility will explain in detail the reasons for variances in project costs, the scope of work, and implementation timeline.

(c) The utility shall provide information on the defined programmatic expense work completed since its last gas infrastructure plan filing.

4555. Approval of a Gas Infrastructure Plan.

(a) Based upon the evidence of record, the Commission shall issue a written decision approving, denying, or ordering modifications, in whole or in part, to the utility's gas infrastructure plan application filed in accordance with paragraph 4552(d).

(b) The Commission's decision regarding the gas infrastructure plan application shall consider the adequacy of the utility's filed information and the methods and processes the utility used in formulating the gas infrastructure plan. The Commission may require refinements regarding the planning methods and processes to be incorporated in the utility's subsequent gas infrastructure plan application filing.

(c) In accordance with subparagraph 4552(d)(II), the Commission's decision regarding the relief sought by the utility regarding specific planned projects or their alternatives shall consider the adequacy of the utility's filed information and the methods and processes the utility used in evaluating those projects and alternatives to those projects, as applicable. The Commission may also grant a presumption of prudence of the cost estimate for a planned project if the Commission determines the record supports the reasonableness and maturity of the cost estimate and evaluation of alternatives, as applicable.

(d) If the Commission declines to approve a utility's gas plan filed in accordance with paragraph 4552 (d), either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 60 days of the issuance of a Commission decision disapproving a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

4556. – 4599. [Reserved].

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[indicates omission of unaffected rules]

4708. – 4724. [Reserved].

CLEAN HEAT PLANS

4725. Overview and Purpose.

These rules implement § 40-3.2-108, C.R.S., for gas distribution utilities and small gas distribution utilities. Consistent with statutory requirements including the statewide greenhouse gas pollution goals set forth in § 25-7-102(2)(g), C.R.S., the purpose of these clean heat plan rules is to maximize methane and carbon dioxide emissions reductions from the distribution and end-use consumption of gas while also maintaining just and reasonable rates, maintaining system safety, reliability and resiliency, and prioritizing investments in disproportionately impacted communities. The utility must utilize clean heat resources to the maximum extent practicable and count greenhouse gas emission reductions resulting from the use of those resources.

4726. Applicability.

(a) A gas distribution utility shall file clean heat plans to meet clean heat targets and implement clean heat resources during the clean heat plan action period pursuant to these rules.

(b) A small gas distribution utility may file clean heat plans to meet clean heat targets and implement clean heat resources during the clean heat plan action period pursuant to rule 4734.

4727. Definitions.

(a) "Clean heat plan total period" means the period from the date the clean heat plan application is filed through year 2050, or 20 calendar years, whichever is greater.

(b) "Clean heat plan action period" means the period beginning the date the plan is filed and extending until December 31st of the fifth year from the filing date.

(c) “Clean heat plan informational period” means the period from the end of the clean heat plan action period through the end of the clean heat plan total period.

(d) “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.

(e) “Green hydrogen” means hydrogen derived from water and a clean energy resource as defined in § 40-2-125.5(2)(b), C.R.S.

(f) “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. The greenhouse gas emission reduction or greenhouse gas removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable. No recovered methane credit may be issued if the greenhouse gas emission reduction or greenhouse gas removal enhancement that the credit would represent is required or accounted for by a proposed or final federal, state, or local rule or regulation.

(g) “Recovered methane protocol” means a set of procedures and requirements established by the Air Quality Control Commission to quantify ongoing greenhouse gas emission reductions or greenhouse gas removal enhancements achieved by a recovered methane project and to calculate and track the project outcomes.

(h) “Small gas distribution utility” means 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.

4728. Clean Heat Targets.

(a) Clean heat targets shall align with the statewide greenhouse gas emission reduction goals set forth in § 25-7-102(2)(g), C.R.S., and shall be consistent with § 40-3.2-108, C.R.S., et seq.

(b) Baseline emissions, system-wide emissions, and reductions in emissions shall be calculated in accordance with rules 4525 through 4528.

(c) Baseline.

(I) The utility shall calculate a baseline level of emissions for calendar year 2015, calculated in accordance with rule 4527.

(II) The utility shall exclude the emissions of customers, and to the extent practicable identify those customers and their associated load, that report their own greenhouse gas emissions to the United States Environmental Protection Agency under applicable federal law.

(d) Targets.

(I) The following clean heat targets apply for a gas distribution utility:

(A) four percent reduction in greenhouse gas emissions in calendar year 2025 as compared to a 2015 baseline, of which not more than one percent (one-fourth of the emission reductions required to meet the 2025 target) can be from recovered methane;

(B) 22 percent reduction in greenhouse gas emissions in calendar year 2030 as compared to a 2015 baseline, of which not more than five percent (five-twenty seconds of the emission reductions required to meet the 2030 target) can be from recovered methane, unless subparagraph (C) below applies;

(C) a jurisdictional gas utility's clean heat plan may exceed the recovered methane caps set forth above in subparagraphs (A) and (B) if the Commission finds that the utility otherwise could not cost-effectively meet the clean heat targets and that exceeding the recovered methane caps is in the public interest.

(II) No later than December 1, 2024, the Commission, in consultation with the Air Pollution Control Division, shall determine a mass-based clean heat target for the utilities' clean heat plans for year 2035 using the 2015 baseline pursuant to § 40-3.2-108(10), C.R.S.

(III) No later than December 1, 2032, the Commission, in consultation with the Air Pollution Control Division, shall determine the mass-based clean heat targets for years 2040, 2045, and 2050 using the 2015 baseline pursuant to § 40-3.2-108(11), C.R.S.

(e) For clean heat targets beginning in year 2035, the maximum amount, if any, of each target reduction in greenhouse gas emissions that may be from recovered methane shall be determined by the Commission if such maximum levels promote investment in Colorado communities, reduce greenhouse gas emissions, are cost-effective, and are in the public interest.

4729. Filing Form and Schedule.

(a) The utility's clean heat plan shall be filed as an application administered pursuant to the Commission's Rules of Practice and Procedure, 4 CCR 723-1, as well as rules 4002 and 4731 of these rules. The Commission may hold a hearing for the purpose of reviewing, and rendering a decision regarding, the contents of the utility's clean heat plan.

(b) The utility's clean heat plan application shall:

(I) present a plan to implement clean heat resources throughout the clean heat plan action period;

(II) demonstrate that the clean heat plan will result in greenhouse gas emissions reductions necessary to meet the applicable clean heat targets that occur during the clean heat plan action period or show compliance with the cost cap; and

(III) demonstrate that the activities contemplated in the clean heat plan facilitates the utility's ability to meet future greenhouse gas emission reduction targets.

(c) No later than August 1, 2023, the largest gas distribution utility in Colorado, as determined by the volume of gas sold in Colorado, shall file its first application for approval of a clean heat plan.

(d) No later than January 1, 2024, all gas distribution utilities other than the largest gas distribution utility in Colorado, as determined by the volume of gas sold in Colorado shall file their first applications for approval of a clean heat plan.

