Decision No. C22-0760

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21R-0449G

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IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, RELATING TO GAS UTILITY PLANNING AND IMPLEMENTING SB 21-264 REGARDING CLEAN HEAT PLANS AND HB 21-1238 REGARDING DEMAND SIDE MANAGEMENT.

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**COMMISSION DECISION ADOPTING RULES**

Mailed Date: December 1, 2022
Adopted Date: November 2, 4, 9, 23, 2022

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# I. BY THE COMMISSION

## A. Statement

1. Through this Decision, the Colorado Public Utilities Commission (Commission) amends the Commission's Rules Regulating Gas Utilities, 4 Code of Colorado Regulations (CCR) 723-4 (Gas Rules). The amendments add to as well as revise the existing provisions of the Commission's Gas Rules in seven areas: (1) the General Provision rules (General Provisions) at 4 CCR 723-4-4000 et seq.; (2) the Operating Authority rules (CPCN Rule) at 4 CCR 723-4-4102; (3) the Facilities rules (Line Extension Rule) at 4 CCR 723-4-4210; (4) the rules governing calculation of Greenhouse Gas Emissions (Greenhouse Gas Emission Rules) at 4 CCR 723-4-4526 et seq.; (5) the rules governing Gas Infrastructure Planning (Gas Infrastructure Planning Rules) at 4 CCR 723-4-4550 et seq.; (6) the rules governing Clean Heat Plan (Clean Heat Plan Rules) at 4 CCR 723-4-4725 et seq.; and (7) the rules governing Demand Side Management (DSM Rules) at 4 CCR 723-4-4650 et seq.

2. The proposed amendments fulfill the requirements in Senate Bill (SB) 21-264, enacted and effective on June 24, 2021, and codified as § 40-3.2-108, C.R.S., and the requirements of House Bill (HB) 21-1238, enacted on June 24, 2021 and effective on September 6, 2021, codified in §§ 40-3.2-103, 40-3.2-106, and 40-3.2-107, C.R.S.

3. As discussed below, we adopt rules with revisions as attached to this Decision in legislative format (Attachment A) and in final format (Attachment B).

## B. Background

### 1. Notice of Proposed Rulemaking

4. The Commission issued a Notice of Proposed Rulemaking (NOPR) in this Proceeding on October 1, 2021. In the NOPR, we explained that the Commission opened this rulemaking to implement numerous statutory changes and additions adopted in the 2021 Colorado legislative session, establish new rule regulatory requirements for gas utility planning, and fulfill the express rulemaking requirements placed on the Commission.

5. As further explained in the NOPR opening this Proceeding, this rulemaking is specifically intended to satisfy the requirements of Senate Bill (SB) 21-264, enacted and effective on June 24, 2021, and codified as § 40-3.2-108, C.R.S. SB 21-264 requires Colorado gas utilities with more than 90,000 retail customers to develop comprehensive clean heat plans designed to achieve greenhouse gas emissions reductions. This rulemaking is also intended to satisfy the requirements of House Bill (HB) 21-1238, enacted on June 24, 2021 and effective on September 6, 2021, codified in §§ 40-1-102, 40-2-123, 40-3.2-103, 40-3.2-105.5, 40-3.2-106, and 40-3.2-107, C.R.S. HB 21-1238 primarily modifies the statutory provisions governing gas utility demand side management.

6. Prior to issuing the NOPR, the Commission opened a non-adjudicatory administrative proceeding, Proceeding No. 20M-0439G, relating to the Commission's general investigation of retail natural gas industry greenhouse gas emissions in light of the statewide greenhouse gas emissions reduction goals adopted in then-recent HB 19-1261. The Commission also gathered information prior to opening this rulemaking through Proceeding No. 21M-0168G,

where parties had proposed rules for a short-term infrastructure planning rulemaking, and through a Commission-initiated miscellaneous proceeding, Proceeding No. 21M-0395G, where the Commission collected comment and information from Colorado utilities and interested stakeholders.

7. In this Proceeding, the Commission has received well over 300 comment filings from participants, in addition to oral comment received during seven days of public comment hearings, and input from six community meetings around the state. Given the significant number of comments and the wide range of issues, instead of summarizing participant comments overall or by participant, we highlight pertinent comments in each respective rule section of this Decision, instead of summarizing the comments received.

### 2. Comments Received on NOPR

8. The NOPR encouraged interested persons to submit written comments before the public comment hearing scheduled for February 17-18, 2022.[1] The Commission received over 100 initial written comments from participants in this Proceeding. Prior to the public comment hearing, written comments were filed by each of the investor-owned gas utilities in Colorado, including Public Service Company of Colorado (Public Service); Atmos Energy Corporation (Atmos); Black Hills Colorado Gas, Inc. (Black Hills); Durango Mountain Utilities, LLC; and Colorado Natural Gas, Inc. (CNG). In addition, the Commission received filed written comments from, among others, the Colorado Energy Office (CEO); the Colorado Utility Consumer Advocate (UCA); the City and County of Denver; Club 20; Laborers Local 720; the City of Boulder; City of Aurora; Coalition for Renewable Natural Gas (RNG Coalition); Rocky Mountain Institute (RMI);

[1] The Commission continued the hearing to a third day, March 7, 2022, to allow more time to receive oral comment from rulemaking participants.

Colorado Communications and Utilities Alliance; the Town of Windsor; the County of Pueblo; Rocky Mountain Environmental Labor Coalition (Labor Coalition); Olson's Greenhouse Gardens, Inc.; and Conservation Colorado, Natural Resources Defense Council (NRDC), Western Resource Advocates (WRA), Sierra Club, and Southwest Energy Efficiency Project (SWEEP, and jointly with Conservation Colorado, NRDC, WRA, and the Sierra Club, "Conservation Advocates").

9. The Commission received reply comments from several participants, including Conservation Advocates, RNG Coalition, the City and County of Denver, UCA, the County of Pueblo, Atmos, CNG, Public Service, the Labor Coalition, Black Hills, CEO, and RMI.

10. The Commission held public comment hearings on February 17, 18, 2022 and March 7, 2022. Individuals and commenters from interested stakeholder groups had an opportunity to provide oral comments on each hearing day. Oral comments offered at the hearing were recorded in a transcript. In addition to reserved time for general public comment during each public comment session, the Commission organized several discussions centered around key issues discussed within the comments received to date.[2] On February 17, 2022, the Commission invited specific commenters to participate in a discussion regarding "Commission Rulemaking and Utility Application Process and Cadence." Presenters from Public Service, Black Hills, CEO, WRA, the County of Pueblo/Labor Coalition, and Staff of the Commission participated. Also on February 17, 2022, the Commission invited specific commenters to participate in a discussion regarding the Clean Heat Rules and Greenhouse Gas Emission Rules. Presenters from Black Hills, CNG, Public Service, WRA, RNG Coalition, Energy Outreach Colorado (EOC), the County of Pueblo/Labor Coalition, SWEEP, Laborers Local 720, CEO, and Atmos participated.

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[2] Decision No. C21-0088I, issued on February 9, 2022, provided participants with a schedule and proposed topic area discussions for the February and March public comment hearings.

11. On February 18, 2022, the Commission invited specific commenters to participate in a discussion regarding the DSM Rules. Presenters from Public Service, CNG, CEO, SWEEP, and EOC participated. Also on February 18, 2022, the Commission invited specific commenters to participate in a discussion regarding Gas Infrastructure Planning Rules and the CPCN Rule. Presenters from Public Service, Atmos, Black Hills, CEO, NRDC, and RMI participated. In addition to the invited commenters, public comment was also welcome.

12. On March 7, 2022, the Commission invited specific commenters to participate in a discussion regarding the Line Extension Rule. Presenters from Public Service, CNG, CEO, NRDC, RMI, and Laborers Local 720 participated. In addition to the invited commenters, public comment was also welcome.

13. Additionally, on March 28, 2022, the Commission received written comments from several participants (referred to in this Decision as, "the Joint Comments") in response to Decision No. C22-0132-I. The Joint Comments were filed by Public Service, API Colorado, Atmos, Black Hills, CNG, Conservation Advocates, CEO, UCA, the City of Boulder, the Coalition for Renewable Natural Gas, RMI, and the Labor Coalition. On April 29, 2022, Commissioner Gilman held a workshop with representatives from the participants filing the Joint Comments to facilitate the Commission's understanding of those comments.

### 3. July Redlines

14. On July 22, 2022, the Commission issued Decision No. C22-0427-I, which proposed additional rule revisions for comment (referred to in this Decision as, "the July Redlines").

15. Decision No. C22-0427-I also scheduled additional days of public comment on the proposed rules for August 9 and September 19, 2022.

16. After issuing the July Redlines, the Commission received comments from Public Service, UCA, Atmos, CNG, Black Hills, the Labor Coalition, Dandelion Energy, CEO, Conservation Advocates and RMI, jointly, API Colorado, Advanced Energy Economy, the City of Aurora, the City and County of Denver, Project Canary, RNG Coalition, CC4CA, Laborers Local 720, and Staff of the Commission, as well as several other organizations and interested members of the public.

17. The Commission conducted public comment hearings on the proposed rules on August 9 and September 19, 2022. Written comments offered at the hearing were included in the record in this Proceeding. Oral comments offered at the hearing were recorded in a transcript.

### 4. Additional Rulemaking Efforts

18. Throughout this rulemaking, the Commission has held additional workshops and events to aid the Commission's understanding of the gas industry and to provide opportunities for public involvement in the rulemaking process. Decision No. C22-0427-I describes more fully earlier workshops and overview meetings held by the Commission.

19. Through its staff, the Commission conducted an informational meeting on January 27, 2022. The purpose of the meeting was to provide educational content on the statutory basis for the rulemaking and on key terms, as well as to help members of the public, including representatives from disproportionately impacted communities, understand opportunities to participate.[3]

20. The Commission convened an additional day of public comment on August 31, 2022, to receive comments from the Air Pollution Control Division of the Colorado

[3] This meeting was conducted pursuant to § 40-2-108(c)(II), C.R.S.

Department of Public Health and Environment (CDPHE) regarding their development of expected greenhouse gas accounting procedures intended to be used by utilities when creating clean heat plan filings. The resulting guidance and workbook developed by the Division is discussed in more detail below.

21. The Commission conducted an additional public comment hearing on the proposed rules on October 19, 2022, primarily for the purpose of receiving comments on labor issues arising in this rulemaking, including, best value employment metrics, the use of Colorado-based labor and out-of-state labor, competitive solicitation provisions, and labor standards for demand side management programs or projects and clean heat plan endeavors. Oral comments offered at the hearing were recorded in a transcript. The Commission received pre-hearing comments related to labor issues from WRA, NRDC, and SWEEP. After the hearing, the Commission received joint comments from the Conservation Advocates, the Labor Coalition, Laborers Local 720, and Public Service on October 20, 2022 (Consensus Labor Comments). The Commission addresses the substance of these comments in more detail below.

**a. Community Meetings**

22. On February 3, 2022, the Commission held a workshop focused on disproportionately impacted communities. Staff from CDPHE presented on the Colorado EnviroScreen and other mapping tools, and presenters from Applied Economics Clinic and Energy Equity Project discussed best practices for engaging representatives from disproportionately impacted communities, as well as the kinds of information that may be useful to assess prioritization.

23. Based on information the Commission solicited from regulated gas distribution utilities, disproportionately impacted communities were identified in which to hold meetings

soliciting input on the contents and evaluation of clean heat plans.[4] The Commission scheduled six community meetings throughout Colorado.

24. Through these community meetings, the Commission sought input regarding community energy priorities in disproportionately impacted communities as well as input on future clean heat plans. To facilitate better discussion with participants on these issues, especially participants who may have limited or no experience interacting with the Commission, these meetings were structured more informally than typical on-the-record public comment hearings with a live court reporter. These meetings were structured as open public meetings with the intent of garnering robust discussion among participants.

25. Through these community meetings held in July and August 2022 in the communities of Greeley, Denver, Grand Junction, Montrose, Pueblo, and Lamar, the Commission satisfied the requirement in § 40-3.2-108(5)(a), C.R.S., which requires the Commission to convene at least four workshops or public meetings to solicit input on the contents and evaluation of gas distribution utilities' clean heat plans, two of which must be located in disproportionately impacted communities served by the utility that is required to submit a clean heat plan. The Commission also gained valuable insights from community members and organizations.

26. Commission advisory staff prepared and filed a summary of comments made by participants into the record of this Proceeding and presented general findings from the community meetings at the Commissioners' Weekly Meeting on October 26, 2022.

[4] In Decision No. C22-0152-I, the Commission directed the regulated gas distribution utilities, Black Hills, Public Service, Atmos, and CNG, to submit information on disproportionately impacted communities in which to hold meetings for soliciting input on the contents and evaluation of clean heat plans.

### C. Discussion, Findings, and Conclusions

27. In the NOPR, the Commission expressed agreement with the sentiment that this rulemaking will be comprehensive and at the forefront of the evolution of the gas utility industry. Fourteen months later, we continue to believe the rules adopted here present an important step in the evolution of the gas utility industry in Colorado. Throughout this rulemaking, participants have requested the Commission bifurcate the numerous topics addressed into one or more separate rulemakings. We have, and continue to find, it appropriate to take the concepts of line extension policies, gas infrastructure planning, and implementation of the requirements in SB 21-264 and HB 21-1238 together in this single rulemaking because we find the topics interwoven and the record supportive of implementing rules in these areas. As stated in the NOPR, the Gas Infrastructure Planning Rules are intended to work in conjunction with the Clean Heat Plan Rules during the coming years when the gas utilities will transition their businesses and the services they provide to their customers in order to achieve the substantial reductions in statewide greenhouse gas emissions required by § 25-7-102(2)(g), C.R.S. The Commission believes having additional insights into system planning, forecasting and investments as provided by the Gas Infrastructure Planning Rules provides a necessary component of the regulatory structure going forward to ensure appropriate oversight of long-term and costly investments in gas system infrastructure. We foresee this rulemaking as one incremental step in the larger evolution of the shifting regulatory framework for the gas industry.

28. The Commission promulgates rules under its legislative function that are necessary for the proper administration and enforcement of the Public Utilities Law (*i.e.*, Articles 1 through 7 of Title 40 of the Colorado Revised Statutes) and within the Commission's broad Constitutional and statutory authority to regulate utilities. *See* Article XXV of the Colorado

Constitution and § 40-2-108(1), C.R.S. In the regulation of public utilities, the Commission has authority unless and until the General Assembly expressly acts to restrict the Commission's authority.[5] While the adoption of the Greenhouse Gas Emission Rules, the Clean Heat Plan Rules, and the amendments to the DSM Rules are rooted in recent statutory changes, the Commission conducts this rulemaking consistent with both these recent statutory directives and its longstanding broad Constitutional and statutory authority to regulate utilities.

29. In rendering this Decision, the Commission has carefully reviewed and considered all of the participant comments in this Proceeding, whether filed in writing or provided orally at a public comment hearing, even if this Decision does not specifically address every comment made.

30. By mailing this Decision on or by December 1, 2022, the Commission satisfies the statutory requirement of § 40-3.2-108(5)(b), C.R.S., which requires the Commission to adopt by December 1, 2022, rules as necessary for gas distribution utilities to implement clean heat plans.

### 1. Basis, Purpose, and Statutory Authority

31. The NOPR proposed revisions to the Basis, Purpose, and Statutory Authority section of the Gas Rules to shift and broaden the focus of the rules to include not only regulation of jurisdictional gas utilities and their services, but also their actions to reduce greenhouse gas emissions from the use of gas by their customers and from leaks in their facilities. We also updated the expanded statutory authority found at §§ 40-3.2-103, 40-3.2-106, 40-3.2-107, and 40-3.2-108, C.R.S. In the July Redlines, we proposed additional minor changes to remove the word "natural" preceding "gas" as proposed by CEO.[6] This change aligned the purpose section more closely to

[5] *Colorado-Ute Electric Association, Inc. v. Public Utilities Commission*, 760 P.2d 627, 638-39 (Colo. 1988); *see also Integrated Network Services, Inc. v. Public Utilities Commission*, 875 P.2d 1373, 1377 (Colo. 1994) (the Commission "has broad constitutional and legislative authority to regulate public utilities in Colorado").

[6] CEO January 25, 2022 Comments, pp. 19-20.

the proposed definition of "gas" in Rule 4001. The Commission has not received additional comments regarding this section and therefore we adopt the rule language as proposed in the NOPR and revised in the July Redlines.[7]

### 2. General Provisions

#### a. Rule 4001. Definitions

32. The NOPR proposed several defined terms arising from the new statutory requirements, including defined terms for "Air Quality Control Commission," "biomethane," "discount rate," amendments to the current defined terms for "gas," "green hydrogen," "mandatory relocation," "pyrolysis," "recovered methane," "recovered methane credit," and "sales customer." In the July Redlines, the Commission also proposed adding a defined term for "Air Pollution Control Division," "disproportionately impacted community," "green hydrogen project," "income-qualified utility customer," "non-pipeline alternative," and "recovered methane protocol."

33. *Air Quality Control Commission and Air Pollution Control Division.* The NOPR proposed a definition for the term "Air Quality Control Commission." The Air Quality Control Commission establishes recovered methane protocols pursuant to § 40-3.2-108(2)(p), C.R.S. In the July Redlines, we also proposed defining the term "Air Pollution Control Division," also referred to as the "Division," to clarify the respective roles for these administrative bodies. The Division is responsible for administering and enforcing air quality control programs adopted by the Air Quality Control Commission and serves as expert staff to the Air Quality Control Commission in rulemaking matters pursuant to §§ 25-7-111(1) and 25-7-111(2)(g), C.R.S. As

[7] Where this Decision states the Commission adopts rule language as proposed in the NOPR or the July Redlines, we mean that we adopted the general substance of the proposed rule language and may have made minor edits for clarity as well as consistency with other rules.

addressed in the adopted rules, the Division publishes the clean heat workbook referenced in Rule 4527(a) and is intended to work with the Commission to set future mass-based clean heat targets for the utilities' clean heat plans for years 2035 and beyond, as described in Rule 4728. Through this Decision, we adopt definitions for these terms as shown in Attachments A and B to this Decision.

34. *Best Value Employment Metrics*. The Consensus Labor Comments, filed October 20, 2022, propose a definition for "best value employment metrics," which the commenters contend gives the Commission "a strong foundation in place to ensure that labor metrics are thoroughly considered and vetted in any alternatives analysis and Clean Heat Plans."[8] We adopt the proposed definition as part of Rule 4001 and for implementation in the utilities' clean heat plan, gas infrastructure plan applications, and CPCN applications, as applicable.

35. *Biomethane.* The NOPR added a definition for the term "biomethane," based on the new statutory definition in § 40-3.2-108(2)(a), C.R.S., added by SB 21-264. In the July Redlines, the Commission proposed for comment refinements to the proposed definition of "biomethane" to more closely match § 40-3.2-108(2)(a), C.R.S., in light of comments received by CEO.[9] We received minor comments from Atmos and Black Hills suggesting that "pipeline quality" is more accurately characterized as "pipeline quality gas standards." With this modification, we adopt the defined term "biomethane" as presented in the July Redlines.

36. *Blue Hydrogen.* API Colorado, CNG, and Public Service each suggest a definition of "blue hydrogen" for inclusion in Rule 4001. CNG maintains that all options for clean heat resources should remain as an option for utilities, and blue hydrogen should be eligible as a clean

[8] Consensus Labor Comments, p. 2.
[9] CEO January 25, 2022 Comments, p. 18.

heat resource because there is no language expressly prohibiting it in SB 21-264. Public Service proposes to define "blue hydrogen" to mean hydrogen that can reduce greenhouse gas emissions when used in a variety of sectors, including the high-heat industrial applications, electricity generation, and the gas distribution system, but is not required to be sourced from renewable energy.[10] API Colorado proposes that hydrogen is "blue hydrogen," and carbon neutral, if it is created from natural gas through a process of steam methane reforming and if the resulting carbon dioxide emissions are captured and stored underground.[11]

37. We decline to adopt a definition of "blue hydrogen" at this time. We are mindful that blue hydrogen is not defined in SB 21-264, nor to date has any other statute or regulation in Colorado defined blue hydrogen. By the plain statutory language, a utility "may include proposals to make investments in green or blue hydrogen projects that will reduce greenhouse gas emissions" in its clean heat plan filing pursuant to § 40-3.2-108(f), C.R.S. If a utility chooses to do so, it should present why its investment qualifies as "blue" hydrogen as part of its filing for the blue hydrogen project proposal. While we agree with Public Service that "blue hydrogen" is generally accepted to mean hydrogen not sourced from renewable energy but that can reduce greenhouse gas emissions, it would be incumbent on the utility to show that the hydrogen project proposed would actually reduce emissions in a manner appropriate to be considered "blue" hydrogen. Further, defining the term in Rule 4001 would be inconsistent with the Commission's typical approach in rules because the term is not used anywhere in the adopted Gas Rules, as it was not included in the statutory list of clean heat resources expressly listed in SB 21-264.

[10] Public Service October 7, 2022 Bluelines.
[11] API Colorado September 1, 2022 Comments, p. 10.

38. *Dedicated Recovered Methane Pipeline.* Under § 40-3.2-108(3)(c), C.R.S., for recovered methane to count towards a utility's compliance with the emission reduction goals, it must be: (1) represented by a recovered methane credit and; (2) delivered either (A) "to or within Colorado through a dedicated pipeline" or (B) "through a common carrier pipeline if the source of the recovered methane injects the recovered methane into a common carrier pipeline that physically flows within Colorado or toward the end user in Colorado for which the recovered methane was produced."[12]

39. The Air Quality Control Commission recently released draft recovered methane protocol rules which must be in effect by February 1, 2023. This rulemaking develops specific protocols for recovered methane produced by: (1) coal mine methane where capture is not otherwise required by state or federal law; (2) gas system leaks; (3) municipal solid waste; (4) pyrolysis of municipal solid waste; (5) biomass pyrolysis or enzymatic biomass; and (6) wastewater treatment. The Air Quality Control Commission also released draft rules to establish a recovered methane credit and tracking system as required by SB 21-264.

40. Neither the Commission's NOPR nor the July Redlines proposed a definition of "dedicated pipeline" and SB 21-264 does not define the term either. For its purposes, Air Quality Control Commission has proposed to define "dedicated pipeline" to mean "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, small gas distribution utility, or

[12] § 40-3.2-108(3)(e), C.R.S.

municipal gas distribution utility."[13] CEO comments that Air Quality Control Commission's proposed definition would not require recovered methane to be injected into a utility pipeline because the cost involved for the necessary interconnections could be prohibitive to recovered methane project developers. CEO proposes revisions to coincide with the Air Quality Control Commission's intended definition of "dedicated pipeline."[14]

41. We recognize the need for the Air Quality Control Commission's recovered methane protocol rules and tracking system to align with the Commission's rules for both clarity and usableness. The Air Quality Control Commission's proposed credit and tracking system would verify both that the recovered methane is represented by a recovered methane credit and delivered via a dedicated or common carrier pipeline. As such, we find it appropriate to adopt a similar defined term of "dedicated recovered methane pipeline" both to remove ambiguity in the Commission's Gas Rules and to ensure workability with Air Quality Control Commission's proposed rules.

42. *Design Day Peak Demand.* The NOPR proposed in Rule 4553(b) that a utility shall prepare a capacity forecast on a design or peak day requirement basis. In the July Redlines, we incorporated for comment the inclusion of peak demand reduction in several places in the DSM Rules. We expressed our interest in exploring factors influencing design day peak demand as part of the clean heat plan and gas infrastructure plan processes moving forward at both the public comment hearing on September 19, 2022 as well as in Decision No. C22-0588-I. The Commission requested participants consider additional comment on several areas in Decision No. C22-0588-I. In particular, we asked for comment on inclusion of consideration of design day peak demand in

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[13] *See* https://drive.google.com/drive/u/0/folders/1HYFMAU7ptCDuib_DabOob90zh83dkG-k.
[14] CEO October 7, 2022 Comments, p. 16.

several areas of the Gas Rules, including (1) in interactive mapping tools; (2) as part of the definition of "full incremental cost" in the Line Extension Rule; (3) the feasibility and value of having a high and a low forecast of peak design day demand and associated capital requirements as part of the clean heat plan process; and (4) the feasibility and value requiring any evaluation of the general benefits of a DSM program or measure under the modified TRC test to fully include the cost and other savings arising from reductions in local, regional, or overall system-wide peak design day demands.

43. To aid consideration of design day peak demand in numerous areas of the Gas Rules, including provisions governing line extension policies, we adopt a definition of "design day peak demand" in Rule 4001. Based off comments from the utilities that explain generally how they model design day demand, we define "design day peak demand" to mean the highest hourly natural gas flow rate projected for a utility system, or a portion thereof, based on the relevant design day coldest temperature, *i.e.*, the 1-in-30-year low temperature data.

44. *Discount Rate.* The NOPR added a definition for the term "discount rate," consistent with the direction in § 40-3.2-107(2)(c), C.R.S., regarding discount rates for future cost streams. The NOPR proposed a general defined term for "discount rate" to replace a specific term in current DSM Rule 4751. In its initial comments, Public Service suggested deleting the proposed definition of "discount rate" because it finds the wording vague and claims a definition is not required by statute. UCA agreed with Public Service that the definition of "discount rate" is vague and recommended the Commission establish a specific value now, in rule, to avoid continued debate in future proceedings. UCA suggested setting a three percent discount rate for use in net present value calculations. CNG also agreed with Public Service that the definition of "discount rate" is vague and supported eliminating this definition. Atmos commented, to the extent this term

needs a definition within the rules, the rules should define a discount rate specific to the social cost of carbon, rather than confuse the term with other uses.

45. We understand stakeholders' concerns that an overall definition of "discount rate" may not be the best approach for the Gas Rules. At this time, we decline to adopt the proposed general definition of "discount rate" in Rule 4001 and will continue to use a specific definition of "discount rate," where appropriate, in specific rule sections.

46. *Disproportionately Impacted Communities.* In the July Redlines, we proposed a definition of "disproportionately impacted communities" derived from § 40-2-108(3)(d), C.R.S. In response, Laborers Local 720 recommends expanding the proposed definition of disproportionately impacted community to include "the construction workforce that has historically relied on natural gas facilities for employment opportunities"[15] We recognize the complexity of this definition and that these issues are arising in different forums across the state. However, Senate Bill 21-272 directs the Commission to identify disproportionately impacted communities in the course of promulgating rules in which it considers how best to provide equity in all of its work.[16] The Commission opened Proceeding No. 22M-0171ALL to gather information and take other steps to prepare to make rules.[17] Additionally, the Environmental Justice Action Task Force that was created under the Environmental Justice Act, HB 21-1266, recently issued its final report which recommended that the state legislature amend and standardize the definition of disproportionately impacted communities across state agencies.[18] Given the efforts in other more appropriate forums to examine this issue, we find it best to not

[15] Laborers Local 720 October 7, 2022 Comments, p. 3.

[16] § 40-2-108(3)(b)-(c)(I), C.R.S.

[17] Proceeding No. 22M-0171ALL, Decision No. C22-0239, issued April 28, 2022.

[18] Colorado Environmental Justice Action Task Force, Final Report of Recommendations (November 14, 2022) 30-31, *available at* https://drive.google.com/file/d/1RGHhlQHnQFC391VTgkLqHxxsPXeNZJfh/view.

adopt Laborers Local 720's proposed modifications to the definition of disproportionately impacted communities at this time.

47. *Gas.* For the same reasons discussed for adopting the defined term "dedicated recovered methane pipeline," we adopt minor edits as proposed by CEO to the Commission's proposed definition of "gas."

48. *Income-qualified Utility Customer.* The July Redlines proposed a definition of "income-qualified utility customer" as a customer meeting the requirements of § 40-3-106(1)(d)(II), C.R.S. CEO highlights that HB 22-1018[19] modified the definition of "income-qualified utility customer" in that statute, and recommends the Commission revise the proposed definition to be consistent with the most-current statutory language.[20] Given the definition directly refers to the currently effective and therefore most up-to-date statute, we do not see a need to change the definition proposed for "income-qualified utility customer." This statutory provision was amended in both 2021 and 2022; the Commission's direct reference to the statute is a reasonable legal practice to promote efficiency.

49. *Mandatory Relocation.* The Commission adopts the definition of "mandatory relocation" proposed in the NOPR with one change. In response to comments from Atmos and CNG, we expand the definition of "mandatory relocation" to also encompass mandatory relocations required by the federal government and tribal authorities.[21]

50. *Natural Gas*. We adopt the defined term "natural gas" as proposed in the NOPR.

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[19] House Bill 2022-1018, *Electric and Gas Utility Customer Protections, Concerning a state regulated utility's practices regarding a customer's ability to pay the customer's utility bill*, enacted April 21, 2022.

[20] CEO August 24, 2022 Comments, pp. 4-5.

[21] Atmos August 8, 2022 Comments, p. 3; CNG August 24, 2022 Comments, p. 3.

51. *Non-Pipeline Alternative*. Section 40-3.2-108(3)(f), C.R.S., states the Commission may require a utility to evaluate non-pipeline alternatives. In the July Redlines, we proposed for comment a definition of "non-pipeline alternative." In response, Atmos comments that demand response should also include compressed natural gas, liquid natural gas facilities that would avoid the construction of pipeline infrastructure through peak-shaving, and dual-fuel capabilities that can reduce the need for additional gas infrastructure. Atmos Energy also notes that a utility's acquisition of existing infrastructure for which abandonment was proposed could also reduce the need for additional gas infrastructure. Atmos argues that the Commission should have the discretion to consider other alternatives on a case-by-case basis.[22] We discuss later changes to the Gas Infrastructure Planning Rules that incorporate requirements for a utility to present a non-pipeline alternatives analysis in certain situations in its gas infrastructure plan. In conjunction with these changes, we adopt a definition of "non-pipeline alternative" as presented in the July Redlines for inclusion in Rule 4001. We find that the definition adopted affords enough flexibility to ensure the Commission retains discretion to consider other alternatives when presented by utilities.

52. *Pressure District.* In the NOPR, we discussed the need for greater visibility into a gas utility's future projects and expenditures and stated that new rules are necessary to understand where new facilities are being considered to meet various needs within specific geographic areas. We also proposed for comment a requirement that utilities conduct analysis on a geographically specific basis. We sought comment on whether forecasts for investments and expenses can be reported by the utility down to the applicable upstream regulator station or some other

[22] Atmos August 8, Comments, pp. 2-3.

geographically defined area to provide an increasingly localized approach to both short-term and long-term planning.

53. After considering the discussion at the public comment hearings and in written comment, we proposed requiring forecasting at the regulator station level in the July Redlines. In response, we received comments from utilities that this level of granularity is too specific to be workable. Black Hills states it has over 900 regulator stations[23] and Public Service states it has some 2,300 regulator stations within its service territory.[24] Black Hills suggested at the public hearing and again in follow-up comments to replace regulator station with "town border station" of which it has approximately 50 of those on its system.

54. CEO generally supports the mapping and granularity requirements and argues for a system-wide understanding of the locations and ages of pipes. CEO also suggests the Commission require utilities to indicate in their maps the age and material type of all pipes.[25]

55. Public Service suggests retaining flexibility by replacing regulator station with "sufficient geographic detail to allow a thorough Commission evaluation."[26]

56. Conservation Advocates and RMI suggest a concept of geographic analysis of "system nodes" to identify the percent of infrastructure of different ages, declining number of gas customers, declining gas throughput, and overlap with disproportionality impacted communities or a higher portion of income-qualified customers.[27] They suggest that the Commission require utilities provide an assessment of the existing system, including identifying nodes of the system

[23] Black Hills August 26, 2022 Comments, p. 25.
[24] Public Service October 7, 2022 Comments, p. 25.
[25] CEO October 7, 2022 Comments, pp. 13-14.
[26] Public Service October 2022 Bluelines.
[27] Conservation Advocates and RMI August 24, 2022 Comments, p. 6.

where the utility forecasts a need to replace distribution mains, service lines, meters, or other distribution equipment within a ten-year period. In response, CNG reiterates concerns about sensitive security information if geographical analyses are too detailed. Black Hills also responds that the node concept is related to "strategic pruning" of utility's distribution system.[28] In order to comprehend where the utility may experience system constraints, the need for investment in capacity expansion projects, and the opportunity presented in non-pipeline alternatives or other alternatives to traditional capacity expansion, the Commission has adopted the term "pressure district." We incorporate into Rule 4001 a definition of "pressure district" which means an area within a utility's service territory with a distinct pressure environment from neighboring regions. As discussed below, we are focused on receiving greater visibility into a gas utility's future projects and expenditures within specific geographic areas. We find that defining areas by "pressure districts" provides a useful geographic specificity to understand capacity expansion and other project needs at a level that the Commission understands to be, in most cases, looser than the regulator station requirement, but more granular than a town border station or citygate, which the Commission feels is an appropriate level of granularity for our first efforts at gas infrastructure planning. The "node" concept proposed by Conservation Advocates and RMI is not sufficiently developed or sufficiently focused on future infrastructure needs to be workable at this time.

57. *Pyrolysis.* We adopt the definition of "pyrolysis" as proposed in the NOPR and adapted from the statutory definition in § 40-2-124(1)(a)(V), C.R.S.

58. *Recovered Methane.* The NOPR added a definition for the term "recovered methane," based on the statutory definition in § 40-3.2-108(2)(n), C.R.S., added by

[28] Black Hills September 6, 2022 Comments, p. 7.

SB 21-264. The July Redlines proposed revisions based on comments from CEO, Public Service, and Conservation Advocates.

59. Section 40-3.2-108(2)(n), C.R.S., requires that recovered methane be "located in Colorado" which is reflected in the proposed rule language in the July Redlines. We received numerous comments regarding this provision.

60. Conservation Advocates has raised several times that it understands SB 21-264 to require that recovered methane be obtained from within the state. It argues, "by its plain language, the Clean Heat statute does not contemplate recovered methane resources or projects located out of the state" and that the "structure of the statute supports this interpretation" because in § 40-3.2-108(1)(b)(I), C.R.S., "the General Assembly determined that, through development of recovered methane projects, there is a potential to reduce methane emissions and create economic development opportunities 'especially in rural Colorado.'"[29] Conservation Advocates also maintains the policy directives of SB 21-264 can only be accomplished if a recovered methane project is geographically located in Colorado.

61. Atmos, API Colorado, and CNG each contend it makes more sense to interpret SB 21-264 to allow for recovered methane to be sourced outside of Colorado for both practical and statutory interpretation reasons. Atmos contends, while the definition requires "recovered methane" to be "located in Colorado," § 40-3.2-108(3)(e), C.R.S. states recovered methane must be represented by a recovered methane credit and delivered "to or within Colorado through a dedicated pipeline" or "through a common carrier pipeline if the source of the recovered methane injects the recovered methane into a common carrier pipeline that physically flows within Colorado or toward the end user in Colorado for which the recovered methane was produced."

[29] Conservation Advocates October 7, 2022 Comments, pp. 15-16.

Based on this language, Atmos reasons a recovered methane project located outside of Colorado could never be a clean heat resource, but its output could still be purchased under a utility's clean heat plan if it was produced subject to a recovered methane protocol approved by the Division and injected into a dedicated pipeline or common carrier pipeline that flowed in Colorado toward the end-user in Colorado for which the recovered methane was produced. API Colorado states, regardless of any confusion in the statutory language, it makes sound economic sense to expand the pool of potential recovered methane to increase economic efficiency and encourage the maximum development of methane recovery.

62. The Air Quality Control Commission recently released its draft recovered methane credit and tracking system rule proposal.[30] We understand their draft credit and tracking system to only track recovered methane sources located in Colorado. The Air Quality Control Commission indicates in its proposed definition of "recovered methane" that it means resources located in Colorado. We find that specifying that recovered methane sources must be located in Colorado is appropriate in the definition of "recovered methane" and in Rule 4731(a)(II)(B). It is important for the Commission's Gas Rules to work in conjunction with the Air Quality Control Commission's recovered methane credit and tracking system. We are also persuaded by comments from Conservation Advocates and others that specifying that recovered methane must be located in Colorado furthers the legislative purposes of SB 21-264.

63. *Sales Customer*. The NOPR proposed a new single definition for a "sales customer" or "full service customer" so that a single definition could apply throughout the Gas Rules. We adopt the definition as proposed in the NOPR.

[30] *See* https://drive.google.com/drive/u/0/folders/1HYFMAU7ptCDuib_DabOob90zh83dkG-k.

#### b. Rule 4002. Applications

64. We adopt Rule 4002 as proposed in the July Redlines.

#### c. Rule 4005. Records

65. In the NOPR, we proposed minor changes to Rule 4005 to incorporate records related to new applications, including gas infrastructure plans, demand side management plans, demand side management strategic issue plans, and clean heat plans. In the July Redlines, we proposed for comment additional changes that (1) update the file retention time to four years; and (2) require utilities to provide complete tariffs on its website. We received limited comments in response from UCA,[31] Black Hills,[32] and Atmos.[33] We adopt Rule 4005 as presented in the July Redlines in light of the comments received.

### 3. Operating Authority

#### a. Request to Bifurcate Gas Infrastructure Planning and CPCN Issues from this Rulemaking

66. Several commenters suggested bifurcating the Gas Infrastructure Planning Rules and the CPCN Rule from this Proceeding, given the statutory deadline of December 1, 2022. Black Hills contends "[t]he Commission should finalize rules that are clearly in compliance with statute while taking the necessary time to fully analyze the remaining issues and their potential impacts, not only on the utilities, but also on our customers."[34] Black Hills argues, "[d]ue to the multitude of rules and issues addressed in the instant rulemaking, along with the rather congested regulatory schedule, the Company does not believe that participants have had a

[31] UCA August 24, 2022 Comments, p. 6.
[32] Black Hills August 24, 2022 Comments, p. 5.
[33] Atmos August 8, 2022 Comments, p. 3.
[34] Black Hills October 11, 2022 Comments, pp. 2-3.

real opportunity to digest the multiple proposed modifications and utilities have not had an opportunity to fully evaluate the proposed demands being imposed"[35] and that the broad rulemaking effort, has sown "confusion as to what goes into an infrastructure plan."[36] Public Service suggests, "[t]he Commission should balance the proposals to make certain that the modified rules are not overly burdensome or ambiguous, that they do not increase economic and judicial inefficiency, and that they do not reduce consumer choice while increasing consumer costs."[37]

67. CNG agrees it would be "beneficial to split some of these more complicated areas out and give them more time to work through."[38] Each utility generally echoed Black Hills' concern about the potential administrative burden.

68. Other commenters supported the Commission continuing its approach of a single rulemaking. At hearing and through comments CEO supports the single rulemaking approach.[39] CEO states the focus of the broader gas rules should be on integrated planning, and that the rules regarding CPCNs, gas infrastructure planning, demand side management, and clean heat plans will all be needed "in order to make progress towards our near-term and long-term emissions goals."[40] CEO contends it is important to issue the rules together in order to see how those different types of plans work together, can balance one another, and avoid leaving any gaps in the planning as we move forward. CEO maintains the Commission's rules are well developed and "on track" to meet the statutory deadline.[41] CEO also stated that confusion on some of the technical details is not an

[35] Black Hills October 11, 2022 Comments, p. 2.
[36] Hrg. Tr. September 19, 2022, at 125:12-16 and 33:4-9.
[37] Black Hills October 11, 2022 Comments, p. 2.
[38] Hrg. Tr. September 19, 2022, at 126:7-9.
[39] CEO October 7, 2022 Comments, p. 5.
[40] Hr. Tr., September 19, 2022 at 126.
[41] Hr. Tr. September 19, 2022 at 127:1-18.

appropriate reason to bifurcate the rules because it is not uncommon to refine the various terms and application requirements during the rulemaking process.[42]

69. WRA agrees with CEO the rulemaking represents a holistic strategy toward building decarbonization which is in line with other jurisdictions that have found gas planning to represent a critical cost-containing strategy to support a decarbonization pathway, and that such concepts are inextricably linked.[43]

70. Atmos suggests it will be difficult to fully comprehend the breadth of the rulemaking until it is put into practice.[44] Public Service also emphasizes the need to continually evaluate the rules, the cost and benefit of such to the customers, and to fine-tune the rules over time.[45]

71. With respect to whether it is appropriate to issue the rules in a single proceeding, we offer the following background. In the wake of a Public Service rate proceeding, the parties to that case—including Public Service, Trial Staff of the Colorado Public Utilities Commission, UCA, CEO, Black Hills, Atmos, CNG, and Rocky Mountain Natural Gas—filed a petition before the Commission requesting the Commission open a rulemaking proceeding for the purposes of adding rules to the Gas Rules to address short-term gas capacity and infrastructure planning and reporting (ST-GIP Petition) in early 2021.[46] The ST-GIP Petition proposed rules to govern the presentation and review of individual planned transmission and distribution capacity and infrastructure projects with the overall intent of provision transparency into the utility planning

[42] Hr. Tr. September 19, 2022 at 126:20-23.
[43] Hr. Tr. September 19, 2022 at 127-128.
[44] Hr. Tr. September 19, 2022 at 128.
[45] Hr. Tr. September 19, 2022 at 128-129.
[46] Joint Petition for a Rulemaking on Short-term gas infrastructure planning and reporting in compliance with Decision No. R20-0673, and request to stay Commission acceptance and any noticing of the Petition, submitted April 30, 2021.

processes. By Decision No. C21-0446, issued July 23, 2021, in Proceeding No. 21M-0168G, the Commission denied the ST-GIP Petition. The Commission explained it is more appropriate to contemplate gas infrastructure planning through a comprehensive rulemaking rather than to proceed with the requested rulemaking focused only on a limited set of capacity and infrastructure projects narrowly encompassed within short-term planning.[47] The Commission reiterated the value of a comprehensive rulemaking when we proposed Gas Infrastructure Planning Rules in the NOPR.[48]

72. The Commission agrees with CEO that the various rule sections proposed through this Proceeding are designed to, among other goals, foster an integrated and holistic approach to maintaining an affordable and reliable gas system, while at the same time reducing emissions in accordance with the State of Colorado's short-term and long-term statutory goals. A comprehensive approach also ensures broad utility planning and investment protocols are conducted in a manner that are fully cognizant of, and consistent with, statutory emission reduction goals. In accordance with our initial statements in the NOPR, and our denial of the ST-GIP Petition, the Commission determines there are distinct benefits to issue integrated, comprehensive rules in the instant Proceeding. The Commission recognizes that these individual processes should strive to be internally consistent and applicable to the broader and individual goals of each process. We also find that, beyond rules that are fully integrated, it is appropriate and necessary that the rulemaking process itself is conducted in an integrated and comprehensive manner, evaluating the array of proceedings contemplated by the Gas Rules and their relevant overlap and interaction, as we have done in the instant Proceeding. Accordingly, we find that it is appropriate and necessary

[47] Decision No. C21-0446, ¶ 6.

[48] Decision No. C21-0610, ¶ 24.

to retain the scope proposed in the NOPR in the instant Proceeding and adopt various provisions of the Gas Rules discussed in this Order.

73. With respect to whether the rules are sufficiently clear, consistent, and effective that they may be issued by the December 1, 2022 statutory deadline, the Commission carefully evaluated three critical elements that we believe facilitate a determination of whether it is appropriate to go forward in issuing gas infrastructure planning rules. These three elements include: (1) whether the overall role and authority of the gas infrastructure planning process can be clearly defined and can adequately address concerns raised; (2) whether the interaction of the CPCN and gas infrastructure planning processes is sufficiently clear, not overly burdensome to administer and appropriate for each individual utility; and (3) whether the alternatives analyses required by the CPCN and gas infrastructure planning processes is sufficiently clear and can appropriately balance regulatory oversight, administrative burden, and utilities' obligation to serve customers reliably.

74. We address each of these critical elements in greater detail in the specific rule sections below. Overall, the Commission determines that the record supports the outcome of the Gas Infrastructure Planning Rules and the CPCN Rules specifically and the Gas Rules in general. We also determine the rules are consistent and applicable to the broader and individual goals of the various processes established. Finally, through these rules, we have adopted numerous accommodations proposed by the utilities to reduce the administrative burden and the cost that may ultimately fall on their ratepayers, and find the adopted rules represent a reasonable and appropriate balance among the various interests.

**b. Rule 4102. Certificate of Public Convenience and Necessity for Facilities: Overall Findings**

**(1) Separate CPCN and Gas Infrastructure Plan Approvals**

75. Rule 4102(b) of the July Redlines proposed that utilities must file a CPCN application for investment projects unless those projects were below a $2 million threshold or otherwise approved by the Commission pursuant to Rules 4550 through 4555. The Commission recognizes this rule language may have resulted in confusion among participants. Public Service states, to the extent the Commission contemplates any project included in a gas infrastructure plan would not require a CPCN, that is a positive development, and it supports the approach.[49] Public Service also contends that CPCNs should not be required for projects approved through either a gas infrastructure plan or clean heat plan.[50] Black Hills raises concern that the CPCN and gas infrastructure planning processes seek identical information. Atmos contends the CPCN and Gas Infrastructure Planning Rules result in double litigation of projects.

76. We have incorporated in the Gas Infrastructure Planning Rules, at Rule 4552(d)(II), and discussed below, a provision to allow a utility to identify and request the specific relief sought for each relevant project presented in a gas infrastructure plan, including a request for the Commission to grant a CPCN, a petition for declaratory order that the planned project is in the ordinary course of business, or a different determination of need the utility thinks appropriate. We also explain in Rule 4552(d)(II) that the only relief available for planned projects above the CPCN cost thresholds in Rule 4102 is issuance of a CPCN. We find this is a necessary step so that the Commission, intervenors, and other stakeholders in future proceedings can fully comprehend the

[49] Public Service September 15, 2022 Comments, p. 9.
[50] Public Service October 7, 2022 Comments, p. 2.

specific relief requested for individual planned projects, as applicable, and be able to weigh the requested relief in light of the supporting information and argument.

77. In 4102(g), we explain that a utility may satisfy the requirements of the CPCN Rules in an application submitted pursuant to the Gas Infrastructure Planning Rules. To further enforce that concept, the Commission adopts language in sections (c), (d) and (e) of rule 4012 specifying a project does not need a separate CPCN where the utility has already received approval by the Commission pursuant to paragraph 4555(c).

78. With respect to whether issuance of a CPCN would be required for projects approved through a clean heat plan, as proposed by Public Service, the Commission anticipates it will gain valuable experience and insight from the initial round of clean heat applications.[51] At this juncture, the Commission declines to address appropriate alignment of CPCN and clean heat plan filings, if any, in the Gas Rules. We find it premature to establish rules regarding what level of approval projects proposed in a clean heat plan would receive until we are more familiar with the type and level of detail presented for clean heat plan related projects. A utility may choose to file its clean heat plan in conjunction with other requests for specific projects as it sees appropriate. The Commission will consider, as is common practice, combined applications or similar requests if presented to the Commission.

**(2) CPCN Dollar Thresholds**

79. The NOPR proposed dollar value thresholds of $15 million for utilities with 500,000 customers or more, and $10 million for utilities with lower customer counts. In the July Redlines, the Commission proposed consistent dollar thresholds for both the CPCN and Gas

[51] Public Service October 7, 2022 Comments, p. 2.

Infrastructure Planning Rules, for the reasons discussed below. A value of $2 million was proposed until the Commission obtained additional information from the utilities. Public Service argues for distinct monetary thresholds for proposed projects under the CPCN and Gas Infrastructure Planning Rules. Public Service states § 40-5-101(1)(a), C.R.S., specifies "a CPCN is not required for an extension necessary in the ordinary course of business within a territory that the utility already serves."[52] Public Service contends the statute appropriately balances the interests of public utilities and their customers, reasoning "[t]his legal construct, coupled with the fact that no legislation requiring or affecting this rulemaking changed § 40-5-101(1)(a), C.R.S., leads to this conclusion: if rules are going to further delineate CPCN filing requirements for certain projects, the rule revisions must be limited and based on appropriate project and utility size considerations."[53] Public Service also contends numerous stakeholders already addressed this question when formulating the rules proposed in the ST-GIP Petition where they reached consensus on appropriate values. Public Service states this consensus had two key components: "(1) it sought to avoid subjecting smaller ordinary course of business projects to CPCN requirements; and (2) it provides certainty as to when a CPCN is required for larger projects, avoiding litigation and promoting administrative efficiency, by setting an appropriate threshold and scope (*i.e.*, "Reliability Projects" in the instance of the ST-GIP)."[54] Public Service states the ST-GIP Petition was developed "after extensive discussions that considered the legal requirements of § 40-5-101(1)(a), C.R.S. and the broader Public Utilities Law, and adhered to established

[52] Public Service August 24, 2022 Comments, p. 12.
[53] Public Service August 24, 2022 Comments, pp. 12-13.
[54] Public Service August 24, 2022 Comments, p. 13.

regulatory principles, *e.g.,* promoting administrative efficiency and providing regulatory certainty to regulated entities and stakeholders alike."[55]

80. By Decision No. C21-0446, mailed July 23, 2021, the Commission rejected the ST-GIP Petition. We found it "more appropriate to develop proposed rules for issuance in a broader notice of proposed rulemaking. Such broader rulemaking will provide an opportunity to consider rule revisions and additions addressing not only the short-term planning contemplated in the joint petition but also issues arising from the new legislation passed in the 2021 Colorado legislative session."[56] Nonetheless, the ST-GIP Petition provided a valuable starting point for the CPCN thresholds proposed in this rulemaking, although the ST-GIP Petition also suggested a third CPCN threshold tier of $5 million for utilities less than 50,000 customers which we did not propose in the NOPR. As mentioned above, we proposed in the July Redlines consistent dollar thresholds for the CPCN and gas infrastructure planning processes using an initial, proposed value of $2 million. We also specifically requested utilities provide data relevant to establishing appropriate dollar thresholds.[57]

81. Through Decision No. C22-0427-I, which accompanied the July Redlines, the Commission required the utilities to submit the number of unique project investments incurred annually from 2019-2021, organized by project type and project cost buckets of over $1 million, over $2 million, and over $4 million.[58] Project type included system safety and integrity, new business, capacity expansion due to, separately growth due to existing customers and growth due to new customers, and mandatory relocations. Public Service further defined the project count for

[55] Public Service August 24, 2022 Comments, p. 13.
[56] Decision No. C21-0446, p. 1.
[57] Decision No. C22-0427-I, ¶ 97.
[58] Decision No. C22-0427-I, ¶ 97.

cost buckets exceeding $3 million, $8 million, $10 million, and $15 million. We refer to this information as the utility historical investment data.

82. The Commission addresses two integrated issues specific to the CPCN dollar threshold: whether to adopt consistent or unique thresholds across the CPCN and gas infrastructure planning processes; and, if unique thresholds are adopted, what is an appropriate threshold for CPCN application requirements. One important consideration in establishing appropriate thresholds is ensuring proposed projects receive the appropriate level of forward-looking analysis by the Commission. Throughout the implementation of Gas Infrastructure Planning Rules, we have expressed our interest in evaluating significant projects prospectively, as we find review of projects only in base rate proceedings after they have been completed as an inadequate way to provide oversight of priorities and expenditures in the midst of a transition for the industry. This retroactive review generally leaves disallowance as the primary option for challenging a project's need or costs and takes place after the investments have already been made making it less flexible than forward-looking and more punitive than a pathway with more proactive planning through gas infrastructure plans. If a planned project does not receive prospective review either through a gas infrastructure plan or a CPCN application, it is still reviewable in a base rate proceeding when a utility seeks cost recovery, as is currently the case. Prospectively reviewing a larger scope of projects should enable more efficient rate cases proceedings since the project details are already familiar to the Commission, utilities, and stakeholders.

83. We have already stated that the record here before us, the changing regulatory environment for gas utilities (*i.e.*, SB 21-264 and HB 21-1238), and other recent proceedings, support the need for more prospective review of significant projects prior to cost recovery. While we foresee a utility's gas infrastructure plan application proceeding to be the primary venue for

that review moving forward, we note that it may be two years or more before we receive fully adjudicated gas infrastructure plan applications. In the meantime, a utility must file CPCN applications for approval of individual projects exceeding the cost threshold as established by this Decision, unless a utility voluntarily files the initial gas infrastructure plan(s) as a fully adjudicated application. We agree with Public Service that an extensive number of adjudicated CPCN applications could be administratively burdensome for all involved, and ultimately costly to ratepayers. Accordingly, the Commission finds it is unnecessary to set equivalent thresholds for the CPCN and gas infrastructure planning processes.

84. With respect to the specific dollar values of the CPCN thresholds, as mentioned above, the July Redlines were based, in part, on the negotiated values proposed in the ST-GIP Petition. However, the ST-GIP Petition offered little insight into how the CPCN thresholds were selected. The utility historical investment data received in this Proceeding provides initial, albeit incomplete, insight into how many projects fall under ST-GIP-proposed threshold values. For example, Public Service indicated that it implemented three projects valued at $15 million, six projects above $10 million, and 9 projects above $8 million during the three-year, 2019-2021 period, most of which were classified as system safety and integrity or capacity expansion.[59]

85. At this time, considering the record before us including specifically the utility historical investment data, we find that the following values are appropriate thresholds for CPCN review. We find these values balance the regulatory burden to utilities proportionally to their size with the Commission's need for greater insight into significant utility expenditures. We find it appropriate to set the CPCN threshold value at $12 million for utilities with

[59] One of nine project over the $8 million threshold was classified as new business.

500,000 customers or more, $10 million for utilities with customer counts ranging between 50,000 and 500,000, and $5 million for utilities with less than 50,000 customers.

### (3) CPCN Project Type Applicability

86. Public Service argues that only capacity expansion projects should be subject to the requirements in the CPCN Rule, and in accordance with that argument, suggested removing what is now included as Rule 4102(f)(III).[60] This provision requires utilities to specify the project type category consistent with the categories identified in the gas infrastructure planning process, at Rule 4553(a)(III), as part of their CPCN applications. Separately, Public Service proposes a "New Business Evaluation Report" as part of their clean heat plan filing and removing reference to new business investment in both CPCN and gas infrastructure planning.[61] Black Hills argues "New Business" projects should be excluded from the CPCN requirement and that the CPCN Rule must be based on relevant statute. It contends that "[b]y virtue of developers or other customers requesting gas service from the Company, the threshold of 'convenience and public necessity' has been achieved."[62]

87. There appears to be a strong interplay between new business and capacity expansion projects. While certain capacity expansion investments may be directly attributable to new business from the outset, other capacity expansion investment needs may lag or be indirectly caused from incorporation of new business on a utility's system over the course of several years. Consistent with our findings in line extension policy section of this Decision, we find it necessary for utilities to meaningfully evaluate the full incremental cost of new business, including the

[60] Public Service October 7, 2022 Comments, p. 4.
[61] Public Service October 7, 2022 Comments, p. 11.
[62] Black Hills October 11, 2022 Comments, p. 5.

impact of lagged capacity expansion requirements. Further, according to the utility historical investment data, between one and three system safety and integrity projects larger than $12 million can be expected over a forward three-year period for the largest utility.[63] The Commission finds that a CPCN may be necessary for all project types in certain instances, as appropriate under § 40-5-101, C.R.S., *except* mandatory relocations which are required by local municipalities and other jurisdictions pursuant to a utility's franchise agreement with that entity. Accordingly, the Commission is not persuaded to adopt Public Service's suggestion to limit the applicability of Rule 4210 to only capacity expansion projects.

#### c. Rule 4102. Certificate of Public Convenience and Necessity for Facilities: Rule Provisions

88. Paragraph (a) of this rule requires a utility seeking authority to construct and to operate a facility or an extension or expansion of a facility to file an appropriate application with the Commission unless the proposal is in the ordinary course of business. This provision sets forth the statutory standard pursuant to § 40-5-101, C.R.S., and does not represent a substantive change from the previous language of 4102(a).

89. New paragraphs (b), (c), and (d) of this rule establish the cost thresholds for utilities as discussed above in paragraphs 79-85. Paragraph (b) requires utilities with 500,000 or more customers to 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 investment value is greater than $12.0 million in 2020 dollars in utility capital investment. Paragraph (c) requires utilities with less than 500,000 customers but more than 50,000 customers to apply to the Commission where the total

[63] The historical investment data for Public Service indicated it had one project over $15 million and three over $10 million. The data did not specifically delineate the number of projects over a $12 million threshold value.

investment value is greater than $10.0 million in 2020 dollars. Paragraph (d) requires utilities with less than 50,000 customers to apply to the Commission where the total investment value is greater than $5.0 million in 2020 dollars.

90. For each respective threshold in paragraphs (b), (c), and (d) of this rule, a utility need not apply for a CPCN if the utility has already received approval by the Commission pursuant to Rule 4555(c). Put otherwise, if a utility seeks a CPCN through its gas infrastructure plan for a proposed project, and the Commission grants a CPCN through an adjudicated gas infrastructure plan proceeding, then the utility need not file an application for the same project under Rule 4210. This interplay between gas infrastructure plans and CPCN applications is discussed in more detail above in paragraphs 75-78.

91. New paragraph (e) establishes that the cost thresholds discussed in paragraphs (b), (c), and (d) of this rule are in 2020 dollars and are subject to annual inflation adjustments by operation of this rule annually on March 1, using 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. 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 to the cost thresholds established in Rule 4102.

92. New paragraph (f) expands information previously found in Rule 4102(b) that a utility must present in an application for issuance of a CPCN. In addition to the existing requirements that a utility must present, including: (1) the information required by Rule 4002; (2) 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; (3) a description of

the proposed facilities; (4) cost information; (5) the construction timeline; and (5) mapping requirements, we add numerous other application requirements in paragraph (f). In particular, we expand the information a utility shall present as part of the existing requirement to show information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate alternatives. By design, the information a utility must present in an application for issuance of a CPCN in paragraph (f) closely matches the required contents of a gas infrastructure plan in 4553(c). We go into further detail regarding the required contents in our discussion of Rule 4553 below and therefore do not repeat that discussion here. *See Section (I)(C)(7)(c) below.*

93. New paragraph (g) incorporates the proposal set forth in the NOPR that a CPCN is not required for mandatory relocations, consistent with the proposed rules attached to the ST-GIP Petition. Consistent with the language above in paragraphs (b), (c), and (d) of this rule, paragraph (h) reflects that in accordance with subparagraph 4552(d)(II), a utility may satisfy the requirements of rule 4210 in an application submitted pursuant to the Gas Infrastructure Planning Rules.

### 4. Facilities

#### a. Rule 4210. Line Extensions.

94. Rule 4210 governs the gas utilities' line extension policies. Paragraph (a) requires the utilities to have tariffs setting out their line extension policies, procedures, and conditions, while paragraph (b) specifies the minimum provisions a utility must include for gas main extensions and service lateral extensions from its distribution system.

95. In the NOPR, the Commission proposed to add a new paragraph (c) that requires that the utility base its line extension policies on the principle that the full incremental cost associated with new development and growth shall be borne generally by the customers that cause those incremental costs. The Commission likewise proposed to add a new paragraph (d) to require

annual updates to the standardized costs in calculating components of the utility's line extension policy based on actual costs for line extensions over time. The Commission further sought to examine potential impacts from the state's greenhouse gas emissions reduction requirements on the utilities' line extension policies. For instance, the Commission proposed to add a new paragraph (e) that requires that a utility's line extension policies, procedures, and conditions to align with the statewide greenhouse gas emissions reduction goals established in § 25-7-102(2)(g), C.R.S.

96. In Decision No. C22-0427-I, the Commission stated that it continued to support in principle the modifications to Rule 4210 proposed in the NOPR. The Commission noted that several rulemaking participants, including UCA, CEO, RMI, and Conservation Advocates, support the proposed changes to Rule 4210. The Commission also recognized that Public Service, CNG, and Black Hills each submitted comments opposing the proposed changes to Rule 4210.

97. Public Service and Black Hills both suggested eliminating proposed paragraphs (c) through (e) in their entirety. Public Service contended that revisiting its line extension policy a few years after it adopted a comprehensive policy in Proceeding No. 18AL-0862G is inappropriate and that addressing line extension policies is beyond the already wide scope of this rulemaking. Public Service further claimed that the proposed changes act as a "*de facto*" ban on gas line extensions and is unfair to new customers. Black Hills similarly commented that a stand-alone proceeding outside of the instant rulemaking is necessary to evaluate this issue holistically and that the proposed changes to paragraph 4210(d) could require an updated class cost of service study annually. CNG claimed the proposed changes to Rule 4210 contravene the prohibition in § 40-3.2-103(3.5)(b), C.R.S., that the Commission shall not ban the installation of gas service lines to any new structure.

98. In response to the specific provisions in proposed paragraph 4210(d), Atmos raises that annual updates could hurt developers that had entered into multi-year projects based upon a specific line extension allowance. The Commission thus invited further suggestions on whether and how to best consider a phase-in date for the modifications to Rule 4210.

99. The Commission further stated that concerns regarding home affordability and the impacts of line extension allowances, or the lack thereof, on income-qualified community members required additional policy and legal comment regarding proposed paragraph 4210(f) that would require each utility shall provide a narrative and any specific, suggested approaches for limited adverse impacts of line-extension policies on income-qualified customers and affordable housing.

100. In written comments responsive to the July Redlines, the utilities, labor entities, and API Colorado suggested the Commission address the issues surrounding line extension policies in a separate proceeding. CEO and UCA disagreed, arguing the Commission is on the right path and should render a decision adopting modified provisions governing line extension policies in this Proceeding. The Conservation Advocates argued for the immediate elimination of line extension allowances, stating: "As market transformation efforts bring down the cost of electric appliances and otherwise lead customers to electrify, it will become likely that new customers might depart the gas system before paying off an allowance in full… leaving fewer customers to pay off the existing costs of the system. This is part of why limiting new, unnecessary fixed costs into the gas system is so important: to ensure that future gas customers – especially low-income customers – are not stranded with gas infrastructure costs that could easily have been avoided."[64] They also contended that a utility's line extension policy is not designed to promote housing affordability as

[64] Conservation Advocates Comments October 7, 2022, p. 12.

line extension allowances are provided to building developers, not gas utility customers, and that developers have no obligation to pass the allowance on to customers. The Conservation Advocates likewise questioned whether line extension policies actually impact housing prices, which are set on supply and demand in the housing market.[65]

101. We conclude that the issues surrounding the modifications to Rule 4210 presented in the NOPR and in the July Redlines have been thoroughly examined and therefore decline to delay rulings on these proposed revisions governing line extension policies, procedures, and conditions. It is not necessary to decide these policy matters in a separate future proceeding. We recognize, however, the need to clarify that the modified provisions in Rule 4210 we adopt by this Decision are not intended to result in the immediate elimination of construction allowances for line extensions or for the imposition of any barriers to the installation of gas service lines to any new structure, concerns expressed by many commenters. We further agree with Public Service that certain aspects of a utility's line extension policies, procedures, and conditions involve rate design and should be addressed within a utility's rate proceedings. As explained below, we retain the basic function of the existing provisions in Rule 4210 to cause Commission review of line extension policies in the context of tariff filings that are usually made in conjunction with a base rate proceeding. As explained below, the new provisions in paragraphs 4210(c), (d), and (e) build on the existing requirements in paragraphs 4210(a) and (b) so that the utilities and the Commission properly address line extension policies, procedures, and conditions through tariff filings. However, such tariff filings will now be considered as Colorado progresses towards meeting its greenhouse gas reduction goals.

[65] Conservation Advocates Comments October 7, 2022, p. 12.

#### (1) Rules 4210(a) and (b)

102. We make no modifications to the existing provisions in paragraphs 4210(a) and (b). It remains necessary for the gas utilities' tariffs to set forth its line extension policies, procedures, and conditions in their tariffs for service including: the terms and conditions for extensions; the relevant information to be provided to new customers seeking to connect to the utility's system; the anticipated cost of the connections or extensions; and the necessary provisions addressing rate and service impacts upon existing customers, the new customers, and future customers. The longstanding implementation of these provisions have standardized the process by which the Commission reviews each utility's line extension policies in a tariff proceeding, generally a base rate case or a follow-on proceeding upon the conclusion of a base rate case. We conclude that tariff proceedings for the Commission's approval of line extension policies, procedures, and conditions will remain the proper means to implement both the new requirements of 2021 legislation and the practical aspects of new customer connection or extensions.

#### (2) Rule 4210(c)

103. In the NOPR, the Commission proposed to add a new paragraph 4210(c) that requires line extension policies to be based on the principle that the full incremental cost associated with new development and growth shall be borne generally by the customers that cause the utility to incur those costs.

104. Public Service summed up the gas utilities' opposition to the proposed new rule, stating that it would require "a customer pay the full incremental costs for line extensions, which essentially acts as a *de facto* ban on gas line extensions."[66] Public Service explained that this

[66] Public Service January 22, 2022 Comments, p. 87.

requirement would cause a new customer to pay the cost of existing infrastructure that serve other customers through their base rate usage charge in addition to their line extension costs up front. Public Service claimed that this would be a fundamental departure from rate making principles, alleging that the new rule would force new customers to unfairly subsidize existing customers. The utilities and other commenters further argued that the term “full incremental cost” is either ambiguous or requires a definition.

105. In the July Redlines, the Commission proposed a reformulated definition of “full incremental cost” to include, at minimum, the incremental or marginal cost associated with new service, meters, and reasonably allocated distribution system costs.

106. At the September 19, 2022 hearing, Chair Eric Blank proposed a further revised definition based on “the difference between the system-wide base rate revenue increases attributable to new customer growth minus the full increase in system-wide costs of meeting new customer growth including the costs of serving increased system design day demand, utility overhead costs, and the metering and other costs directly attributable to new customers.”[67] In response to that further revised definition offered by Chair Blank, Public Service stated that the concept remains problematic because “it is based on the assumption that the incremental system-wide costs for new customers is higher than the incremental revenue that new customers will contribute.”[68] Public Service argues transmission pipelines are used by all customers and growth in its customer base will eventually drive the need for incremental additions. However, identifying which customer is responsible for a new transmission pipeline is generally impossible. “Upstream capacity additions such as these are driven by system wide increases in design day

[67] The Commission requested comments on this topic by Decision No. C22-0588-I, ¶ (7)(d), issued September 29, 2022.

[68] Public Service October 7, 2022 Comments, p. 12.

volume and generally cannot be directly assigned to a single customer or housing development. Other incremental costs such as customer account/billing, administrative costs, general, and common plant would be very difficult to quantify. While conceptually customer accounting costs should grow as the number of customers increases it is not possible to point to discrete incremental additions that are added to accommodate customer growth."[69]

107. Black Hills contends that to conduct this assessment of incremental costs via a retrospective review, the utility would have to track the revenues associated with customers connected since the last construction allowance calculation through billing software. Additionally, utility overhead costs cannot be tied directly to customer growth because it is an allocation produced in a rate case's class cost of service study.[70] Black Hills further contends the Commission's approach "is more equivalent to a revenue-based calculation. Line extension construction allowance calculations make more sense from an average embedded costs or DCF methodology, where the costs are functionalized to customer specific services and meters/regulators."[71]

108. UCA also does not support the new language proposed by Chair Blank, stating it believes the new version is somewhat similar to the times revenue method which Public Service offered for gas line extension construction allowances in Proceeding No. 18AL-0362G. UCA states that the "Commission rejected that approach and agreed with the administrative law judge that the

[69] Public Service October 7, 2022 Comments, p. 13.
[70] Black Hills October 11, 2022 Comments, p. 16.
[71] Black Hills October 11, 2022 Comments, p. 17.

use of this methos was 'an extreme reallocation of costs' and a 'drastic change in ratepayers contribution to line extensions.'"[72]

109. Conservation Advocates contends the proposed language "focuses too narrowly on equalizing the financial costs and benefits of connections to the gas system between new and existing customers," and "it fails to consider the social externalities of continued connections to the gas system, such as climate and air pollution externalities; nor does it account for who pays for these connections, and whether the burden of these payments falls on those customers who are least able to pay higher utility bills."[73]

110. The intent of paragraph 4210(c) is to ensure that when the Commission reviews for approval the utility's tariffs for their line extension policies, procedures, and conditions, most likely in a base rate proceeding, the Commission will base its review, in part, on the principle that new customers will be responsible for covering their contribution towards the cost of growth and in a way that also incorporates the additional net revenues associated with new customer growth with appropriate consideration of the impacts of policy and efficiency on those projections. This change to Rule 4210 expands on the existing provisions in subparagraph 4210(b)(IV), that already requires the utilities to address rate and service impacts upon existing customers that result from line extensions. As compared to the proposed rule language in the NOPR, we clarify the cost of growth includes "any costs associated with increases in design day peak demand," and we add to Rule 4001 a definition for that term (design day peak demand) as shown in the attachments to this Decision.

[72] UCA October 7, 2022 Comments, p. 4, citing Decision No. C19-0634 issued on July 26, 2019, in Proceeding No. 18AL-0862G, ¶¶ 62-64, at pp. 20-21 and Recommended Decision No. R19-0470, issued on June 6, 2019, ¶¶ 92-102, at pp. 29-32.

[73] Conservation Advocates October 7, 2022 Comments, p. 9.

111. The extensive and conflicting comments related to paragraph 4210(c) indicate that the implementation of this new rule will likely require the adjudication of related issues in each utility's line extension tariff proceedings, and that such adjudications are likely to evolve as the utilities also implement the new rules for Gas Infrastructure Planning, Clean Heat Plans, and DSM as being adopted here. The comments also persuade us to remove the additions to the rule the Commission proposed in the July Redlines. We nevertheless conclude that paragraph 4210(c) in the form as shown in the attachments to this Decision is necessary and sufficient to cause the utilities to begin providing the Commission with the information needed to properly establish line extension policies in accordance with paragraph 4210(e), as discussed below. Importantly, there have been major updates to Colorado statute impacting the state's gas utilities necessitating a holistic evaluation of line extension policies.

112. Although we do not adopt the revised version of paragraph 4210(c) from the July Redlines, we expect that the presentation of incremental costs will include both the additional net revenues as well as all the costs of customer growth including new services, meters, and certain distribution system costs that the Commission will find in line extension policy tariff proceedings are part of the incremental costs of growth. We find that limiting the scope to only the most locationally or temporally adjacent infrastructure upgrades likely obscures the total costs of growth, which cumulatively lead to system capacity expansions and drive investments that may not have previously been included in the calculations but should rightfully be considered. While we understand that identifying the appropriate share of upstream capacity and overhead expenses is complex and requires some assumptions, failing to evaluate these costs of adding growth on the system is likely to undercount the actual costs, falling short of an allocation of the full incremental costs. We also expect an evaluation of full incremental costs to take into account emissions and

environmental costs related to new customer connections to the utilities' systems, recognizing, however, the distinctions between costs used to establish rates and costs that are borne by the residents of Colorado at large.

113. In the July Redlines, the Commission proposed a new paragraph 4210(f) that would require each utility to provide a narrative and any specific, suggested approaches for limited adverse impacts of line-extension policies on income-qualified customers and affordable housing.

114. Given that the Commission will review line extension policies, procedures, and conditions in the context of the general requirements in paragraph 4210(c), we conclude that it is unnecessary to adopt the provisions proposed in the July Redlines to require from the utilities a narrative on limiting adverse impacts of their line extension policies. The Commission will consider the anticipated cost of the connections or extensions from the perspectives of existing, new, and future customers, with an eye toward specific impacts for income-qualified community members. We generally agree with commenters that line extension policy is not, at its core, housing policy, especially with no direct linkage between savings from line extension allowances provided to developers and the end costs paid by homebuyers.[74]

**(3) Rule 4210(d)**

115. In the NOPR, the Commission also added to Rule 4210 provisions addressing the utility's standardized costs that are generally part of its line extension policies as set forth in tariffs. The proposed rule required that such standardized costs be updated annually. No revisions were made to paragraph 4210(d) in the July Redlines. However, by Decision No. C22-0427-I, the Commission solicited comments as to whether a phase-in date for the updated

[74] Conservation Advocates October 7, 2022 Comments, p. 12-13.

costs should apply to all or only certain types of construction projects and as to an appropriate timeframe to qualify a project to be "grandfathered" relative to changes in the utility's line extension policy.

116. The Conservation Advocates and RMI contend the Commission should phase-in new line extension allowances as soon as possible: "Pending the results of Section 4210(f) evaluations, Conservation Advocates and RMI support an implementation date of mid-2023 for the elimination of gas line extension allowances across all customer classes. Specifically, we recommend the Commission adopt the rules as proposed and direct utilities to adjust tariffs, as needed, by no later than six months after a final decision is issued in this rulemaking. However, the Commission could allow utilities to exempt from the new tariff those customers who have submitted applications that are approved or pending as of the date these rules become effective, as well as those customers who can demonstrate or attest that their applications have been submitted to local permitting offices prior to the date these rules become effective."[75]

117. Public Service contends implementation by mid-2023 is "not administratively doable." Public Service explains that while it can track applications it receives, it should not be obligated to verify applications submitted to local permitting offices.[76] Public Service further recommends moving the implementation date to mid-2024 but reminds the Commission its position that "this proposal taken as a whole is problematic and should not be adopted by the Commission."

118. Black Hills notes that "[u]tilities will likely be required to implement any line extension modification to the Commission rules through an advice letter and tariff filing, which

[75] Conservation Advocates and RMI August 24, 2022 Comments, p. 12

[76] Public Service October 7, 2022 Comments, p. 14.

could go into effect on 30-days' notice or could result in a litigated proceeding taking approximately ten months. After the new tariffs go into effect, additional flexibility may still be required with respect to certain terms in the tariffs."[77] Black Hills also argues the Commission rule should recognize all current contractual agreements it has entered into for construction allowance refunds, and that new line extension policies would only be applicable to contracts executed after approval of new tariffs.

119. Upon consideration of these and the other comments addressing Rule 4210, we again clarify that paragraph 4210(d) simply expands on the existing provisions in subparagraph 4210(b)(IV) that requires the utilities to address rate and service impacts upon existing customers that result from line extensions. Regular updates to standardized construction costs used for determining payments from new connecting customers (or the developers of their new facilities) are as necessary to achieve the longstanding intent of subparagraph 4210(b)(IV) as the Commission's periodic review of other aspects of the utility's line extension policies, procedures, and conditions. Without regular updates, it appears that ratepayers, rather than new customers are made to bear an increasing percentage of the cost burden of new connections, because there has been no mechanism to automatically adjust the standardized costs to reflect actual costs, with ratepayers making up the difference.

120. As a general matter, we conclude that each utility must update their line extension policies in accordance with all of the provisions in Rule 4210 through a tariff filing submitted in accordance with the Commission's Rules of Practice and Procedure for a line extension policy for effect no later than January 1, 2025. Further updates shall be filed and considered by the Commission in each of the utility's base rate proceedings. We further conclude that standardized

[77] Black Hills October 11, 2022 Comments, p. 6.

costs used in a line extension policy also must be updated in each base rate proceeding and should be calculated using the most recent consecutive 12 months of data that is available to the utility at the time of the calculation. These requirements are set forth in paragraph 4210(d) in the attachments to this Decision.

121. We also recognize the need to allow for the phase in of changes in standardized costs and construction allowance values to avoid interfering with existing contractual agreements for new service and to preserve, within reason, the economics of existing developments that may be relying upon the existing policy. However, we do not find that prolonging existing line extension policies longer than necessary would best serve the public interest. Accordingly, we modify paragraph 4210(d) to provide an exemption from updated policies for those customers or prospective customers with executed contractual arrangements for new line extensions prior to May 1, 2023.

#### (4) Rule 4210(e)

122. Section 25-7-102(2)(g), C.R.S., states:

> … Colorado shall strive to increase renewable energy generation and eliminate statewide greenhouse gas pollution by the middle of the twenty-first century and have goals of achieving, at a minimum, a twenty-six percent reduction in statewide greenhouse gas pollution by 2025, a fifty percent reduction in statewide greenhouse gas pollution by 2030, and a ninety percent reduction in statewide greenhouse gas pollution by 2050. The reductions identified in this subsection (2)(g) are measured relative to 2005 statewide greenhouse gas pollution levels.

123. In the NOPR, the Commission proposed to add a new paragraph 4210(e) that requires that a utility's line extension policies, procedures, and conditions to align with the statewide greenhouse gas emissions reduction goals established in § 25-7-102(2)(g), C.R.S.

124. In Decision No. C22-0427-I, the Commission explained that it continued to support the policy proposed in the NOPR that line extension policies should generally align with the Colorado's greenhouse gas emission reduction goals and minimize, to the extent possible, concerns regarding stranded costs that may result from the elimination of greenhouse gas emissions by 2050.

125. The gas utilities generally oppose the introduction of 4210(e), arguing, for example, that rules addressing line extension policies is beyond the scope of this rulemaking and add odds with "the overall thrust of the public policy that [Public Service] believes the 2021 legislative package, and SB 21-264, in particular, stand for."[78]

126. We disagree with Public Service. The record in this Proceeding demonstrates that load growth since 2015, the statutory baseline for clean heat targets pursuant to § 40-3.2-108(3)(b)(II), C.R.S., is largely incompatible with greenhouse gas emission reductions and is likely to make compliance with the clean heat targets more difficult or costly for gas utilities. It would be illogical for the Commission to evaluate line extension policies without any regard as to how those policies relate to other overarching statutory requirements specifically impacting the industry. Line extension policies, procedures, and conditions must therefore be reviewed by the Commission in this context. We adopt paragraph 4210(e) as set forth in the attachments to this Decision, modified from the NOPR proposal to indicate that a gas utility's line extension policies, procedures, and conditions must "generally align" with § 25-7-102(2)(g), C.R.S to help distinguish between costs that are used to set rates and those environmental and other costs that are borne by the residents of Colorado at large.

[78] Public Service January 25, 2022 Comments, p. 87.

### 5. Air Pollution Control Division Emissions Calculation Guidance

#### a. Commission Approval of Workbook

127. On October 7, 2022, the Division published its Clean Heat Plan Emissions Calculation Guidance and associated Clean Heat Plan Calculation Workbook and filed these same published versions in this Proceeding along with associated comments.