(e) All gas distribution utilities shall file subsequent clean heat plans not less often than every four years, unless otherwise directed by the Commission.

(f) After a utility's clean heat plan is filed and prior to any evidentiary hearing, the Commission shall schedule a public hearing that specifically solicits, among other applicable topics, public comment on the labor impacts and benefits of the proposed clean heat plan.

4730. Clean Heat Resources.

(a) Clean heat resources include any one or a combination of the following resources:

(I) demand side management programs in accordance with the demand side management provisions in these rules and as defined in § 40-1-102(6), C.R.S.;

(A) the Commission shall collaborate with the Air Pollution Control Division to ensure that any emissions reductions achieved through gas demand side management programs are appropriately accounted for in accordance with § 25-7-102(2)(g), C.R.S.

(II) recovered methane;

(A) All recovered methane shall be represented by a recovered methane credit, issued subject to a recovered methane protocol approved by the Air Quality Control Commission.

(B) All recovered methane projects shall be located in Colorado and shall be delivered within Colorado through a dedicated recovered methane pipeline or through a common carrier pipeline.

(C) Any recovered methane credit or other tradable and severable mechanism representing the emission reduction attributes of a clean heat resource shall be retired in the year generated and may not be sold by the utility or the utility's customer.

(D) A utility may count emissions reductions represented by the retirement of a recovered methane credit only if the credit was retired in its clean heat target year. A utility may only count emissions reductions represented by a methane credit one time toward achieving any clean heat target.

(E) Repairs to the utility's distribution system shall be reviewed in accordance with the gas infrastructure planning rules 4550 through 4555. In order to qualify as a clean heat resource, recovered methane from such repairs must meet a recovered methane protocol approved by the Air Quality Control Commission and be determined cost-effective by the Commission based on actual reductions in methane achieved.

(III) green hydrogen;

(IV) beneficial electrification programs, as defined in § 40-1-102(1.2), C.R.S.;

(V) pyrolysis of tires that meets a recovered methane protocol approved by Air Quality Control Commission; and

(VI) any other technology approved by the Commission that the Commission finds is cost-effective and that the Air Pollution Control Division finds results in a reduction in carbon emissions from the combustion of gas in customer end uses or meets a recovered methane protocol approved by the Air Quality Control Commission.

(b) A clean heat resource shall not include a change in service by a customer from sales service to transportation service. The Commission shall address changes from sales service to transportation service by the utility's customers as such changes relate to baseline emissions, projected emissions, and clean heat targets in evaluating whether a clean heat plan is in the public interest.

4731. Clean Heat Plan Application Requirements.

(a) Initial forecasts.

(I) A utility shall present reference (base), low and high forecasts of sales, customer counts, system-wide capacity (design peak demand) requirements, throughput by Btus and volumes of green hydrogen, recovered methane, and total gas, and system-wide greenhouse gas emissions.

(A) All forecast elements shall be provided for the total utility and by customer class, for each year of the clean heat plan action period and in five-year increments during the clean heat plan informational period.

(B) Forecasts should be disaggregated by pressure district, unique planning zones requiring a distinct design peak demand condition, or other geographical segmentation, as appropriate.

(C) The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop forecasts pursuant to this rule.

(D) The greenhouse gas emissions forecast should be based on the latest Commission-approved workbook developed by the Air Pollution Control Division, consistent with paragraph 4527(a), updated for the most recent calendar year of data, and include the factors identified in below in subparagraph (E).

(E) Forecast(s) shall include consideration of the following factors, to the extent practicable and applicable:

(i) the effect of current and enacted state and local building codes;

(ii) changes in line extension policies, and the associated potential impact on gas customer growth, in the aggregate;

(iii) building electrification programs or incentives offered by the local electric utility or local or federal entities that overlap with a utility's gas service territory;

(iv) the price elasticity of demand; and

(v) other known factors affecting sales and gas supply capacity needs.

(F) Low and high forecasts shall incorporate alternative projections of customer growth and sales, and any underlying supporting assumptions, to assess a reasonable range of variation surrounding the reference (base) forecast.

(b) Portfolios.

(I) A utility shall present the following portfolios of clean heat resources:

(A) at least one portfolio shall use the maximum amount of clean heat resources practicable and also comply with a 2.5 percent annual retail cost impact cap; This portfolio may or may not meet the clean heat target in the applicable plan period, but must demonstrate reductions in methane emissions;

(B) at least one portfolio shall meet the clean heat target regardless of the annual retail cost impact of such portfolio;

(C) the utility may present other alternative portfolios;

(D) the Commission may direct the utility to present additional alternative portfolios; and

(E) the utility shall identify a preferred portfolio that best balances, given the information available, the goals of maintaining just and reasonable rates, maintaining system safety, reliability and resiliency, protecting disproportionately impacted communities, the labor standards identified below in subparagraph (d)(II)(F), and contribution to statewide progress on meeting the greenhouse gas emission reduction goals established in § 25-7-102(2)(g), C.R.S., and the associated clean heat targets in rule 4728.

(II) If a utility is unable to present portfolios that show compliance with the cost cap or compliance with the clean heat target, as described above, the utility must show that it has fully investigated all available categories of clean heat resources.

(c) Portfolio forecasts.

(I) For each portfolio presented, the utility shall provide the forecasts identified above in subparagraph (a)(I), updated to include the set of actions proposed in the respective portfolio for each year of the clean heat plan action period and every fifth year during the clean heat plan informational period.

(d) Components of a portfolio.

(I) For each portfolio presented, the utility shall provide, on a portfolio basis:

(A) identification of the proposed clean heat resources;

(B) the annual and total cost for implementing the portfolio;

(C) the annual and total cost for implementing the portfolio in income-qualified or disproportionately impacted communities;

(D) the annual and cumulative projected greenhouse gas emissions and reduction in emissions from the baseline emission level calculated pursuant to rules 4525 through 4528;

(E) an analysis of the projected costs and benefits of the portfolio:

(i) the cost-benefit analysis shall include but not be limited to:

(1) fuel costs;

(2) non-fuel direct investment associated with the clean heat plan;

(3) gas infrastructure costs;

(4) gas system operations costs; and

(5) the social cost of carbon and the social cost of methane, consistent with rule 4528.

(F) an analysis of the annual retail cost impact, which shall be calculated:

(i) net of the utility's approved gas demand side management program budgets, except for the costs of any incentive adopted or approved by the Commission associated with the utility’s demand side management programs; and

(ii) net of the utility's approved beneficial electrification plan program budget if the clean heat plan application includes a request for approval of a beneficial electrification plan.

(G) a description of the effects of the proposed actions and investments in the portfolio on the safety, reliability, and resilience of the utility's gas service.