128. The Division developed these documents consistent with the directive in SB 21-264 for the Commission to consult with the Division to estimate reductions of emissions of greenhouse gases and other air pollutants under utilities' clean heat plan portfolios. In its comments supporting the filing, the Division explains that it utilized an extensive stakeholder process in creation of the guidance document and workbook, beginning in early 2022. The Division explains the stakeholder process included input and participation from the academic community, environmental organizations, local governments, and utilities. Division staff provided periodic updates to the Commission on progress made, areas of consensus, and outstanding issues.

129. In the published Clean Heat Plan Emissions Calculation Guidance document, the Division states that it recognizes there are multiple federal actions expected to occur shortly, including pending proposed revisions to the greenhouse gas reporting provisions in 40 C.F.R. Part 98, Subparts NN and W[79], as well as expected updates to leak detection and repair and reporting requirements for local distribution companies under the *Protecting Our Infrastructure of Pipelines and Enhancing Safety* (PIPES) Act of 2020, Pub. L. No. 116-260, and the *Inflation Reduction Act of 2022*, Pub L. No. 117-169. The Division states that it intends to continue the technical

[79] Hereinafter referred to as Regulation NN (Carbon Dioxide) and Regulation W (Methane).

stakeholder engagement in 2023 and anticipates updating its guidance document and workbook when necessitated by these developments and any other future actions.

130. The Division previously submitted a draft guidance document and workbook on August 26, 2022, to enable rulemaking participants to comment on the proposal. The Division discussed these draft versions at a public comment hearing before the Commission on August 31, 2022. In response to that draft, Public Service, and Black Hills each filed comments generally recommending the Commission adopt the documents as proposed.[80] CEO also filed comments generally supporting adoption, reasoning the Division is the appropriate entity to develop this methodology and a single uniform approach used by all utilities required to develop clean heat plans will provide consistency in reporting.[81]

131. Staff of the Commission filed a response to the Divisions drafts on September 19, 2022, raising several concerns for the Commission's consideration. Staff contends the workbook uses an assumed natural gas composition that is known to be incorrect, that the workbook does not include requirements to verify the precision and accuracy of leakage rate calculations, and that the workbook does not include requirements to verify the thoroughness and accuracy of emission reduction calculations. In essence, Staff takes issue with the use of Subparts W and NN for primary inputs to the Division's model, claiming these federal Environmental Protection Agency reporting measures do not accurately represent Colorado utilities , and thus, "are likely to prevent [the] Commission from being able to find that the resulting baseline and emission reduction calculations are accurate enough to serve as a baseline."[82] Staff recommends using actual carbon dioxide per unit of energy produced and methane content in the workbook. Staff also recommends that a

[80] Public Service October 7, 2022 Comments, p. 27; Black Hills October 11, 2022 Comments, pp. 10-12.
[81] CEO August 24, 2022 Comments, p. 13.
[82] Staff September 19, 2022 Comments, p. 1.

professional engineer be required to approve all calculations including mass and energy balances (such as metering, fuel, and lost and unaccounted for gas), actual gas composition, known leaks, and published leak factors adjusted for known quantities (such as pressure, pipe age and pipe material).

132. Public Service and Black Hills responded to Staff's comments, urging the Commission to not find them persuasive. In its October 7, 2022 comments, Public Service critiques that Staff's comments were filed after and outside of the public working group process that the Division undertook over the entire preceding year, which Staff did not participate in. Public Service maintains the Division properly utilized U.S. Environmental Protection Agency reporting methodologies to create the workbook because it was plainly directed to do so in SB 21-264, codified at § 40-3.2-108(3)(c)(II), C.R.S., and that Staff's proposals would require straying from the federal methodologies. Finally, Public Service urges the Commission to move forward now with approving an accounting methodology to maximize opportunities for success in light of the August 2023 filing deadline for utilities first clean heat plans.[83] Black Hills similarly responds in its October 11, 2022 comments that the Division correctly utilized the Subpart W and NN methodologies and Staff's proposal to deviate from the federal methodologies is inconsistent with § 40-3.2-108(3)(c)(II), C.R.S. Black Hills also states that Staff's suggestion to use a professional engineer fails to recognize the expertise of the Division, the utilities filing clean heat plans, and the work of the technical working group.[84]

133. The Division also responded to Staff's concerns, as part of its October 7, 2022 comments filed with the published versions of the guidance document and

[83] Public Service October 7, 2022 Comments, pp. 27-30.
[84] Black Hills October 11, 2022 Comments, pp. 10-11.

workbook. The Division reiterates that the guidance document and workbook were developed through a robust technical stakeholder process involving numerous participants. It maintains the workbook adheres to the statute, which specifically references the federal emissions reporting requirements in Subparts W and NN, and notes the U.S. Environmental Protection Agency is currently working to update those standards to improve the quality and consistency of the data collected under the rule.[85] The Division argues that Staff fails to provide a legal rationale for abandoning this statutory directive and substituting an entirely different process for determining how to calculate these emissions.[86]

134. After reviewing the Clean Heat Plan Emissions Calculation Guidance and associated Clean Heat Plan Calculation Workbook, the statutory requirements and directives in SB 21-261, and the comments in this Proceeding, we find it appropriate for utilities to utilize the Division's calculation guidance document and workbook as the basis for calculating greenhouse gas emissions for future clean heat plans. We acknowledge the concerns raised in Staff's filing, but we agree with other commenters that these arguments came too late in the process to be given serious consideration. On the other hand, we recognize the Division engaged in a lengthy process with a technical working group to develop the methodology presented in the workbook. Given these considerations, we find the Division's workbook is the best tool available to the Commission at this time. The Division utilized a fulsome process to create the Clean Heat Workbook and it represents a generally consensus approach as a result. The Division has indicated it intends to continue to partner with the Commission to create future iterations of the workbook and the

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[85] Division Clean Heat Plan Emissions Calculation Guidance (published Oct. 7, 2022), p. 6.
[86] Division Clean Heat Plan Emissions Calculation Guidance (published Oct. 7, 2022), p. 6.

Commission intend to continue to consult with the Division in future efforts to improve the greenhouse gas accounting methodology used for utility submissions at the Commission.

135. Through this Decision, we approve the Clean Heat Plan Emissions Calculation Guidance and associated Clean Heat Plan Calculation Workbook, as published by the Division on October 7, 2022, available for public review and download through the Commission's website at: https://puc.colorado.gov/. In the future, the Commission may consider a revised or updated version of the workbook developed by the Division through separate a proceeding and order. We agree with commenters that flexibility to adjust to future updates is important moving forward. To enable flexibility for utilizing future iterations that may be developed by the Division and approved by the Commission, we therefore refer in Rule 4527(a) to the Division's guidance document and workbook by specifying that a utility shall use the most recent Commission-approved version of the Division's clean heat workbook.

### b. Advanced Leak Detection

136. In its October 7, 2022 filing, the Division indicates the published workbook does not adjust for any advanced leak detection protocols, but that advanced leak detection programs and improvements to system leakage estimations are topics the Division continues to be interested in and intends to continue developing through ongoing technical stakeholder workgroup discussions.[87] The Division notes that technology is now available and assessment and reconciliation protocols are currently being developed in order to move away from the pipeline materials based estimation methods utilized in the federal reporting program toward utility specific emission factors developed and updated through systematic measurement programs.

[87] Division Clean Heat Plan Emissions Calculation Guidance (published Oct. 7, 2022), pp. 10-11.

137. In response, Conservation Advocates and RMI raised concern that, because advanced leak detection technologies may find more leaks than would otherwise be found or reported under the U.S. Environmental Protection Agency's Subpart W, utilities may be disincentivized from deploying it. They suggest mitigating this disincentive by allowing the utilities to petition the Commission for a one-time adjustment to the 2015 baseline to calibrate the emissions reported under Subpart W with emissions measured using advanced leak detection.[88]

138. We agree with Conservation Advocates and RMI that incentivizing advanced leak detection program implementation by utilities is advantageous. We therefore adopt the proposed language that allows a utility to petition the Commissions for a one-time adjustment to its baseline emission data if it implements an advanced leak detection program. The mechanism for requesting an adjustment is adopted as part of Rule 4527(a). Otherwise, we find the best course of action at this time is to approve the Division's methodology as presented in the workbook.

#### c. Adjustments to the Baseline

139. In its October 7, 2022 filing, the Division indicates the published workbook does not weather normalize the baseline and instead uses actual reported sales data for 2015. The Division states it took this approach because: (1) usage and emissions data reported under the current federal reporting requirements and Regulation 22 for Colorado is reported on an actual natural gas supplied basis; (2) Colorado greenhouse gas emissions reduction goals are mass-based percentage reductions that are not calculated on a normalized basis with respect to population, economic, meteorological or other indicators; and (3) SB 21-264 specifies the use of calculation methodologies in the Subpart NN of the federal reporting rules.[89] The Division states it designed

[88] Conservation Advocates and RMI September 2, 2022 Comments, p. 5.
[89] Division Clean Heat Plan Emissions Calculation Guidance (published Oct. 7, 2022), pp. 7-8.

the workbook to accept the outputs from the modeling process whether or not a normalization procedure is used in the creation of a utility's clean heat plan. The Division states, for the same reasons, the workbook also does not adjust the baseline for customer growth or system expansion since 2015.

140. In response, several participants continued to advocate for implementing a normalization procedure. Public Service supports weather normalization of the baseline and of any projected emission reduction.[90] CNG recommends the Commission maintain consistency in its measurement of usage, and weather normalize all volumetric usage used in the clean heat plan process, both for the 2015 baseline and in the current year.[91] Atmos believes both the 2015 baselines and subsequent years should be weather normalized. Atmos reasons, without weather normalization, an otherwise compliant utility could "fail" to meet targets due to cold weather or a non-compliant utility could "pass" targets based upon warm weather.[92]

141. In contrast, Conservation Advocates argue that weather normalization of the base year and target year emissions would be inappropriate. They argue, if the Commission decides to allow weather normalization, the specific methodology should be determined as part of an adjudicated proceeding, which would enable broader stakeholder scrutiny.[93]

142. Other participants continue to advocate for adjusting the baseline to account for growth in customer base since 2015. CNG reiterates that adjusting emissions levels for customer growth is necessary to correctly measure against a 2015 baseline and recommends that the rules allow for utilities to introduce and provide support for an alternative method of emission

[90] Public Service September 15, 2022 Comments, p. 16.
[91] CNG September 2, 2022 Comments, p. 9.
[92] Atmos August 8, 2022 Comments, p. 15.
[93] Conservation Advocates and RMI August 24, 2022 Comments, p. 18.

measurement that more accurately reflects the true emissions of the utility, to allow for realistic reduction goals that the utility is likely to achieve.[94]

143. Considering the discussion in the Division's guidance document, the statutory language, and the comments in this Proceeding, we find the best course of action at this time is to approve the Division's methodology as presented in the workbook. We do not find good cause to order the baseline or future target year emission data should be weather normalized and therefore we decline to adopt a mechanism for any type of weather normalization. Significantly, we agree with the Division that SB 21-264 does not call for normalization of the baseline data year to any parameters such as weather or customer growth. And if the baseline is not adjusted, it makes little sense to adjust future years. We conclude that utilities should be able to plan and meet their clean heat targets even in particularly cold years. Thus, we decline to adopt a mechanism for weather normalization in the Greenhouse Gas Emission Rules at this time. Similarly, we decline to adopt a mechanism for adjusting a utility's baseline for customer growth in the Greenhouse Gas Emission Rules.

#### d. Behind the Meter Emissions

144. In the NOPR, we proposed in Rule 4527(a) a minimum list of emissions sources which a utility must include in greenhouse gas emission projections derived from the list in § 40-3.2-108(3)(c)(I), C.R.S. This listed included 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." In response, we received comments from several participants, including UCA and Public Service, that the term "the customer's meter" more appropriately aligned with statutory requirements. We stated in Decision No. C22-027-I that we were not persuaded by comments

[94] CNG August 24, 2022 Comments, p. 26.

received at that time that accounting for behind the meter emissions is inconsistent with § 40-3.2-108 (3)(c)(I)(A), C.R.S.

145. The Division indicated in its October 7, 2022 filing that the published workbook does not account for behind the meter emissions. The Division explains in its guidance document:[95]

> Estimation of behind the meter leakage is not currently performed under the Subpart NN or Subpart W reporting methodologies. Accurate estimations for this type of leakage should utilize inventories of natural gas appliances including manufacturer, model, and age of equipment that exist in each utility's customer base as well as comprehensive leakage studies covering various types of appliance to create utility specific adjustment factors. It is important to analyze system specific data to make these adjustments accurately and avoid having to make repeated, potentially significant, revisions to baseline emissions in successive CHPs.
>
> Behind the meter leakage estimations is a topic that the Division continues to be interested in and intends to continue exploring through ongoing technical stakeholder workgroup discussions. At this time, however, it is not addressed in the workbook consistent with the reporting methodologies set forth in Subparts NN and W.

146. Several participants continue to advocate for the Commission to limit subject emissions to those *at* the customer's meter and to not count behind the meter emissions. Public Service raises two issues. First, it claims the Commission's interpretation of § 40-3.2-108(3)(c)(I), C.R.S., is incorrect because it impermissibly expands the (undefined) term "distribution system" as used in SB 21-264. Public Service contends, as defined by the Commission's existing rules, "distribution system" does not include elements of gas infrastructure that are not part of a pipeline system owned by a utility and does not include behind the meter customer-owned infrastructure. Therefore, Public Service contends § 40-3.2-108(3)(c)(I), C.R.S., did not intend to include behind the meter emissions.[96] Second, Public Service contends behind the meter emissions from

[95] Division Clean Heat Plan Emissions Calculation Guidance (published Oct. 7, 2022), p. 11.

[96] Public Service August 5, 2022 Comments, pp. 18-19, and associated *errata* filed August 8, 2022.

residential, commercial, or industrial uses have not been well studied in the United States. It argues it is not appropriate to include behind the meter emissions in the 2015 baseline or target year emission calculations because the current state of scientific studies on behind the meter or post-meter methane emissions do not provide an emission factor that is representative of residential, commercial, or industrial use in Colorado or the United States as a whole.[97]

147. CNG argues that emissions accounting should utilize the demarcation point that ends the utility's responsibility (*i.e.*, distribution infrastructure up to the meter).[98] It points to customer owned yard lines as a similar situation in which ownership and responsibility ends with the physical point of the meter. CNG notes, if the Commission determines to count behind the meter emissions, for consistency it must also adjust the baseline.[99]

148. UCA states it does not oppose the rule as revised, but efforts should be made to ensure emissions are not "double counted" within a clean heat plan and then again within a utility's demand side management plan.[100]

149. API Colorado notes there is little in the published literature that provides reliable estimates of leaks from behind the meter in residential structures.[101]

150. Conservation Advocates and RMI maintain the Division's workbook should provide the ability to account for behind the meter emissions in alignment with the Commission's proposed Rule 4527(a).[102] Conservation Advocates suggest the "the workbook can include a default factor for behind the meter emissions using the best available data, and the Commission

[97] *Id*. at 20.
[98] CNG August 24, 2022 Comments, p. 13.
[99] CNG August 31, 2022 Comments, p. 8.
[100] UCA September 12, 2022 Comments, p. 9.
[101] API Colorado September 1, 2022 Comments, p. 14.
[102] Conservation Advocates and RMI August 24, 2022 Comments, p. 6.

may allow utilities to provide utility-specific data to adjust that factor, as research improves."[103] Conservation Advocates suggest implementing this by additional language in Rule 4527(a)(I) that allows for a utility to petition the Commission to adjust its baseline emissions based on empirical data of behind-the-meter methane leakage emissions in the utility's service territory. They propose setting a default factor based on the best available data from other jurisdictions, specifically data from a survey in California which presents a leakage rate of 0.5 percent.[104]

151. Colorado Communities for Climate Action also comments that the Division's methodology should have included behind-the-meter leaks.[105]

152. Considering the discussion in the Division's guidance document, the statutory language, and the comments in this Proceeding, we find the best course of action at this time is to approve the Division's methodology as presented in the workbook. We find the statute allows for the consideration of behind the meter emissions, by its plain language, and we agree with the Division that the data available, at present, does not provide sufficiently reliable information to account for behind the meter emissions in Colorado. At minimum, we find we do not have a record before us to appropriately determine an emissions factor to account for behind the meter emissions. However, we support the Division's continued interest in exploring ways to account for behind the meter emissions going forward and expect to evaluate, along with the Division, any necessary revisions to the workbook to appropriately account for all relevant emissions once additional empirical data or revisions by the EPA provide an enhanced basis upon which to do so.

[103] Conservation Advocates and RMI September 2, 2022 Comments, p. 5.
[104] Conservation Advocates October 7,2022 Comments, p. 17; Attachment CA-3.
[105] Colorado Communities for Climate Action October 7, 2022 Comments, p. 4.

### 6. Greenhouse Gas Emission Rules

153. The NOPR proposed a new section of the Gas Rules for the purpose of putting forth a methodology for the evaluation of greenhouse gas emissions for use in utilities' clean heat plan and demand side management applications. The Greenhouse Gas Emission Rules further three purposes. First, they implement the pollution cost requirements in §§ 40-3.2-106, 40-3.2-107, 40-3.2-108, C.R.S., second, they reference the Commission-approved Division-developed clean heat workbook, and third, they provide a consistent approach to calculating the social cost of carbon and the social cost of methane for use in demand side management, clean heat plan, and gas infrastructure plan applications.

#### a. Rule 4525. Overview and Purpose

154. We proposed a new Rule 4525 in the NOPR that presented the overview and purpose of the Greenhouse Gas Emission Rules. In response, several commenters, including Black Hills and CEO, suggested the Overview and Purpose rule should reference statutory provisions more broadly than only § 40-3.2-106, C.R.S. In the July Redlines, we added §§ 40-3.2-107 and 40-3.2-108, C.R.S., to the overview and purpose section. We have not received additional comments on Rule 4525 and as such we adopt Rule 4525 as presented in the July Redlines.

#### b. Rule 4526. Definitions

155. We proposed new Rule 4526 in the NOPR to specify a definition for the term "federal technical support document" as used in the Greenhouse Gas Emission Rules. CEO proposed changes to the definition of "federal technical support document" because it is anticipated the federal government will release an updated assessment for the social cost of

greenhouse gases in the near future.[106] We incorporated CEO's proposed changes in the July Redlines. We have not received additional comments on Rule 4526 and as such we adopt Rule 4526 as presented in the July Redlines.

### c. Rule 4527. Measurement and Accounting

156. The NOPR proposed certain requirements for how utilities shall measure and account for greenhouse gas emissions in formulating their required projections in Rule 4527.

157. We made several additional proposed changes in the July Redlines to paragraph (a) to: (1) require methane and carbon dioxide emissions be presented separately in short tons and presented in carbon dioxide equivalents; and (2) to reference the Division's working documents as the proper methodology to calculate baseline, systemwide, and emission reductions. In response, we received several comments, including from Public Service and CEO, that the proper term is "metric" tons. We adopt this proposed revision in Rule 4527(a) and universally.

158. Additionally, CEO suggests language revisions to paragraph (a) to clarify the manner in which updates to the Division's workbook are incorporated in the Commission's rules.[107] We adopt this suggested language in part. As discussed above, we refer to the Division's guidance document and workbook in Rule 4527(a) by specifying that a utility shall use the most recent Commission-approved version of the Division's clean heat workbook to enable flexibility for utilizing future iterations that may be developed by the Division and approved by the Commission. The Commission may consider a revised or updated version of the workbook developed by the Division, and approve such update, through separate a proceeding and order.

[106] CEO January 25, 2022 Comments, pp. 24-25.
[107] CEO October 7, 2022 Comments, p. 24.

#### d. Rule 4528. Social Cost of Carbon and Social Cost of Methane

##### (1) Rules 4528(b) and 4528(d)

159. In the NOPR, we set forth a new proposed Rule 4528 to describe the Commission's statutory obligations when establishing the cost of carbon dioxide and methane emissions, based on the requirements in § 40-3.2-106(4), C.R.S. In the July Redlines, we proposed additional minor edits to paragraph (d) to specify, pursuant to § 40-3.2-106(4), C.R.S., which methane emissions need to be considered when determining the net present value of the social cost of methane emissions. Proposed paragraph (b) sets forth the discount rate for certain presentation of net present values for the social cost of carbon. Proposed paragraph (d) sets forth the discount rate for certain presentation of net present values for the social cost of methane.

160. Public Service suggested in comments that we remove the discount rate directives in paragraphs (b) and (d). In earlier comments, Public Service had asserted that discount rates should be set in individual proceedings and not by rule, and therefore requested the Commission strike proposed Rules 4528(b) and 4528(d), which set the social cost of carbon and social cost of methane discount rate to "equal to the lessor of 2.5 percent or the discount rate established by the federal technical support document."[108] Public Service believes the rule reaches beyond § 40-3.2-106, C.R.S., which creates requirements for the discount rate used in the calculation of the social cost of carbon, but it contends that it does not set a discount rate for net present value calculations.

161. UCA supports the revisions proposed by CEO and included in revised Rule 4528 clarifying which methane emissions need to be considered when determining the net

[108] Public Service January 25, 2022 Comments, pp. 41-42.

present value of the social cost of methane. UCA also supports retaining the original proposed rule addressing appropriate discount rates for the social cost of carbon and social cost of methane as consistent with § 40-3.2-106(4), C.R.S., and with § 40-3.2-107, C.R.S.[109] Atmos believes a rate of 2.5 percent is too low and the rate should be at least 3 percent; Atmos points out, for reference, the last 30 years of the 10-year treasury bond average is 3.94 percent.[110]

162. As proposed in the NOPR, paragraph (d) establishes that, for the 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 by the federal technical support document, proposed paragraph (b) establishes the same value for net present value calculations of the social cost of carbon dioxide emissions. In the NOPR, we stated that the aim of the proposed rules is to structure the provisions for the social cost of carbon and the social cost of methane in a parallel manner. We continue to believe the Commission creates efficiencies and ensures uniform application of cost-benefit analyses by setting the net present value through a rule for social cost of carbon and methane applications.

**(2) Rule 4528(c)**

163. Proposed Rule 4528(d)(I) in the July Redlines required utilities to use the "best available leakage rates" to determine methane emissions from fossil gas extraction and processing. Black Hills previously articulated that Black Hills should not be responsible for the life cycle emissions upstream of its transportation and delivery of gas. Black Hills states it has no way to determine the gas leakage that occurs during process that are not within its control, such as the extraction process. Additionally, it argues the phrase "best available" leakage rates is vague and

[109] UCA August 24, 2022 Comments, p. 9.
[110] Atmos August 8, 2022 Comments, p. 9.

ambiguous and recommends the Commission not adopt proposed Rule 4528(d)(I).[111] Public Service presents in its proposed bluelines (Public Service October 7, 2022 Bluelines) that the language proposed in Rule 4528(d)(I) should be included under the Commission's proposed paragraph (c) instead.[112] We find it appropriate to adopt the proposed language regarding applying the best available values for natural gas leakage during the extraction, processing, transportation, and delivery of natural gas by the gas public utility as well as leakage from piping or other equipment on customer premises which is found directly in § 40-3.2-107(2)(a), C.R.S. However, we agree with Public Service that the directive fits most appropriately in paragraph (c) and therefore adopt it as Rule 4528(c)(III).

164. Except as discussed above, we adopt all other proposed changes to the Greenhouse Gas Emission Rules as presented in the July Redlines.

### 7. Gas Infrastructure Planning Rules

165. We set forth several reasons why the Commission proposed Gas Infrastructure Planning Rules in the NOPR. We expressed that the enactment of SB 21-264 and the development of the Clean Heat Plan Rules were essential to the statewide greenhouse gas emission reduction goals established in § 25-7-102(2)(g), C.R.S., but that SB 21-264 and corresponding rules will not address all of the issues that gas utilities and its customers will face through the transitions required to meet Colorado's goals. We also proposed new Gas Infrastructure Planning Rules to improve the Commission's visibility into a gas utility's future projects and expenditures. In large part, the rules proposed in the NOPR were in response to difficulties faced by the Commission in addressing

[111] Black Hills August 26, 2022 Comments, pp. 13-14.
[112] Public Service October 2022 Bluelines.

recovery of system safety and integrity investments and surrounding the transparency of planning and cumulative investment and expenditures.

166. The NOPR envisions the Gas Infrastructure Planning Rules as a venue for: (1) general planning (including system planning and infrastructure modeling processes, budgeting planning processes, and forecasted capital spending); (2) short- and long-term forecasting (of metrics including sales, customer counts, and capacity (design or peak day) requirements); (3) gas commodity purchasing planning[113]; (4) presentation of planned projects, including those categorized as new business and capacity expansion projects, system safety and integrity projects; and (5) long-term planning, including non-pipeline alternative considerations. The Gas Infrastructure Planning Rules adopted through this Decision expand upon and provide greater detail of the requirements of the respective the categories of information above, based on the expansive record before us. Throughout this Proceeding, we have gained a better understanding of the complexity of the gas system and the associated planning and investment practices of the gas utilities. We remain committed to implementing a more fulsome gas infrastructure planning regime to aid the Commission's ability to evaluate infrastructure planning in concert with the greater focus on reduced greenhouse gas emissions under the Clean Heat Plan rules.

167. The Commission sees the purpose of the Gas Infrastructure Planning Rules as threefold. The Gas Infrastructure Planning Rules and associated filings will serve as a venue to: (1) facilitate the Commission's understanding of the current gas system; (2) serve as a place to approve specific projects on a prospective basis, as well as a place develop both better and more specific project alternative analysis processes, and (3) examine the future use of the system and

[113] In Decision No. C22-0427-I, ¶ ¶ 107-110, we proposed for comment striking the proposed rule sections addressing gas commodity purchase planning; we continue to agree with commenters that this planning is better addressed by already established gas commodity planning processes.

the economics of the retail service provided over the long term, culminating in the 2050 statewide reductions in emissions as set forth in § 25-7-102(2)(g), C.R.S.

168. First, the record before us in this Proceeding exposes the need of both the Commission and stakeholders to understand the gas system better on a system-wide basis. To that end, we adopt specific subsections of the Gas Infrastructure Planning Rules that will enable us to better contextualize discrete infrastructure projects and investments by having a better understanding of the overall system and existing utility planning processes. Provisions that further this purpose include the requirements in Rule 4553(a) that a utility: (I) describe its planning methodology; (II) describe its budget planning process; (III) categorize its projects based on standard definitions; and (V) provide current system maps, as well as the requirements in Rule 4553(d) regarding existing infrastructure assessments.

169. Second, we see the Gas Infrastructure Planning Rules and associated filings as a venue for a greater analysis of specific infrastructure projects. The concept of "non-pipeline alternatives" analysis is admittedly nascent, but nevertheless a necessary and useful analysis to undergo now and improve upon over time. We see the need for greater emphasis on prospective project-specific analysis to examine more fully planned projects and to get a more holistic look at expenditures and planning for gas utilities. This purpose of the Gas Infrastructure Planning Rules, to analyze specific projects, is achieved primarily by Rule 4553. Overall, Rule 4553(c) develops a gas infrastructure plan filing as a venue for analysis of specific, future projects prior to cost recovery. The current framework of looking at only gas infrastructure investment only retrospectively does not enable the Commission to fully analyze projects before they are completed. We see a prospective analysis of specific projects, as implemented through Rule 4553(c), as a benefit to stakeholders and utilities because it alleviates some of the difficulties of

litigating issues related to specific project expenses in future rate cases and improves the Commission's ability to make more educated decisions in a pre-emptive capacity. We set out the Gas Infrastructure Planning Rules, and particularly Rule 4553(c)(I)(P), as a first step in developing a "nonpipeline alternatives" analysis framework for specific project investment.

170. Finally, we have developed the gas infrastructure planning proceeding as a venue to examine the future use of the utility pipeline system. This goal is achieved by requiring utilities to develop forecasts in Rule 4553(b) which align the Gas Infrastructure Planning Rules with the Clean Heat Plan Rules and the requirement for a utility to plan over both a short-term action period and a longer-term informational plan period.

171. We continue to see implementing Gas Infrastructure Planning Rules as advantageous for the Commission, utilities, ratepayers, and other stakeholders and necessary to ensure that gas utilities facilitate Colorado in reaching its greenhouse gas emission goals in a manner that protects the public interest, ensures just and reasonable rates, ensures system safety, reliability, and resiliency, while also minimizing impacts to income-qualified utility customers and disproportionately impacted communities. The Commission is further sensitive to the necessary balance between the regulatory process and associated costs

### a. Rule 4551. Definitions

#### (1) Customer-owned Yard Line

172. In the Decision issuing the July Redlines, we specifically sought proposals for a definition of "customer-owned yard line," if participants saw value in adding such a defined term to the Gas Rules. In response, CEO proposes to define the term to mean "a gas line running

underground from the utility meter to a customer's home, business, or other customer end use."[114] UCA supports CEO's proposal and CNG proposed similar language. We adopt a definition of "customer-owned yard line" based off the proposals of CEO and CNG because we find that defining the term adds clarity to the Gas Rules, particularly with the addition of the term "defined programmatic expense" discussed below.

**(2) Defined Programmatic Expense**

173. Paragraph (a) of proposed Rule 4551 in the July Redlines defined a planned project to represent, among other descriptions, a "program of similarly-situated investment." This concept was also referenced in the proposed CPCN Rule.

174. Public Service argues the phrase "invites litigation and dispute about whether or not particular investments are similarly-situated" or whether they constitute a program.[115] Public Service suggests the phrase could potentially "paralyze any needed actions to maintain and safe and reliable system."[116] Black Hills argues the concept will result in utilities being required to provide a "mountain of data," making such a filing "unwieldly."[117] Black Hills recommends that "program of similarly-situated investment" should be stricken from both the proposed Gas Infrastructure Planning Rules and the CPCN Rule.[118] Atmos suggests a minor change so that review of similarly-situated investment is only relevant to new program expenditures.

175. The Commission is currently aware of two programs of expenditure for which we consider to be similarly-situated investment that warrant review via the gas infrastructure planning

[114] CEO August 24, 2022 Comments, p. 14.
[115] Public Service August 5, 2022 Comments, p. 11.
[116] Public Service August 5, 2022 Comments, p. 11.
[117] Black Hills August 26, 2022 Comments, pp. 17-18.
[118] Black Hills August 26, 2022 Comments, p. 18.

process: the relocation and replacement of problematic meters and the replacement of customer-owned yard lines. The Commission had raised concerns with these two programmatic expenditures, which represent millions of dollars in ongoing annual investment, in previous proceedings.[119] However, we find merit in the arguments of Public Service and others that the phrase "similarly-situated investment" is broad and may likely be difficult to effectively determine what falls under such a definition during the course of a gas infrastructure plan proceeding. Accordingly, we modify this term to "defined programmatic expense" and specifically reference replacement of meters and customer-owned yard line programs in the definition of that term. We believe this modification, consistent with our stated objectives in finalizing these rules, should improve the clarity of the Gas Infrastructure Planning Rules and mitigate the administrative burden to submit and adjudicate gas infrastructure plan applications. The Commission may expand the list of expenditures that fall under the definition of defined programmatic expense, either through a future revision to these rules or through an order in a utility-specific application, as appropriate, in order to better comprehend and provide appropriate regulatory oversight of the investments and expenditures gas utilities make on behalf of their customers. We anticipate that the approval of a defined programmatic expense will be best addressed in a gas infrastructure plan filing, and limited to the gas infrastructure plan action period for which it is presented in a given gas infrastructure plan application, unless the utility can make a reasonable case for a longer-term approval.

**(3) Gas Infrastructure Plan Periods**

176. The July Redlines proposed new concepts further defining a plan period. First, the gas infrastructure plan *action* period, representing the three-year period beginning on the gas

[119] *See e.g.,* Decision No. C21-0397, issued on July 6, 2021 at ¶ 61, and Decision No. C21-0517, issued on August 25, 2021, in Proceeding No. 20A-0379G.

infrastructure plan submission date, and the gas infrastructure plan *informational* period, representing the subsequent the three-year period. Combined, the action and informational periods comprise the gas infrastructure plan *total* period. The Commission explained: “[a] utility should present project-level information where available, and particularly for all planned projects with an expected construction start date during the gas infrastructure plan action period. 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.”[120] Public Service suggests the gas infrastructure plan action period begin on January 1 of the gas infrastructure plan application submission year. Atmos suggests the gas infrastructure plan action period begin March 1 of the gas infrastructure plan application submission year.[121] The Commission finds the gas infrastructure plan action period is best defined as the full calendar years, the first year beginning January 1 of the year of the filing, and then two forward years. The Commission finds Public Service’s suggestion to begin January 1 reasonable and incorporates it into the adopted rules.

**(4) Planned Project Threshold**

177. Rule 4551(a) defines the dollar threshold by which a utility planned project would be subject to a gas infrastructure plan. The July Redlines maintained the $2 million threshold proposed in the original NOPR. As discussed above, the Commission required submission of utility historical investment data. Public Service also provided historic information for projects over $3 million, which it argues is the appropriate threshold for gas infrastructure plan project inclusion. Public Service’s data indicate it invested in 29 projects over $3 million during the 2019-

[120] Decision No. C22-0427-I, ¶ 113.

[121] Atmos August 8, 2022 Comments, p. 11.

2021 period, 18 of which were new business or capacity expansion projects. Atmos had 12 projects over $2 million and two projects over $4 million. Black Hills had 15 projects over $2 million and six over $4 million. CNG had 1 project over $2 million and none over $4 million.

178. Atmos suggests the threshold not be a dollar value but a percent increase in rate base. Atmos argues this mechanism will ensure the threshold is "appropriately sized for each utility and ensures that the benefits of additional review exceed the costs" of such a review.[122] Atmos also argues a threshold tied to incremental increase to rate base is also "helpful" in that it would focus only on utility investment and ignore contribution in aid of construction from customers.[123]

179. While the Commission agrees that Atmos' rate impact proposal provides certain advantages, we decline to adopt it at this time. We find the dollar value threshold is straightforward and easily comprehensible to the Commission, application participation participants, and the broader public whereas a percentage threshold would be relatively opaque. Utilizing a percent increase in rate base approach would require the utility to use a depreciation schedule for planned projects, well prior to the Commission considering a specific deprecation schedule for that particular investment. Because the percent increase in rate base approach would rely on premature inputs, such as a contrived depreciation schedule, we maintain that the dollar value threshold approach is advantageous.

180. We agree with Public Service that the $3 million proposal is appropriate for utilities with greater than 50,000 customers, which currently includes Atmos, Black Hills, and Public Service. We find this threshold value will provide intervenors and the Commission an opportunity to review an appropriately sized range of investments while imposing a reasonable level of

[122] Atmos October 7, 2022 Comments, p. 2.
[123] *Id*. at 3.

administrative burden. For utilities smaller than 50,000 customers, which currently includes CNG, we find a $2 million threshold appropriate considering smaller utilities have fewer customers over which to spread investments and relatively fewer projects that would warrant review at that price threshold than larger utilities.

181. Atmos seeks clarification that certain projects undertaken pursuant to requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA) are excluded from planned projects. It explains, "[f]or example, Grade 1 leaks are supposed to be fixed immediately, and Grade 2 leaks are supposed to be fixed within one year."[124] The gas infrastructure planning process is not intended to interfere with immediate or near-term utility requirements pursuant to federal PHMSA guidelines. We agree with Atmos and do not expect planned projects to include repairs for Grade 1 and 2 leaks due to their expedited timeframes.

### b. Rule 4552. Filing Form and Schedule

#### (1) Initial Submission Date

182. Rule 4552(a) defines the initial filing dates for the utilities. The July Redlines proposed a filing date of March 1, 2023, for the largest gas distribution utility, Public Service, and March 1, 2024, for all other utilities. In response, Public Service questioned whether the rules would be in effect by that time and suggested instead a May 1, 2023, submission deadline for its first filing. The Commission finds Public Service's suggestion reasonable and adopts the revised filing deadline for the largest utility, presently Public Service. We retain a March 1, 2024 filing deadlines for all other utilities in paragraph (a).

[124] Atmos August 8, 2022 Comments, p. 10.

### (2) Extending Alternatives beyond Non-Pipeline Alternatives

183. Public Service proposes the Commission allow a broader evaluation of alternatives beyond non-pipeline alternatives, or "NPAs," which were referenced in the proposed Gas Infrastructure Planning Rules and the CPCN Rule. The Commission finds this suggestion reasonable and hereafter refers to *alternatives analysis*, or *analysis of alternatives*, with the intent of referring to NPAs as well as other potential approaches, as applicable.

184. As indicated in paragraph 4552(b) and more fully development in rule 4553, a utility must present an alternatives analysis for certain planned new business and capacity expansion. We note that capacity expansion projects, in particular, are designed to meet peak demands attributable to customers' coincident use of gas appliances, including space heating, water heating, and potentially other uses that may or may not be attributable to design day conditions. We also note that demand response technologies and programs, as a basic tenet of such, are designed to mitigate coincident use of a resource. By staggering customers' consumption patterns, a utility may be able to cost-effectively reduce coincident customer demand, and by doing so, mitigate the need for investment to serve an otherwise higher peak load. The Commission recognizes the record in this rulemaking did not delve into the opportunity or complexities of demand response other than to recognize it as a potential non-pipeline alternative in paragraph 4001(ii). The definition of "non-pipeline alternative" in Rule 4001 is flexible enough to encompass future proposals by utilities and stakeholders for demand response programs and technologies. We encourage utilities and stakeholders to raise cost effective alternative DSM strategies, including demand response, through future adjudication.

#### (3) Planned Projects Subject to Alternative Analysis

185. Rule 4552(b) addresses initial gas infrastructure plan submissions. The NOPR proposed that a utility's initial filing would be informational, but otherwise did not prescribe the elements to be filed or the procedures to be followed. We address procedural requirements for the first round of gas infrastructure plan filings below.

186. As we stated above, a key purpose of the Gas Infrastructure Planning Rules is to create a venue for prospective review of planned projects. For certain planned projects, the Commission sees value in requiring a utility to evaluate alternatives to the planned project. However, non-pipeline alternatives analysis is a new concept for the Commission, utilities, and stakeholders. In light of this, we must ensure that the number of planned projects subject to alternatives analysis begins at a manageable level for utilities and that there is a way to build common understanding of best practice for these evaluations.

187. As background, separately, in Rule 4553(c)(I)(P), the Commission proposed in the July Redlines that alternatives analyses should be conducted for all new business and capacity expansion projects. Public Service, Black Hills, and others respond that this would create extraordinary administrative burden, and, for many proposed new business and capacity expansion projects, the timing or efficiency of pursuing alternatives was simply unrealistic. Public Service proposes to select itself five projects for alternatives analysis based on the suitability of each, given the timing, emissions-avoidance potential, total project cost, and total project deferral value.[125] Public Service maintains this is necessary to make the gas infrastructure planning process "manageable, actionable, and efficient."[126]

[125] Public Service October 8, 2022 Comments, p. 7.
[126] Public Service October 8, 2022 Comments, p. 18.

188. Conservation Advocates and RMI support the broad application of alternatives analysis to all planned new business, capacity expansion, and system integrity projects where the utilities are replacing fully depreciated assets. They also contend that projects not subject to an alternatives analysis should not be eligible for a presumption of prudence.[127] UCA agrees with that argument.

189. At this juncture, we have limited insight into the utility's planning process or the type, size, and inter-relationship of projects to be presented in an upcoming application. We recognize the record was insufficient to establish a detailed methodology for planned project selection for alternatives analysis. We also recognize that alternatives analyses may be administratively burdensome if required of all new business and capacity expansion projects. We also note an open review process, with stakeholder feedback and cooperation, may be able to provide innovative outcomes with less adjudication generally, and that such a process may be specifically well suited to select the projects to be subject to alternatives analysis. Accordingly, we find it is necessary to not expressly prescribe, at this juncture, the number of, or criteria by which, planned projects should be subjected to alternative analysis under a fully adjudicated gas infrastructure plan in Rule 4553(c)(I)(P).

190. We recognize that Public Service's proposal that a utility identify a set number of planned projects for alternatives analysis provides the Commission limited transparency into the selection of those projects. However, under 4553(c)(I)(P)(ii)(6), a utility must explain 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)(II); this should provide the Commission with more insight into a utility's decision-making process in determining

[127] Conservation Advocates and RMI September 2, 2022 Comments, p. 2.

which projects receive an alternatives analysis. As such, we find it is an appropriate first step to adopt Public Service's proposal for the purposes of the initial gas infrastructure plan submissions under Rule 4552(b), until we can establish more appropriate criteria, if necessary, that may apply to subsequent applications. We adopt Public Service's proposed number of at least five projects subject to alternatives analysis as an appropriate minimum for utilities larger than 500,000 customers. Utilities with less than 500,000 customers but greater than 50,000 customers, currently Atmos and Black Hills, shall present at least two planned new business and capacity expansion projects for alternatives analysis, and utilities smaller than 50,000 customers, currently only CNG, shall submit at least one planned new business and capacity expansion project for alternatives analysis in their respective initial gas infrastructure plan filings, Rule 4552(b) sets forth these set number of projects for alternatives analysis for initial gas infrastructure plan filings. We discuss the scope and application of alternatives analysis for fully adjudicated applications below.

**(4) Initial Filing Proceeding Logistics**

191. As we stated above, gas infrastructure planning is a new process for the Commission, utilities, and stakeholders. The Commission anticipates the initial plan filings will refine the process for future, adjudicated gas infrastructure plan filings. In order for the first plan filings to provide valuable insight and opportunity for refinement, utilities shall include in their initial filing submissions all of the elements required under Rule 4553, discussed below. Further, we establish the process we expect to use for the first informational filings and adopt these procedures in 4552(b). Specifically, we set forth the following protocols: upon receipt of the filing, the Commission shall open a proceeding, notice the filing, and establish an intervention period for the purpose of establishing parties; the Commission will establish procedures for the proceeding that shall include one or more public comment hearings; the Commission in response to a motion

or on its own mission, may request additional supporting information from the utilities or the parties; and the Commission will issue a written decision 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. As mentioned above, that decision will also provide guidance to be used in the preparation of the biennial applications pursuant to Rule 4552(d).

### (5) Limited Review of Initial Filings

192. Public Service suggested the Commission's review of an informational filing be limited to 120 days. In light of the informational nature of the initial filings, we find it appropriate to strive for a shortened review period of initial gas infrastructure plan submissions to a 150-day review process, to the extent practicable.

### (6) Exceptions for Gas-only Utilities

193. Rule 4552(c) of the July Redlines proposed that each utility would be eligible to file its first initial gas infrastructure plan under the less-than-fully adjudicated process addressed in Rule 4552(b). Black Hills contends the gas infrastructure planning process would be onerous on smaller utilities and notes it has commented on this issue during the rulemaking.[128] Black Hills suggests, because it has minimal opportunity to implement beneficial electrification given the limited overlap in its gas and electric service territories, it should submit only informational filings and not fully adjudicated applications.[129] Atmos similarly contends the discussion in this rulemaking "has not distinguished between gas transmission and distribution [which] are fundamentally different functions and processes." Atmos claims its Colorado operations are limited to distribution and new investment in such systems "is typically limited to replacement

[128] Black Hills October 11, 2022 Comments, p. 8, citing Joint Comments, p. 8.
[129] Black Hills October 11, 2022 Comments, p. 9.

projects, mandatory relocations, and leak reduction projects."[130] Accordingly, Atmos contends, the Commission "should consider making distribution project infrastructure filings informational for the first two cycles so that all stakeholders can learn from their experiences with the transmission filings."[131]

194. The Commission recognizes Black Hills' argument with respect to the challenges of beneficial electrification. We also recognize the potential administrative burden of litigating a fully adjudicated gas infrastructure plan proceeding can have on a smaller utility. We therefore find it appropriate to adopt Atmos' suggestion to allow the smaller, gas-only utilities (including Atmos, Black Hills and CNG) to file less-than-fully adjudicated applications, as outlined in Rule 4552(b) for the first two rounds of submissions (currently expected in years 2024 and 2026). The Commission expects the initial filings of smaller, gas-only utilities are expected to lean toward less-formal dockets in order to reduce the associated administrative burden, although we reserve the right to allow a more thorough assessment to take place given the circumstances of the filing upon its submission. Subsequent filings (in year 2028 and after) shall be filed under Rule 4552(d).

**(7) Utility Request for Relief**

195. Rule 4552(d) defines the general expectations under a fully adjudicated gas infrastructure plan application. In comments, the utilities each requested the Commission provide regulatory support for an approved project in the form of a CPCN, or to otherwise specify a CPCN is not further required for projects approved in a gas infrastructure plan. The utilities also requested approved projects receive a presumption of prudence, which we take up below.

[130] Atmos October 7, 2022 Comments, p. 4.
[131] Atmos October 7, 2022 Comments, pp. 4-5.

196. A utility is expected to apply to the Commission for issuance of a certificate of public convenience and necessity for all projects over the dollar thresholds established in Rule 4102, either through the gas infrastructure plan process or through an individual CPCN application. While a main purpose of the Gas Infrastructure Plan Rules is review of projects on a prospective basis, we acknowledge that the issuance of a certificate of public convenience and necessity may not be necessary or appropriate for smaller projects. We are persuaded by the comments from the utilities that some form of regulatory relief on a project-level could create efficiencies in Commission processes and provide certainty to utilities. However, we find that it is premature to identify explicit paths and standards for every possibility for regulatory relief available in the gas infrastructure plan process at this time. We do not have the record before us or the experience in gas infrastructure planning to create prescriptive rules in this area. Accordingly, in Rule 4552(d)(II) we allow a utility to identify in its application the form of relief it seeks for any applicable planned projects, including but not limited to, a CPCN, a declaratory order that the planned project is in the ordinary course of business, or some other form of relief as the utility proposes to be applicable. For regulatory and administrative efficiencies, we expect the utility to apply for a CPCN for the larger projects over the CPCN dollar threshold as part of its gas infrastructure plan application filed pursuant to paragraph 4552(d).

### (8) Pre-Filing Public Workshop

197. By Decision No. C22-0588-I, the Commission asked rulemaking participants to comment on: “the concept and potential procedural implications of a pre-filing conferral process whereby parties to a utility’s gas infrastructure plan application can review, among other things, system growth projections, planned infrastructure investments (that meet the approved threshold), and potential alternatives to those planned infrastructure investment in order to further the goals

of: adjudicatory efficiency, innovation in system planning and meeting reliability requirements, and adhering to Federal data and infrastructure security requirements."[132]

198. UCA states it supports a transparent, pre-filing conferral process as described in this question as a means to potentially limit contested issues and as a means to likely to reach consensus on the resolution of issues contained in a utility's gas infrastructure plan application. UCA believes such a process could also provide informal feedback to utilities in proposing their gas infrastructure plan applications.[133]

199. Public Service suggests a pre-filing stakeholder process is appropriate if it is limited to the alternatives analyses and to address the directives of the Decision. Public Service explains that starting the stakeholder process with the alternatives analyses, with potential to add other gas infrastructure plan components as future gas infrastructure plan are developed and the process matures, is the best and most realistic approach. Public Service proposes the process would commence ahead of the first adjudicated gas infrastructure plan (Public Service notes the initial, informational gas infrastructure plan is unsuitable for this process because of timing considerations).[134] Public Service contends the pre-filing conferral process, focused particularly on the projects to be selected for alternatives analyses, supports its proposal to bring forward a set number of projects, and that it will facilitate that the process evaluate "considerations of timing, emissions avoidance, total project cost, and overall potential project deferral value."[135] Public Service also agrees with the Commission's description that projects required in the four-to-six-year timeframe represent the "sweet spot" for alternatives analyses.[136]

[132] Decision No. C22-0588-I, ¶ 7(a), issued September 29, 2022.
[133] UCA October 7, 2022 Comments, p. 2.
[134] Public Service October 8, 2022 Comments, p. 6.
[135] Public Service October 8, 2022 Comments, p. 6.
[136] Public Service October 8, 2022 Comments, p. 6.

200. The Commission agrees with the arguments of UCA and Public Service. Adopted Rule 4552(d)(III) requires utilities, prior to filing an application, to 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 Rule 4553(c)(I)(P) with the goal of facilitating a robust and broadly supported set of alternatives analyses upon the filing of the application.

### c. Rule 4553. Contents of a Gas Infrastructure Plan

#### (1) Categorization of Projects

201. Rule 4553(a)(III) describes how planned projects shall be identified by type, broken out by system safety and integrity, new business, capacity expansion, mandatory relocation, and defined programmatic expense. The Commission notes that the July Redlines described two programs of similarly-situated investment: the relocation and replacement of problematic meters, and the replacement of customer-owned yard lines. Because we have modified the classification of these programmatic expenses and removed the phrase "similarly-situated investment" from the rules, as discussed above, list defined programmatic expenses as a separate category in Rule 4553(a)(III)(C). Atmos suggested adding the concept that a planned project may be included in more than one category. We find this suggestion reasonable and incorporate in Rule 4553(a)(III).

202. Conservation Advocates and RMI argue that projects may be inter-related and, if so, should be appropriately treated as a single project. The Commission agrees with Conservation Advocates and RMI that inter-related projects should be presented as a single project. For the Gas Infrastructure Planning Rules to properly serve as a venue for approval specific projects on a prospective basis, and for the Commission to comprehend where a utility may experience system

constraints and resulting needs for investment in capacity expansion projects, we must be able to understand the scope of actions a utility must undertake to meet a specific need. As such, we find it necessary to modify the definition of capacity expansion projects to include both individual projects and sets of inter-related facilities needed to maintain system reliability or meet a specified capacity expansion need.

203. Atmos suggests the threshold assessment should be based on utility investment alone and exclude investment by customers or other parties. The Commission agrees and adopts this change for the Gas Infrastructure Planning Rules and the CPCN Rule.

**(2) System Maps**

204. In Rule 4553(a)(V), utilities are required to provide one or more system maps to indicate the general locations of individual planned projects and whether planned projects are located within disproportionately impacted communities.

205. Project-specific mapping is required in Rule 4553(c)(I)(J), which we take up below. The system level maps required in this rule are expected to help convey a wide array of information including the overlapping requirements on, and capabilities of, the utilities' gas system. So that the Commission has the appropriate insight into such requirements and capabilities, we require utilities to provide system maps using two distinct forms of geographic segmentation that could impact utility planning, in addition to the statutory overlay of disproportionately impacted community boundaries. The first is related to system pressure. Capacity expansion projects are driven by a present condition, or future projection, of system constraint whereby the utility may not be able to maintain adequate system pressure necessary to reliably serve customers during periods of peak demand, particularly customers at the farthest corners of the constrained region of the system. In order to comprehend where the utility may experience system constraints, the need

for investment in capacity expansion projects, and the opportunity presented in non-pipeline alternatives or other alternatives to traditional capacity expansion, the Commission has adopted the term "pressure districts," and defined this term as "an area within a utility service territory with a distinct pressure environment from neighboring regions."

206. The second geographic segmentation required in the broader system maps are any additional distinct zones the utility may contemplate through its clean heat plan applications in accordance with Rule 4730. Clean heat plan segmentation may include disaggregation by unique weather zones which have specific design day temperatures for which the utility plans toward, but may also be organized in a different manner, as the utility presents as applicable in that process. To enable the Commission to fully comprehend a utility's infrastructure planning process, the Commission finds it necessary to adopt both forms of geographic segmentation in this section. We also define the map(s) required in Rule 4553(a)(V) as designed to provide sufficient detail to enable the Commission to evaluate and comprehend the extent and purpose of the overall gas infrastructure plan. Project-specific mapping, discussed below, is expected to provide the additional granularity required to assess individual planned projects.

207. CEO recommends that system maps with type and age of pipe be required as part of gas infrastructure plans and clean heat plans for the purpose of facilitating the Commission's review and understanding of NPA analysis. CEO believes that a system-wide understanding of the locations and ages of pipes will help the Commission consider where new gas infrastructure investments are prudent based on age of existing infrastructure, where new gas infrastructure may be imprudent due to the feasibility of cost-effective DSM and electrification measures, and where strategic gas decommissioning may be possible.[137] With respect to CEO's suggestion to require

[137] CEO October 7, 2022 Comments, pp. 13-14.

utilities to submit all pipeline age and material, the Commission declines, at this juncture, to add this requirement for the purposes of the system-wide map(s) in Rule 4553(a)(V). The utilities have indicated they do not have such information for their entire systems or that it would require a significant effort to compile. The Commission agrees such information requirements, if applied across the system, would require significant effort, and may represent more information than necessary to review the overall gas plan. We take this up again in the discussion of project-level mapping below.

**(3) Stakeholder Participation**

208. Rule 4553(a)(VII) requires the utility to provide a summary of the nature of stakeholder participation and input, including what communications were made and what findings came from engagement with members of disproportionately impacted communities related to projects located in these communities. Through Decision No. C22-0427-I, the Commission proposed to add both this requirement and a similar requirement related CPCNs. We address these similar rules together consistent with comments received.

209. UCA agreed with these additions, stating if a utility files an application in accordance with Rules 4102, 4731, 4753, or 4761, and any proposed project or activity is located in a disproportionately impacted community, then robust outreach must be conducted within that community in advance of the filing. According to UCA, utilities have the most information about communities in their service territories and entering it into procedural records will best enable the Commission to address equity concerns over time and therefore to meet its obligations under SB 21-272. UCA recommends that companies provide detailed reports of their outreach efforts with their applications as part of equity analysis, including factors like:

- The physical location of the disproportionately impacted community

- The ways in which the population is disproportionately impacted
- A description and nature of the outreach conducted within disproportionately impacted communities
- Names of community members and/or organizations conferred with
- The means by which those individuals or organizations were contacted
- When, how, and to whom notice was provided
- Communications and copies of written materials
- Locations, dates, and times of meetings
- Questions raised or responses from community members
- Utility findings or takeaways
- How the utility's application addressed feedback provided by members of a disproportionately impacted community
- How the application will provide equity, minimize impacts, and prioritize benefits to disproportionately impacted communities

210. Black Hills states that stakeholder participation is meaningful for certain types of programs, such as how to improve participation in demand-side management programs, but not for others, such as safety and integrity projects, as the utility may not be able to modify its approach. Accordingly, Black Hills recommends not adopting Rule 4102(c)(XIII) on CPCNs and Rule 4553(a)(VI) on gas infrastructure plans as proposed in July that require conferral with members of disproportionately impacted communities prior to filing. Black Hills recommends public comment hearings should be held after utility filings are incorporated, arguing that UCA's recommendation for "robust outreach" is ambiguous and that UCA is attempting to shift responsibility for engaging disproportionately impacted communities under HB 21-1266 from state agencies to utilities.

211. We decline to adopt either recommendation. First, Black Hills references concerns regarding system safety and integrity, but that is not the only type of project that could be addressed in gas infrastructure plans or CPCN applications, so we decline to remove engagement requirements based solely on that concern. However, we also find UCA's proposal to be overly prescriptive to incorporate into rules at this time. As UCA and other commenters acknowledge, the Commission has initiated a pre-rulemaking regarding SB 21-272, Proceeding No. 22M-0171ALL, which will gather information about best practices regarding community engagement and appropriate roles for the Commission and other entities, including state agencies and regulated applicants, among other objectives. UCA raises public comments received at community meetings as to how the Commission, other agencies, and regulated entities can improve outreach practices, and as we discussed at the October 26, 2022 Commissioners' Weekly Meeting, we take these comments to heart. We also expect that all stakeholders will have a role to play in the Commission's consideration of equity pursuant to SB 21-272. The utilities thus should expect that the effectiveness of their outreach may be a consideration as they bring forward cases under these rules in the future.

212. These rules are only one of potentially many settings in which appropriate community engagement must be considered as the Commission implements SB 21-272, and regulated entities may need flexibility, especially in the first stages of implementing new rules, to define appropriate engagement. Without taking a holistic view of what constitutes appropriate community engagement across industries and cases, the Commission risks establishing overly prescriptive requirements that burden communities with excess case-specific meetings rather than lead to meaningful engagement.

213. Accordingly, recognizing the concerns of both UCA and Black Hills, we adopt a minor modification to the rules to clarify that the nature of the outreach should be appropriate to the filing and that should be described as part of relevant applications. We further acknowledge and appreciate UCA's detailed list of proposed reporting requirements and suggest that utilities look to this list as they develop relevant filings. The list provided by UCA may be helpful in the future when the Commission assesses the effectiveness of utility engagement when a relevant application is submitted or approved. For example, UCA's list addresses factors like type and timing of notice, which are considered as part of HB 21-1266, as well as what feedback was received and how the application, including feedback, addresses factors related to SB 21-272 such as minimizing impacts and prioritizing benefits. The Commission has indicated that it wishes to explore its evolving role in stakeholder engagement generally and compared to other state agencies and to regulated entities as part of Proceeding No. 22M-0171ALL.[138] Accordingly, that proceeding may be the best venue to consider important questions such as what information is most critical to understand in which types of proceedings, and whether outreach-related rules should be specific to applications or rather, whether rules specific to outreach requirements should be crafted and applied in varying ways depending on the nature of the proceeding.

**(4) Design Day Updates**

214. The Commission anticipates that planning and forecasting activities will likely require a vast array of relevant inputs. The Commission also notes that utilities may need to regularly update such primary inputs, including the calculation of design day temperatures, which are generally based on 30 years of temperature data. Accordingly, in Rule 4553(a)(IX), the

[138] Proceeding No. 22M-0171ALL, Decision No. C22-0239, issued April 28, 2022, ¶ 38.

Commission requires utilities to update the design day temperatures assigned to unique segments of their utility systems, to the extent applicable, based on the coldest one-hour temperature in such defined segments over the previous 30-year period.

**(5) Design Day Peak Demand**

215. Rule 4553(b)(I) describes the general expectations for utility forecasts. The Commission recognizes that capacity expansion projects are driven by peak demand and regional constraints to serve that peak demand. Accordingly, and in accordance with Rule 4001(r), the Commission finds it necessary to add "design day peak demand" to the list of elements utilities are required to forecast, which also includes customer counts, sales and capacity requirements, gas content, and system-wide greenhouse emissions in accordance with their most recent clean heat plan forecast or interim update.

**(6) Sensitivity Forecasts**

216. Through Decision C22-0588-I, the Commission sought comment on the feasibility and value of having a high and a low forecast of peak design day demand and associated capital requirements and generally identifying in the gas infrastructure plan or clean heat plan those capital projects that could be avoided or delayed by the lower peak design day forecast, and specific projects that would need to be accelerated to meet the higher peak design day forecast. In response, Black Hills comments that the system is already designed to meet high peak design day, which is the maximum usage on the coldest day possible, and thus no high forecast is necessary. Black Hills was generally confused by the Commission's reference to a low peak design day and asked if it should assume a zero-gas usage day or some other alternative to high peak. Atmos agrees and argues "[c]lean Heat Plans are designed to reduce overall greenhouse gas emissions; not peak design day demands. While Atmos Energy concedes that the two are often correlated, that is not

always the case."[139] Black Hills and Atmos contend it is important to distinguish between distribution- and transmission-level assets in the discussion of sensitivity forecasts, as transmission investment and procurement of transmission is conducted through a long-term plan whereas distribution planning is not.[140] Black Hills contends "if you just add a neighborhood, a subdivision, it doesn't change a whole lot of our Design Day on the system … that really is a conversation we have with our upstream pipes."[141] CNG contends any requirement to predict design day changes could be challenging for small utilities, and that growth is not understood until they are approached by developers of new residential and commercial structures.[142]

217. For example, CNG states it plans for a peak design day in order to ensure that the system supports serving all customers under the coldest foreseeable conditions and therefore it has never contemplated a "low" peak design day. CNG explains that modeling a peak design day involves a number of assumptions and changing any of those to result in a lower system flow would negate the purpose of the design day, which is to ensure safe and reliable service to customers. System demand associated with new large customers and groups of small customers are added to its peak design day model and system improvement projects are identified as needed.[143]

218. Public Service responds that the Commission appears to potentially be confusing or conflating the concept of a design day, *i.e.*, the conditions the system is built to meet as compared to expected usage on the coldest day of the year, with expected usage on a particular day. However, Public Service is supportive of considering both a high and low forecast (in the form of a sensitivity

[139] Atmos October 7, 2022 Comments, p. 8.
[140] Hr. Tr. September 19, 2022 at 201:23 – 202:2, 204:14-205:8.
[141] Hr. Tr. September 19, 2022 at 205:4-8.
[142] Hr. Tr. September 19, 2022 at 202:24-203:6.
[143] CNG October 7, 2022 Comments, p. 12.

analysis), provided that design day criteria is uniform across these forecasts. In other words, the difference between the high and low forecast would not be the result of a different design day assumption. Public Service has concerns with the feasibility and utility of modifying the design day into a high and low forecast and does not recommend the adoption of such rules.[144] Similarly, Atmos cautions the Commission from conflating the concepts of peak design day and overall gas usage.[145]

219. Conservation Advocates agree that a high and low forecast of peak design day demand would be useful in the planning processes contained in the rules and also suggest the Commission require utilities to include high and low forecasts of gas throughput as well.

220. The gas infrastructure planning process leverages the forecasts created through the clean heat plan process, as suggested in the Joint Comments and proposed in the July Redlines. The gas infrastructure planning and clean heat plan processes will utilize the forecasts in overlapping but ultimately unique ways. The clean heat plan process will use the forecasts to project emissions in order to reduce such emission projections. The gas infrastructure planning process will use forecasts to assess infrastructure investment and alternatives to such investment in order to serve customer peak requirements as cost-effectively as possible.

221. The Commission also notes the idea behind the low and high sensitivities to the reference forecast is not to assess the impact of alternative design day temperatures used for planning purposes, as suggested by Black Hills and others, but to assess the impact of alternative growth projections – due to sensitivities of customer count, adoption of beneficial electrification and energy efficiency technologies by new and existing customers, and other elements that may

144 Public Service October 7, 2022 Comments, p. 24.

145 Atmos October 7, 2022 Comments, p. 9.

drive growth – that could ultimately affect peak design day requirements for which the utility plans for. The Commission recognizes utilities may not have planned distribution system investment in the past to the extent that may warrant sensitivities to such planning. But that is precisely the intent of the gas infrastructure planning process, which is to begin to better understand potential growth as early as possible in the development process and evaluate potential cost-effective means to reduce infrastructure investment requirements and, for distribution-only utilities, infrastructure procurement requirements that may be necessary to meet growth-related obligations.

222. For these reasons, the Commission agrees with Conservation Advocates, and we expand the forecast requirements to include low and high sensitivities around a "reference" forecast. We believe the sensitivities created around the reference case will provide valuable insight into a utility's planning process, the impacts of customer growth on system costs, and how such planning recognizes and accounts for the changing business environment brought about, not only by referenced statute and these rules, but also municipal efforts to modify building codes, federal initiatives to improve the cost-effectiveness of electrification technologies, and other shifts in policy and economics that could impact the manner in which utilities historically ran the gas businesses.

**(7) Small Utility Forecasts**

223. Rules 4553(b)(II) establishes the forecasting criteria that apply to utilities that qualify as small utilities, per the Clean Heat Planning Rules (*i.e.*, those with less than 90,000 customers). This rule is designed so that such small utilities forecast with a precision similar to that required of larger utilities.

### (8) Project Life

224. Rule 4553(c) specifies the planned project information a utility must present in a gas infrastructure plan filing. Subsection (c)(I)(D) of the July Redlines proposed requiring a utility to specify the projected engineering life. Public Service suggested removing engineering from the description. Atmos suggested replacing "engineering" with "depreciation." We agree with Public Service and decide to remove "engineering" and require a utility to present simply the projected project life.

### (9) Construction and Financing Information

225. The July Redlines proposed requiring utilities to provide "the entities responsible for constructing and financing the project" as part of its gas infrastructure filing under 4553 or a CPCN application under 4102. In response, Black Hills contends "[d]epending on the size and extent of any specific project, a utility utilizes multiple subcontractors to complete the project in a timely manner. … The Commission should strike [this] proposed rule."[146]

226. Atmos generally agreed and argued that is "does not always have 'line of sight' on corporate parents or higher-level entities, we sometimes only know who is 'cutting the check.' In many cases, this type of financing information is protected by a non-disclosure agreement and the utility may not be permitted to provide it. Lastly, it is not clear that there is any public benefit in evaluating third-party financing of facilities. If regulated utilities are not contributing their own capital, the investment decision does not increase rate base nor is it subject to Commission review."[147]

[146] Black Hills August 26, 2022 Comments, p. 7.
[147] Atmos August 8, 2022 Comments, p. 6.

227. The Commission recognizes the complexity of providing the entities responsible for constructing and financing the project. We also recognize the merit in the arguments of Black Hills and Atmos of the difficulty knowing the specific entities that will construct unique components of a larger project well in advance of project implementation. Accordingly, we decline to adopt a requirement to provide the entities responsible for constructing and financing planned projects.

### (10) Cost Estimation Information

228. In recent comments, utilities urge the Commission to offer regulatory support in the form of a presumption of prudence related to project costs, for approved projects in a gas infrastructure plan. We recognize that utility projects can have a wide range of maturity in the project scoping and cost estimation process. While exceptions may arise, projects nearer in time generally have more mature project scopes and cost estimates, and vice versa for projects farther in time. Rule 4555(c) establishes that, in certain instances, a presumption of prudence may be granted to approved projects revised in a gas infrastructure plan. To align the application requirements with the Commission's rule regarding plan approval, we incorporate in Rule 4553(c)(I)(G), a requirement that utilities provide a cost estimate classification using an industry-accepted cost estimate classification index.

### (11) Project-specific Mapping: Required Elements

229. Rule 4553(c)(I)(J) outlines the project-specific mapping requirements of a utility's gas infrastructure plan application. We break down the project mapping requirements into a list of discrete elements. The first element is related to the geographic area served by the planned project. We find it necessary to also require specification of the relevant pressure district, or

geographic area that requires the proposed facilities, here in Rule 4553(c)(I)(J)(i) for project-specific maps.

#### (12) Project-specific Mapping: Sensitive Data

230. Several additional issues were raised during the course of the Proceeding regarding Rule 4553(c)(I)(J). In Decision No. C22-0588-I, the Commission requested comment regarding specific examples or elaboration on utilizing interactive mapping tools as a forum to communicate and review localized levels of information, including the forecasting of peak design day demands and the assessment of planned project designs and costs.[148] The utilities uniformly raised concerns regarding sensitive security information protected by federal regulation. Public Service, Atmos, and Black Hills each discussed in comments that Transportation Security Administration (TSA) regulations, and specifically the TSA Designation of Sensitive Security Information Order, limit any maps available to the public to a scale of 1:24,000 or less and prohibit a publicly-available map from including more than three of the following attributes: valves, pump stations, compressor stations, supervisory control and data acquisition ("SCADA") control centers, operating pressure, throughput, and wall thickness. Public Service explains that because it has an extensive transmission system, it is subject to heightened security considerations. Public Service argues that it is unclear why the Commission would need an interactive mapping tool, and if such a tool were to be considered or implementing, a full list of map attributes would be needed to evaluate security and legal concerns. Instead, Public Service offered simplifying language to stay clear of the federal guidelines.[149]

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[148] The Commission requested comments on this topic by Decision No. C22-0588-I, ¶ (7)(c), issued September 29, 2022.

[149] Public Service October 7, 2022 Comments, p. 18.

231. The Commission recognizes the concern raised by the utilities. We do not have a sufficient record before us to implement interactive mapping or maps that contain sensitive security information in a workable way at this time, given concerns about security, details and functionality that were not thoroughly addressed as part of this Proceeding. We find Public Service's proposed language reasonable and adopt it in subparagraph 4553(c)(I)(J). Evaluation of utility systems through detailed mapping and modeling remains an interest of the Commission we expect to explore more in the future.

**(13) Project-specific Mapping: Interactive Mapping**

232. We posed for comment the prospect of implementing interactive mapping as a requirement of a gas infrastructure plan for evaluating system capacity adequacy or planning. Specifically, the Commission asked for feedback on the concept of utilizing interactive mapping tools as a forum to communicate localized levels of information, including the forecasting of peak design day demands and the assessment of planned project designs and costs.

233. The utilities broadly replied that such interactive mapping requirements, as proposed, could fall afoul of the TSA regulations regarding sensitive security information discussed above, and that such a proposal was generally unworkable. Public Service noted does not currently have any similar external-facing tools and does have the capability to provide such a tool in the near term. It contends the current static mapping requirements are sufficient for the purposes of the Gas Infrastructure Planning Rules at this time.

234. The Commission recognizes that interactive mapping could present extensive technical challenges and that it raises questions regarding the dissemination of potentially sensitive data. We agree with Public Service that, at least presently, static maps are sufficient for the purposes of implementing the gas infrastructure planning process. However, we will continue to

assess the opportunity for the efficient transfer of information and visualization of system characteristics including loads, expenses and materials through interactive mapping or Commission review of operational and planning models.

**(14) Project-specific Mapping: Disproportionately Impacted Community Overlay**

235. Finally, with respect to Rule 4553(c)(I)(J), the rules require the overlay of information related to disproportionately impacted communities. Black Hills argues that maps regarding disproportionately impacted communities are currently in the control of CDPHE and that utilities should not be tasked with trying to overlay that changing data with their GIS maps. The Commission disagrees and believes that utilities are reasonably charged with the function of mapping their planned projects as they relate to disproportionately impacted communities. Utilities' filings in response to Decision No. C22-0152-I demonstrated they are capable of acquiring data from CDPHE mapping tools and comparing it to service territories. We find this approach to be reasonable unless and until the Commission determines whether other practices for identifying disproportionately impacted communities should be used in the course of creating rules pursuant to SB 21-272. We thank the CDPHE for maintaining mapping tools and hope they will continue to work with utilities as necessary and appropriate to promote accurate portrayal of disproportionately impacted community boundaries.

**(15) Project-specific Mapping: Granularity**

236. For project-specific maps, we maintain our interest in reviewing sufficient detail to allow a thorough comprehension of the existing and proposed facilities. Accordingly, we require that project maps shall indicate existing and proposed regulator station and existing and proposed distribution piping and higher capacity pipelines served by or representing the proposed facilities. We find this modification will allow a thorough review without unnecessary administrative burden.

#### (16) Customers Directly Served by a Project

237. Rule 4553(c)(I)(K) requires utilities to indicate the number of customers and quantity of load, by class, directly impacted or served by the project. Public Service suggested adding the phrase "to the extent practicable." We find this modification reasonable because such information may not be known with precision at the time of filing and adopt it for use in the adopted rule.

#### (17) Project-specific Emissions Calculation

238. Rule 4553(c)(I)(N) requires a projection of the change in greenhouse gas emissions due to the planned project. The July Redlines proposed the calculation shall be presented on a utility-wide basis and calculated relative to the last approved clean heat plan greenhouse gas emission forecast or subsequent interim-year update. Public Service argued against such level of detail, contending most planned projects, including capacity expansion and system integrity projects, have essentially no throughput or associated emissions impact as they are designed to meet peak demand or replace aging infrastructure, respectively, so it is not necessary to link the proposed requirement to clean heat plans.[150] Public Service deleted the reference to utility-wide emissions and the calculation process expected of utilities in their clean heat plan applications. The Commission finds merit in the argument that many planned projects are likely to have individually modest or even negligible associated emissions with the exception of new business projects where, for example, a significant number of new customers may be added. However, we find the utility may reasonably be able to conduct an analysis of projected customers, by class, and the associated emissions of such, separate from system-wide forecasts pursuant to the clean heat plan process.

[150] Public Service August 5, 2022 Comments, p. 26.

Accordingly, we adopt Public Service's suggested modifications and incorporate in Rule 4553(c)(I)(N).

**(18) New Business Projects Subject to Alternatives Analysis**

239. Rule 4553(c)(I)(P) guides utilities on the new business and capacity expansion projects to be selected for alternatives analysis in a fully adjudicated application. In its bluelines, Public Service eliminated planned new business projects from the type of projects subject to an alternatives assessment in a gas infrastructure plan application and added that requirement to the clean heat plan as Rule 4731(i). Public Service explains, per its proposal, the clean heat plan process will include "New Business Evaluation Reporting," which would consider all relevant projects over $3 million in utility investment and for which "the Company proposes that it would work with developers… to discuss potential alternatives and explore opportunities to bring stakeholders into those discussions."[151] Public Service notes such reporting could be done through either the gas infrastructure plan or clean heat plan processes, but contends there is logic in keeping it with clean heat planning "because the alternatives presented to customers would likely be statutory Clean Heat Resources, and the Company could incorporate any alternatives accepted by the potential customer… into its Clean Heat Plan."[152]

240. CEO agrees with Public Service's position. It contends new business projects are likely to be driven by a single customer requesting new service and do not result in capacity expansion of the system.[153] On this basis, CEO proposes to move those projects from evaluation

[151] Public Service October 7, 2022 Comments, p. 9.
[152] Public Service October 7, 2022 Comments, p. 9.
[153] CEO October 7, 2022 Comments, p. 8.

in a gas infrastructure plan to the clean heat plan process where the utility would work directly with the customers to assess potential alternatives for that individual customer.[154]

241. Black Hills detailed the complexity of altering a new business project, contending development of a new neighborhood can take years, for which it has little insight on the progress or when the request for service will take place.

242. The Commission notes that the gas infrastructure planning process will take place every two years, whereas the clean heat plan process, as discussed elsewhere, initially incorporates a four-year cadence. As new business projects are implemented on a relatively quick time horizon, we find the more frequent cadence of the gas infrastructure plan makes it the appropriate vehicle to assess planned new business projects. We also note the gas infrastructure planning process is designed to assess infrastructure investment, whereas the clean heat plan process is designed to calculate emissions. New business projects are, first and foremost, a planned investment, and thus best incorporated into the gas infrastructure planning process. Accordingly, we find unpersuasive Public Service's arguments and do not adopt Public Service's proposal to remove the new business projects from the alternatives analysis in the gas infrastructure planning process or to substitute it with a new business evaluation report in the clean heat plan process. We find it necessary to maintain the opportunity for alternatives analysis for both capacity expansion and new business projects presented in the utility's gas infrastructure plan.

#### (19) Selection of Planned Projects for Alternatives Analysis: Fully Adjudicated Proceedings

243. During the September 19, 2022 public comment hearing, and through Decision No. C22-0588-I, the Commission requested feedback on the timing of alternatives, recognizing that

[154] CEO October 7, 2022 Comments, p. 8.

NPAs, in particular, can take several years of lead time to mitigate growth and associated capacity expansion requirements. The Commission recognized that "the ideal timeframe to assess NPAs is approximately 3-5 years ahead of a planned infrastructure project.[155]

244. Public Service generally agrees that an alternative analysis should be saved for capacity expansion projects that are well enough into the future that there is realistic time to implement the alternatives sufficiently. It contends that the four-to-six-year time window is "the best window for alternatives analyses."[156] Public Service also argues the time window reinforces why its five-project proposal results in a process that is "manageable, actionable, and efficient."[157] Public Service states it is particularly concerned with the potential administrative burden associated with the alternatives analysis section of the rules. Public Service notes the Joint Comments agreed that some projects are more appropriately suited to alternatives analyses than others. Public Service argues, utilities should be granted discretion and flexibility when identifying the projects foremost suitable for a non-pipeline alternatives analysis.[158]

245. Atmos generally argues that any analytic requirement, across the gas infrastructure planning process, provide a positive cost-benefit: "the Commission must be mindful that the costs of creating, collecting, and reviewing additional data, and additional contested proceedings, will ultimately fall upon the utilities' customers."[159]

246. CEO proposed alternative analyses should be required based on a separate dollar threshold of $8 million for Public Service and $1 million for other utilities (*i.e.*, those below 500,000 customers).

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[155] Decision No. C22-0588-I, ¶ 7(a), issued September 28, 2022
[156] Public Service October 7, 2022 Comments, p. 16.
[157] Public Service October 7, 2022 Comments, p. 16.
[158] Public Service August 24, 2022 Comments, p. 21.
[159] Atmos October 7, 2022 Comments, p. 2.

247. Conservation Advocates and RMI also propose a two-tier system for NPAs to alleviate the administrative burden. They suggest a lower tier of $2-$5 million that could rely on NPA cost curves from utilities' most recently approved clean heat plan. The upper tier, for projects above $5 million, would require more project specific NPA price information. Conservation Advocates and RMI also believe there are opportunities for gas-only utilities to offer beneficial electrification measures to customers through new business models that can allow the utility to diversify its revenue stream during the gas transition. They point to several examples in other states, including VGS (formerly Vermont Gas Systems) which offers installation services and leasing options for heat pump water heaters (including to customers not connected to its system) and notes that many gas utilities in the northeast and New York have been piloting shared geothermal systems, where the gas company owns and operates community systems and sells heating and cooling services to customers in those areas instead of gas. Conservation Advocates and RMI point to Minnesota, where gas utilities may file natural gas innovation plans.