(II) For each portfolio presented, the utility shall provide and shall quantify, as practicable, on a clean heat resource category basis:

(A) the annual and total cost for each clean heat resource category;

(B) identification of any additional air quality, environmental, and health benefits of each clean heat resource category in addition to the greenhouse gas emission reductions;

(C) the proportion of projects or programs that benefit disproportionately impacted communities, or customers who meet the requirements for income-qualified programs;

(D) a reasonable estimate of the labor costs associated with development of the clean heat resources in each category that reflect compliance with all applicable labor standards set forth in § 40-3.2-105.5, C.R.S., net of avoided capital infrastructure costs; and

(F) an explanation of whether the portfolio incorporates projects addressed by § 40-3.2-108(8)(d), C.R.S., and how it satisfies the labor standards under § 40-3.2-105.5, C.R.S., to the extent applicable. The utility shall also develop and provide an estimate of the number of gas distribution jobs that may be affected by each clean heat plan portfolio and the pay and benefit levels of those jobs.

(e) Green hydrogen.

(I) If one or more proposed portfolios include green hydrogen as a clean heat resource, the utility shall present an analysis demonstrating its distribution system can safely carry the expected concentrations and volumes of hydrogen, including the age and material of pipe, fittings, and other relevant infrastructure, in the locations of the system where the green hydrogen is intended to be introduced and transported. The utility should also present a plan to monitor and verify the impact of injecting and transporting hydrogen over time to ensure the continued safety and reliability of the system.

(f) Project-based information.

(I) It is the Commission's policy that utilities should acquire clean heat resources in the most cost-effective manner. To this end, the utility shall use competitive solicitations to the maximum extent practical.

(A) If a utility's clean heat plan includes the purchase or development of green hydrogen, the utility must include the gross quantity of green hydrogen transported by a common carrier or dedicated pipeline on an annual basis and the corresponding Btu content.

(B) With the exception of a green hydrogen project proposed in coordination with the State of Colorado, to secure benefits under a federal law, or as part of a State of Colorado application for a hydrogen hub, a proposal for a green hydrogen project shall include a competitive solicitation proposal, which shall include, at minimum, the following information:

(1) a copy of the request for proposals to be offered in the competitive solicitation;

(2) an explanation of required milestones and development-related penalties;

(3) the timing of the competitive solicitation and review and negotiation processes;

(4) a copy of the proposed contract to be signed by the utility and any third-party entity;

(5) the utility's standards for interconnection, including purity standards and metering methods; and

(6) an explanation of how best value employment metrics, as defined in paragraph 4001(h), will be evaluated in the utility's review of bids.

(II) For all proposed projects, the utility shall identify any developer or operator, if not the utility, and any customers on whose property the investment will be placed.

(III) The utility shall provide a map of disproportionately impacted communities located within the utility's service territory. The map must show the location of any anticipated green hydrogen or recovered methane projects and identify any portions of the project that are located in disproportionately impacted communities.

(g) Cost recovery proposals.

(I) The utility may propose a rate adjustment clause or structure that provides for recovery of the utility's clean heat plan costs, or any costs incurred to meet additional emission reduction requirements under § 25-7-105(1)(e)(X.7), C.R.S.

(II) The utility shall identify any potential changes to depreciation schedules or other actions to align the utility's cost recovery with statewide policy goals, including reducing greenhouse gas emissions, minimizing costs, and minimizing risks to customers.

4732. Approval of a Clean Heat Plan.

(a) The Commission shall approve a clean heat plan, including the associated forecasts set forth in paragraph 4731(b), if it finds the plan to be in the public interest. The Commission may modify the plan if the modifications are necessary to ensure the plan is in the public interest.

(b) In evaluating whether the clean heat plan is in the public interest, the Commission shall consider, at a minimum, the following factors:

(I) whether the plan achieves the clean heat targets using clean heat resources that, in aggregate, maximize greenhouse gas emission reductions;

(A) The Commission shall consult with the Air Pollution Control Division to estimate reductions of emissions of greenhouse gases and other air pollutants under the portfolios and verify the utility's calculations.

(B) The Air Pollution Control Division may participate as a party in the proceeding in which a utility files for approval of a clean heat plan.

(II) whether the plan can be implemented at the lowest reasonable cost and rate impact, taking into account savings to customer bills resulting from investments made pursuant to the plan. In determining the reasonableness of the cost and the cost impact, the Commission shall consider:

(A) fuel costs;

(B) non-fuel direct investment associated with the clean heat plan;

(C) gas infrastructure costs;

(D) gas system operation costs;

(E) a cost test that includes both the social cost of carbon and the social cost of methane; and

(F) any other costs and benefits found relevant by the Commission.

(III) whether the plan provides additional air quality, environmental, and health benefits in addition to the greenhouse gas emission reductions, and otherwise supports environmental justice goals;

(IV) whether the utility has demonstrated the investments in the clean heat plan prioritize serving customers participating in income-qualified programs and communities historically impacted by air pollution and other energy-related pollution;

(V) whether the plan presents risks to the utility's customers, including the risk of market volatility and the risk of stranded investment costs;

(VI) whether the plan provides long-term impacts on Colorado's utility workforce as part of a just transition including consideration of the labor metrics and benefits as specified in § 40-3.2-108(8), C.R.S., and defined in rule 4001(h); and

(VII) whether the plan maintains system safety and reliability.

(c) The Commission may approve a utility's proposed rate adjustment clause or structure that allows for current recovery of the utility's clean heat plan costs.

(d) The utility may recover the prudently incurred costs associated with actions under an approved clean heat plan or other actions to meet any additional emission reduction requirements imposed on the utility pursuant to § 25-7-105(l)(e), C.R.S.

4733. Interim Clean Heat Plan Reporting.

(a) By March 31 in all calendar years that a clean heat plan application is not submitted, each utility shall submit to the Commission an annual clean heat plan report that shows, pursuant to its approved clean heat plans:

(I) the amount spent on each clean heat resource relative to the amount budgeted, with an explanation for any deviations;

(II) the amount spent on income-qualified programs or programs that serve customers in a disproportionately impacted community or in communities historically impacted by air pollution and other energy-related pollution, including, relative to the amount budgeted, an explanation for any deviations;

(III) the annual greenhouse gas emissions consistent with rules 4525 through 4528, and a description of any significant deviations from the emissions reductions anticipated by project or program based on the utility's most recently approved clean heat plan;

(IV) the actual greenhouse gas emissions reduced or avoided for each clean heat resource category as calculated consistent with the most recent Commission approved methodology developed by the Air Pollution Control Division, and evaluated consistent with rules 4525 through 4528, and a description of any significant deviations from the emissions reductions anticipated by project or program based on the utility's most recently approved clean heat plan;

(V) the actual emission reductions and corresponding recovered methane credits as well as a statement or certification from the utility that any recovered methane credits were retired in the year generated;

(VI) an update to the forecasts provided in subparagraph 4731(c)(I), if applicable;

(VII) detailed information obtained from contractors about their use of Colorado-based labor, use of contractors participating in apprenticeship programs meeting the criteria in § 40-3.2-105.5(3), C.R.S., use of out-of-state labor to construct and deliver clean heat resources, and other labor metrics and information as specified in § 40-3.2-108(8), C.R.S., and defined in paragraph 4001(h);

(VIII) an update on the status of any competitive solicitation issued in accordance with paragraph 4731(f), including:

(A) status of contract negotiation;

(B) project development and milestone fulfillment;

(C) relevant labor metrics in accordance with subparagraph 4731(d)(II)(F); and

(D) use of out-of-state labor.

(b) The utility may request a revision to an existing, approved clean heat plan, as necessary, in order to improve its opportunity of achieving future clean heat targets or otherwise fulfill the purpose of these clean heat plan rules.

(c) The utility shall submit the annual clean heat plan reports required in this rule 4733 in the most recently concluded proceeding in which the Commission approved a clean heat plan filed by the utility.

4734. Small Utility Clean Heat Plan.

(a) Notwithstanding the requirements in paragraph 4729(d), a small gas distribution utility may file a clean heat plan to meet greenhouse gas emission reductions targets for 2025 and 2030 pursuant to this rule 4734. Such utilities then shall file additional clean heat plans in accordance with the clean heat plan rules, comprising rules 4725 through 4733, unless otherwise directed by the Commission.

(b) A clean heat plan filed in accordance with this rule 4734 must:

(I) propose greenhouse gas emission reduction targets for years 2025 and 2030;

(II) identify the clean heat resources to be used to reduce emissions on its system during the clean heat plan action period;

(III) quantify the annual greenhouse gas emission reductions expected during action plan period in total and for each clean heat resource calculated pursuant to rules 4525 through 4528;

(IV) propose program budgets, disaggregated by each clean heat resource, to meet the proposed greenhouse gas emission reduction targets; and

(V) quantify the cost of the clean heat resources and other actions to reduce greenhouse gas emissions during the plan period and demonstrate that such costs satisfy the analysis of the annual retail bill impact in accordance with § 40-3.2-108.6(a)(I), C.R.S.

(c) A clean heat plan filed in accordance with this rule 4734 may solicit clean heat resources through a competitive solicitation as set forth in paragraph 4731(f).

(d) The Commission shall approve a clean heat plan submitted under this rule 4734 if the Commission finds it to be in the public interest. The Commission may modify the clean heat plan if modifications are necessary to ensure that the plan is in the public interest. In evaluating whether the plan is in the public interest, the Commission shall consider the factors in paragraph 4732(b) and the annual retail cost impact in accordance with § 40-3.2-108.6(a)(I), C.R.S.

(e) The small gas distribution utility whose clean heat plan is approved by the Commission in accordance with this rule 4734 shall submit the annual clean heat plan reports required in rule 4733.

4735. – 4749. [Reserved].

DEMAND SIDE MANAGEMENT

4750. Overview and Purpose.

These rules implement §§ 40-1-102, 40-3.2-101, 40-3.2-103, 40-3.2-105, 40-3.2-106, and 40-3.2-107, C.R.S. for LDCs required by statute to be rate-regulated. Consistent with statutory requirements, the purpose of these Demand Side Management (DSM) rules is to reduce end-use gas consumption in a cost effective manner, in order to save money for consumers and utilities, and protect the environment by encouraging the reduction of emissions and air pollutants. These rules direct LDCs in the design and implementation of programs that will enable sales customers to participate in DSM. The LDC shall design DSM programs for its full-service customers to achieve cost-effective energy savings, considering factors such as: achievable energy savings, customer benefits, cost effectiveness ratios, the effects on disproportionately impacted communities, adoption potential, market transformation capability and ability to replicate in the utility service territory.

(a) Each utility shall file an application to open a DSM strategic issues proceeding in accordance with rule 4761.

(b) Each utility shall file an application for approval of a DSM plan within the parameters set forth in these rules. In the application, the utility shall include a proposed expenditure target, ensuring that a significant portion of the program expenditures are targeted to improve energy efficiency in income-qualified households in accordance with the percentage specified in subparagraphs 4753(i)(II) and (III), as applicable, as well as a savings target, funding mechanism, and cost-recovery mechanism.

(c) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.

(d) Each utility shall annually file a DSM report. The DSM report shall include the results of any measurement and verification (M & V) evaluation conducted during the DSM report period.

4751. Definitions.

The following definitions apply to rules 4750 through 4761, unless § 40-1-102, C.R.S., provides otherwise.

(a) “Amortization” means the systematic spreading of expenditures or capital costs incurred for DSM programs, through regular accounting entries over a specified period of time.

(b) “Benefit/cost ratio” means the ratio of the net present value of benefits to the net present value of costs, as calculated using the modified TRC test.

(c) “Cost effective” means a benefit/cost ratio of greater than one.

(d) “Demand side management” (DSM) means the implementation of programs or measures which serve to shift or reduce the consumption of, or demand for, gas.

(e) “Discount rate” means the interest rate used in determining the present value of future cash flows of DSM costs and benefits, for both forecasted and actual cash flows. The forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost effective DSM portfolio. The actual DSM costs and benefits, which are the actual costs of the program and the documented energy savings, are used to determine net economic benefits for the purpose of calculating the bonus. Discount rate shall be the utility's after-tax weighted average cost of capital (WACC).

(f) "DSM education" means a program, including but not limited to an energy audit, that contributes indirectly to a cost-effective DSM program by promoting customer awareness and participation.

(g) "DSM measure" means an individual component or technology, such as attic insulation or replacement of equipment.

(h) "DSM period" means the effective period of an approved DSM plan.

(i) "DSM plan" means the DSM programs, goals, and budgets over a specified DSM period, generally considered in one year increments, as may be proposed by the utility.

(j) "DSM program" means any of the following programs or combination of programs: energy efficiency, including weatherization and insulation; conservation; load management; beneficial electrification, as defined in § 40-1-102(1.2), C.R.S.; demand response; DSM education targeted at market transformation; and services offered to customers to reduce gas usage.

(k) "Energy efficiency program" see DSM program.

(l) "Gas Demand-Side Management Cost Adjustment" (G-DSMCA) means a rate adjustment mechanism designed to compensate a utility for its DSM program costs.

(m) "Gas Demand-Side Management bonus" (G-DSM bonus) means a bonus awarded to a utility in accordance with § 40-3.2-103(2)(d), C.R.S.

(n) "Market transformation" means a strategy for influencing the adoption by consumers of new techniques or technologies. The objective is to overcome barriers within a market through coordinating tactics such as education, training, product demonstration and marketing, often conducted in concert with rebates or other financial incentives.

(o) "Modified Total Resource Cost test" or "modified TRC test" means an economic cost-effectiveness test used to compare the net present value of the benefits of a DSM program or measure over its useful life, to the net present value of costs of a DSM measure or program for the participant and the utility, consistent with § 40-1-102(5), C.R.S.