248. Public Service countered that, "amongst the 18 Gas LDCs in New York State, only six NPA opportunities have been identified [and] only two have actually resulted in successful implementation that was able to meet a gas system need."[160] It also notes that "NPA efforts in New York have generally taken three years for implementation on the early side, providing support for the targeting of a four-to-six year range" in the instant Proceeding.[161]

249. The Commission agrees with many comments received regarding the importance of developing a fulsome alternatives analysis process, and that utilities may need to be innovative in their search for alternatives, even if that requires the evaluation of non-traditional business

[160] Public Service October 7, 2022 Comments, p. 5.
[161] Public Service October 7, 2022 Comments, pp. 5-6.

models. However, we also agree that review of all potential alternatives to planned projects could be burdensome and a less-than-cost-effective manner to target utility resources, and ultimately, ratepayer funds. We already addressed the selection process for initial filings above in our discussion of Rule 4552(b). That discussion also indicated the Commission's expectation that such initial filings will improve the Commission's ability to specify the criteria and/or number of planned projects to be subjected to an alternatives analysis. In Rule 4553(c)(I)(P), we find it necessary to reference that process. At this juncture, we do not find it necessary to establish rules requiring or limiting future use of alternative analysis for adjudicated future gas infrastructure plans. We may revisit this after we learn from the initial filings. For new business and capacity expansion projects submitted as part of a gas infrastructure plan in accordance with 4552(d), the utility shall present an analysis of alternatives meeting the minimum standards described in Rule 4553(c)(I)(P), unless directed otherwise by the Commission

250. With respect to Conservation Advocates and RMI's two-tiered approach designed to reduce the administrative burden of evaluating alternatives to smaller projects, as well as CEO's proposal of a separate dollar threshold for alternatives analysis, we note these concepts may indeed offer an effective way to parse projects for alternative analysis for future filings. However, we find it important to allow the initial filing process an opportunity to provide greater insight, and at this juncture, decline to incorporate suggestions by Conservation Advocates and RMI and CEO.

### (20) Alternatives Analysis Required Detail

251. We establish in Rule 4552(c)(I)(P) a detailed list of the considerations and requirements expected of an alternatives analysis within a gas infrastructure plan, filed either under 4552(b) or 4552(d). Specifically, we require a utility alternatives analysis to consider, at a minimum, one or more clean heat resources, a cost-benefit analysis including the costs of direct

investment and the social costs of carbon and methane emissions, and the best value employment metrics associated with each alternative. So that utility applications may be sufficiently robust, the Commission also finds it necessary to specify alternatives analyses shall include, at a minimum, the technologies or approaches evaluated and proposed, the projected timeline and annual implementation rate for each technology or approach proposed, the technical feasibility of the alternatives assuming full adoption of the technologies and approaches proposed, and the utility's strategy to facilitate the technologies or approaches evaluated.

**(21) Strategic Pruning of Distribution System**

252. Conservation Advocates and RMI propose the Commission expand the evaluation of NPAs to not just planned new business and capacity expansion projects but to segments of the existing system that may be fully depreciated or slated for replacement in order to facilitate strategic pruning of such segments.

253. Public Service countered that the notion of "strategic pruning" relies on the faulty premise that the gas system is going away. It argues gas will remain a part of the future alongside electrification. Public Service also contends it will broaden the scope of gas infrastructure plans even further by subjecting all infrastructure replacements, in addition to expansions, to the thresholds and alternatives analysis, which Public Service claims is unworkable.

254. We recognize that participants in this Proceeding have competing visions for the future of the gas industry, and their rule proposals reflect this. We emphasized above that this rulemaking is one incremental step in the larger evolution of the shifting regulatory framework for the gas industry. The clean heat planning process is not yet underway, and neither the Commission, the utilities, nor any potential stakeholders, yet know the outcome of such clean heat plan applications. In particular, we do not know whether the utilities' approach to statutory emission

reduction requirements, as approved by this Commission, will include the procurement and distribution of green hydrogen or recovered methane in quantities that support continued expansion of the system while meeting statutory emission goals. Accordingly, we find it premature to require gas infrastructure plan applications to contemplate strategic pruning at this time.

#### (22) Explanation of Alternative Analysis Project Selection Methodology

255. Rule 4553(c)(I)(P)(6) requires utilities to provide an explanation of how and why the utilities selected the projects it proposed for alternatives analysis, including discussion of the public review process pursuant to Rule 4552(d)(IV). As discussed above, we find the record insufficient, at this juncture, to determine a specific approach to selecting planned projects for alternatives analysis. We have adopted Public Service's proposed set-number approach for the initial filings, until we can determine a more appropriate criteria, if applicable for future adjudicated filings. To ensure flexibility as the gas infrastructure planning regime evolves, we adopt subparagraph (6) which requires utilities to provide 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(c)(III). We also find it necessary to add in Rule 4553(c)(I)(Q) a requirement that a utility explain why any planned new business or capacity expansion project was not selected for alternatives analysis.

#### (23) Avoided or Incremental Investment Due to Low or High Sensitivity Forecast

256. In Rule 4553(c)(II), we require specific investment-related information to comprehend the cost impact of lower or higher growth in customers, sales, and design day demand. Accordingly, we add the requirements in Rule 4553(c)(II) that a utility must calculate the total incremental investment that may be needed, in association with the reference, low and high forecasts, over the gas infrastructure plan action and information periods. We also find it necessary

to add the requirement that utilities identify the primary individual new projects avoided in the low design day demand forecast as well as the projected additional capital expenditure associated with the high forecast of peak design day demand.

**(24) Existing Infrastructure Investment Reporting**

257. Rule 4553(d) relates to the assessment of existing infrastructure, including customer-owned yard lines, hydrogen compatibility, and advanced leak detection. Atmos suggested certain clarifying phrases, including "if applicable" to assess customer-owned yard lines and "to the extent known" to the assessment of hydrogen compatibility. We find these suggestions reasonable and incorporate them into the adopted rule.

258. We title this section "Existing Infrastructure Assessment Reporting" as proposed by Public Service.

259. Public Service also suggests specifying that the existing infrastructure assessment reporting is for "for informational purposes." We find that suggestion would leave the Commission without authority to order modifications or otherwise require actions based upon the insight the required information provides. Accordingly, we decline to add the qualifier "for informational purposes only" to Rule 4553(d).

260. Finally, with respect to customer-owned yard lines, the July Redlines suggest at Rule 4553(d)(I)(A) that this information should be disaggregated by regulator station. As discussed above, we have removed the granularity of regulator station proposed at various places in the July Redlines. We find it appropriate to replace regulator station in Rule 4553(d)(I)(A) with "municipality" because that provides an appropriate level of specificity to contextualize where a utility proposes to address customer-owned yard lines. Similarly, in Rule 4553(d)(II)(B), we remove regulator station from the identification of areas of the gas distribution

system with unknown materials or materials known not to be compatible with hydrogen mixtures up to 20 percent by volume.

#### d. Rule 4554. Interim Gas Infrastructure Plan Reporting.

261. Atmos suggests replacing the language defining when interim reporting shall be required from "six months from the mail date of the decision in the last gas infrastructure plan proceeding" to "March 1st in the year after the last gas infrastructure plan proceeding."[162] We find this suggestion reasonable and adopt it. We otherwise adopt Rule 4554 as presented in the July Redlines.

#### e. Rule 4555. Approval of Gas Infrastructure Plan.

##### (1) Utility "Move Forward" Language

262. Public Service suggested numerous changes to Rule 4555, including that the rules should recognize that the utility's obligation to serve its customers is paramount, and that it should be allowed to invest in any project necessary to meet that obligation. Specifically, Public Service suggests adding the phrase: "[t]he utility may move forward with one or more planned projects in any modified plan, without limitation, that the utility deems necessary to meet its obligations under Sec. 40-3-101(2), C.R.S."[163] Public Service maintains this revision provides the necessary certainty to the approval process so that the utility can continue to make necessary investments and advance projects in a timely manner.

263. The Commission recognizes the utility bears the ultimate responsibility to serve its customers reliably, and generally agrees that these Gas Infrastructure Planning Rules should not

[162] Atmos August 8, 2022 Comments, p. 11

[163] Public Service October 7, 2022 Comments, p. 21.

interfere with or otherwise impede a utility's ability to meet that core obligation. Accordingly, if the utility needs to invest in infrastructure other than what is authorized through its approved gas infrastructure plan, it should do so and intend to fully justify the circumstances of such when it seeks cost recovery in a subsequent base rate proceeding, consistent with historical practice. However, the Commission finds the Gas Infrastructure Plan Rules do not run counter to the utility's obligation to serve responsibly. Accordingly, we decline to add Public Service's proposed language to Rule 4555.

**(2) Determination of Need / Presumption of Prudence**

264. The NOPR modeled proposed Rule 4555 on the rules that govern Commission decisions on electric resource plans (ERP). We proposed for comment granting a presumption that the utility's actions consistent with the Commission decisions approving its gas plan, are presumed prudent in rate cases. The July Redlines proposed removing this provision because of the changing scope and timing of the proposed Gas Infrastructure Planning Rules presented there. Public Service and the other utilities request the Commission provide appropriate regulatory support and reinstate Rule 4555(c) or a corollary to Rule 3617(d), the relevant electric resource planning provision.

265. Public Service suggests the Commission initiate a two-step process that (1) re-establishes Rule 4555(c); and (2) opens a new miscellaneous proceeding to assess potential future rate structures that can be used as the gas system continues to evolve.[164] Public Service states the proceeding could focus on regulatory support approaches both for clean heat plans and gas infrastructure plans and commence late this year or early next year. The suggest the data from the proceeding could then inform cost recovery proposals in clean heat plans as well as future gas

[164] Public Service October 7, 2022 Comments, pp. 10-11.

infrastructure plans.[165] Conservation Advocates argue against regulatory support for projects that are not subject to an alternative analysis. Black Hills argues that: "Prudence is intended to evaluate what was known when the action occurred. Monday morning quarterbacking should not become the practice at the Commission. Furthermore, stakeholders shouldn't be afforded multiple bites at the apple. Utilities should be entitled to recover prudently incurred costs associated with the actions taken to comply with a Commission decision."[166]

266. The Commission understands the regulatory support requested by Public Service and other utilities to have two distinct components: a determination of need for the proposed project, and a determination of presumption of prudence of the costs associated with the proposed project. A presumption of prudency affords a certain weight to the cost estimate for a project that is only appropriate when the estimate is sufficiently developed. The maturity and expected accuracy of a project's cost estimate is closely tied to how distant in time implementation of the proposed project is as well as the level of analysis that went into the budgeting effort. Because the gas infrastructure planning process projects forward, at minimum, three years, there may be wide variety in the maturity and accuracy of cost estimates. We expect that, if the cost estimation is appropriately mature, the Commission's findings will provide regulatory expediency and efficiency in future rate cases. It will also place important guard rails on the utility's cost estimation process, as the Commission would expect the ultimate cost recovery of approved projects provided a presumption of prudence will closely match the cost estimate provided in a utility's gas infrastructure plan.

[165] Public Service October 7, 2022 Comments, p. 11.
[166] Black Hills October 11, 2022 Comments, pp. 9-10.

267. With respect to the first component of regulatory support, determination of need, we note Rule 4552(d)(II), as discussed earlier, allows a utility to indicate the specific relief it seeks for each planned project, whether that be through a request for CPCN, a declaratory order for the ordinary course of business, or some other form of relief. The Commission declines to adopt Conservation Advocates' suggestion that planned projects not subject to alternatives analysis be denied any potential determination of need. Instead, we find it necessary decide on the relief sought by the utility based on 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. We adopt such language in Rule 4555(c). We believe this decision process will allow a case-specific evaluation of each requested planned project, and more likely to lead to an appropriate decision given the project-specific facts at hand rather than a blanket denial of projects based on the limited criteria of whether or not they were subject to an alternatives analysis.

**(3) Timeframe to File Modified Plan**

268. In Rule 4555(d), the Commission guides utilities if it declines to approve a gas infrastructure plan in accordance with Rule 4552(d), either in full or in part. The July Redlines proposed requiring a utility to file a modified gas infrastructure plan within 90 days. Public Service suggested shortening this timeframe to 60 days. The Commission finds this suggestion reasonable and will incorporate it into the adopted rule.

**(4) Proceeding to Investigate Cost Recovery**

269. With respect to the miscellaneous proceeding that Public Service suggests assessing regulatory support approaches for both the gas infrastructure planning and clean heat plan processes, discussed above in paragraph 267. The Commission generally agrees such an assessment of both cost recovery mechanisms as well as mechanisms to align the incentives of

utilities and the goals of the gas infrastructure planning and clean heat plan processes could provide significant value. However, we find this Decision is not the appropriate vehicle to assess the specifics of, nor to open, such a proceeding, and thus deny the Public Service's request for a miscellaneous proceeding at this juncture. However, the Commission may elect to open such a proceeding by separate decision in the upcoming months.

### 8. Clean Heat Plan Rules

270. The NOPR proposed a new section of rules (Rules 4725-4734) to implement SB 21-264. In addition to implementing SB 21-264, we adopt the Clean Heat Plan Rules to further several other purposes. Through implementation of the Joint Comments and further refinements, we establish the Clean Heat Plan Rules as the venue for long-term forecasting of design day peak demand, customer count, sales and capacity requirements, gas content, and system-wide greenhouse gas emissions. Additionally, the Clean Heat Plan Rules further the Commission's stated policy that utilities acquire clean heat resources in the most cost-effective manner.

271. SB 21-264, codified as § 40-3.2-108, C.R.S., requires Colorado gas utilities with more than 90,000 retail customers to develop, file, and receive approval of comprehensive clean heat plans designed to achieve greenhouse gas emission reductions, specifically the reduction of carbon dioxide and methane emissions from gas distribution systems and the associated end-use consumption. In SB 21-264, the General Assembly declares four purposes of the legislation. First, it states that it enacts the legislation to implement a performance standard that will allow Colorado gas utilities to use available tools to achieve greenhouse gas emission reductions, cost-effectiveness, and equity. Second, it states that that Colorado is focused on a transition to a decarbonized economy that recognizes the historic injustices that impact lower-income Coloradans and Black, Indigenous, and other people of color who have borne a disproportionate share of

environmental risks while also enjoying fewer environmental benefits. Third, it directs the Commission must maximize greenhouse gas emission reductions and benefits to customers, with particular attention to residential customers who participate in income-qualified programs, while managing costs and risks to customers, including stranded-asset cost risks, and in a manner that supports family-sustaining jobs. Finally, the General Assembly finds that decarbonizing Colorado's homes and businesses will require investments in building and equipment upgrades, clean fuel projects, and infrastructure upgrades.[167] The Clean Heat Plan Rules adopted by the Commission further the purposes of SB 21-264 outlined by the General Assembly.

272. We implement the purposes of SB 21-264 as outlined by the General Assembly, as well as the Commission's additional stated purposes of the Clean Heat Plan Rules, by making several categories of changes to the adopted rules as compared to the rules proposed in the NOPR. In addition to minor clean up and changes necessary for clarity, the Commission institutes changes to the Clean Heat Plan Rules which fall into the following categories: (1) changes that require a utility to present long-term forecasts as part of a clean heat plan (*e.g.*, Rule 4731(a)); (2) changes that ensure utilities acquire clean heat resources in the most cost-effective manner—including, bolstering the competitive solicitation process for green hydrogen projects (*e.g.*, Rule 4731(f)) and including a cost-benefit analysis on a portfolio basis (Rule 4731(d)(I)(D)); (3) changes that further the consideration of communities historically impacted by air pollution and other energy-related pollution and disproportionately impacted communities (*e.g.*, Rule 4731(b)(IV), 4733(a)(II)) and labor-related concerns (*e.g.*, Rule 4731(d)(II)(E)); and (4) changes that further investment in building and equipment upgrades, clean fuel projects, and infrastructure upgrades (*e.g.*, Rule 4726(b) and (c)).

[167] § 40-3.2-108(1)(c), C.R.S.

#### a. Rule 4725. Overview and Purpose

273. As noted above, the purpose the Clean Heat Plan Rules is to implement § 40-3.2-108, C.R.S., for gas distribution utilities and small gas distribution utilities; this is reflected in Rule 4725. Consistent with statutory requirements, the purpose of these Clean Heat Plan Rules is to reduce greenhouse gas emissions from the distribution and end-use consumption of natural gas in accordance with clean heat targets. We also find it appropriate to expand the overview and purpose of the Clean Heat Plan Rules to also require that a clean heat plan shall also maintain just and reasonable rates, system reliability and resiliency, and prioritize investments in disproportionately impacted communities. We further reference in Rule 4725 the statewide greenhouse gas pollution goals set forth in § 25-7-102(2)(g), C.R.S.

#### b. Rule 4726. Applicability

274. Paragraph (a) clarifies that the Clean Heat Plan Rules apply to all jurisdictional utilities. Paragraphs (b) and (c) implement §§ 40-3.2-108(2)(g) and (q), C.R.S., which allows small gas distribution utilities to file clean heat plans to meet clean heat targets for 2025 and 2030 in accordance with Rule 4734, the Commission's rule regarding small gas distribution clean heat plans. In the July Redlines, we proposed for comment referencing that a clean heat plan shall both meet clean heat targets and implement clean heat resources pursuant to § 40-3.2-108(4)(d), C.R.S. We received no additional comments on Rule 4726 and thus adopt the rule as proposed in the July Redlines.

#### c. Rule 4727. Definitions

275. *Clean Heat Plan Periods.* In the NOPR, we proposed a definition of "plan period." However, in the July Redlines, we proposed for comment defined terms "clean heat plan total period," "clean heat plan action period," and "clean heat plan informational period." We proposed

these additional terms to incorporate the concept put forth in the Joint Comments that the clean heat application paradigm was the appropriate venue for long-term planning. In the Joint Comments, they agreed that clean heat plans have several long-term aspects and evaluations, including long-term system planning, long-term system capacity planning considerations, and scenario analyses that evaluate long-term approaches to decarbonization.[168]

276. The Commission has since received comments on the proposed defined terms related to plan periods, including from Atmos, CNG, and Public Service. Atmos states that the "action period" term is problematic for the first cycle because statute requires that period to be through 2025, which is less than five years from the filing date.[169] CNG is not opposed to the Commission's further delineation of the Clean Heat Plan into a "total period" consisting of an "informational period" and an "action period" but comments that while the five year action period is likely reasonable in terms of how representative its emissions forecasts are compared to the emissions reductions achieved, the longer "informational period" will require utilities to forecast emissions based on less available information, and likely introduce considerable inaccuracy.[170] Public Service suggests changing the "action period" to the year of the applicable clean heat target, instead of a five-year period.[171]

277. We continue to agree with the Joint Comments that the Clean Heat Plan Rules are the most appropriate venue for long-term analysis, and that adopting the total period term, which means the longer of the period from the date of the application through 2050, or the date of the application plus 20 years, affords the Commission that ability. Similarly, we think it is important

[168] Joint Comments, p. 5.
[169] Atmos August 8, 2022 Comments, p. 15.
[170] CNG August 24, 2022 Comments, p. 25.
[171] Public Service October 2022 Bluelines.

to define the "action period" as the five-year period beginning the date the plan is filed. Defining the "action period" to always include five years ensures the Commission has sufficient data to determine whether a utility's clean heat plan meets the clean heat target and implements clean heat resources over an appropriate time frame. Section 40-3.2-108(4)(c)(I), C.R.S., requires a clean heat plan to demonstrate that a utility "will meet the applicable clean heat targets specified" for the "applicable plan period." A plan period is, at minimum, five years pursuant to § 40-3.2-108(4)(b), C.R.S.[172] Finally, we find it appropriate to adopt the proposed definition of "informational period" because it strikes a reasonable balance in requiring utilities to consider broadly how it will meet future clean heat targets and what changes may be expected on the system, while acknowledging that forecasts get increasingly less reliable farther out, as pointed out by CNG in its comments. Overall, we find that implementing an informational period, action period, and total period approach furthers the goal of SB 21-264 that clean heat plans will aid the State of Colorado in achieving its greenhouse emission reduction goals by ensuring that each plan looks out at least to 2050. We also find that this change ensures utilities are implementing clean heat resources in a manner that promotes investment in building and equipment upgrades, clean fuel projects, and infrastructure upgrades over the long term.

278. *Gas Distribution Utility and Small Gas Distribution Utility.* In the July Redlines, we proposed for comment using the statutorily defined terms "gas distribution utility" and "small gas distribution utility" to clarify paragraphs (b) and (c), as proposed by CEO.[173] In its comments, UCA raises whether these definitions should specify that they are only applicable within the

[172] *See also* § 40-3.2-108(4)(h), C.R.S. (a first clean heat plan must use a planning period that extends through 2025—this does not require a plan period to end in 2025). Further, it makes little sense to require a utility plan filed no later than August 2023 or January 2024 to use a planning period as short as 12 months.

[173] CEO January 25, 2022 Comments, p. 32.

context of the Clean Heat Plans section of the Gas Rules to avoid confusion or these definitions being bootstrapped to apply in other sections of the Gas Rules. However, we do not share UCA's concerns because these defined terms are found in Rule 4727 which must only apply to clean heat plans. We therefore adopt the definition of "small gas distribution utility" and the definition of "gas distribution utility" in Rule 4727.

279. *Green Hydrogen*. The NOPR proposed adding a definition for the term "green hydrogen," consistent with §§ 40-3.2-108(2)(c)(III), 40-3.2-108(2)(j), and 40-3.2-108(4)(f), C.R.S., regarding hydrogen that qualifies as a clean heat resource. In the July Redlines, we proposed for comment a revised defined term for "green hydrogen." We did not receive additional comment on this proposal, so we adopt this term as presented in the July Redlines.

280. *Recovered Methane Credit.* In the NOPR, we proposed for comment a definition of the term "recovered methane credit" for inclusion in Rule 4001. In response, CEO proposes adding: "[t]he 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"[174] to the definition of "recovered methane credit." By incorporating CEO's suggestion, the adopted definition for "recovered methane credit" matches the statutory definition found in § 40-3.2-108(2)(o), C.R.S.

281. *Recovered Methane Protocol.* In the July Redlines, we proposed for comment a definition of "recovered methane protocol" derived from language suggested by Public Service. CEO proposes adding several additional provisions to the definition, including that a recovered

[174] CEO October 7, 2022 Attachment CEO-1 Bluelines.

methane protocol must specify relevant data collection and monitoring procedures and emission factors, conservatively account for uncertainty, activity-shifting leakage risks, and market-shifting, leakage risks associated with a type of recovered methane project, and determine data verification requirements.[175] While the language proposed by CEO is found within § 40-3.2-108(2)(p), C.R.S., we do not believe such level of detail is necessary for the Commission's definition of "recovered methane protocol" because it is already found in the statute, and the development of recovered methane protocols is under the preview of the Air Quality Control Commission.

**d. Rule 4728. Clean Heat Targets**

282. Paragraph (a) cites the relevant statewide greenhouse gas emission reduction goals set forth in § 25-7-102(2)(g), C.R.S., and requires clean heat targets to be consistent with § 40-3.2-108, C.R.S., *et seq*.

283. Paragraph (b) is adopted in more streamlined way than presented in the NOPR because we already implement the requirements in §§ 40-3.2-108(3)(b)(c)(II) and 40-3.2-108(11), C.R.S., in the Greenhouse Gas Emission Rules. We now cite Rules 4525-4528 instead of repeating the requirements that baseline emissions, system-wide emissions, and reductions in emissions shall be based on reported amounts to the U.S. Environmental Protection Agency, in addition to best methods for calculating emissions that may fall outside of the federal reporting requirements.

284. Paragraph (c) addresses the 2015 baseline against which all clean heat targets are based in § 40-3.2-108, C.R.S. and which must be calculated pursuant to paragraph 4528(b). Additionally, paragraph (c) requires that a utility exclude emissions of customers that already

[175] CEO October 7, 2022 Attachment CEO-1 Bluelines.

report their own greenhouse gas emissions to the U.S. Environmental Protection Agency. It also requires a utility to identify those customers and their associated load, to the extent practicable.

285. Paragraph (d) sets forth the clean heat targets for years 2025 and 2030 as well as the requirements for clean heat targets for year 2035 and beyond. Subparagraphs (d)(I)(A)-(C) establish the targets for the 2025 and 2030 filings. Subparagraphs (d)(II) and (d)(III) establish the process for setting year 2035 and beyond targets, pursuant to §§ 40-3.2-108(10), C.R.S. and § 40-3.2-108(11), C.R.S.

286. Paragraph (e) implements § 40-3.2-108(4)(d)(II)(B), C.R.S., and addresses the maximum amount, if any, of each established clean heat target after year 2030 that may be satisfied with recovered methane.

287. The Commission appreciates the comments responsive to the questions posed in paragraph 131 of the NOPR. As we discussed in above regarding the Division's anticipated continued technical stakeholder engagement in 2023 and beyond, we expect the emission reduction calculation guidance and methodology to evolve with respect to inclusion of methane leaked behind the customers' meter, and on improving beyond Subparts W and NN for ensuring accurate, reliable, and complete information about greenhouse gas emissions from the city gate to customer end uses.

**e. Rule 4729. Filing Form and Schedule**

288. We adopt paragraph (a), which requires a utility to file its clean heat plan as an application, with the attendant processes and procedures for adjudicating an application, as proposed in the NOPR with minor edits.

289. In the July Redlines, we proposed for comment including the three purposes of a clean heat plan as proposed paragraph (b). We outlined the goals of a clean heat plan as:

(1) present a plan to implement clean heat resources throughout the clean heat plan action period; (2) 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; and (3) demonstrates that the activities contemplated in the clean heat plan facilitates the utility's ability to meet future greenhouse gas emission reductions. In the Decision accompanying the July Redlines, we expressed our interest in ensuring that a clean heat plan demonstrates that a utility is on the appropriate emission-reduction path to meet future clean heat targets before it is too late to correct course.

290. In response, we received comments on proposed paragraph (b) from participants, including CNG, UCA, Conservation Advocates and RMI, and Atmos. CNG states, although subparagraphs 4729(b)(I) through (III) seem to reflect the Commission's policy goals pursuant to the recent statutory directives, and CNG generally supports those goals, there will be factors the utility is unable to control, such as a necessary expansion of facilities that will, by definition, increase the level of emissions. CNG comments, as a result, the predicted trend in reductions versus actual achievements measured at a considerable time in the future is not likely to be realistic.[176] Conservation Advocates and RMI support proposed paragraph 4729(b), which clarifies utilities' plans should meet both the near-term emission reduction targets and be reasonably expected to achieve long-term goals.[177] Similarly, UCA supports the revisions to this rule and the Commission's effort to ensure gas utilities are on an appropriate emission-reduction path to meet future clean heat targets.[178]

[176] CNG August 24, 2022 Comments, p. 27.
[177] Conservation Advocates and RMI August 24, 2022 Comments, p. 22.
[178] UCA September 12, 2022 Comments, p. 13.

291. As discussed above regarding the Commission's adoption of defined terms for action, informational, and overall plan period, we see need for a utility's clean heat plan to have a long-term focus to ensure the utility's efforts are in line with the state's long-term climate goals. We are mindful of the concerns expressed by CNG about far out projections losing precision but expect only that a utility's application demonstrates the activities contemplated in the clean heat plan facilitate the utility's ability to meet future greenhouse gas emission reduction targets. Similarly, a clean heat plan application must demonstrate the plan will meet the applicable clean heat targets during the action period. We therefore adopt paragraph (b) as proposed in the July Redlines, with one addition.

292. In subparagraph (b)(II), we add "or shows compliance with the cost cap" in light of comments received by Atmos.[179] Atmos comments proposed Rule 4729(b) fails to contemplate the filing of clean heat plans that do not meet the emission reduction targets but instead meet the cost cap established in SB 21-264. We incorporate the change proposed by Atmos to ensure consistency with Rule 4731.

293. Paragraphs (c) and (d) implement the timing requirements found in § 40-3.2-108(4)(a), C.R.S., for the largest gas distribution utility in Colorado, as determined by the volume of gas sold in Colorado, and all other utilities, respectively.

294. In the July Redlines, we proposed a three-year filing cadence. In response, Public Service urges flexibility on these filing sequence and timing matters and states the statutory requirement for a four-year cadence in § 40-3.2-108(4)(b), C.R.S., provides sufficient guidance.[180] We agree with Public Service that a more prescriptive requirement in rule is unnecessary at this

[179] Atmos August 8, 2022 Comments, p. 16.
[180] Public Service August 5, 2022 Comments, p. 28.

juncture. Therefore, we adopt in paragraph (e) a requirement that subsequent clean heat plans shall be filed not less often than every four years, unless otherwise directed by the Commission. Given the proximity to the first two clean heat targets and the significant learnings and changes likely with the initial plans, it is possible that the cadence of Clean Heat filings may necessarily be shorter than the maximum interval. Adopted Rule 4729 retains the flexibility of a combined application (as discussed in Decision No. C21-0610, paragraph 138), that includes both of the first two heat plans if filed no later than the deadlines established by paragraphs (c) and (d).

295. The Consensus Labor Comments propose the Commission schedule a public hearing that specifically solicits public comment on the labor impacts and benefits of the proposed plan after a utility files its application, but prior to any evidentiary hearing. We agree with that receiving public comment related to labor impacts and benefits will be important during the Commission's review of a utility's clean heat plan filing. We therefore generally adopt the language proposed by the Consensus Labor Comments as paragraph (f). We expand the purpose of the public comment hearing referenced in paragraph (f) to include labor impacts and benefits, as well as other applicable topics, to retain flexibility on behalf of the Commission in scheduling public comment hearings and on behalf of commenters who may seek to address additional topics at a public comment hearing.

#### f. Rule 4730. Clean Heat Resources

296. Rule 4730 defines the clean heat resources that may be included in a utility's clean heat plan, including demand side management, recovered methane, pyrolysis of tires, green hydrogen, beneficial electrification, and other technologies the Commission may classify as clean heat resources in the future.

297. *Demand Side Management*. Subparagraph (a)(I) includes demand side management as a clean heat resource and includes the provisions in § 40-2-123(1)(b)(I), C.R.S., from HB 21-1238. Subparagraph (A) requires the Commission to collaborate with the Air Quality Control Commission to ensure emissions reductions achieved through gas demand side management programs are appropriately accounted for in meeting statewide greenhouse reduction goals. Subparagraph (B) likewise requires that the carbon dioxide and methane reductions achieved by implementing gas demand side management are consistent with the amounts used to apply the social cost of carbon and the social cost of methane in the determination of the cost-effectiveness of the demand side management measure pursuant to the implementation of the DSM Rules.

298. The Commission proposed in the NOPR an additional concept to ensure the gas demand side management that qualifies as a clean heat resource does not prolong a customers' reliance on gas for end use consumption. In the July Redlines, we noted that we received comments in support of, as well as in opposition to, this provision but declined to remove the requirement at that time. Since then, we have received additional comments on this proposal.

299. Conservation Advocates and RMI maintain the Commission is correctly preventing misuse of ratepayer dollars on demand side management that would lock in levels of gas use that are incompatible with the state's climate goals as a component of incremental demand side management approved in a utility's clean heat plan. They recommend the Commission adopt the rule as proposed.[181] Dandelion Energy similarly supports the inclusion of this qualifier.

300. Other comments received were less supportive. API Colorado objects that the proposal unlawfully expands the Commission's authority. They caution that the proposed rule

[181] Conservation Advocates and RMI September 2, 2022 Comments, pp. 7-8.

would preclude use of demand side management tools such as high efficiency gas appliances as clean heat resources and the Commission, instead, should maximize utilities' flexibility.[182]

301. Black Hills argues that the proposed rule language is ambiguous and could result in utilities developing both a clean heat compliant demand side management program and a non-compliant demand side management program. Black Hills also argues this approach would effectively eliminate any gas utility from developing any new home construction demand side management programs and is not supported by statue.[183]

302. CEO argues that the inclusion of this qualifier contradicts the statute defining and including demand side management programs as clean heat resources and argues that demand side management is an important pathway for utilities to meet clean heat targets, particularly for gas-only local distribution companies, which cannot readily help customers switch to electric appliances.[184] CEO also comments that it recently initiated a study to evaluate important strategic questions about the role of gas and building electrification in reducing emissions from buildings. Its study will evaluate several scenarios about the future of the gas industry, and CEO believes the study can help provide meaningful insight into the overall system level (including the electric sector, gas sector and building sector) and costs and impacts of all electric versus mixed fuel approaches, which will inform deliberations on the long-term role of gas and that adopting such a qualifier on demand side management now is premature.[185]

303. Public Service supports the comments of Black Hills and CEO.[186] Likewise, CNG states it agrees with CEO that the language proposed in Rule 4730(a)(I)(B) should not be adopted.

[182] API Colorado September 1, 2022 Comments, p. 16.
[183] Black Hills August 26, 2022 Comments, p. 24.
[184] CEO August 24, 2022 Comments, pp. 19-20.
[185] CEO October 7, 2022 Comments, pp. 24-25.
[186] Public Service September 15, 2022 Comments, pp. 19-20.

304. We are persuaded by the comments in this record that qualifying demand side management in this manner may be premature as discussed by CEO. While we are mindful that demand side management investments should be made in a manner that is compatible with the state's long-term emission reduction goals, we are also mindful of the difficulty utilities, and particularly gas-only utilities, may have in reaching the clean heat targets in the short-term. We also find merit in avoiding separate "classes" of demand side management as several commenters warn us may be unwieldly and administratively burdensome. For these reasons, we decline to adopt the provision that was proposed as subparagraph (a)(I)(B) in the NOPR.

305. Atmos seeks to clarify that a utility would still be free to propose demand side management programs as part of a clean heat plan that are not part of its demand side management program under Rules 4750-4761, and that the Commission could consider those programs for inclusion in the clean heat plan.[187] We agree with Atmos that a utility could propose demand side management programs for the first time as part of a clean heat plan filing. The provision found in Rule 4754(g), that requires a utility to report DSM programs identified as a clean heat resource is meant to align the demand side management and clean heat plan filings in such instance.

306. *Recovered Methane*. Subparagraph (a)(II) includes recovered methane as a clean heat resource consistent with the definitions and limitations in § 40-3.2-108, C.R.S. Subparagraph (a)(II)(A) implements § 40-3.2-108(3)(e), C.R.S., such that all recovered methane that qualifies as a clean heat resource must be represented by a recovered methane credit issued by protocol approved by the Air Quality Control Commission.

307. Subparagraph (a)(II)(B) implements both § 40-3.2-108(2)(n), C.R.S., that requires recovered methane to be located in Colorado and the additional requirements set forth in

[187] Atmos August 8, 2022 Comments, pp. 15-16.

§ 40-3.2-108(3)(e), C.R.S. As we discussed above when adopting a definition of "recovered methane" in Rule 4001, we find it necessary to limit recovered methane to those resources found within Colorado. This is reflected in subparagraph (a)(II)(B) which requires recovered methane to be located in Colorado and delivered within Colorado through a dedicated recovered methane pipeline or through a common carrier pipeline.

308. The concepts proposed in the NOPR as paragraphs (c) and (d) are now incorporated into subparagraph (a)(II) in (C) and (E) in the adopted Gas Rules. These concepts implement the provision in the statutory definition of clean heat resources in § 40-3.2-108(2)(c), C.R.S., that to qualify as a clean heat resource, any recovered methane credit must be retired in the year generated and may not be sold, and the requirement in § 40-3.2-108(3)(f), C.R.S., that, to qualify as a clean heat resource, any repairs to the utility's system shall be determined to be cost-effective by the Commission, respectively. We also reiterate our understanding of § 40-3.2-108(3)(f), C.R.S., set forth in the NOPR, that this provision is intended to require a utility to show that repairs to the utility's system must be shown to be cost-effective as a greenhouse gas mitigation measure when compared to other alternative clean heat resources.

309. In recent comments, CEO suggests utilities should be able to use prior year's retired recovered methane credits to meet future target years because the clean heat targets are mass based, not emission based. Additionally, CEO notes that applying a prior year's retired credits will ensure a robust market for recovered methane credits and incentivize developers to create recovered methane projects. To implement this concept in the Commission's rules, CEO suggests draft language for Rule 4730. We agree with CEO that there must be a mechanism for credits to have some value outside of the year generated—otherwise it will be difficult to create a robust market for recovered methane development in Colorado. Further, the statute contemplates, for the 2030

target, a maximum amount of recovered methane of five percent of the total reduction for the period 2026 through 2030.[188] For these reasons, we adopt a modified version of CEO's proposal as subparagraph (a)(II)(D) which allows a utility to count recovered methane credits generated since the last clean heat target year towards compliance with the next target. However, we stress that a credit can only be used once to ensure accurate emission reduction accounting.[189]

310. *Green Hydrogen*. Subparagraph (a)(III) lists green hydrogen as a clean heat resource. Pursuant to § 40-3.2-108(1)(c), C.R.S., green hydrogen is a clean heat resource. The Commission's rules define "green hydrogen" as hydrogen derived from water and a clean energy resource as defined in § 40-2-125.5(2)(b), C.R.S. Green hydrogen is defined in Rule 4727(e).

311. *Beneficial Electrification.* Subparagraph (a)(IV) lists beneficial electrification as a clean heat resource in accordance with the statutory definition in § 40-3.2-108(2)(c), C.R.S.

*312. Pyrolysis of Tires.* Subparagraph (a)(V) lists the pyrolysis of tires as a clean heat resource in accordance with the statutory definition in § 40-3.2-108(2)(c), C.R.S.

313. *Other Clean Heat Resources.* Subparagraph (a)(VI) establishes that in the future, the Commission may consider other technologies as clean heat resources if the Commission finds the technology cost-effective and if the Division finds the technology will result in a reduction of carbon emissions from the combustion of gas in customer end uses, or if the technology meets a recovered methane protocol approved by the Air Quality Control Commission. The Commission anticipates approving additional clean heat resources by rule change or by future order.

[188] § 40-3.2-108(4)(d)(I), C.R.S.

[189] Commissioner Megan Gilman dissented from this decision to allow a utility to count recovered methane credits generated since the last clean heat target year towards compliance with the next target and would have instead required utilities to count an average of the recovered methane credits generated since the last clean heat target year towards compliance.

314. *Conversion of Sales Service Customers*. Paragraph (b) addresses the exclusion of transport customers in the calculation of emission reductions relative to the 2015 baseline which aligns with the exclusions in §§ 40-3.2-108(3)(c)(I)(B) and 40-3.2-108(11), C.R.S. A change in service from sales service to transportation service shall not be considered a clean heat resource. In recent comments, Atmos questions whether this provision is necessary because its tariff, and to Atmos' knowledge, the tariffs of other gas utilities, make transportation service available to all small commercial, commercial, and irrigation customers.[190] Atmos does not believe a utility could propose a clean heat resource that would force a customer to switch from sales to transportation service. We choose to retain this provision to incorporate the statutory directives in §§ 40-3.2-108(3)(c)(I)(B) and 40-3.2-108(11), C.R.S., and to ensure that a utility does not promote or benefit from reclassification of customers to transport service to artificially reduce its reportable emissions.

**g. Rule 4731. Clean Heat Plan Application Requirements**

315. Rule 4731 sets forth the required components of a clean heat plan, including forecasts as required by paragraph (a), portfolios as required by paragraph (b), portfolio forecasts as required by paragraph (c), the subcomponents of a portfolio as required by paragraph (d), as well as specific requirements for certain situations, such as proposal of green hydrogen projects in paragraph (e), competitive solicitation proposals as set forth in paragraph (f), and cost recovery related provisions in (g).

316. *Forecasts.* The NOPR proposed several provisions in Rule 4731 that require a utility to present certain forecasts as part of its clean heat plan as well as several provisions in Rule 4553 that proposed other forecasting as part of a gas infrastructure plan. In the July Redlines, we

[190] Atmos August 8, 2022 Comments, p. 18.

proposed adding all long-term forecasting into the Clean Heat Plan Rules. The Joint Comments suggested that the clean heat plan is a more appropriate venue for conducting forecasting. We agreed that the clean heat plan requires analysis on a longer timeframe and is an appropriate place for adjudicating a utility's forecasted customer counts, sales, and capacity requirements, as well as gas content including expected mixtures by volume of hydrogen and recovered methane, and systemwide greenhouse gas emissions.