(p) "Net economic benefits" means the net present value of all benefits in the modified TRC test, as applied to the utility's portfolio of DSM programs, less the net present value of the costs in the modified TRC test associated with that same portfolio.

(q) "Savings goal(s)" refers to the energy and demand savings levels approved in a strategic issues proceeding.

(r) "Savings target(s)" refers to the energy and demand savings levels approved in a DSM plan proceeding and are designed to meet or exceed the savings goals set by the Commission in a strategic issues proceeding.

(s) “Strategic issues proceeding” means a proceeding in which the Commission examines, addresses, and establishes high-level DSM policy findings for a utility. In a strategic issues proceeding, the utility’s application shall include proposed savings goals, peak demand reduction resulting from energy efficiency and demand response and commensurate budgets. The outcome of a strategic issues proceeding results in a DSM policy framework from which the utility then develops and files its DSM plan for Commission approval.

4752. Filing Schedule.

(a) Each utility shall implement and maintain its DSM plan and G-DSMCA, as approved by the Commission.

(b) Each utility shall submit its annual DSM report on or before April 1 of each year.

(c) Each utility seeking a G-DSM bonus shall include the bonus amount and its calculation in its annual advice letter filing adjusting the G-DSMCA consistent with paragraph 4752(d).

(d) Each utility shall file an advice letter on or before May 31 of each year to adjust the G-DSMCA to be effective July 1 for a period of 12 months.

(e) By July 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective gas DSM plan for Commission approval.

(f) Commencing in 2022, and no less frequently than every four years thereafter, each utility shall file an application to open a DSM strategic issues proceeding, consistent with § 40-3.2-103(1), C.R.S., and in accordance with rule 4761.

4753. DSM Plan.

Each utility shall file, in accordance with paragraph 4752(e), a prospective gas DSM plan that covers a DSM period of two years, unless otherwise ordered by the Commission. The plan shall demonstrate how the utility will meet or exceed the energy savings goals established by the Commission pursuant to these rules through the implementation of DSM programs and should also be consistent with the utility’s most recent clean heat plan approved by the Commission pursuant to rule 4732. The plan shall include the following information:

(a) the utility’s proposed expenditures by year for each DSM program, by budget category, in accordance with the Commission’s order addressing the utility’s most recent strategic issues proceeding application;

(b) the utility’s estimated gas energy savings and avoided greenhouse gas emissions over the lifetimes of the measures implemented in a given annual DSM program period, expressed in dekatherms per dollar of expenditure, and presented for each DSM program proposed for Commission approval; this represents the utility’s proposed savings target required by § 40-3.2-103(2)(b), C.R.S.;

(c) the anticipated units of energy to be saved annually by a given annual DSM program, which equals the product of the proposed expenditure target and proposed savings target; this product is referred to herein as the energy target;

(d) anticipated design peak demand savings, as applicable to individual DSM programs and to the portfolio as a whole;

(e) the estimated dollar per therm value that represents the utility's annual fixed costs that are recovered through commodity sales on a per therm basis;

(f) the utility shall include in its DSM plan application data and information sufficient to describe the design, implementation, oversight and cost effectiveness of the DSM programs. Such data and information shall include, at a minimum, program budgets delineated by year, estimated participation rates and program savings (in therms), and the greenhouse gas emissions avoided from each program;

(g) the utility's plans to comply with the labor standards in § 40-3.2-105.5, C.R.S.; and

(h) in the information and data provided in a proposed DSM plan, the utility shall reflect consideration of the factors set forth in the Overview and Purpose, rule 4750. At a minimum the utility shall provide the following information detailing how it developed its proposed DSM program:

(I) descriptions of identifiable market segments, with respect to gas usage and unique characteristics;

(II) a comprehensive list of DSM measures that the utility is proposing for inclusion in its DSM plan;

(III) a detailed analysis of proposed DSM programs for a utility's service territory in terms of markets, customer classes, anticipated participation rates (as a number and a percent of the market), estimated energy savings and cost effectiveness;

(IV) a ranking of proposed DSM programs, from greatest value and potential to least, based upon the data required in subparagraph (f)(III);

(V) proposed marketing strategies to promote participation based on industry best practices;

(VI) calculation of cost effectiveness of the proposed DSM programs using a modified TRC test. Each proposed DSM program is to have a projected value greater than or equal to 1.0 using a modified TRC test, except as provided for in paragraph 4753(g);

(VII) an analysis of the impact of the proposed DSM program expenditures on utility rates, assuming a 12-month cost recovery period;

(VIII) the best available values for gas leakage during the extraction, processing, transportation, and delivery of gas by the utility, categorized by each stage, as well as leakage from piping or other equipment on customer premises, and any relevant data and emissions accounting methodologies developed by the Air Pollution Control Division regarding methane leakage rates and the appropriate global warming potential of methane, for the purpose of calculating the cost of methane emissions; and

(IX) a narrative discussion showing that the DSM measures and programs, particularly in new construction, do not discourage otherwise economic beneficial electrification.

(i) In its DSM plan, the utility shall address how it proposes to prioritize DSM services and programs for income-qualified customers and customers in disproportionately impacted communities.

(I) The utility may propose one or more DSM programs for income-qualified customers or customers in disproportionately impacted communities that yield a modified TRC test value below 1.0.

(II) For a utility with 50,000 or more full-service customers, no less than 25 percent of annual residential DSM expenditures shall be targeted on one or more DSM programs or measures for income-qualified residential customers.

(III) For a utility with fewer than 50,000 full-service customers, no less than 15 percent of annual residential DSM expenditures shall be targeted on one or more DSM programs or measures for income-qualified residential customers.

(IV) On or after January 1, 2026, the Commission may commence proceedings to adjust the percentages set forth in subparagraphs 4753(i)(II) and (III) so long as the resulting percentages represent a significant portion of DSM program expenditures and continue to make progress toward achievement of the State of Colorado's energy efficiency and greenhouse gas emission reduction goals.

(j) In proposing an expenditure target for Commission approval, the utility shall comply with the following:

(I) the utility's annual expenditure target for DSM programs shall be consistent with the estimated budget for DSM program expenditures established by the Commission in the utility's most recent strategic issues proceeding; and

(II) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to gas DSM programs may be recovered without having to show that such expenditures, on an independent basis, are cost-effective; such costs shall be included in the overall benefit/cost ratio analysis.

(k) The utility shall propose a budget to achieve the expenditure target proposed in paragraph 4753 (a). The budget shall be detailed for the overall DSM plan and for each program for each year and shall be categorized into:

(I) planning and design costs;

(II) administrative and DSM program delivery costs, including labor costs reflecting compliance with all applicable labor standards set forth in § 40-3.2-105.5, C.R.S.;

(III) advertising and promotional costs, including DSM education;

(IV) customer incentive costs;

(V) equipment and installation costs;

(VI) measurement and verification (M & V) costs; and

(VII) miscellaneous costs.