317. The Commission requested participants consider additional comment on several areas in Decision No. C22-0588-I. In particular, we asked for comment on the feasibility and value of having a high and a low forecast of peak design day demand and associated capital requirements as part of the clean heat plan process. We expressed our interest in exploring factors influencing design day peak demand as part of the clean heat plan and gas infrastructure plan processes moving forward at both the public comment hearing on September 19, 2022 as well as in Decision No. C22-0588-I. These comments are discussed further above inSection –"sensitivity forecast" in 7(c)(6).

318. As we stated above, we expand the forecast requirements to include low and high sensitivities around a "reference" forecast. In subparagraph (a)(I), we find it appropriate to adopt the requirement that utilities shall present a reference (base), low, and high forecast. We also find it appropriate to adopt subparagraph (a)(I)(F) that requires a utility, for the low and high forecast, to 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. A utility must present forecasts of sales, customer counts, system-wide capacity (design or peak day) requirements, throughput by Btus and volumes of green hydrogen, recovered methane, and total gas, and system-wide greenhouse gas emissions.

319. We otherwise adopt paragraph (a) regarding forecasts as proposed in the July Redlines with two changes. As proposed in the July Redlines, a utility shall consider the price elasticity of demand, changes in line extension policies, and other known factors affecting sales and capacity needs. We adopt these three forecasting considerations, but add two additional considerations discussed below.

320. First, in subparagraph (a)(I)(B), we require forecasting to be disaggregated by pressure district or unique planning zone as discussed in paragraphs 55 and 205 above.

321. Second, we change the list of factors that a forecast must consider in (a)(I)(E) in two ways. Black Hills argues "it is unrealistic to charge the utility with forecasting changes in state and local building codes, changes in line extension policy, available electric utility building electrification program, and potential extreme weather events and the likelihood of those dynamic elements with any reasonable certainty. The Company is unable to forecast the local building code changes for the approximately 100 towns and municipalities it serves as local regulations are constantly in flux. Similarly, the Company's natural gas footprint crosses numerous electric providers, including investor-owned electric utilities, municipal electric utilities and cooperative electric utilities. Because municipal electric and cooperative electric utilities are not regulated by the Commission, those entities electrification programs may vary drastically from one another and change frequently, making it difficult to assume how those electrification policies impact the Company's natural gas business."[191] We agree that forecasting potential changes in building codes is unworkable; we adopt that a utility shall include only current or enacted building codes. We also adopt that a utility should consider 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

[191] Black Hills October 11, 2022 Comments, p. 7.

when forecasting, as significant incentives are likely to have an impact on the economics and customer decisions in that area related to adoption of energy efficiency and beneficial electrification.

322. *Portfolios*. Section 40-3.2-108(4)(c), C.R.S. sets forth certain portfolios that a utility must present; we incorporate these required portfolios in paragraph (b). We adopt this provision as proposed in the July Redlines with two modifications. First, in response to comments from Public Service, we clarify that the portfolio required by subpart (A) does not necessarily need to meet the clean heat target, but must demonstrate reductions in methane emissions. Second, we find it appropriate to clarify in subparagraph (b)(II) that a utility must show it has fully investigated all available clean heat resources at the category level.

323. *Portfolio Forecasts*. We proposed for comment in the July Redlines that a utility shall provide forecasts for each portfolio presented, updated to include the set of actions proposed within the portfolio. We did not receive any additional comments on this proposal and therefore adopt it as proposed in the July Redlines.

324. *Components of a Portfolio.* Paragraph (d) sets forth the information a utility shall present on a portfolio-level for each portfolio presented. This includes: identification of the proposed clean heat resources, the annual and total costs for implementing the portfolio, the annual and cumulative projected greenhouse gas emissions anticipated from the portfolio, an analysis of the projected costs and benefits of the portfolio, an analysis of the annual retail cost impact of the portfolio, as well as a description of the effects of the actions and investments in each portfolio regarding the safety, reliability, and resilience of the utility's gas service. Pursuant to (d)(I)(D), the cost-benefit analysis that a utility must present on the portfolio level must include the factors that the Commission will consider when determining if a clean heat plan is in the public interest under

4732(b)(II). On a category level, the utility shall report for each portfolio several metrics to the extent practicable pursuant to subparagraph (d)(II). First, the utility shall present the annual and total cost for each clean heat resource category. Second, the utility shall identify any additional air quality, environmental, and health benefits of each clean heat resource category in addition to the greenhouse gas emission reductions. Third, a utility shall present 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. Fourth, we incorporate the intent of the proposal from the Consensus Labor Comments that requires a utility explain 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.

325. *Existing System Analysis—Green Hydrogen*. In the Decision adopting the July Redlines, we proposed additional analysis that a utility must perform to ensure that its transmission and distribution pipeline system can facilitate proposed green hydrogen, if applicable. We did not receive additional comment on this proposal and thus adopt it as proposed in the July Redlines.

326. *Project-Based Information.* A utility's clean heat plan may also include specific project proposals. Certain information must be presented on a project level, including details on competitive solicitation processes, identification of the developer or operator, if not the utility, and any customers on whose property the investment will be placed, and a map showing locations of green hydrogen or recovered methane projects and with any portions of the project that are located in disproportionately impacted communities identified.

327. *Competitive Solicitation.* Section 40-3.2-108(4)(f), C.R.S., requires any proposal for green or blue hydrogen projects in a clean heat plan include a proposal for competitive solicitation. In the July Redlines, we proposed for comment expanding the competitive solicitation provision to encompass both green hydrogen and recovered methane resources. We also proposed a list of required elements to present as part of a competitive solicitation proposal.

328. In response, the Commission received numerous comments regarding the elements of a competitive sonication process as well as what resources it should apply to.

329. Public Service comments that by statute: the utility is encouraged to bring forward proposals to invest in green and blue hydrogen projects; if it does, then it must utilize a competitive process to identify the most cost-effective and beneficial investments to make. It states that the statute confines the competitive solicitation requirement to investments, not commodity supply. Public Service distinguishes between one form of competitive solicitation, which resembles the ERP process, as distinct from competitive processes for other purposes which it classifies as "non-regulated competitive solicitations."[192] Public Service anticipates using both approaches as the gas system evolves. For "regulated competitive solicitations" Public Service suggests requiring a copy of the request for proposal, a timeline and review process, submission of model contracts, and requiring use of best value employment metrics could be reasonable for hydrogen projects. Public Service also says that other competitive processes may be used for hydrogen procurement, including through newly developed Department of Energy program awards and that the Commission's rules should be clear that the competitive solicitation requirement of SB 21-264 is not the exclusive pathway for developing or advancing green or blue hydrogen projects.

[192] Public Service August 5, 2022 Comments, p. 14.

330. Public Service believes the best approach is for the Commission's rules to allow for procurement of hydrogen through several avenues. First, for investments in green and blue hydrogen infrastructure contemplated as part of a clean heat plan, a utility shall present competitive solicitation proposal in line with 4731(f). Second, for green or blue hydrogen opportunities outside of a clean heat plan, utilities would be required to seek appropriate approvals from the Commission. Finally, for fuel procurement (*i.e.*, recovered methane or green hydrogen) the utility could pursue the procurement of approved levels with oversight and reporting occurring through the existing procurement processes.[193]

331. CEO proposes revisions to Rule 4731(f)(II) and (III) to account for state-led hydrogen hub applications. Utilities are encouraged to work in coordination with the state on developing hydrogen hub applications for the Department of Energy's consideration. These are not competitive solicitations within a utility's discretion to accept and develop. Such applications are for federal grant funds and should not be included in Clean Heat Plan reporting. Thus, CEO has proposed language exempting some applications from reporting requirements and clarifying the minimum information required is only in relation to proposals for competitive solicitation.[194]

332. We continue to see the need to maximize the innovation and cost-reduction benefits of the competitive market, through robust competitive solicitation requirements. We emphasize that 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. However, we are mindful of the comments received from Public Service that a utility may implement competitive bidding processes in manners less formal than those in a process

[193] Public Service August 24, 2022 Comments, p. 8.
[194] CEO October 7, 2022 Comments, p. 28.

similar to the ERP approach to competitive solicitation. We also are mindful for the need for flexibility at this juncture. We therefore require competitive solicitation for hydrogen project procurement only at this time. For hydrogen projects presented through a clean heat plan, a utility shall include a proposal for competitive solicitation that includes a copy of the request for proposal, an explanation of the required milestones and development-related penalties, the timing of the process, a copy of the proposed contract, standards for interconnection, and an explanation of how best value employment metrics will be evaluated.

333. We realize that it may be advantageous for utilities to acquire hydrogen and other clean heat resources through multiple avenues. In particular for hydrogen, we adopt the language proposed by CEO to exclude green hydrogen project proposed in coordination with the State of Colorado or as part of a State of Colorado application for a hydrogen hub from the competitive solicitation process outlined in Rule 4731(f).

334. *Cost Recovery Proposals.* The Commission adopts two provisions related to cost recovery in paragraphs (g). Paragraph (g) allows a utility to propose a rate adjustment clause that provides for recovery of the utility's clean heat plan costs, or any costs prudently incurred to meet additional emission reduction requirements under § 25-7-105(1)(e)(X.7), C.R.S.

335. UCA opposes cost recovery approval when the approving a clean heat plan because a utility's cost recovery of the costs and expenses associated with its clean heat plan should be reserved for a rate case proceeding where all costs and expenses and all other pertinent items can be analyzed and decided upon in a holistic manner. UCA argues that to provide approval outside the confines of a rate case may give rise to challenges based on single-issue ratemaking.[195] We are cognizant of UCA's concerns regarding the appropriate venue to determine cost recovery of an

[195] UCA September 12, 2022 Comments, pp. 13-14.

approved clean heat plan. However, we choose to retain this provision that allows a utility to propose a rate adjustment mechanism as part of a clean heat plan application. It will be important to retain flexibility for both the Commission and utilities, particularly during the inaugural clean heat plans. Paragraph (g) also requires a utility to identify 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 pursuant to § 40-3.2-108(4)(c)(XII), C.R.S.

### h. Rule 4732. Approval of Clean Heat Plan

336. Rule 4732 sets forth the Commission's considerations regarding approval of a clean heat plan and implements § 40-3.2-108(6), C.R.S.

337. Paragraph (a) establishes, consistent with § 40-3.2-108(6)(d)(I), C.R.S., that the Commission shall approve a plan if it finds the utility's proposed plan to be in the public interest. The Commission will also approve the associated forecasts under Rule 4731(a) if it finds the forecasts to be in the public interest. Atmos suggests modifying (a) to limit the Commission's ability to modify a clean heat plan in a manner that would increase plan spending to a level higher than the greater of: (1) the cost cap or (2) the amount initially proposed by the utility.[196] We decline to adopt the change proposed by Atmos. Section 40-3.2-108(6)(d)(III), C.R.S., expressly recognizes that the Commission may approve, or amend and approve, a clean hear plan with costs greater than the cost cap only if it finds that the plan is in the public interest, costs to customers are reasonable, the plan includes mitigation of rate increases for income-qualified customers, and the benefits of the plan, including the social cost of methane and carbon dioxide, exceed the costs. Under statute, the Commission's ability to modify a plan to ensure it is in the public interest is not

[196] Atmos August 8, 2022 Comments, p. 19.

limited in the manner suggested by Atmos, and we decline to limit the Commission's ability to modify plans as necessary through the Gas Rules. We therefore adopt paragraph (a) as proposed by the July Redlines.

338. Paragraph (b) sets out the factors the Commission will consider in determining whether a utility's clean heat plan is in the public interest, and implements §§ 40-3.2-108(6) and 40-3.2-108(2)(k), C.R.S.

339. *Emission Reductions.* First, the Commission shall consider whether the plan achieves the clean heat targets through the use of clean heat resources that, in the aggregate, maximize greenhouse gas emission reductions. In evaluating whether the clean heat plan achieves the clean heat target, the Commission will consult with the Air Pollution Control Division to estimate reductions of emissions of greenhouse gases and other air pollutants under the portfolios presented in the utility's plan. Subparagraph (b)(I)(B) recognizes the Air Pollution Control Division may participate in clean heat plan proceedings before the Commission as a party. We received no comments specifically related to this subsection, and therefore adopt this portion of the rule generally as proposed in the July Redlines.

340. *Cost Impact.* Second, the Commission will consider whether the plan can be implemented at the lowest reasonable cost and rate impact. SB 21-264 defines "lowest reasonable cost" to include numerous factors, including available technologies, resource costs, market volatility risks, risks to ratepayers, system operation costs, infrastructure costs, environmental justice goals, the social cost of carbon, and the social cost of methane. § 40-3.2-108(2)(k), C.R.S. While we recognize that "lowest reasonable cost" is defined by statute, we find it most workable to separate the quantifiable requirements outlined in statute from the more qualitative factors. Subparagraph (b)(II) therefore focuses on the quantifiable factors the Commission will use in

determining 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.

341. We received several comments related to quantifiable factors that the Commission should consider when evaluating whether a clean heat plan is in the public interest. Public Service suggests incorporating costs and benefits in consideration of the social cost of carbon, social cost of methane, and without the pricing of any externality value or societal costs as well as risks to the utility's customers.[197] CEO suggests incorporating the cost of fuel as well as a cost test that includes both the social cost of carbon and the social cost of methane. CEO also suggest adding the net cost of implementing a preferred portfolio to avoided infrastructure costs to the list of factors the Commission shall take into account.[198] More generally, CEO suggests the Commission direct parties to present multiple cost tests in their clean heat plans. CEO also observes that § 40-3.2-108, C.R.S., does provide guidance for how the Commission should consider cost-effectiveness, but does not require the Commission to adopt a specific cost test for all clean heat plans, nor does it prescribe, if the Commission adopts a cost test, whether the cost test must be applied to the entire plan or to parts of a plan.[199]

342. CEO also illustrates the distinction and potential relationship among the terms "measures," "clean heat resources," and a clean heat "portfolio."[200] CEO asserts that the statute is not clear on whether the Commission should compare the cost and benefits of alternatives in its lowest reasonable cost assessment at the measure, resource, or portfolio level. CEO suggests it would be unnecessary to evaluate cost-effectiveness on a measure-level, but that the Commission

[197] Public Service October 7, 2022 Bluelines.
[198] CEO October 7, 2022 Comments, pp. 29-30.
[199] CEO August 24, 2022 Comments, pp. 7-13.
[200] CEO August 24, 2022 Comments, p. 11.

may choose to evaluate cost-effectiveness at a resource level when appropriate. In response, Public Service states it strongly believes that any application of the "lowest reasonable cost" standard of review should occur at the portfolio level, which would allow for the comparison of the different clean heat resources, packaged into approaches that achieve different levels of emissions reduction and measure in different ways against the statutory cost test, on a net present value of revenue requirements basis with appropriate discounting.[201]

343. Public Service further stresses the need for flexibility in the Commission's standard of review at this time and suggests a flexible standard similar to the Electric Resource Plan flexible standard of review. It points to Colorado's Electric Resource Plan process is a "gold-standard" process, with the drivers of its success in part due to the regulatory support flowing from an approved plan. Public Service argues that a sometimes-overlooked aspect of the Electric Resource Plan process is the use of a flexible standard of review through a cost-effectiveness evaluation that is able to adjust to the shifting contours of the State of Colorado's energy policy.[202]

344. We find that the quantitative factors the Commission will consider include: (1) fuel costs; (2) non-fuel direct investment associated with the clean heat plans; (3) gas infrastructure costs;(4) gas system operations costs; (5) a cost test that includes both the social cost of carbon and the social cost of methane; and (6) any other costs and benefits, as determined by the Commission. Factors 1, 3, 4, and 6 come directly from the statutory definition of "lowest reasonable cost." Factor 5 also comes directly from the statutory definition of "lowest reasonable cost" in addition to being recommended by CEO and Public Service. We find that "fuel costs" and "non-fuel direct investment associated with the clean heat plan" together provide better direction

[201] Public Service September 15, 2022 Comments, pp. 4-6.
[202] Public Service September 15, 2022 Comments, p. 7.

than "resource costs" as indicated in the definition of "lowest reasonable cost" while capturing the same concept.

345. We are persuaded by Public Service's comments that flexibility is key when developing a workable standard of review at this time. We also appreciate CEO's thoughtful comments on establishing a cost-effectiveness test and anticipate the level of detail provided to benefit the Commission's analysis during clean heat plan adjudications. Overall, we see alignment between Public Service's emphasis on overall flexibility and CEO's suggestion that the Commission retain flexibility in its rules to permit the use of multiple tests, consideration of multiple factors, and determination of whether a cost-effectiveness test is necessary in each individual clean heat plan proceeding.

346. As stated above, one of the quantitative factors the Commission will consider when determining if a plan is in the public interest is gas infrastructure costs. Some commenters, including Public Service, suggest striking "gas" so it is a consideration of infrastructure costs generally. We decline to broaden the costs considered as "infrastructure costs" at this time. It is not reasonable to require a utility, and particularly a gas-only utility, to provide cost data for infrastructure and operation beyond the utility's own system, and we question the accuracy of such cost data. Additionally, including only costs and no revenue or benefits on other infrastructure systems could lead to an incomplete analysis.

347. *Qualitative Factors*. In addition to the quantitative factors the Commission will consider, we also will consider several qualitative factors when determining if a clean heat plan is in the public interest.

348. *Additional Benefits*. In subparagraph (b)(III), we state that we will consider 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. The consideration of public health impacts appears in proposed Rule 4731(d)(II)(B) and Rule 4732(b)(II). In post-hearing comments, CNG follows up on discussion regarding consideration of public health impacts in clean heat plans and supports the removal of such considerations until there are improvements in measuring related data because they are speculative and currently difficult to quantify.[203] We are mindful of the discussion between CNG and others that public health impacts are not easily quantifiable. However, we find that a qualitative consideration of health impacts as a factor among many is an appropriate metric in determining whether a plan is in the public interest. Further, § 40-3.2-108(6)(d)(B), C.R.S., specifically directs the Commission to consider the additional air quality, environment, and health benefits of a clean heat plan. As such, we find consideration of these factors appropriate and in line with § 40-3.2-108(6)(d)(I), C.R.S.

349. *Communities Historically Impacted by Pollution.* In subparagraph (b)(IV), we list whether the plan demonstrates that investments in the clean heat plan prioritize serving customers participating in income-qualified programs, disproportionately impacted communities, and communities historically impacted by air pollution. In the July Redlines, we used the term "disproportionately impacted communities" instead of "communities historically impacted by air pollution and other energy-related pollution," and sought stakeholder comment as to whether the terms should be treated as synonyms. CEO, however, does not believe the terms are interchangeable but that instead "communities historically impacted by air pollution and other energy-related pollution" are a subset of disproportionately impacted communities, given the

[203] CNG October 7, 2022 Comments, p. 11.

statutory definition of disproportionately impacted communities at § 40-2-108(3)(d)(II), C.R.S.[204] We agree with CEO. Had the General Assembly intended the terms to be fully synonymous, it could have done so. We believe there will be opportunities for the Commission to further understand nuances in the definition of disproportionately impacted community and related terms through Proceeding No. 22M-0171ALL and subsequent rulemakings, as well as the review of future clean heat plans. As staff of the Colorado Department of Public Health and Environment presented at the February 3, 2022, workshop, tools to identify and engage disproportionately impacted communities continue to be developed and refined. As such, we revise the language proposed in the July Redlines to refer to communities historically impacted by air pollution and other energy-related pollution in subparagraph (b)(IV).

350. By Decision No. C22-0427-I, the Commission asked whether it should further define "prioritization" (¶ 187) for clarity in utility applications and Commission evaluation of those applications.

351. In response, we received comments from participants both opposing and supporting further defining prioritization. CEO opposes a definition in rules, arguing that prioritization is a likely a method or process and participants' collective understanding of what it requires may change. Instead, CEO suggests that the Commission's decision adopting rules explain how the Commission intends to use "prioritization," such as through a listing of principles, criteria, or a process it will undertake when it evaluates the first round of clean heat plan. CEO explains that in common use, "prioritize" means to put something first or above something else. One way to do this could be to adopt budgets for clean heat resources that are directed to customers that allocate

[204] CEO August 24, 2022 Comments, pp. 5-6. CEO notes, however, that in practice this may result in identifying the same Census block groups for both terms.

funding first to programs or measures for customers who meet income thresholds and are included in disproportionately impacted communities. CEO also suggests that when approving a system-level investment, the Commission should work to find portfolios that do not "perpetuate environmental harms" on disproportionately impacted communities and instead seek to approve investments that reduce existing environmental harms.[205]

352. CNG states that any attempt to prioritize investments in a clean heat plan would depend on known facts about disproportionately impacted communities in each utility's service territory. In this instance, the utility may have more flexibility to pursue demand-side management programs that may not be technically cost-effective but would provide a specific benefit to disproportionately impacted communities.[206]

353. UCA does not believe the Commission should define "prioritization" which it argues has a commonly understood meaning as arranging items or activities in order of relative importance. However, UCA does believe that the first investments in clean heat resources in a utility's service area should be in disproportionately impacted communities. Utilities should also electrify homes in disproportionately impacted communities to transition those customers off the natural gas system, as income-qualified individuals or members of disproportionately impacted communities are less likely to be able to afford electrification and likely live in older housing stock with less efficient infrastructure.[207]

354. Atmos recommends this being addressed on a utility-by-utility basis to promote flexibility, independent thinking, and consideration as to the unique needs of different

[205] CEO August 24, 2022 Comments, pp. 6-7.
[206] CNG August 24, 2022 Comments, p. 35.
[207] UCA September 19, 2022 Comments, p. 19.

communities.[208] Black Hills believes "investments" must be defined before "prioritization." It suggests they are outlays of money, and usually refer to capital investments, but could also refer to customer education and outreach, and energy efficiency rebates. Black Hills recommends the Commission take comments on this and allow utilities to address it in their individual clean heat plan filings.[209]

355. At this time, we agree with UCA, Atmos, CNG, and others that attempting to define prioritization in the Gas Rules at this time is unworkable. We agree with CEO that this topic is likely to evolve. However, we expect utilities to clearly explain how they are undertaking to prioritize customers who are income-qualified, historically impacted by air pollution, or disproportionately impacted communities, including through outreach, program design, funding, data collection, and other efforts. At the community meetings, participants stated that they would like to better understand how "benefits" are defined and how investments could be prioritized to disproportionately impacted communities. We also expect utilities, within their clean heat plans, to indicate what they consider a "benefit" to these communities and whether that determination was reached through stakeholder outreach. This information may support more robust engagement with impacted communities as plans are filed and evaluated.

356. In subparagraph (b)(V), we list the other qualitative factors defined in "lowest reasonable cost," including risk to utility customers from market volatility. We also include risk to utility's customers of stranded costs as another qualitative factors to consider when determining if the clean heat plan is in the public interest.

[208] Atmos August 8, 2022 Comments, p. 22.
[209] Black Hills August 26, 2022 Comments, pp. 4-5.

357. *Labor Considerations.* In subparagraph (b)(VI), we adopt the Consensus Labor Comment proposal that the Commission consider labor metrics and benefits as specified in § 40-3.2-108(8), C.R.S., and defined in Rule 4001(h). Similarly, we also will consider whether the plan provides long-term impacts on Colorado's utility workforce as part of a just transition.

358. *System Reliability.* Finally, in subparagraph (b)(VII), we state we will consider whether the plan maintains system safety and reliability, consistent with § 40-3.2-108(6)(d)(I)(E), C.R.S.

359. Paragraph (c) establishes the Commission will consider cost recovery proposals by a utility that provide for recovery of the costs of an approved clean heat plan.

360. In response to the July Redlines, Black Hills argues that the language (previously in Rule 4731(d)(III)), that allows a utility to recover the prudently incurred costs associated with actions under an approved clean heat plan should be retained. Black Hills argues that clean heat plans are filed with the Commission and will be subject to a Commission approval process so utilities should be entitled to recover prudently incurred costs associated with actions undertaken pursuant to a Commission-approved Clean Heat Plan.[210] Paragraph (d) establishes that 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.

### i. Rule 4733. Interim Clean Heat Plan Reporting

361. The NOPR proposed Rule 4733 to implement the statutory provisions for annual reporting found in § 40-3.2-108(7), C.R.S. A utility must file an interim clean heat plan report

[210] Black Hills October 11, 2022 Comments, p. 12.

annually pursuant to paragraph (a). In the NOPR, we originally only required a utility to report the information required by §§ 40-3.2-108(7)(A) and (B), C.R.S., which includes: (1) the amount spent on each clean heat resource relative to the amount budgeted, (2) the amount spent on income-qualified programs that serve communities historically impacted by air pollution and other energy-related pollution, (3) a calculation of emissions reduced or avoided pursuant to the utility's approved clean heat plan, and (4) actual emission reductions achieved on a project basis for recovered methane projects. We also incorporated in paragraph (a) the reporting of information regarding the use of Colorado-based labor in accordance with § 40-3.2-108(8)(b), C.R.S.

362. In the July Redlines, we added that a utility shall include emissions both on an overall basis (in subparagraph (a)(III)) and on a resource category basis (in subparagraph (a)(IV)). We also proposed a provision that requires a utility to provide an update on the status of any competitive solicitation issued in accordance with Rule 4731 and a requirement that the utility state or certify that it has retired any recovered methane credits in the year issued. Finally, we proposed expanding the reporting requirements to include an update to the forecasts provided for in Rule 4731.

363. We discuss the comments received since the July Redlines and further edits the Commission finds necessary compared to the NOPR and the July Redlines for each provision below.

### (1) Report Deadline and Logistics

364. The NOPR proposed a filing deadline of August 1 for interim clean heat plan reports. In recent comments, UCA states that it overall supports the proposed revisions to Rule 4734 that expands the reporting requirements, but questions why the Commission set an August 1 deadline. UCA comments that most annual reports are filed in the first quarter of a given year (or

by April 1).[211] We see merit in earlier annual reports and set a March 31deadline for such interim clean heat plan reports. We believe a March 31 deadline is appropriate because it will give a utility sufficient time to gather necessary data from the preceding year but will allow the Commission to receive the report before too much of the next year has passed.

365. The NOPR proposed interim reports on an annual basis. In the July Redlines, the Commission proposed requiring interim reports only in calendar years where a clean heat plan application is not submitted. We received no comments on this proposed change. We continue to think this change is reasonable and eliminates duplicative filings and alleviates some burden during years a utility needs to file a clean heat plan.

366. The NOPR proposed in paragraph (b) that a utility shall submit the report in the most recently concluded proceeding in which Commission approved a clean heat plan filed by the utility. We include this logistical requirement in adopted paragraph (c). We incorporate the filing deadline from former paragraph (b) into paragraph (a) of adopted Rule 4733.

### (2) Reporting Requirements

367. Section 40-3.2-108(7), C.R.S. requires a utility to submit an annual report that includes the information discussed above, as well as any other information required by the Commission. We find it important that a utility's annual report also include several other categories of information.

368. Subparagraph (a)(I) requires a utility to report the amount spent on each clean heat resource relative to the amount budgeted, with an explanation for any deviations. This provision derives from § 40-3.2-108(7)(A), C.R.S., and we adopt it as proposed in the NOPR.

[211] UCA September 12, 2022 Comments, p. 14.

369. Subparagraph (a)(II) requires a utility report the amount spent on income-qualified programs, programs that serve customers in disproportionately impacted communities, or those that serve communities historically impacted by air pollution and other energy-related pollution, relative to the amount budgeted, with an explanation for any deviations. The NOPR mirrored the language in § 40-3.2-108(7)(A), C.R.S. In the July Redlines, we swapped "communities historically impacted by air pollution and other energy-related pollution" for the term "disproportionately impacted communities." In light of the Commission's discussion in para. 349, we revise the language proposed in the July Redlines to refer to communities historically impacted by air pollution and other energy-related pollution in subparagraph (b)(IV).

370. Subparagraph (a)(III) requires a utility to report annual greenhouse gas emissions consistent with the Greenhouse Gas Emission Rules, 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. This provision requires the utility to report emissions on an overall basis, as well on a project or program basis. While the statute only requires emissions to be presented on a project basis for recovered methane, we find it appropriate to expand this requirement to require a utility to report emissions on a project basis for every resource. Section 40-3.2-108(7)(B), C.R.S., dictates how a utility must present emissions reduced or avoided, however, we do not repeat these requirements here because the Greenhouse Gas Emission Rules already require a utility to present in this manner. Subparagraph (a)(IV) requires a utility to report the actual greenhouse gas emissions reduced or avoided for each clean heat resource category as calculated 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.

371. Subparagraph (a)(V) requires a utility to show the actual emission reductions and corresponding recovered methane credits for each recovered methane credit, as well as a statement or certification from the utility that any recovered methane credits were retired in the year generated. The July Redlines previously proposed referring to credits recited in the year "issued" but we modify this wording to use "generated" based off comments received from CEO. CEO states that in proposed Rule 4733(a)(V), the word "issued" should be changed to "generated" consistent with Rule 4730(a)(II)(C), statute, and the Division proposed rules. CEO raises that in the current Regulation 22 rulemaking before the Air Quality Control Commission, it is considering when credits are "generated" for purposes of this statutory provision, and credits in the Division's proposed crediting and tracking system will expire after twelve months from the credit generation date unless retired.[212]

372. Subparagraph (VI), as proposed in the July Redlines, requires a utility to include an update to the forecasts provided in Rule 4731(b)(II), if applicable, in its interim clean heat plan report. We adopt this proposal because we find it important that a utility's forecasts remain as up to date as possible since they are incorporated in a meaningful matter in a utility's gas infrastructure plan filings. If a utility files a clean heat plan pursuant to Rule 4734, then it would not have forecasts to update under subparagraph (VI).

373. The NOPR addressed the reporting of information regarding the use of Colorado-based labor in accordance with § 40-3.2-108(8)(b), C.R.S. In response, the Consensus Labor Comments suggest a reporting provision for Rule 4734 that requires a utility to provide information obtained from contractors about use of Colorado-based labor, use of contractors participating in apprenticeship programs, the use of out-of-state labor to construct and deliver clean

[212] CEO October 7, 2022 Comments, p. 31.

heat resources, and other labor metric. We find the Consensus Labor Comments proposal workable and adopt it as subparagraph (VII).

374. Subparagraph (VIII), originally proposed in the July Redlines, requires a utility to present an update on the status of any competitive solicitation issuances. We adopt this provision as proposed in the July Redlines because we find it furthers the Commission's stated purpose that utilities acquire clean heat resources in the most cost-effective manner.

#### (3) Course Corrections

375. Atmos suggests that Commission's Clean Heat Plan Rules should contemplate a process by which a utility could "course-correct" or change an approved clean heat plan during the clean heat plan action period.[213] We agree that such flexibility may be valuable for utilities, particularly for the first round of clean heat plans. Atmos provides draft language in 4729(f) that permits a utility to file an application within a clean heat plan action period to seek prospective adjustments to its clean heat plan within that clean heat plan action period. While we decline to adopt the language proposed by Atmos in Rule 4732, we do incorporate the concept of utility requests for course correction into Rule 4733. In paragraph (b) we state that a 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 the Clean Heat Plan Rules.

### j. Rule 4734. Small Utility Clean Heat Plan

376. We did not receive any additional comments on proposed changes to Rule 4734 as presented in the July Redlines. As such, we adopt Rule 4734 as presented in the July Redlines.

[213] Atmos August 8, 2022 Comments, p. 16.

We find that Rule 4734, strikes a reasonable balance between regulatory burden and ensuring proper oversight of investment and greenhouse gas emissions of smaller utilities.

### 9. DSM Rules

377. The NOPR proposed several changes to the DSM Rules in response to HB 21-1238, including expanding the definition of demand side management (DSM) programs and requiring utilities to file a "DSM Strategic Issues" application. Regarding the DSM Rules, we adopt the majority of the rule revisions presented in the NOPR, which were relatively uncontentious and provide rule changes necessary to implement HB 21-1238. Further, we make revisions throughout the rules for clarity and consistency in other areas raised by commenters.

378. Overall, we adopt the changes presented in the NOPR and in the attached for three purposes. First, as stated above, many of the changes presented are necessary to implement HB 21-1238. Second, the record before us supports implementing demand response reduction as a purpose of a utility's DSM efforts. Third, we make changes to the DSM Rules to ensure alignment between a utility's DSM and clean heat plan filings.

#### a. Rule 4750. Overview and Purpose

379. We adopt the changes proposed in the NOPR to Rule 4750, including adding the statutory references of §§ 40-3.2-105.5, 40-3.2-106 and 40-3.2-107, C.R.S., to the overview and purpose section, as well as adding a paragraph (a) that requires a utility to file a strategic issues application.

380. In the July Redlines, we proposed for comment adding a statement to paragraph (b) to ensure that utilities spend a significant portion of DSM program expenditures targeted to improve efficiency in income-qualified households. In response, Atmos suggests referring to the rule provisions that establish program expenditures targets at improving efficiency in income-

qualified households directly.[214] Black Hills and Public Service suggest removing the proposed addition to paragraph (b) entirely.[215] We adopt Atmos' suggestion to specify that a utility shall ensure a significant portion of program expenditures are targeted to improve efficiency in income-qualified households in accordance with the percentage specified in Rule 4753(i)(III) or Rule 4753(i)(IV), as applicable.

### b. Rule 4751. Definitions

381. *Discount Rate*. In the NOPR, we proposed to move the definition of "discount rate" in current paragraph (e) to the general definitions in Rule 4001 for general applicability. However, we have received numerous comments that the general applicability definition proposed in the NOPR for "discount rate" in Rule 4001(o) was ambiguous (*See* Decision Section (I)(C)(2)(a)). As such, we decline to delete the definition of "discount rate" in current Rule 4751(e) as proposed in the NOPR.

382. *DSM Program.* In the NOPR, we proposed to modify the definition of "DSM program" to reflect statutory changes in § 40-1-102(6), C.R.S. In the July Redlines, we added "DSM education targeted at market transformation" to the list of programs or combinations or programs that are defined as "DSM programs." In response, CEO seeks clarity from the Commission on whether all education programs must be directed at market transformation, or whether this is a preference from the Commission.[216] We clarify that DSM education efforts such as energy audits or other DSM education efforts that are not aimed at "market transformation"

[214] Atmos August 8, 2022 Comments, p. 19.
[215] Black Hill August 26, 2022 Comments, p. 25; Public Service October 2022 Bluelines.
[216] CEO August 24, 2022 Comments, p. 20.

should count as DSM programs and revise the proposed definition of "DSM program" to reflect this understanding.

383. *Strategic Issues Proceeding*. Paragraph (p) in the NOPR proposed a definition for a DSM "strategic issues proceeding" (DSM-SI Proceeding or SI Proceeding) based revisions to § 40-3.2-103(1), C.R.S., established by HB 21-1238. In the July Redlines, we proposed striking the filing cadence from the NOPR definition of "strategic issues proceeding" because the cadence is covered by Rule 4572(f). For comment, we also added to the definition of "strategic issues proceeding" to recognize the importance of peak demand reduction resulting from energy efficiency and demand response as part of the application provisions. We received numerous comments in opposition to expanding the definition of "strategic issues proceeding" to include demand response and peak reduction programs. CNG does not support the revision to the definition of SI Proceeding to include demand response goals and peak reduction goals. It suggests this revision appears to be misplaced in that it includes pure-play gas utilities with combination gas/electric utilities—demand response and peak reduction programs are primarily electric utility programs. CNG operates no demand response or peak reduction programs in Colorado. To the extent the Commission seeks to include such programs and budgets for combination utilities, CNG recommends that pure-play gas utilities be exempted.[217]

384. However, we find demand response and peak reduction programs are important additions to a utility's DSM efforts, especially as they may relate to specific opportunities to reduce peak design day needs, thereby relating to potentially cost-effective opportunities to limit future investment. The Commission has expressed specific interest in this relationship and further exploration of these opportunities. These programs are most appropriately analyzed in an SI

[217] CNG August 24, 2022 Comments, p. 29.

Proceeding. We therefore adopt the definition of "strategic issues proceeding" as proposed in the July Redlines.

385. *Savings Goals and Savings Targets.* In the July Redlines, we proposed for comment new definitions for the term "saving(s) goals" and "savings target(s)." In response, Atmos comments that the proposed definitions do not reflect its understanding of the common use of these terms and suggests modifying the definitions to require goals be set in a DSM plan proceeding and targets be set in an SI Proceeding.[218] No other participant expresses confusion over the proposed definitions of "savings goal" and "savings target."

386. We also adopt any other changes to Rule 4751 proposed in the NOPR and in the July Redlines not discussed above, including changes to the term "Modified Total Resource Cost Test," and deletion of the defined term "sales customer."

### c. Rule 4752. Filing Schedule

387. The NOPR proposed modified procedures for calculating the G-DSM bonus in paragraph (c). We adopt these proposed changes in light of the introduction of the DSM Strategic Issues (DSM-SI) proceedings by amendments to § 40-3.2-103(1), C.R.S.

388. The NOPR also proposed a new paragraph (f) that requires, commencing in 2022, and no less frequently than every four years thereafter, each utility to file an application to open a DSM-SI Proceeding, consistent with § 40-3.2-103(1), C.R.S. Black Hills and CNG each argue that a DSM-SI filing in 2022 is too cumbersome and difficult in light of the rulemaking deadline.[219] However, we do not believe § 40-3.2-103(1), C.R.S., affords utilities an option to delay their DSM-SI filing. The statute states "commencing in 2022" a utility shall file an application to open

[218] Atmos August 8, 2022 Comments, pp. 19-20.

[219] Black Hills October 11, 2022 Comments, pp. 4-5; CNG October 7, 2022 Comments, pp. 10-11.

a DSM-SI Proceeding. While Black Hills points to § 40-3.2-103(2.5), C.R.S., as justification for a 2023 filing (when its next DSM plan is due), we are not convinced the General Assembly intended for a combined DSM plan and strategic issues filing to occur later than 2023 by the plain language of the statute. Per the statutory language, which the Commission cannot waive or alter, the utilities are each required to file an application to open a DSM-SI Proceeding before December 31, 2022.

389. Black Hills comments that § 40-3.2-103(2.5), C.R.S., allows the Commission, gas utilities with fewer than 250,000 customers, to establish energy savings targets, budgets, funding and cost recovery, and the financial bonus structure in the same proceeding in which the utility's gas DSM program plan is submitted for approval. Black Hills comments that Rule 4752(f) should include a new subpart (I) to address this statutory provision for small gas utilities.[220] We decline to add a new subpart as proposed by Black Hills because this is already addressed by Rule 4761(d).

390. In the July Redlines, we proposed for comment implementing a July 1 (previously May 1) filing deadline for DSM plans in paragraph (e). We have not received any comments in opposition to this proposed change and therefore adopt a July 1 filing deadline.