(l) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.

(m) A utility may spend more than the annual expenditure target established by the Commission up to 25 percent over the target, without being required to submit a proposed DSM plan amendment. A utility may submit a proposed DSM plan amendment for approval when expenditures are in excess of 25 percent over the expenditure target.

(n) As a part of its DSM plan, each utility shall propose a DSM plan with a benefit/cost value of unity (1.0) or greater, using a modified TRC test.

(o) For the purposes of calculating and reviewing a modified TRC, the following components shall be included. Forecasted DSM costs and benefits are used to estimate the cost-effectiveness of DSM measures to develop a cost-effective DSM portfolio.

(I) Benefits shall include, but are not limited to, as applicable: the utility's avoided transmission and distribution capital cost savings associated with reductions or limited growth in design peak demand; energy costs; the participant's avoided operating and maintenance costs; the valuation of avoided greenhouse gas emissions; and non-energy benefits, as set forth in this rule 4753. The valuation of avoided greenhouse gas emissions shall include the social cost of carbon dioxide and the social cost of methane, consistent with rule 4528.

(II) Costs shall include utility and participant costs. The utility costs shall include the net present value of costs incurred in accordance with the budget set forth in rule 4753. For comparative purposes, in addition to this base case calculation of cost-effectiveness, the utility may also provide a case that does not include the social costs of carbon dioxide and methane. Forecasted DSM costs and benefits are used to estimate the cost effectiveness of DSM measures to develop a cost-effective DSM portfolio.

(III) The initial TRC ratio, which excludes consideration of societal benefits, shall be multiplied by a factor established by the Commission in the utility's strategic issues proceeding to reflect the value of the societal and non-energy benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for societal impacts, but must submit documentation substantiating the proposed value.

(IV) A determination of cost-effectiveness using the modified TRC test by the Commission will ultimately be measured at the DSM portfolio level.

(V) For purposes of evaluating a gas DSM program or measure that incorporates innovative technologies with the potential for significant impact, such as energy-saving technologies that go beyond what is achievable using energy efficiency measures alone, the Commission may find the program or measure cost-effective, even if its initial benefit-cost ratio is not greater than 1.0 when calculated using currently available data and assumptions.

(p) Measurement and verification (M & V) plan. The utility shall describe in complete detail how it proposes to monitor and evaluate the implementation of its proposed programs. The utility shall explain how it will accumulate and validate the information needed to measure the plan's performance against the standards, pursuant to rule 4755. The utility shall propose measurement and verification reporting sufficient to communicate results to the Commission in a detailed, accurate and timely basis.

(q) If a utility files an application to open a DSM strategic issues proceeding pursuant to rule 4761, its subsequent DSM plan application shall include programs and measures to, at a minimum, meet the energy savings targets and policy goals established by the Commission in the strategic issues proceeding.

(r) As a part of its DSM plan, each utility shall describe its consideration of incentives for customers to utilize behind-the-meter thermal renewable resources as defined in § 40-1-102(1.1), C.R.S. If the utility proposes to include such incentives in its DSM plan, the cost of such incentives shall be reflected in the budget proposed under subparagraph (j)(IV) above.

4754. Annual DSM Report.

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report.

(a) In the annual DSM report, the utility shall describe its actual DSM programs as implemented. For each DSM program, the utility shall document actual program expenditures, energy savings, and peak demand reduction as a result of energy efficiency programs, peak demand reduction as a result of specific demand reduction programs, avoided greenhouse gas emissions, cost-effectiveness, and participation levels at the measure level for census block groups or zip codes if restrictions apply at the census block group.

(b) Annual program expenditures shall be separated into cost categories contained in the approved DSM plan.

(c) For each DSM program, the utility shall compare the program's proposed and actual expenditures, energy and demand savings, participation rate, avoided greenhouse gas emissions, and cost-effectiveness; in addition, the utility shall prepare an assessment of the success of the program and list any suggestions for improvement and greater customer involvement.

(d) The utility shall provide actual benefit/cost results for the overall DSM plan and individual DSM programs implemented during the plan year. The benefit/cost analysis shall be based on the costs incurred and benefits achieved, as identified in the modified TRC test pursuant to paragraphs 4751(o) and 4753(m) and (n). Benefit values are to be based upon the results of M & V evaluation when such evaluation has been conducted as set forth in rule 4755. Otherwise, the benefit values of the currently approved DSM plan are to be used.

(e) If the annual report covers a year within which an M & V evaluation was completed, the complete M & V results are to be included as part of the annual report.

(f) The greenhouse gas emissions reductions achieved from DSM programs shall be calculated consistent with rules 4525 through 4528.

(g) The annual DSM report shall contain the level of greenhouse gas emissions reductions from DSM programs that qualify as a clean heat resource, reported in levels of carbon dioxide, methane, and carbon dioxide equivalents as well as a report of DSM measures approved as part of a clean heat plan.

4755. Measurement and Verification.

(a) Each utility shall implement a measurement and verification (M & V) program to evaluate the actual performance of its DSM program. The utility shall present its M & V plan as a part of its DSM plan application, pursuant to rule 4753, and shall include the complete M & V evaluation results with its annual DSM report in those years when the M & V is conducted.

(b) As a part of its M & V program, the utility shall, at a minimum, design a M & V plan to evaluate the effectiveness of the actual DSM measures and programs implemented by the utility. The M & V plan shall address: sampling bias; a data gathering process sufficient to yield statistically significant results; and generally accepted methods of data analysis. The M & V plan shall also include an evaluation of free ridership, spillover, and the net-to-gross ratio. The M & V evaluation shall be implemented at least once per the DSM plan period. Subsequent DSM plan applications shall reflect the results of all completed M & V evaluations.

(c) The M & V evaluation shall, at a minimum, include the following:

(I) an assessment of whether the DSM programs have been implemented as set forth in its Commission approved DSM plan;

(II) a measurement of the actual energy savings for each DSM program, in dekatherms per dollar expended and in total dollars, and a comparison to the corresponding utility projections in the approved DSM plan;

(III) to the extent feasible, an assessment of the period of time that each DSM measure actually remains in service, and a comparison to the corresponding utility projections in the approved DSM plan;

(IV) a summary of the actual benefit/cost ratio for each DSM program within the approved DSM plan;

(V) an assessment of the extent to which education and market transformation efforts are achieving the desired results; and

(VI) recommendations for how the utility can improve the market penetration and cost effectiveness of individual DSM programs.

4756. General Provisions Concerning Cost Allocation and Recovery.

(a) Amortization periods.

(I) For the base rate method, the utility shall propose the amortization period. The utility shall specify and explain the rationale for the amortization period proposed for each DSM program as a part of its DSM plan application, filed pursuant to rule 4753.

(II) For the expense method, the utility shall recover the annual expenditures projected for that year over a one-year period.