391. We also adopt any other changes proposed and explained in the NOPR to Rule 4752 although not expressly discussed above.

**d. Rule 4753. DSM Plan**

392. Rule 4753 sets forth requirements for utilities to file a gas DSM plan that covers a DSM period of three years (or as ordered by the Commission). Public Service suggests in switching the filing cadence to every two years to better align with the requirement of DSM-SI

[220] Black Hills August 26, 2022 Comments, p. 26.

filings every four years.[221] We received no comments opposing this change in filing cadence. We support Public Service's reasoning for switching to a two-year filing cadence and reflect that change in the adopted rules.

393. In the July Redlines, we stated that we foresee DSM as an important component of a successful clean heat plan and anticipate a need for strong alignment between a utility's approved DSM plan and approved clean heat plan. To support this alignment, we proposed for comment language in Rule 4753 which requires a utility's DSM plan to be consistent with the utility's approved clean heat plan. Public Service and Atmos suggest deleting this proposed language. However, we decline to remove this language because we continue to see need for strong alignment between a utility's approved DSM plan and approved clean heat plan. This language is meant to require that the DSM plan filed by a utility includes all the DSM proposed as a clean heat resource. It will be helpful for the Commission to be able to see all DSM together within the context of a DSM plan, including that which originally was presented inside of a Clean Heat Plan. It would not require a combined filing as permitted under § 40-3.2-108(4)(e), C.R.S.

394. In the July Redlines, we added Rule 4753(d) which requires that a utility must present the anticipated peak demand reduction by a given annual DSM program, including specific indications of the anticipated peak demand reduction specifically attributed to demand reduction or demand flexibility programs. In response, Public Service suggests deleting the proposed language in paragraph (d) and replacing it with "anticipated peak demand savings, as applicable to individual DSM programs and to the portfolio as a whole."[222] Public Service maintains that gas peak demand is different than electric peak demand. It explains, while many (though not all)

[221] Public Service September 15, 2022 Comments , p. 27.
[222] Public Service September 15, 2022 Comments, p. 29.

electric energy efficiency measures also avoid some amount of peak demand, gas energy efficiency may have no impact on peak demand or may have an effect only in a very specific location.[223] Public Service asserts that it is working on developing more sophisticated approaches in its ongoing DSM-SI Proceeding (Proceeding No. 22A-0309EG), and rules should avoid codifying older less sophisticated methods. CNG comments that it does not operate peak demand reduction DSM programs, and states that such programs are typically associated with electric utilities, not pure-play gas utilities.[224] We agree with Public Service that peak demand savings goals may not be applicable to every DSM program, but do believe there may be demand savings from programs for which demand savings may not be the primary purpose. We require utilities to determine that peak demand savings goals for those programs which are anticipated to deliver some level of demand savings and thus adopt its proposed language for Rule 4753(d).

395. CEO and other commenters suggested Rule 4753 should reference the labor standards set forth in § 40-3.2-105.5, C.R.S., which we incorporated for further comment in the July Redlines. We have not received additional comment and thus adopt paragraph (f) which requires a utility to provide plans to comply with the labor standards set forth in § 40-3.2-105.5, C.R.S.

396. In the NOPR, we proposed adding new subparagraph, regarding the utility's information detailing how it developed its proposed DSM program, to require the utility to include the best available values for gas leakage during the extraction, processing, transportation, and delivery of gas by the utility as well as leakage from piping or other equipment on customer premises, and any relevant data and emissions accounting methodologies developed by the AQCC

[223] *Id*.
[224] CNG August 24, 2022 Comments, p. 30.

pursuant to § 25-7-140, C.R.S., regarding methane leakage rates and the appropriate global warming potential of methane, for the purpose of calculating the cost of methane emissions. We find it appropriate to implement this provision as proposed in the NOPR, except referencing the Air Pollution Control Division instead of AQCC. This addition to 4753(f)(VIII) implements § 40-3.2-107(2)(b), C.R.S.

397. The Commission proposed that a utility include an analysis showing that DSM measures and programs, particularly in new construction, do not discourage otherwise economic beneficial electrification.

398. We proposed revisions to update the nomenclature to refer to "income qualified" customers instead of "low income" to implement changes established by §§ 40-3.2-107(3)(a)(III) and (IV), C.R.S. We also proposed new subparagraphs that address how the utility shall target expenditures for income qualified customers. Public Service suggests that the subparagraph found in currently in (I), that a utility shall address whether it proposes to provide DSM programs directly or indirectly, should be deleted in light of statutory changes. HB 21-1238 removed the distinction between direct income-qualified DSM programs and indirect financial support of conservation programs for income-qualified customers administered by the State of Colorado from § 40-3.2-103(3)(a), C.R.S. We agree with Public Service and eliminate this provision. We otherwise adopt the changes and additional subsections proposed in the NOPR as Rule 4753(i).

399. We proposed significant revisions in the NOPR to the paragraph addressing calculation and review of the utility's modified TRC to implement the changes to the calculation of the modified TRC consistent with HB 21-1238.

400. In the NOPR we proposed a new subparagraph (I), which moved provisions governing the calculation of the modified TRC from the definitions in Rule 4751 and add the

valuation of avoided emissions, including new provisions that address the use of the social cost of carbon and the social cost of methane. These modifications also implement the addition of § 40-1-102(5)(d), C.R.S., regarding the circumstances when the utility may present a calculation of the modified TRC without using the social costs of carbon and methane. In addition to the language proposed in the NOPR, we find it appropriate that benefits shall include the utility's avoided transmission and distribution capital cost savings associated with reductions or limited growth in design day peak demand; energy costs; the participant's avoided operating and maintenance costs; the valuation of avoided greenhouse gas emissions; and non-energy benefits.

401. In subparagraph (II), we implement the addition of § 40-1-102(5)(d), C.R.S., regarding the circumstances when the utility may present a calculation of the modified TRC without using the social costs of carbon and methane. We also establish that costs shall include utility and participant costs.

402. In subparagraph (III), we strike the defined non-energy benefit factor of 1.05, as non-energy benefits (other than benefits associated with the reduction of greenhouse gases as measures by the social costs of carbon and methane) will be addressed in Strategic Issues proceedings. We sought comment in the NOPR on whether a new value to account for other non-energy benefits from gas DSM should replace the factor of 1.05 in light of the changes to the Gas DSM Rules required by HB 21-1238. UCA opposes the open-endedness of the multiplication factor for the TRC ratio and argues the Commission should either leave the 1.05 factor in or cap it at 1.05.[225] Other commenters supported the flexibility that removing a set factor creates. At this time, we decline to set a factor by rule and will address establishing a multiplier in utility's strategic issue proceedings.

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[225] UCA September 12, 2022 Comments, p. 15.

403. In new subparagraph (IV), we clarify that a determination of cost-effectiveness using the modified TRC test by the Commission will ultimately be measured at the DSM program level. This change is supported by several participants, including CNG, Conservation Advocates, and Public Service.

404. In the new subparagraph (V) we establish that, for purposes of evaluating a gas DSM program or measure that incorporates innovative technologies with the potential for significant impact, the Commission may find the program or measure cost-effective, even if its initial benefit-cost ratio is not greater than one calculated using currently available data and assumptions. This is consistent with § 40-2-123(2)(b), C.R.S., as modified by HB 21-1238.

405. New paragraph (q) aligns a utility's DSM plan and DSM Strategic Issues plan by requiring that, 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.

406. New paragraph (r) requires a utility to 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 proposed budget. Because we consider the inclusion of incentive costs of behind-the-meter thermal resources in a utility's budget in paragraph (r), we do not adopt the language proposed in the NOPR in 4753(i)(IV) because it would be redundant.

407. Except as discussed above, we adopt the changes proposed in the NOPR to Rule 4753.

**e. Rule 4754. Annual DSM Report.**

408. Rule 4754(a) requires utilities to include in their annual DSM report specific details with respect to each DSM program. In the NOPR, we proposed several changes intended to streamline DSM-related filings and also to move certain G-DSM bonus related provisions to Rule 4760.

409. In the July Redlines, we proposed adding several additional reporting metrics to Rule 4754, including in paragraph (a) requiring reporting of peak demand reduction as a result of energy efficiency programs, peak demand reduction as a result of specific demand reduction programs, greenhouse gas emissions reductions, participation levels at the measure level, and cost-effectiveness. We also proposed for comment requiring a utility to report in (f), the greenhouse gas emissions reductions achieved from demand side management programs shall be calculated consistent with rules 4525 through 4528. To further alignment between clean heat plan filings and DSM filings, we also proposed in (g) that a utility must report 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.

410. In response, Black Hills believes the intent was to require details at the program level for each and every category except for participation levels, which would be provided at the measure level. In order to eliminate the ambiguity, Black Hills would propose to rearrange the specific language to group all categories requiring details at the program level and concluding with the sole category requiring details at the measure level. Black Hills proposes the following modifications to Rule 4754(a):

> For each DSM program, the utility shall document actual program expenditures, … greenhouse gas emissions reductions, cost-effectiveness, and participation levels at the measure level, and cost-effectiveness.[226]

411. We agree with Black Hills that its proposed language clarifies that the Commission expects utilities to present participation levels at the measure level but other information at the program level. We incorporate this change.

412. The City and County of Denver proposes adding that participation levels at the measure level should be reported for census block groups or zip codes if restrictions apply at the census block group. It states that this is a helpful reporting approach because it would capture gaps in program participation and outreach and engagement efforts, allowing utilities to better target income-qualified and disproportionately impacted communities. Denver comments that reporting for census block groups aligns well with other efforts to consider disproportionately impacted communities in utility programs. Denver also proposes adding zip codes as an alternative if census block groups prove restrictive for data sharing purposes. Denver says that Since zip codes are larger areas than census block groups, this provision would allow for an additional metric should reporting be limited by customer participation within specific census blocks.[227]

413. We agree with Denver that getting more granular data and tracking participation for census block groups and zip codes would capture gaps in program participation and outreach and engagement efforts, allowing utilities to better target income-qualified and disproportionately impacted communities. As such, we incorporate Denver's suggested language into paragraph (a).

414. CNG comments that it has concerns with the additions to Rule 4754(a) proposed in the July Redlines because the addition of reporting on peak demand reduction programs seems

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[226] Black Hills August 26, 2022 Comments, p. 27.

[227] City and County of Denver September 16, 2022 Comments, pp. 3-5.

misplaced with respect to pure-play gas utilities.[228] As discussed above, we see development of demand reduction programs as an important avenue for DSM efforts in Colorado. We decline to remove demand response provisions from the reporting provisions in paragraph (a). In the July Redlines, we proposed requiring a utility to present in its Annual DSM report documentation of greenhouse gas emission reductions as suggested by Conservation Advocates. We also proposed for comment, an additional paragraph 4754(f) which specifies that greenhouse gas emission reductions shall be calculated pursuant to the Greenhouse Gas Emission Rules. We adopt this proposed language as reflected in the July Redlines.

415. In the July Redlines we also proposed that a utility's annual DSM Report should specify the reductions from DSM programs that qualify as a clean heat resource. Public Service suggests removal of proposed Rule 4754(g) which requires a utility to report greenhouse gas emission reductions in the Annual DSM Report because Public Service contends this is already covered under Rule 4754(a).[229] We think it is important to retain a reporting requirement that reflects the level of reductions and DSM measures adopted as part of a clean heat plan for tracking purposes and therefore adopt new paragraph (g) which requires a utility to report approved DSM measures and associated emission reductions.

#### f. Rule 4756. General Provisions Concerning Cost Allocation and Recovery

416. The NOPR proposed revisions to paragraph (b) to align it with § 40-3.2-103(3.5)(b), C.R.S., and to remove the prohibition against fuel switching. In the July Redlines, this proposed change was inadvertently removed. We decline to adopt the proposed changes to paragraph (b) put forth in the NOPR and simply eliminate paragraph (b). The language

[228] CNG August 24, 2022 Comments, p. 29.

[229] Public Service September 15, 2022 Comments , p. 27.

proposed in (b) needlessly repeats the statutory language found in § 40-3.2-103(3.5)(a), C.R.S. As such, we decline to adopt it in Rule 4756.

417. In the NOPR, the Commission added Rule 4756(d) to address utility requests for approval of a revenue decoupling mechanism consistent with the direction in § 40-3.2-103(5)(b), C.R.S. In response, Conservation Advocates suggested adding language that allows the Commission the option to establish a revenue target decoupling mechanism for gas utilities, where actual rate class revenue would be compared to a rate class revenue target set at the time a decoupling mechanism was implemented. Conservation Advocates contended that this removes the incentive for utilities to add customers. The Commission incorporated this proposed change in the July Redlines for comment. Public Service proposes several modifications to paragraph (d) that is asserts aligns the rule language more closely with § 40-3.2-103(5)(b), C.R.S., including adding "to customers in the applicable rate class or classes" as stated in the statute and adding that the Commission shall not "reduce a gas utility's return on equity based solely on approval of a revenue decoupling mechanism."[230] We decline to adopt Public Service's proposed language and instead adopt 4756(d) as proposed in the July Redlines.

### g. Rule 4760. Gas DSM Bonus (G-DSM Bonus)

418. This rule addresses a utility's DSM bonus application.

419. In the July Redlines, we proposed for comment an update to the language in subsection 4760(d)(II) which recognizes the importance of peak demand reduction and the distinction between energy savings and peak demand reductions.

[230] Public Service October 2022 Bluelines.

420. The Commission received several comments regarding proposed Rule 4760(h) in the NOPR, which requires a utility to show that its gas DSM programs did not impair beneficial electrification in order to receive its DSM bonus. Public Service, Black Hills, and CNG each propose striking this language. Specifically, CNG suggests that it is inappropriate to expect "pure play" gas utilities to analyze, compare, evaluate or otherwise support electrification. In response to these comments, in the July Redlines we proposed for comment edits to this provision to requires any combined electric and gas utility seeking a Gas DSM Bonus for new residential or commercial construction to provide a narrative discussion that explains why that Gas DSM program does not incent additional gas usage as compared to a beneficial electrification alternative. While we agree that requiring a showing that a specific investment does not incent additional gas usage may be inappropriate and burdensome, we continue to believe that requiring utilities to provide a narrative explanation of the interplay between beneficial electrification and additional gas usage for gas DSM efforts for new residential or commercial construction is useful information to provide to the Commission and may help protect against individual utilities receiving DSM Bonuses and lost revenue recovery for investments that may potentially result in increased commodity sales, revenues, and profits. Accordingly, this Commission hereby retains the requirement in 4756(i) using the same language as was proposed in the July Redlines.

421. We otherwise adopt the changes proposed to 4760 proposed in the NOPR and the July Redlines.

**h. Rule 4761. Filing of DSM Strategic Issues Application**

422. The NOPR adds Rule 4761 to address the filing of a utility's Strategic Issues application, as required by the revisions to § 40-3.2-103(1), C.R.S., as enacted by HB 21-1238. Considering the timing of this Proceeding, we strike "by July 1, 2022" and replace

with "commencing in 2022" for the first filing of a utility's DSM-SI Proceeding application in paragraph (a).

423. Proposed paragraph (b) sets forth the information a utility must include in a DSM strategic issues application.

424. Subparagraph (I) requires a utility to present an estimated budget, corresponding energy savings and peak capacity reduction goals for all DSM programs. Subparagraph (II) requires a utility to present funding and cost-recovery mechanism proposals.

425. Subparagraph (III) requires a utility to present a proposed methodology for estimating peak demand savings and the resulting cost savings. We find that this requirement furthers the Commission's goal of implementing demand response reduction as a purpose of a utility's DSM efforts.

426. Subparagraph (IV) requires a utility to provide an analysis of the comparative economics of DSM measures and programs, distinguished by the following: new construction, existing homes and businesses, and all building types. CNG questions (III) and states it is unclear how it would be aware of the building characteristics of new construction, unless a specific development is specified. As for existing homes, CNG states this requirement is duplicative to the evaluation measurement and verification (EM&V) standards.[231] We adopt subpart (IV) because we think it is an important analysis to review during a strategic issues proceeding where large overarching policy decisions are before the Commission.

427. Subparagraph (V) requires a utility to present an analysis of the comparative economics of DSM measures and programs, particularly targeted at the weatherization of existing

[231] CNG August 24, 2022 Comments, p. 32.

homes, and beneficial electrification. CNG opposes the proposed paragraph requiring "an analysis of the comparative economics of DSM measures and programs, particularly targeted at the weatherization of existing homes, and beneficial electrification" because it appears to duplicate the cost effectiveness test performed through the modified TRC calculation.[232] This was originally proposed by CEO[233] and we incorporated it for comment in the July Redlines. We find it appropriate to adopt this provision as part of the strategic issues application requirements.

428. Subparagraph (VI) requires a utility to present 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.

429. Subparagraph (VII) requires 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 natural gas alternative. Public Service suggests deleting this provision because it is "not supported by statute" and it argues that the proposed provision improperly elevates beneficial electrification above gas energy efficiency, despite express legislative support for gas energy efficiency.[234] We do not find that this improperly elevates beneficial electrification because it requires only that the utility present an analysis and does not direct policy in one particular direction.

430. In subparagraph (VIII), we adopt a proposal by Conservation Advocates and RMI that requires a utility to present the 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.

[232] CNG August 24, 2022 Comments, pp. 32-33.
[233] CEO January 25, 2022 Comments, p. 59.
[234] Public Service September 15, 2022 Comments, p. 27.

431. Paragraph (c) specifies, if the filing of a Strategic Issues application overlaps with the filing of a DSM plan application, a utility with 250,000 or more full-service customers may request Commission approval of an extension of its currently effective DSM plan until the Strategic Issues proceeding is concluded. This is intended to avoid a conflict where a utility could have occasion to file overlapping Strategic Issues and DSM plan applications at the same time. This rule ensures that, in such circumstance, the Strategic Issues proceeding should take precedence over the DSM plan proceeding. In parallel to paragraph (c), paragraph (d) implements § 40-3.2-103(c)(2.5), C.R.S., specifying a utility with fewer than 250,000 full-service customers can combine a Strategic Issues proceeding with a DSM plan filing. Public Service proposes incorporating language that 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 gas utility as achieved the targets established in subparagraphs.[235] We find this addition reasonable and in adherence to the provisions in § 40-3.2-103(2)(d), C.R.S., addressing a permitted bonus structure for gas utilities.

432. Paragraph (e) provides that, in its decision addressing the utility's Strategic Issues application, the Commission will establish energy and demand savings goals for the utility to be addressed by future DSM plan filings, an estimated budget for DSM program expenditures that is commensurate with the energy savings targets, and a structure for any DSM bonus to be awarded to the utility.

## D. Conclusion

433. The statutory authority for the rules adopted by this Decision is 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,

[235] Public Service January 25, 2022 Comments, p. 51.

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.

434. We adopt the rule revisions shown in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) attached to this Decision, consistent with the discussion above.

## II. ORDER

### A. The Commission Orders That:

1. The Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* (CCR) 723-4, contained in redline and strikeout format attached to this Decision as Attachment A, and in final format attached as Attachment B, are adopted and are available in the Commission's Electronic Filing System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=21R-0449G

2. Consistent with paragraph 134, the Commission approves the Air Pollution Control Division's Clean Heat Plan Emissions Calculation Guidance and associated Clean Heat Plan Calculation Workbook, as published by the Division on October 7, 2022, available for public review and download through the Commission's website at: https://puc.colorado.gov/.

3. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted.

4. A copy of the final, adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State.

5. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

6. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATION MEETINGS November 2 and 4, 2022 and COMMISSIONERS' WEEKLY MEETINGS November 9 and 23, 2022.**

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

Commissioners

ATTEST: A TRUE COPY

G. Harris Adams,
Interim Director

COMMISSIONER MEGAN M. GILMAN
CONCURRING IN PART AND
DISSENTING IN PART.

# 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 ~~rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing~~ the manner of regulation over jurisdictional gas utilities, ~~master meter operators, and~~ 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 found 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) ~~and/~~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~~d~~) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).

(g~~e~~) "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~~f~~) "Commission" means the Colorado Public Utilities Commission.

(k~~g~~) "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~~h~~) "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~~i~~) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.

(n~~j~~) "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~~k~~) "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~~l~~) "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 day peak demand" refers to the highest hourly natural gas flow rate projected for a utility system, or a portion thereof, based on relevant 1-in-30-year low temperature data.

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

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

(y~~q~~) "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~~r~~) "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~~s~~) "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 ~~and/~~or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.

(bb~~t~~) "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~~u~~) "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~~v~~) "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~~w~~) "Mcf" means 1,000 standard cubic feet.

(gg~~x~~) "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.

(~~y~~jj) "Non-standard customer data" means all customer data that are not standard customer data.

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

(mm~~bb~~) "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 an area within a utility's service territory with a distinct pressure environment from neighboring regions.

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

(ss~~ee~~) "Sales customer" or "full service customer" means a customer~~person~~ who receives sales service from a utility and is not served under a utility's gas transportation service rate schedules.

(tt~~ff~~) "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~~gg~~) "Security" includes any stock, bond, note, or other evidence of indebtedness.

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

(ww~~ii~~) "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~~jj~~) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.

(yy~~kk~~) "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~~ll~~) "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~~mm~~) "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~~nn~~) "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~~oo~~) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.

(ddd~~pp~~) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.

(eee~~qq~~) "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.

~~(rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.~~

(fff~~ss~~) "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~~tt~~) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(hhh~~uu~~) "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~~II~~) appeal of a local government land use decision, as provided in rule 4703; or

(XVII~~IV~~) 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 ~~three~~ 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~~IV~~) records concerning demand side management, pursuant to rules 4750 through 4761~~0~~; 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. ~~If the utility maintains a website, it shall also maintain its c~~Current and complete tariffs shall also be available on a utility's~~on its~~ 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 ~~pursuant to~~in accordance with this rule. ~~The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business.~~ 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~~b~~) 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 ~~paragraphs~~ rule 4002~~(b) and 4002(c)~~;

(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) a description of the proposed facilities to be constructed;~~

~~(IV) estimated cost of the proposed facilities to be constructed;~~

~~(VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and~~

(III) the project type 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;

(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 an industry-accepted cost estimate classification index;

(X) an illustrative map of the proposed facilities that shows, at a minimum:

(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) the service territory of any electric utility service provider(s) at that location; 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 day 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~~II~~) 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, ~~as applicable,~~

~~information on alternatives studied,~~ 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 4102 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 ~~natural gas energy~~ or receiving ~~natural~~ gas ~~energy~~ 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 ~~insure~~ 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 ~~insure~~ 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 day 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. Exemptions from updated line extension allowances and standardized costs shall not extend to applications for line extensions submitted after May 1, 2023.

(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) Unless prevented by safety concerns, a~~A~~ utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, if the customer does any of the following:

(I) pays in full the amount for regulated charges shown on the notice and any deposit ~~and/~~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 certificatione~~e~~, 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 ~~low-income~~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,

* * * *
[indicates omission of unaffected rules]

(IV) A ~~municipally~~ 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 ~~natural~~ gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which ~~natural~~ 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 ~~natural~~ 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 ~~natural~~ 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 ~~s~~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 ~~natural~~ 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 ~~natural~~ gas consumption in PIPP participants' homes;

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

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[indicates omission of unaffected rules]

**4506. – 4524~~99~~. [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, as certified by 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.

**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 approval of a gas infrastructure plan. Defined programmatic expense includes company-wide investment in activities related to relocation or replacement of meters and customer-owned yard lines.

(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 2020 dollars, or $2 million 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 if that number is equal to or 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 new business and capacity and 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 new business and 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 new business and 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.

(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). 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. Planned projects exceeding the cost thresholds in rule 4102 for which the utility seeks relief pursuant to this subparagraph (d)(II) shall be filed as an application for issuance of a certificate of public convenience and necessity.

(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.

**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), including:

(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 system maps indicating locations of individual planned projects, pressure district 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. 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, 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 update the design day temperature assigned to unique segments of the utility system, to the extent applicable, based on the coldest one-hour temperature in such defined segments over the previous 30-year period.

(b) Forecast requirements.

(I) The utility shall present reference, low, and high forecasts of design day 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;

(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 an industry-accepted cost estimate classification index;

(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 and quantity of load, by class, directly impacted or served by the project; detailed justification of need for the project investment, including any applicable U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration code requirements for 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 projects addressed in previous plans, as well as changes, additions or deletions in the current plan when compared with prior plans; and

(P) for new business and capacity expansion projects, in the initial filings made in accordance with subparagraph 4552(b)(I)(A) through (C), and for any alternatives analysis ordered by the Commission for inclusion in future filings pursuant to paragraph 4552(d), 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 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 day peak demand forecast and an identification of the primary individual new projects and capital spend added in the high design day 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 March 1 in the year after the utility's last gas infrastructure plan proceeding, 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 programs of 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.

(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~~4506~~. – 4599. [Reserved].**

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[indicates omission of unaffected rules]

**4708. – 4724~~4549~~. [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) These rules apply to all jurisdictional gas utilities.

(b) 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.

(c) 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 that was retired prior to 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 or peak day) 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 day, 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;

(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 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 to be injected 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 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 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~~08~~. – 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~~5~~, 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 ~~natural~~ 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 ~~natural gas utilities~~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~~b~~) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.

(d~~c~~) 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~~0~~, 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, ~~natural~~ 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; ~~measures, information~~ and services offered to customers to reduce ~~natural~~ 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.~~ In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. 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.~~

(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.

<u>(q) “Savings goal(s)” refers to the energy and demand savings levels approved in a strategic issues proceeding.</u>

<u>(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.</u>

<u>(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.</u>

~~(q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.~~

**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) ~~file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year~~.

(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. ~~Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.~~

(e) By ~~May~~ July 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective ~~natural~~ 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. ~~Periodic~~ DSM Plan ~~Filing~~.**

Each utility shall ~~periodically~~ file, in accordance with paragraph 4752(e), a prospective ~~natural~~ gas DSM plan that covers a DSM period of ~~three~~ 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~~; the sum of these expenditures represents the utility's proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.~~;

(b) the utility's estimated ~~natural~~ 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 day peak demand savings, as applicable to individual DSM programs and to the portfolio as a whole;

(e~~d~~) 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~~e~~) 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~~f~~) 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);~~and~~

(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~~g~~) In its DSM plan, the utility shall address how it proposes to ~~target~~ prioritize DSM services and programs for income-qualified ~~to low-income~~ customers and customers in disproportionately impacted communities. ~~The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S.~~

(I) The utility may propose one or more ~~low-income~~ 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~~h~~) In proposing an expenditure target for Commission approval, ~~pursuant to § 40-3.2-103 (2)(a), C.R.S.,~~ 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~~, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater~~; and

~~(II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and~~

(II~~I~~) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to ~~natural~~ 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~~i~~) 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~~j~~) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.

(m~~k~~) 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~~l~~) 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~~m~~) 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 ~~non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows~~.

(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 day 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 ~~avoided emissions and other~~ societal benefits, shall be multiplied by a factor established by the Commission in the utility's strategic issues proceeding ~~1.05~~ to reflect the value of the ~~avoided emissions and other~~ societal and non-energy benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for ~~avoided emissions and~~ 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~~n~~) 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 ~~c~~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~~ and Application for Bonus and Bonus Calculation~~.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report~~ and application for bonus~~.

(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, participation levels at the measure level for census block groups or zip codes if restrictions apply at the census block group, and cost effectiveness~~participation levels and cost-effectiveness~~.

(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.

~~(f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.~~

~~(g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.~~

~~(I) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:~~

~~(A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;~~

~~(B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;~~

~~(C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;~~

~~(D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(I); and~~

~~(E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.~~

~~(II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(I), in order to earn a bonus.~~

~~(III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:~~

~~(A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.~~

~~(B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.~~

~~(IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per $1 million expended, and the utility's actual savings is 18,000 dekatherms per $1 million.~~

~~The energy factor would be: 50 percent x (106 – 80), or 13 percent~~

~~The savings factor would be: 18,000/15,000 or 1.2~~

~~The resulting bonus percentage would be: 13 percent x 1.2, or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.~~

~~(h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:~~

~~(I) the costs and benefits associated with a low-income 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 low-income program is below 1.0; and~~

~~(II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.~~

~~(i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.~~

~~(j) 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.~~

**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) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.~~

(b~~c~~) 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~~d~~) 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 ~~the gas DSMCA~~ 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, or other appropriate decoupling metric 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 p~~P~~rovisions.

(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 p~~P~~rovisions. 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) ~~Applications~~.**

(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 ~~application submitted~~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~~a~~) ~~G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754.~~ 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~~b~~) ~~Contents of G-DSM bonus filing.~~ 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) ~~gas~~ 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;~~ and~~

(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.

~~(c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.~~

(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~~d~~) ~~Accounting for G-DSM bonus.~~ 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~~e~~) ~~Prudence review and adjustment of G-DSM bonus.~~ 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) By July 1, 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 natural 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~~1~~. – 4799. [Reserved].**

# 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 day peak demand" refers to the highest hourly natural gas flow rate projected for a utility system, or a portion thereof, based on relevant 1-in-30-year low temperature data.

(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 an area within a utility’s service territory with a distinct pressure environment 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 rate schedules.

(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 type 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;

(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 an industry-accepted cost estimate classification index;

(X) an illustrative map of the proposed facilities that shows, at a minimum:

(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) the service territory of any electric utility service provider(s) at that location; 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 day 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 4102 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 day 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. Exemptions from updated line extension allowances and standardized costs shall not extend to applications for line extensions submitted after May 1, 2023.

(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) Unless prevented by safety concerns, a utility shall restore service within 24 hours (excluding weekends and holidays), or within 12 hours if the customer pays any necessary after-hours charges established in tariffs, 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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(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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(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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(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, as certified by 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.

**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 approval of a gas infrastructure plan. Defined programmatic expense includes company-wide investment in activities related to relocation or replacement of meters and customer-owned yard lines.

(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 2020 dollars, or $2 million 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 if that number is equal to or 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 new business and capacity and 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 new business and 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 new business and 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.

(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). 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. Planned projects exceeding the cost thresholds in rule 4102 for which the utility seeks relief pursuant to this subparagraph (d)(II) shall be filed as an application for issuance of a certificate of public convenience and necessity.

(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.

**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), including:

(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 system maps indicating locations of individual planned projects, pressure district 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. 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, 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 update the design day temperature assigned to unique segments of the utility system, to the extent applicable, based on the coldest one-hour temperature in such defined segments over the previous 30-year period.

(b) Forecast requirements.

(I) The utility shall present reference, low, and high forecasts of design day 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;

(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 an industry-accepted cost estimate classification index;

(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 and quantity of load, by class, directly impacted or served by the project; detailed justification of need for the project investment, including any applicable U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration code requirements for 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 projects addressed in previous plans, as well as changes, additions or deletions in the current plan when compared with prior plans; and

(P) for new business and capacity expansion projects, in the initial filings made in accordance with subparagraph 4552(b)(I)(A) through (C), and for any alternatives analysis ordered by the Commission for inclusion in future filings pursuant to paragraph 4552(d), 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 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 day peak demand forecast and an identification of the primary individual new projects and capital spend added in the high design day 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 March 1 in the year after the utility’s last gas infrastructure plan proceeding, 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 programs of 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.

(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].**

* * * *
[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) These rules apply to all jurisdictional gas utilities.

(b) 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.

(c) 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 that was retired prior to 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 or peak day) 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 day, 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;

(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 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 to be injected 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 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 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 day 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 day 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, participation levels at the measure level for census block groups or zip codes if restrictions apply at the census block group, and cost effectiveness.

(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, or other appropriate decoupling metric 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) By July 1, 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 natural 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].**

Decision No. C23-0039

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21R-0449G

IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, RELATING TO GAS UTILITY PLANNING AND IMPLEMENTING SB 21-264 REGARDING CLEAN HEAT PLANS AND HB 21-1238 REGARDING DEMAND SIDE MANAGEMENT.

**COMMISSION DECISION GRANTING APPLICATION FOR REHEARING, REARGUMENT, OR RECONSIDERATION FOR THE SOLE PURPOSE OF TOLLING THE STATUTORY TIME LIMIT**

Mailed Date: January 17, 2023
Adopted Date: January 11, 2023

# I. BY THE COMMISSION

## A. Statement

1. This matter comes before the Commission for consideration of several applications seeking rehearing, reargument, or reconsideration (RRR) of Decision No. C22-0760. On December 21, 2022, the Commission received applications for rehearing, reargument, or reconsideration of Decision No. C22-760 filed by each (1) Natural Resources Defense Council, Western Resource Advocates, and Southwest Energy Efficiency Project, jointly the "Conservation Advocates;" (2) the Colorado Energy Office; (3) Colorado Natural Gas, Inc; (4) Atmos Energy Corporation; (5) Public Service Company of Colorado; and (6) Black Hills Colorado Gas, Inc. (together, the RRR Applications). By this Decision, we grant the RRR Applications for the sole purpose of tolling the 30-day statutory time limit in § 40-6-114(1), C.R.S., to act upon such applications. We will issue a future order ruling upon the merits of the RRR Applications.

## B. Findings and Conclusions

2. On December 1, 2022, the Commission issued Decision No. C22-0760 in this Proceeding, adopting new and amended Commission Rules Regulating Gas Utilities found at 4 *Code of Colorado Regulations* (CCR) 723-4.

3. Consistent with the statutory time limit in § 40-6-114(1), C.R.S., and the procedures in Rule 4 CCR 723-1-1506 of the Commission's Rules of Practice and Procedure, any applications for RRR were originally due within 20 days after Decision No. C22-0760 became effective (in this case by December 21, 2022).

4. Pursuant to § 40-6-114(1), C.R.S., we are required to consider and act upon any application for RRR within 30 days of its filing (in this case by January 20, 2023) or the RRR will be denied by operation of law. We find that, due to the complexity of the issues presented in the RRR Applications, as well as the breadth of requests presented, the Commission requires further time to consider the RRR Applications. Therefore, to preclude a denial by operation of law, we grant the RRR for the sole purpose of tolling the statutory time limit.

5. This grant is procedural, and undertaken only to toll the statutory time limit in § 40-6-114(1), C.R.S. We will consider the merits of the RRR Applications at a future Commissioners' Weekly Meeting and by separate order, will rule upon the merits of the RRR Applications.

## II. ORDER

### A. It is Ordered That:

1. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Black Hills Colorado Gas, Inc., is granted consistent with the discussion above.

2. The application for rehearing, reargument, or reconsideration of Decision No. C22-760 filed on December 21, 2022, by Natural Resources Defense Council, Western Resource Advocates, and Southwest Energy Efficiency Project, jointly the "Conservation Advocates," is granted consistent with the discussion above.

3. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by the Colorado Energy Office, is granted consistent with the discussion above.

4. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Colorado Natural Gas, Inc., is granted consistent with the discussion above.

5. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by the Atmos Energy Corporation, is granted consistent with the discussion above.

6. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Public Service Company of Colorado, is granted consistent with the discussion above.

7. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING January 11, 2023.**

(S E A L)

STATE OF COLORADO
THE PUBLIC UTILITIES COMMISSION
NIL SINE NUMINE

ATTEST: A TRUE COPY

G. Harris Adams.,
Interim Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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JOHN GAVAN

MEGAN M. GILMAN

Commissioners

Decision No. C23-0117

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21R-0449G

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IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, RELATING TO GAS UTILITY PLANNING AND IMPLEMENTING SB 21-264 REGARDING CLEAN HEAT PLANS AND HB 21-1238 REGARDING DEMAND SIDE MANAGEMENT.

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**COMMISSION DECISION ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION OF DECISION NO. C22-0760**

Mailed Date: February 24, 2023
Adopted Date: February 1, 2023

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# I. BY THE COMMISSION

## A. Statement

1. Through Decision No. C22-0760 (Gas Rulemaking Decision), the Commission adopted new and amended Commission Rules Regulating Gas Utilities found at 4 *Code of Colorado Regulations* (CCR) 723-4.

2. Through this Decision, the Commission addresses the six applications for rehearing, reargument, or reconsideration of the Gas Rulemaking Decision (RRR Applications) filed on December 21, 2022 by each of Natural Resources Defense Council, Western Resource Advocates, and Southwest Energy Efficiency Project, (jointly the Conservation Advocates); the Colorado Energy Office (CEO); Colorado Natural Gas, Inc (CNG); Atmos Energy Corporation (Atmos); Public Service Company of Colorado (Public Service); and Black Hills Colorado Gas, Inc. (Black Hills).

3. Consistent with the discussion below grant, the Commission grants in part and denies, in part, the RRR Applications.

4. Through this Decision, the Commission adopts new and amended Commission Rules Regulating Gas Utilities found at 4 CCR 723-4. The adopted rules are attached to this Decision in legislative format (*i.e.,* strikeout/underline) as Attachment A, and in final format as Attachment B.

**B. Background**

5. On October 1, 2021, the Commission commenced this rulemaking by a Notice of Proposed Rulemaking (NOPR) issued as Decision No. C21-0610.

6. On December 1, 2022, the Commission issued the Gas Rulemaking Decision which amended the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4 (Gas Rules). The amendments add to as well as revise the existing provisions of the Commission's Gas Rules in seven areas: (1) the General Provision rules (General Provisions) at 4 CCR 723-4-4000 *et seq*.; (2) the Operating Authority rules (CPCN Rule) at 4 CCR 723-4-4102; (3) the Facilities rules (Line Extension Rule) at 4 CCR 723-4-4210; (4) the rules governing calculation of Greenhouse Gas

Emissions (Greenhouse Gas Emission Rules) at 4 CCR 723-4-4526 *et seq*.; (5) the rules governing Gas Infrastructure Planning (Gas Infrastructure Planning Rules) at 4 CCR 723-4-4550 *et seq*.; (6) the rules governing Clean Heat Plan (Clean Heat Plan Rules) at 4 CCR 723-4-4725 *et seq*.; and (7) the rules governing Demand Side Management (DSM Rules) at 4 CCR 723-4-4650 *et seq*.

7. On January 17, 2022, the Commission granted the RRR Applications for the sole purpose of tolling the 30-day statutory time limit in § 40-6-114(1), C.R.S., to act upon such applications through Decision No. C23-0039. In that decision, we stated that a future order ruling upon the merits of the RRR Applications was forthcoming.

## C. Discussion, Findings, and Conclusions

### 1. Rule 4001: Definitions

#### c. Rule 4001(r)—Definition of "design day peak demand"

8. In the Gas Rules Decision, the Commission adopted a definition of "design day peak demand" for use in several other rules, including the Line Extension Rule as well as in 4553, Contents of a Gas Infrastructure Plan, and in 4731(a), which specifies requirements for initial forecasts under a clean heat plan. The Commission defined "design day peak demand" in Rule 4001(r) to mean "the highest hourly natural gas flow rate projected for a utility system, or a portion thereof, based on relevant 1-in-30-year low temperature data."