(b) A utility that provides both regulated gas and electric service shall give consideration to the administrative benefits and reduced costs associated with combining gas and electric DSM activities and shall assign costs and benefits appropriately to each plan.

(c) Distribution of DSM program expenses.

(I) The utility shall include in its portfolio-level benefit/cost analysis all indirect costs relating to DSM, including but not limited to DSM customer education, program design, and evaluation costs.

(II) A utility's existing gas efficiency and conservation customer education tools, such as on-line energy assessment tools or other similar internet based tools, may be included in a utility's gas DSM plan and costs recovered pursuant to a gas DSM cost adjustment consistent with rule 4758.

(d) Decoupling.

(I) The utility may file for approval of a revenue decoupling mechanism to remove disincentives to the implementation of effective gas DSM programs.

(A) The decoupling rate adjustment mechanism shall ensure that the revenue per customer, as established by the Commission, in setting base rates in a general rate case, is recovered by the utility without regard to the utility's sales to customers in the applicable rate class or classes after the date the adjusted base rates take effect.

(B) The Commission shall separately calculate, for the rate class or classes to which a decoupling rate adjustment mechanism applies, the regulatory disincentives removed through that decoupling mechanism and collected or refunded by the utility through a tariff mechanism.

(II) The implementation of a revenue decoupling mechanism does not preclude a utility from receiving a G-DSM bonus pursuant to rule 4760.

4757. Funding and Cost Recovery Mechanism.

The purpose of the G-DSMCA is to enable utilities to recover prudently incurred gas DSM program expenses without requiring a change in their base rates for gas sales. All such costs, plus any G-DSM bonus approved by the Commission, shall be recovered through the G-DSMCA that is set on an annual basis, and collected from July 1 through June 30. The G-DSMCA allows for prospective recovery of prudently incurred costs of DSM programs within the DSM program expenditure target approved by the Commission in order to provide for funding of the utility's DSM programs, as well as recovery of deferred G-DSMCA costs, without having to file a rate case.

(a) A utility may spend a disproportionate share of total expenditures on one or more classes of customers, provided, however, that cost recovery for programs directed at residential customers are to be collected from residential customers only and that cost recovery for programs directed at nonresidential customers are to be collected from nonresidential customers only, except as provided for in paragraph 4757(f).

(b) The utility may recover its DSM program expenditures either through expensing or by adding DSM program expenditures to base rates as a part of, or outside of, a rate case, with an amortization period as set forth in rule 4756.

(c) There shall be no financial penalty assessed on a utility for failing to reach its approved DSM program expenditure target, nor shall there be a bonus simply for meeting its DSM program expenditure target. All prudently incurred expenditures for the utility's portfolio of DSM programs are recoverable. However, the portion of costs yielding a modified TRC test value below 1.0 loses its presumption of prudence and is subject to review.

(d) Amounts not spent under the DSM program expenditure target shall not roll-over to the next DSM period.

(e) A utility has the discretion and the responsibility of managing the portfolio of DSM programs to meet the benefit to cost ratio and the energy and savings targets. In implementing DSM programs, a utility shall use reasonable efforts to maximize energy savings consistent with the approved DSM plan.

(f) A utility may continue DSM programs that were in existence on or before May 22, 2007, the effective date of § 40-3.2-103, C.R.S., concerning measures to promote energy efficiency, and shall not be required to obtain approval from the Commission for recovery of costs associated with such programs. Any new expenditure for such programs must be included in the annual DSM plan filing and G-DSMCA application. Existing low-income DSM programs that recover costs from all customer classes shall continue such recovery.

(g) A utility shall file a request to adjust its G-DSMCA factor either through an application or an advice letter and tariffs, pursuant to the relevant provisions of title 40, articles 1 through 7 of the Colorado Public Utilities Law and of the Commission rules. The G-DSMCA shall be filed pursuant to the schedule provided in rule 4752.

(h) The G-DSMCA filing shall include information and attachments as required in rule 4758. If the M & V evaluation required by rule 4755 yields benefit/costs test results that impact the allowable recovery of costs or currently approved bonus, then the utility shall include such adjustments in the G-DSMCA filing and tariffs.

(i) If the projected DSM program costs have changed from those used to calculate the currently effective G-DSMCA cost or if a utility's deferred G-DSMCA cost balance increases or decreases sufficiently, the utility may file an application to revise its currently effective G-DSMCA factor to reflect such changes, provided that the resulting change to the G-DSMCA factor equates to a base rate change of at least one cent ($0.01) per Mcf or Dth. A utility has the burden of proof to justify any interim G-DSMCA filings and the Commission has the discretion to consolidate the interim G-DSMCA filing with the next regularly scheduled annual G-DSMCA filing.

(j) Applicability of the G-DSMCA factor. The G-DSMCA factor shall be separately calculated and applied to the utility sales gas base rate schedules of residential and non-residential customers.

(k) Return on DSM program expenditures to be amortized. For utilities that choose to amortize the DSM program expenditure, the balance of a utility's investments in cost-effective DSM programs shall earn a return equal to the utility's current after-tax weighted average cost of capital.

(l) Interest on under- or over-recovery. The amount of net interest accrued on the average monthly balance in sub-accounts of Account No. 186 (whether positive or negative), is determined by multiplying the monthly balance by an interest rate equal to the Commission-authorized after-tax weighted average cost of capital.

(m) Calculation of the G-DSMCA factor. The G-DSMCA factor shall be calculated separately for residential and non-residential customers to at least the accuracy of two significant places.

4758. Contents of Gas DSM Cost Adjustment Filing.

(a) General provisions.

(I) A filing for a gas DSM cost adjustment (G-DSMCA) shall contain justifying information sufficient in detail to permit the Commission to determine the accuracy of the supporting calculation.

(II) The G-DSMCA filing shall include a complete set of work papers and all other documents relied on in preparing the adjustment.

(III) The provisions of this rule do not supersede other Commission rules that contain additional applicable filing requirements.

(b) Specific provisions. The filing shall contain detailed schedules and supporting documents that establish, at a minimum, the following:

(I) the detailed calculation of the G-DSMCA for each customer class based on the following general formula:

(A) current G-DSMCA factor = (current G-DSMCA cost + deferred G-DSMCA cost) / (forecasted sales customer x monthly service charge + forecasted sales gas quantity x base rate); and

(B) the G-DSMCA factor will also include the current G-DSM bonus plus any adjustment necessary to previously approved G-DSM bonuses;

(II) a detailed schedule showing the computation of interest, as applicable, to deferred amounts;

(III) the absolute and percentage impact of the proposed rate on the base rates and on the total monthly bills of typical customers in each customer class;

(IV) a schedule detailing the allocation of costs to each customer class;

(V) proposed customer notice detailing rate impact and effective date;

(VI) proposed tariff implementing the proposed G-DSMCA; and

(VII) if any gas DSM costs are proposed to be recovered by rate base treatment, with a return on the unamortized balance, a statement of current net operating earnings, a detailed calculation of the related revenue requirement and an attachment detailing any differences in the proposed rate base treatment compared to the regulatory practices employed by the Commission in its last general rate case for the applicant.

4759. Bill Itemization.

Consistent with rule 4406, a utility shall provide itemized gas cost information with gas DSM costs to all customers commencing with the first complete billing cycle in which the new rates are in effect.

4760. Gas DSM Bonus (G-DSM Bonus).

(a) The Commission shall determine a financial bonus structure for gas DSM. The bonus amount shall be a percentage net economic benefits resulting from a DSM plan over the period under review, with the specific structure and calculation mechanism of the bonus determined by the Commission in the utility's strategic issues proceeding.

(b) The Commission shall review each G-DSM bonus calculation and shall determine the level of bonus, if any, for which the utility is eligible consistent with the bonus framework established in the utility's most recent strategic issues proceeding. The collection on any G-DSM bonus awarded will be apportioned between residential and nonresidential customers based on the proportion of residential and nonresidential net economic benefits used to calculate the G-DSM bonus.

(c) The G-DSM bonus, as modified and approved by the Commission, shall not count against a gas utility's authorized rate of return or be considered as net operating earnings in rate proceedings.

(d) In the G-DSM bonus filing, the utility shall submit to the Commission the following, at a minimum:

(I) documented expenditures on DSM programs for the current G-DSMCA period;

(II) energy savings and peak demand reductions for the calendar year for which the bonus is to be awarded estimated following and the techniques approved in the DSM plan. The utility shall explain whether the actual gas savings are validated through the measurement and verification process as approved in the utility's DSM plan;

(III) estimated cost-effectiveness of program expenditures for the current G-DSMCA period in terms of the amount of gas saved per unit of program expenditures;

(IV) actual gas savings and the techniques used to calculate these gas savings for the prior G-DSMCA period. The utility shall explain whether the actual gas savings are validated through the measurement and verification process, pursuant to rule 4755;

(V) actual cost-effectiveness of program expenditures for the prior G-DSMCA period in terms of the amount of gas saved per unit of program expenditures. The utility shall explain whether the actual cost effectiveness of program expenditures is validated through the measurement and verification process, pursuant to rule 4755;

(VI) proposed tariffs containing rates to collect the bonus over 12 months; and

(VII) any additional information required by the Commission in the utility's most recent strategic issues proceeding.

(e) For the purposes of calculating the bonus, the costs and benefits associated with an income-qualified DSM program may be excluded from the calculation of the net economic benefits for the entire DSM portfolio if the modified TRC value for the income-qualified program is below 1.0. If the modified TRC value for the income-qualified program is above 1.0, the Commission may exclude the net economic benefits attributable to income-qualified programs from the bonus if the utility has met its targets for income-qualified programs.

(f) For the purpose of calculating the bonus, the modified TRC shall be calculated in accordance with paragraph 4753(o), unless otherwise specified in paragraph 4760(e).

(g) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less, or any other incentive cap set by the Commission in the utility's strategic issues proceeding.

(h) Any awarded bonus shall be authorized as a supplement to a utility and not count against its authorized rate of return or be considered in rate proceedings. The awarded bonus shall be recovered through the G-DSMCA over a 12-month period after approval of the bonus.

(i) Any combined electric and gas utility seeking a G-DSM bonus for new residential or commercial construction shall provide a narrative discussion that explains why that gas DSM program does not incent additional gas usage as compared to a beneficial electrification alternative.

(j) Accounting for G-DSM bonus shall follow what has been prescribed for G-DSMCA costs, specifically in regard to interest on over- and under- recovery. A separate sub-account in Account No. 186 shall be created for any deferred G-DSM bonus amount.

(k) If the Commission finds that the actual performance varies from performance values used to calculate the G-DSM bonus in rule 4754, then an adjustment shall be made to the amount of G-DSM bonus award. Any true-up in G-DSM bonus will be implemented on a prospective basis.

4761. Filing of DSM Strategic Issues Applications.

(a) Commencing in 2022, and no less frequently than every four years thereafter unless otherwise directed by the Commission, each utility shall file an application to open a DSM strategic issues proceeding. Strategic issues proceedings shall result in the development of energy savings and peak demand reduction goals to be achieved by the utility, taking into account its potential for cost-effective DSM as well as the State of Colorado's greenhouse gas reduction goals in accordance with § 25-7-102(2)(g), C.R.S.

(b) In its application to open a DSM strategic issues proceeding, the utility shall provide:

(I) an estimated budget, corresponding energy savings and peak capacity reduction goals for all DSM programs;

(II) funding and cost-recovery mechanisms;

(III) a proposed methodology for estimating peak demand savings and the resulting cost savings;

(IV) an analysis of the comparative economics of DSM measures and programs, distinguished by the following:

(A) new construction;

(B) existing homes and businesses; and

(C) all building types;

(V) an analysis of the comparative economics of DSM measures and programs, particularly targeted at the weatherization of existing homes, and beneficial electrification;

(VI) a proposed financial bonus structure for DSM programs implemented by the utility, including any methodologies or formulas used to determine the bonus under that structure;

(VII) for only combined electric and gas utilities, and only for new construction, a narrative analysis of the impact of the proposed gas DSM measures on the comparative economics of beneficial electrification versus the gas alternative; and

(VIII) a cost effectiveness methodology and assumptions that will be in effect during the time period of the goals and budgets set in the strategic issues proceeding.

(c) If the filing of an application to open a strategic issues proceeding overlaps with the filing of a DSM plan application pursuant to paragraph 4752(e), a utility with 250,000 or more full-service customers may request Commission approval for an extension of its currently effective DSM plan until the strategic issues proceeding is concluded. The utility will then file a new DSM plan application with proposed programs and measures to meet the energy savings goals and policy goals established by the Commission in the strategic issues proceeding.

(d) Notwithstanding the requirements in paragraph 4761(a), for gas utilities with fewer than 250,000 full-service customers, the energy savings targets, a budget for gas DSM program expenditures, funding and cost-recovery mechanisms, and a financial bonus structure may be established in the same proceeding in which the utility's DSM plan is submitted for approval.

(e) In its decision addressing the utility's application, the Commission will establish:

(I) savings goals for the utility to be addressed by DSM plan filings in accordance with rule 4753;

(II) an estimated budget for DSM program expenditures commensurate with the savings goals;

(III) a modifying factor to include in the TRC test to account for non-energy societal benefits (excluding the benefits incorporated in the social cost of carbon, the social cost of methane, and other provisions in these rules; and

(IV) a structure for any gas DSM bonus awarded to the utility in accordance with rule 4760. The bonus structure shall reward the utility's investment in cost-effective DSM programs and shall result in an annual bonus amount that reflects the extent to which the utility has achieved the targets established in subparagraphs (I) and (II) above.

4762. – 4799. [Reserved].