9. In response, each of Black Hills, Atmos, and Public Service requested changes to the definition of "design day peak demand" in their respective RRR Applications. Public Service states that the Commission's definition appears to conflate the concepts of pipeline capacity needed to serve peak demand in geographically specific areas as determined by hydraulic modeling and peak system supply. Public Service also states that the Commission's definition is not aligned with

how the utility determines design day requirements for purposes of capacity planning because Public Service bases its approach on the probability of a 1-in-30-year occurrence of an expected low temperature, rather than the 1-in-30 year low temperature data, contemplated in the Commission's definition. Public Service suggests changing the definition to refer to the "highest hourly natural gas flow rate projected for a utility system, or a portion thereof…"[1] Black Hills requests the Commission provide stakeholders the opportunity to explore design day peak demand and pressure district definitions since they were introduced late in the proceeding to ensure that the rules adopt an accurate definition that is applicable to utility operations. Atmos believes that the Commission was interested in identifying the maximum estimated hourly throughput over relevant sections of a utility's system or portion thereof in a 1-in-30-year occurrence, regardless of whether that throughput was attributable to sales gas or transportation gas. To remove confusion over the mixed usage of "day" and "hour," and to not to change the alphabetical order of the proposed rules, Atmos believes the term should be changed to "design hourly peak demand."[2]

10. We recognize the concerns raised by Atmos and Public Service that defining "design day peak demand" to reference an hourly flow rate is confusing. We are also cognizant of the concerns raised by utilities that each utility may employ slightly different approaches to calculating design day peak demand. At this juncture, we see value in retaining a flexible definition that allows utilities to present their methodology as currently employed to the Commission. We expect that in future gas infrastructure plan filings, the Commission will gain an understanding of the underlying data and factors that a utility uses to determine design day peak

[1] Public Service RRR Application, p. 3.
[2] Atmos RRR, pp. 2-3.

demand. We adopt in part the definitions presented by Public Service and Atmos and incorporate in the Gas Rules the following definition for design peak demand:

> "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 infrastructure capacity planning.

11. We reject Black Hills' request to provide additional opportunity to comment on this definition. The NOPR proposed in Rule 4553(b) a requirement that utilities prepare forecasts of capacity on a design or peak day requirement basis. While the definition in the Gas Rules Decision was not put forth in original NOPR, the Commission expressed its interest in exploring the design day concept, at least for forecasting purposes, as far back as October 2021. Further, we find that the added flexibility in the above definition should alleviate concerns expressed by utilities regarding their use of differing methodologies that could have potentially required additional opportunities for refinement through comment. We also make the change universally in the Gas Rules to reflect "design peak demand" instead of "design day peak demand" as the defined term.

#### d. Rule 4001(q)—Definition of "dedicated recovered methane pipeline"

12. In the Gas Rules Decision, the Commission adopted a definition of "dedicated recovered methane pipeline" in 4001(q). CEO requests the Commission use the defined term "dedicated pipeline," which is used by the Air Quality Commission (AQCC) as well as Senate Bill (SB) 21-264, rather than the term "dedicated recovered methane pipeline" found in the Gas Rules Decision to prevent any confusion.

13. Similarly, CEO suggests the Commission revise the provision found in Rule 4731(f)(I)(B) that currently requires a utility to report the gross quantity of green hydrogen "to be injected" on an annual basis if its clean heat plan includes the purchase of development of green hydrogen. CEO suggests, instead of requiring reporting of injection of green hydrogen, the

Commission should require reporting of the quantity of green hydrogen "transported by a common carrier or dedicated pipeline."[3] CEO suggests this would ensure accurate accounting of all green hydrogen conveyed throughout the utility's service territory.

14. We do not find it necessary to incorporate CEO's request to change "recovered methane dedicated pipeline" to "dedicated pipeline" at this time. We think the more specific term is more suitable for the Gas Rules and may well avoid future confusion that the more general terminology could cause.

15. We adopt CEO's suggestion regarding 4731(f)(I)(a); we agree that the rule should ensure that all green hydrogen, whether transported via the common carrier pipeline system or not, should be reported.

#### e. Rule 4001(nn)—Definition of "pressure district"

16. The Gas Rules Decision adopted a definition for the term "pressure district" to mean an area within a utility's service territory with a distinct pressure environment from neighboring regions. The pressure district concept is intended to provide a useful geographic specificity to understand capacity constraints and other project needs at a level that the Commission understands to be, in most cases, looser than the regulator station requirement, but more granular than a town border station or citygate, which the Commission feels is an appropriate level of granularity for our first efforts at gas infrastructure planning. It was intended to provide continuity within the localized level at which system forecasting and planned needs are being expressed. Public Service and Atmos each suggest modifications to the definition of "pressure district." Atmos suggests modifying the definition to mean "a utility system or portion of a utility

[3] CEO RRR, pp. 12-13.

system with a distinct pressure profile."[4] Atmos states that its definition captures what it believes the Commission is interested in knowing about—which is pipeline systems, or portions of pipeline systems that have a distinct pressure profile. Atmos states the current definition is confusing because an "area" does not have a specific gas pressure and a "neighboring region" could be interpreted to refer to other utilities' nearby systems, since it is not clearly tied to neighboring regions within the same utility service territory. Public Service raises similar concerns that the definition requires further clarification and suggests the term be defined as "means a localized area within a utility's service territory with a distinct pressure profile."[5]

17. Black Hills requests the Commission provide stakeholders the opportunity to explore design day peak demand and pressure district definitions since they were introduced late in the proceeding to ensure that the rules adopt an accurate definition that is applicable to utility operations.

18. The Commission introduced the concept of pressure districts to facilitate planning processes based on appropriately-sized geographic regions. From the start of this proceeding, the Commission has expressed an interest in identifying an appropriate geographic area upon which to base localized forecasting and planning. The utilities explained that planning to the regulator station level would be burdensome. The Commission understands pressure districts as localized areas within utility service territories which have unique minimum and maximum pressure ranges, are fairly static in shape and size, and reasonably-sized by which to conduct and convey planning practices and results. We modify the definition slightly in order to improve the understanding of the concept to "Pressure district means a localized area within a utility's service territory whereby

[4] Atmos RRR, p. 3.
[5] Public Service RRR, p. 4.

an established minimum and maximum pressure range can be maintained, which is distinct from neighboring zones." If a utility continues to believe the concept of pressure districts does not apply to their service territory, it should plan to thoroughly explain the operation of its system in its informational gas infrastructure plan application(s) and present reasonably-sized localized zones within which to present forecasting and planning, so the Commission better comprehend such operations and rule on utility-appropriate geographic designations in subsequent applications.

#### f. Rule 4001(qq)—Definition of "recovered methane"

19. In its RRR Application, Public Service suggests altering "customer end use" with the "customer's meter" in Rule 4527(b)(I) and in the definition of "recovered methane." Public Service asserts that this change will better align the rules with the language used by the AQCC in its recovered methane credit accounting and tracking regulations. Doing so, according to Public Service, will "avoid ambiguity and potential regulatory conflict."[6]

20. CNG continues to argue that the Commission's definition of "recovered methane" should include sources located outside of Colorado. It states that by the plain language of § 40-3.2-108(3)(e), C.R.S., recovered methane that is delivered to or within Colorado is eligible. It urges the Commission to not rely on AQCC's draft rules and that AQCC reached an erroneous conclusion regarding the statutory interpterion. CNG also argues that emission reduction generally, even if occurring outside of Colorado, further the goals of the Colorado Legislature. CNG urges the Commission to retain flexibility in this instance to ensure recovered methane sourced outside of Colorado remains an option for clean heat plans.

[6] Public Service RRR, pp. 17-18.

21. We reject Public Service's RRR request to change "customer end use" with "customer's meter" in the definition of "recovered methane" found in 4001(qq) and corresponding language in Rule 4527(b)(I). As we discussed in the Gas Rules Decision, consideration of behind the meter emissions is something the Commission and the Air Pollution Control Division of CDPHE (the Division) intend to explore further in the future. While we generally see benefit in alignment between the Commission's Rules and the AQCC's Rules, Public Service does not give a specific reason why it is necessary to use the same phrasing in this instance. Further, the term "customer's end use" is used within SB 21-264 and we find it appropriate to use the same terminology as § 40-3.2-108, C.R.S.

22. We also reject the request by CNG to remove from the definition of "recovered methane" the requirement that recovered methane must be sourced in Colorado. We continue to find that it furthers the legislative purposes of SB 21-264 to ensure that only recovered methane sourced in Colorado may be utilized to meet clean heat targets. For example, a purpose outlined in SB 21-264 is to "achieve Colorado's science-based greenhouse gas emission reduction goals…" and the listed means to do so include "improving the energy efficiency of Colorado's buildings."[7] The statutory purpose also emphasizes that "there is significant potential to reduce emissions of methane…especially in rural Colorado."

23. While CNG is correct that the statute states that recovered methane can be delivered "to or within Colorado through a dedicated pipeline" or "physically flows within Colorado or toward the end user in Colorado," we also note that the statutory definition of recovered methane requires it to be "located in Colorado."[8]

[7] § 40-3.2-108(1)(b)(I), C.R.S.

[8] § 40-3.2-108(2)(n), C.R.S.

24. Additionally, we continue to see importance in aligning the Commission's rules with the AQCC rules. It is important for the Commission's Gas Rules to work in conjunction with the AQCC's recovered methane credit and tracking system. In the AQCC rules, recovered methane is defined as "located in Colorado…and is delivered to or within Colorado through a dedicated pipeline or through a common carrier…"[9] Further, the rules require "proof that the recovered methane project is located in Colorado," which must include a physical street address.[10] For these reasons, we deny CNG's request to reconsider allowing use of recovered methane that is sourced outside of Colorado to meet clean heat targets within Colorado.

### g. Rule 4001(ss)—Definition of "sales customer"

25. In its RRR Application, Atmos states that it has some customers that take sales service at one meter but use transportation service to another meter. Atmos argues that to the extent the customer is taking sales service through a meter, they should fall under the definition of "sales customer" and be eligible for inclusion in demand side management programs. Accordingly, Atmos asks that the Commission modify the definition of "sales customer" to state, "means a customer who receives sales service from a utility and is not served under a utility's gas transportation service rate schedules at that same meter."[11]

26. Regarding Atmos' request to modify the definition of "sales customer" in Rule 4001(ss), the Commission grants this RRR request. We find that the modification requested by Atmos will clarify distinctions between transport and sales customers and therefore adopt the definition of "sales customer" suggested by Atmos in its RRR Application.

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[9] 5 CCR 1001-26 I.B.15.
[10] 5 CCR 1011-26 I.D.1.d.
[11] Atmos RRR, p. 4.

### 2. Rule 4102: Certificate of Public Convenience and Necessity for Facilities

#### a. Commission Authority

27. Rule 4102 implements § 40-5-101, C.R.S., for certificates of public convenience and necessity (CPCN) for operation or extension or expansion of facilities. In the Gas Rules Decision, we adopted new provisions in Rule 4102 that require utilities to apply for a CPCN for projects above certain monetary thresholds of utility capital investment by customer size. We also updated the CPCN application requirements to require a utility to present similar information to the filing requirements in Rule 4553.

28. Black Hills, CNG, and Public Service each argue that the Commission's adopted CPCN Rule impermissibly expand the Commission's authority under § 40-5-101, C.R.S.

29. CNG contends that by establishing cost thresholds over which the Commission mandates the filing of a CPCN, the Commission assumes authority to make a ruling whether or not projects are in the ordinary course of business, so the rules circumvent the absolute exclusions afforded in § 40-5-101(1)(a)(I), (II), and (III), C.R.S. CNG argues that the Commission must recognize that public utilities have an "obligation to serve" customers requesting service established by statute, specifically § 40-3-101(2) and 40-4-101(2), C.R.S., and case law.[12] CNG maintains that the Commission's approval of a utility's expansion of the system is only required in limited circumstances under § 40-5-101(1)(a)(I)-(III), C.R.S. CNG argues that the Commission's policy determination in the adopted rules unlawfully places conditions on the utilities' statutory ability to extend their facilities without having to seek a CPCN.

[12] CNG RRR, pp. 4-6.

30. Black Hills makes a similar argument that Rule 4102(a) unlawfully conflicts with § 40-5-101, C.R.S. Black Hills contends that, per the statute, a project that is not in the ordinary course of business, but is within a city in which the utility has already lawfully commenced operations, is exempt from any further CPCN requirements.[13] In its RRR Application, Black Hills requests the Commission reassess the project cost thresholds found in paragraphs 4102(b), (c), and (d) for the same reasons.

31. Public Service reiterates its concerns about the breadth of Rule 4102 and the monetary threshold above which it must obtain a CPCN. Public Service states it does not take issue with the threshold in and of itself; however, it continues to have concerns that the broad applicability of this rule could create conflict with its statutory obligation to serve under § 40-3-101(2), C.R.S.[14]

32. The Commission denies the utilities' RRR on this issue. We continue to find that adopting the CPCN Rule as presented in the Gas Rules Decision (with minor modifications discussed below) is a lawful exercise of the Commission's authority and furthers several important policy purposes. As we stated in the Gas Rules Decision, the changing regulatory environment for gas utilities (*i.e.,* SB 21-264 and House Bill (HB) 21-1238), and the issues arising in recent Commission proceedings, demonstrate the pressing need for more prospective review of significant utility projects prior to cost recovery.[15]

33. As a threshold matter, the Commission has the regulatory authority to require greater preplanning and approval of utility expenditures of capital for utility investments in new

[13] Black Hills RRR, pp. 3-4.
[14] Public Service RRR, pp. 4-7.
[15] Gas Rules Decision, ¶ 83.

facilities or extension or expansion of facilities. Rates and charges for utility service are to be just and reasonable pursuant to § 40-3-101(1), C.R.S. The Colorado Supreme Court has held that it is the primary purpose of utility regulation to ensure that the rates charged are not excessive or unjustly discriminatory.[16] Further, § 40-3-101(2), C.R.S., requires a utility to furnish, to provide, and to maintain such service, instrumentalities, equipment, and facilities as shall promote the safety, health, comfort, and convenience of its patrons, employees, and the public, and as shall in all respects be adequate, efficient, just, and reasonable. *See also* § 40-3-111, C.R.S. The Colorado Constitution charges the Commission with the duty of regulating the rates of public utilities and ensuring that rates are just and reasonable. Similarly, under § 40-4-101, C.R.S., the Commission is charged with prescribing rules and regulations to ensure that electric and gas utility service in Colorado is furnished in a manner that is adequate, reliable, and promotes the health, safety, and welfare of the citizens of Colorado.

34. The CPCN and Gas Infrastructure Plan Rules further both purposes of Commission regulation of ensuring just and reasonable rates and adequate service. Under the Commission's ratemaking authority, and in fulfilling its duty to ensure just and reasonable rates and adequate service, the Commission has authority to require greater preplanning and approval of utility expenditures through the adopted Rule 4102 and Rule 4550 *et seq*. This heightened process for preplanning provides a needed opportunity to scrutinize costly projects before they are undertaken,

[16] *See, Colo. Office of Consumer Counsel*, 275 P.3d at 660-61; *Pub. Serv. Co. v. Pub. Utils. Comm'n.*, 26 P.3d 1198, 1207-08 (Colo. 2001) (holding that the Commission acted reasonably in its legislative capacity to accomplish its ratemaking function when it required Public Service to include a merger savings adjustment to benefit ratepayers because there was sufficient support in the record); *CF&I Steel, L.P.*, 949 P.2d at 586-87; *Colo. Office of Consumer Counsel v. Pub. Utils. Comm'n.*, 786 P.2d 1086, 1095-97 (Colo. 1990) (holding that the Commission did not act arbitrary or capriciously in setting rates, even though it did not accept any of the experts' opinions in full); *Pub. Serv. Co. v. Pub. Utils. Comm'n*., 653 P.2d 1117, 1120 (Colo. 1982) (holding that the Commission did not abuse its discretion when it chose not to include out-of-test year debt cost because the decision was reasonable and based on the record).

and before the utility incurs costs it may later seek to recover from its customers. Greater emphasis on preplanning infrastructure investment provides greater consumer protection and supports planning for emissions reductions as well.

35. Additionally, a utility is required under § 40-5-101, C.R.S., to apply for a CPCN before beginning construction of a new facility, plant, or system or the extension of its facility, plant, or system. While § 40-5-101, C.R.S., governs CPCNs for both authorizations to serve a service territory as well as constructing or extending facilities, Rule 4102 implements § 40-5-101, C.R.S., for review of the facility-related investment. The Commission has additional rules for CPCNs for service territory expansion that are not at issue here.

36. We find no merit to the contention of CNG and Black Hills that, once a utility has a CPCN for a particular service territory, then the utility's further activities within that service territory are entirely excepted from any requirement for a CPCN. In many instances, for example transmission projects and the West Metro CPCN proceeding,[17] the Commission considers applications for CPCNs to build specific facilities or extension of facilities within existing service territories of a utility. We therefore reject this contention as legally unsound and, as a practical matter, inconsistent with recent cases.

37. We also find significant that the Legislature did not prescribe a definition for the term "ordinary course of business" in § 40-5-101(a), C.R.S. As a result, it is the Commission's task, in implementing this provision, to attach the proper meaning to this term. Given this discretion, we reject the utilities' contention that Rule 4102 and Rule 4550 *et seq*. contravene § 40-5-101(a), C.R.S. We find instead that our adopted rules lawfully implement the statutory CPCN

[17] *See e.g.*, 21AL-0096E; 21AL-0091E; 21A-0472G.

requirement. The Commission can place reasonable limits on where and how it reviews infrastructure investments. Further, SB21-264 and HB21-1238 indicate a desire of the Legislature for the Commission to review system growth more meaningfully and indicate a need for changes to historical practices of gas utilities (*i.e.*, greater emphasis on pre-construction review). These new authorities provide even more cause for the Commission to adopt an updated approach to implementing § 40-5-101(a), C.R.S., that requires more preplanning for significant utility expenditures.

38. Finally, as we stated in the Gas Rules Decision, the stakeholders' initial petition for a rulemaking on short-term gas infrastructure planning and reporting, submitted in April 2021 provided a valuable starting point for the CPCN thresholds proposed in this rulemaking.[18] While the Commission denied the petition in order to open a more comprehensive rulemaking, we note that Black Hills, CNG, Atmos, and Public Service each at that time *supported* a monetary threshold approach for certain utility infrastructure capital projects. We therefore give less weight to their contention now that this approach is unlawful.

39. In sum, we find that the Commission has the authority to implement additional infrastructure investment review processes and that doing so through the adopted Gas Infrastructure Plan Rules and the CPCN Rule is a lawful and viable approach to implementing additional review. We therefore deny the RRR Applications by Public Service, CNG, and Black Hills to the extent that they recommend the Commission decline to adopt these rules or contend that the Commission is acting outside its authority.

[18] Gas Rules Decision, ¶ 80.

### 3. Rule 4102(f): CPCN Filing Requirements

40. Public Service requests the Commission make several changes to Rule 4102(f). First, it requests that the Commission modify where and how it requests Pipeline and Hazardous Materials Safety Administration (PHMSA)-related project information. In 4102(f)(IV), Public Service suggests adding the PHMSA code requirement, Public Service requests that the Commission allow utilities to use a utility-developed cost estimate classification index. Public Service explains that it has invested a lot of time and resources into its classification methodology.[19]

41. We adopt these requests by Public Service. We find each adds clarity to the respective rule provisions.

42. Additionally, Public Service requests that the Commission remove "utility-wide" from the greenhouse gas reporting requirement in Rule 4102(f)(XV).

43. We decline to adopt this change regarding utility-wide changes in greenhouse gas emissions in Rule 4102(f)(XV). Because CPCN applications are likely to be some of a utility's largest projects, we find that calculating greenhouse gas emissions on a utility-wide basis is appropriate and in line with other state policy objectives related to greenhouse gas emission reductions.

44. Additionally, Public Service requests in Rule 4102(f)(X), the Commission add language to the mapping requirement provision that it is subject to necessary and appropriate confidentiality provisions. We adopt this change which aligns Rule 4102(f)(X) with Rule 4553(c)(I)(J).[20]

[19] Public Service RRR, pp. 14-15.

[20] Commissioner Gilman dissents from this decision.

45. In its RRR Application, Black Hills argues that the requirements of Rule 4102(f) and related provisions increases the administrative burden significantly and will result in more regular rate case filings, which will ultimately increase costs to customers. As such, Black Hills suggests that the Commission take this opportunity to "institute real change with respect to the regulatory process and adopt in this rulemaking proceeding language allowing for concurrent recovery of costs associated with any projects approved through the multitude of new rules."[21]

46. Black Hills also requests the Commission exclude new business projects from the CPCN requirement in Rule 4102(f)(XVI). Black Hills argues that by virtue of developers or other customers requesting gas service, the threshold of "convenience and public necessity" has been achieved.[22] It argues that developing an analysis of alternatives is not appropriate for new business projects because a developer would have already considered alternatives, including electrifying the development, prior to requesting natural gas service from a utility. Black Hills states that energy efficiency and demand response measures are the only non-pipeline alternatives available to gas-only utilities and either would not avoid the need to install a new business service lateral. Black Hills again notes that electrification is not a non-pipeline alternative option for gas-only utilities. It suggests corresponding changes to Rule 4102(f)(XVI) to implement excluding new business projects from CPCN requirements.

47. Public Service similarly requests that the Commission remove any reference to new business projects in 4102(f) and (g). Public Service argues that the CPCN rules should be limited to capacity expansion projects, and suggests removing integrity projects from CPCN oversight as

[21] Black Hills RRR, p. 8.
[22] Black Hills RRR, p. 8.

well as 4102(f)(XVII) which requires that a utility must provide the risk ranking and associated methodology to conduct risk ranking associated with integrity projects.

48. We decline to modify for which projects a utility must seek a CPCN under Rule 4102. As we stated above, the Commission has the authority and finds that it is important to have a better understanding of utility investment prior to construction of major projects. This need for greater preplanning and review of investment includes new business projects as well as other types of major investments gas utilities make on behalf of existing and new customers. The Commission denies both Public Service and Black Hills' requests to limit the applicability of the CPCN Rule.

#### c. Public Service Waiver Proposal

49. Public Service requests the Commission incorporate an expedited waiver process into Rule 4102 which it states will enable it to serve and maintain safety and reliability where time is of the essence. Public Service proposes re-incorporating the Commission's original waiver proposal from the October 2021 proposed rules to this effect as Rule 4102(i).

50. In Decision C22-0427-I, we proposed for comment striking this language based of comments from the Colorado Utility Consumer Advocate that the proposed waiver language was duplicative of the Commission's existing Rules of Practice and Procedure, 4 CCR 723-1 and that waivers for good cause should require a showing of more than just a statement that safety or reliability is at issue. While we emphasize the importance of safety and reliability and recognize that utilities have an obligation to serve, we find that Commission Rule 1003 already establishes a process to address situations Public Service seeks to address by adding waiver language to Rule 4102(i). We therefore decline to reincorporate the waiver language into Rule 4102, but reiterate that a utility may always request a waiver or variance under existing Commission regulations when

it believes good cause exists for such request, and particularly in situations where safety or service reliability are at issue.

### 3. Rule 4210: Line Extension

51. In the Gas Rules Decision, the Commission adopted an amended version of Rule 4210, which governs gas utility line extension policies. The adopted Line Extension Rule established a requirement that utilities present updated line extension policies by December 31, 2024, in a base rate proceeding or separately filed application. It also requires that 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 day peak demand. We also emphasized in the Gas Rules Decision that line extension tariff filings will now be considered as Colorado progresses towards meeting its greenhouse gas reduction goals and reflected this in Rule 4210(e), that states that 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.

#### a. Requests for RRR

52. Black Hills continues to "be concerned that proposed Rule 4210 modifies a cost allocation principle on regulated utility service that has been in place for decades."[23] Black Hills continues to advocate that the Commission reconsider its modifications to Rule 4210, and institute a specific rulemaking to address only Rule 4210 so that a uniform policy can be developed that will be applicable to all utilities – both gas and electric. It also raises concerns that the term "standardized costs" is vague and ambiguous and that it is unsure how the construction allowance

[23] Black Hills RRR, p. 9.

calculation would change, if at all, compared to the current construction allowance calculation used by Black Hills.

53. In its RRR Application, Conservation Advocates continue to urge the Commission to explicitly eliminate gas line extension allowances through this proceeding. They argue that the version of Rule 4210 adopted by the Gas Rules Decision is ambiguous and risk prolonging the base rate proceedings in which updated line extension rules would be established. Conservation Advocates states that eliminating gas line extension allowances now would provide affordability benefits for existing gas customers, climate benefits for all Coloradans, and certainty to the builders and the gas workforce.

54. If the Commission declines to eliminate line extension allowances entirely, Conservation Advocates argue that in the alternative, the Commission should at minimum clarify the rule language to streamline future proceedings and ensure that gas utilities adopt uniform line extension policies. Conservation Advocates recommend that the Commission should clearly define the "full incremental cost of growth" and ensure that it explicitly includes the cost of greenhouse gas emissions attributable to a new connection using the social cost of carbon and social cost of methane. Conservation Advocates also argue that the Commission should remove the word "generally" from Rule 4210(e) which currently reads that "[l]ine extension policies . . . shall generally align with greenhouse gas emission reduction goals . . ."

55. Rule 4210(d) establishes that exemptions from updated line extension allowances and standardized costs shall not extend to applications for line extensions submitted after May 1, 2023. The Gas Rules Decision stated that the changes to Rule 4210 are not intended to result in the immediate elimination of construction allowances for line extensions or for the imposition of any barriers to the installation of gas service lines to any new structure. We also recognized the

need to allow for the phase in of changes in standardized costs and construction allowance values to avoid interfering with existing contractual agreements for new service and to preserve, within reason, the economics of existing developments that may be relying upon the existing policy. To that end, we established an exemption from updated policies for those customers or prospective customers with executed contractual arrangements for new line extensions prior to May 1, 2023. CNG seeks clarification as to whether a contract executed sometime after the exemption period ending May 1, 2023, but prior to the adjudication of either an application or base rate case addressing line extension policy, would still be subject to the utility's existing tariffed line extension policy. If the terms and conditions of the existing line extension policy would still apply after May 1, 2023, it is unclear to CNG what the purpose of ending the "grandfathering" is on that date. In CNG's view, the "grandfather" period should coincide with the effective date of the change to the policy pursuant to either the base rate proceeding or separate application, which must be implemented no later than December 31, 2024.

56. The Gas Rules Decision adopted the language that if a utility uses standardized costs to calculate a portion of its line extension policy, then, the utility must use 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." In its RRR Application, Atmos offers an adjustment to the standardized cost calculation to allow a utility to use cost data no older than the "most recent consecutive 12-month period for which compiled cost data is available at the time it initiates a base rate proceeding."[24]

57. Public Service raises two issues with Rule 4210 in its RRR Application. First, it seeks clarification that the rule requires utilities to make a filing that allows for the implementation

[24] Atmos RRR, p. 4.

of these rules by the end of 2024, but that the form of that filing is in the discretion of the utility. Second, Public Service raises concerns about potential disparity between utility gas line extension policies. It argues that such disparate treatment could cause competitive harm to customers and providers. Public Service proposes an addition to Rule 4210 that "will ensure consistency amongst line extension policies across utilities."[25]

### a. Findings and Conclusions

58. We reject the requests by both Black Hills and Conservation Advocates to reconsider the entirety of Rule 4210. The Commission finds the parties' arguments on RRR do not provide persuasive grounds to further adjust or refine this rule. We continue to find the final language adopted by the Gas Rule Decision strikes the right balance in how we approach this issue in terms of evaluating the costs and benefits of new customer growth. Conservation Advocate's argument to remove line extensions fully is based on the concept that clean heat targets can only be met by reducing throughput. We find that eliminating line extension policies at this juncture prejudges the outcome of the clean heat plan process; we do not yet know whether utilities may present a viable approach to statutory emission reduction requirements that supports continued expansion of the system.[26] We also do not see merit in ensuring consistency of line extension policies between electric and gas utilities, which is not currently the case either. As such, we decline to eliminate line extension allowances entirely at this time and reject Conservation Advocates' request. Although we reject Conservation Advocates' suggested edits, we recognize that the interaction between the state's greenhouse gas reduction policy and line extension allowances will remain important to consider and expect that utilities will present information

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[25] Public Service RRR, p. 17.

[26] Gas Rules Decision, ¶ 254.

identifying the environmental costs, including the social costs of emissions, associated with new gas customers, such that that information can be considered by the Commission. We also decline to reconsider Rule 4210 to implement uniform policies for gas and electric utilities as requested by Black Hills.

59. We also reject Public Service's request to add language ensuring the consistency amongst line extension policies across utilities. Utilities do not have consistent policies now, and differences between utilities, including in service territory areas, customer bases, and geographic characteristics may require the Commission to take unique approaches to line extension allowances and policies among utilities.

60. We confirm Public Service's understanding that the form of filing (whether by standalone advice letter or via full a full base rate case) is under the discretion of the utility in Rule 4210(c).

61. With respect to Black Hills' argument that the concept of standardized costs is vague and ambiguous, and that they are uncertain how that construction allowance calculation would change, if at all, the Commission notes that if a utility does not incorporate standardized costs of service lines to calculate its line extension allowances, it need not alter its calculation approach. However, if a utility does incorporate the standardized cost of service lines to calculate line extension allowances, then the Commission's decision in our final order was clear and with sufficient guidance. Accordingly, we reject Black Hills' suggestion to institute a specific rulemaking to address Rule 4210 so that a uniform policy can be developed.

62. With respect to Atmos' suggestion that the Commission should clarify the historical period by which standardized costs are calculated to the most recent consecutive 12 month period for which compiled data is available at the time it initiated a base rate proceeding, the Commission

agrees and adopts this clarification to our rules, but modifies it slightly so that it may be applicable to a base rate proceeding or a stand-alone proceeding to implement the line extension allowances, as either type of proceeding is available to utilities to implement the new line extension allowance policy.

63. With respect to CNG's request to clarify whether a contract executed after the exemption period ending May 1, 2023, but prior to the adjudication of line extension policy would still be subject to the utility's existing tariffed line extension policy, the Commission believes the policy, as implemented is appropriate. Line extension contracts signed after May 1, 2023, will be subject to the line extension allowance tariff in place when the work is completed.

### 4. Rule 4409: Restoration of Service

64. Atmos[27] and Public Service both request the Commission not adopt the changes to Rule 4409 (b), (c), and (d) that were presented in the attachments to the Gas Rules Decision. Both point out that these substantive changes were not deliberated upon or discussed throughout Proceeding No. 21R-0449G and as such should not be included in the adopted rules.

65. The Commission updated Rule 4409 by Decision No. C21-0765 in Proceeding No. 20R-0349EG, issued October 29, 2021. We grant this RRR request by Atmos and Public Service and ensure that the final Gas Rules reflect only those changes to Rule 4409 adopted by Decision No. C21-0765.

### 5. Rule 4527: Measurement and Accounting

66. *Weather Normalization*. The Gas Rules Decision declined to adopt a mechanism for weather normalization of the baseline a utility presents for greenhouse gas accounting

[27] Atmos RRR, p. 4.

purposes. Public Service notes that the lack of a weather normalized baseline makes the clean heat targets more stringent "in a material way."[28] Public Service requests that at the utility's discretion, it may provide a sensitivity analysis in the first clean heat plan that illustrates the emission reductions demonstration for portfolios under a weather-normalized baseline and target. Public Service requests that the Commission find the "discretionary sensitivity approach is permissible and clarify that it has discretion under the Rules to weather normalize the baseline and Clean Heat target in future proceedings if conditions warrant such action."[29]

67. In the Gas Rules Decision, we declined to adopt a mechanism for weather normalization of the baseline, which we found in line with the Division's methodology and SB 21-264. While a utility may submit sensitivity analyses that are in addition to the required materials, we decline to make a finding as requested by Public Service regarding weather normalization on RRR.

68. *Implementation of Advanced Leak Detection*. In the Gas Rules Decision, the Commission established through Rule 4527(a) that if a utility seeks to implement an advanced leak detection program, then it may petition the Commission for a one-time adjustment to its baseline for greenhouse gas emission calculations. Rule 4527(a)(I)(A) requires that the petition include the measured leakage data utilizes advanced leak detection technologies and approaches, as certified by the Division or the Commission. Public Service requests the Commission replace "certify" with "consistent with the directives from" the Division with respect to utility petitions to adjust its emission baseline after implementing advanced leak detection technologies.

[28] Public Service RRR, pp. 18-19
[29] *Id*.

69. We adopt this change as requested by Public Service and incorporate into Rule 4527(a) that petitions for adjustments to the emission baseline for implementation of advanced leak detection technologies should be consistent with directives, if any, from the Division.

### 6. Rule 4528: Social Cost of Carbon and Social Cost of Methane

70. *Net Present Value Calculations*. Rule 4528(b) and 4528(d) requires a utility to use a discount rate equal to the lesser of 2.5 percent or the discount rate established by the federal technical support document for net present value calculations of the social cost of carbon dioxide emission and social cost of methane emissions, respectively. Public Service requests an addition to include a new Rule 4528(e) that clarifies that, "[f]or 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."[30] Public Service asserts that this approach will allow for presentations using differentiated discount rates across cost streams and net present value calculations that use a single uniform discount rate, *i.e.*, the utility's weighted average cost of capital. We note that § 40-3.2-107(2)(c), C.R.S., requires the Commission to use a discount rate for future cost streams, other than the discount rate for cost of methane emissions, that considers the parties responsible for financing or paying for future costs and requires the Commission to give consideration to discounting those costs with a stable long-term inflation rate that, in the commission's judgment, accurately represents the net present value of future cash flows experienced by ratepayers. Presentation of additional information, including presenting the net present value calculations in numerous ways, including using the utility weighted average cost of capital as the discount mechanism, could aid the Commission in determining appropriate discount

[30] Public Service RRR, p. 19

rates for other cost streams. Utilities may opt to provide additional discount rate options to present to the Commission, even when not explicitly required by rule. We find it appropriate to adopt this change requested by Public Service.[31] We understand Public Service's additional language to only require utilities to file the net present value calculations in numerous ways, including using the utility weighted average cost of capital as the discount mechanism.

### 7. Rule 4550: Gas Infrastructure Plans, Overview and Purpose

71. Black Hills requests that the Commission remove the provision in Rule 4550 that specifies that the Gas Infrastructure Plan Rules apply to the examination of capital investment of jurisdictional utilities. Black Hills instead requests that the rule specify that it applies to "gas distribution" utilities.[32] It argues that the term jurisdictional gas utility is not used in § 40-3.2-108, C.R.S., and is not defined in the Commission's Gas Rules.

72. We agree with Black Hills and incorporate this change to Rule 4550.

### 8. Rule 4551: Definitions

73. *Utility Capital Spend.* The Gas Rules Decision established that threshold assessments for utility investment found in the CPCN, and Gas Infrastructure Plan Rules should be based on utility investment alone and exclude any investment by customers or other parties.[33] Atmos,[34] Black Hills,[35] and Public Service[36] each request that the Commission clarify in 4551(f) that the monetary thresholds for a "planned project" are based on utility capital investment. Each

[31] Commissioner Gilman dissents from this decision.
[32] Black Hills RRR, p. 10.
[33] Gas Rules Decision, ¶ 203.
[34] Atmos RRR, p. 5.
[35] Black Hills RRR, p. 11.
[36] Public Service RRR, p. 11.

point out that this is congruent with the CPCN thresholds in Rule 4102 and in line with the Commission's statements in the Gas Rules Decision. We find this change reasonable and adopt it in the attached.

74. *Specifying At-Risk Meters*. Black Hills and Public Service each suggest adding "at-risk" to the definition of "defined programmatic expense" in Rule 4551(b). Black Hills argues that as currently written, "relocation or replacement of meters" could also mean meters being replaced for reasons other than at-risk meters that were located at the property line and needed to be moved to the structure. Black Hills suggests that, as written, meters replaced for other reasons, including a Commission-approved Gas Meter Sampling Program, and that such an outcome would be an absurd result and result in an unintended consequence.[37]

75. The Commission notes that meters are replaced under numerous utility programs, and that such expense program may not be fully understood by the Commission or intervening parties. The Commission finds that specifying Defined Programmatic Expense to include "at-risk" meter replacement programs may inappropriately limit our oversight function. Accordingly, the Commission declines to include the phrase "at-risk" to describe the meter replacement programs subject to Commission oversight under Defined Programmatic Expenses.

### 9. Rule 4552: Filing Form and Schedule

76. *Initial Filings.* CEO proposes that the Commission modify the rules adopted by the Gas Rules Decision to consider new business for smaller, gas-only utilities in a fully-litigated proceeding prior to March 2028. CEO suggests that there are two paths to achieve this—either reduce the number of informational gas infrastructure plan filings in Rule 4552(c) or include new

[37] Black Hills RRR, p. 18; Public Service RRR, p. 11.

business considerations as a clean heat plan application requirement in Rule 4731(i). CEO requests this change because it is concerned that the Commission and stakeholders will not have the opportunity to examine utility customer and capacity additions to the gas system in a litigated proceeding for smaller utilities until March 2028.

77. In their RRR Application, Conservation Advocates request the Commission reconsider allowing Atmos, Black Hills, and CNG to file two less-than-fully adjudicated applications per Rule 4552(b). Conservation Advocates notes that this request came late in the proceeding, and as such, they and other participants were unable to comment on the proposal from Atmos. Further, Conservation Advocates suggests that Atmos' suggestion that smaller utilities can file two informational filings in contradiction with the joint comments filed earlier in the proceeding. Conservation Advocates are concerned that Atmos' request for two informational gas infrastructure plan filings is inadequately justified, unnecessary on its own terms, and contradictory to consensus comments that Atmos submitted previously with other parties. Conservation Advocates suggest that the Commission reconsider its decision to grant Atmos' request, and recommend modifying Rule 4552(c) to eliminate the carve-out that permits smaller utilities make two informational filings.

78. Public Service also requests the Commission add "informational" to Rule 4552(b) to specify that the non-litigated gas infrastructure plan filings are only for informational purposes. Public Service also requests that the phrase "to the extent practicable and applicable" be added to the filing requirements found in Rule 4552(b)(I). Public Service notes that May 1, 2023, is quickly approaching so flexibility in filing requirements would be helpful.

79. We deny each of these RRR requests to Rule 4552 regarding the non-adjudicated filings. We find that the process established by the Gas Rules Decision strikes a reasonable balance

by allowing two non-litigated filings prior to a litigated gas infrastructure plan for smaller utilities. While it is true that the Commission and stakeholders will not litigate new business investment for small gas-only utilities until 2028, the Commission will be reviewing these investments via the gas infrastructure plan filings, reviewing their progress to meet clean heat goals via fully-adjudicated clean heat plan filings, and overseeing additions to rate base through rate case proceedings in this interim period. Through the envisioned structure, the Commission can make findings that could include ordering reasonable adjustments to processes or information for upcoming filings, allowing improvements throughout these initial filings.

80. We see no need to specify that the filings are "informational" and anticipate issuing important guidance to utilities through our decisions approving gas infrastructure plans to guide future adjudicated filings. While we do not plan these initial filings to be fully adjudicated, there will likely be important roles for other stakeholders to play in their review, so a description of "informational" may not fully encompass the review and adjustments likely to be made as part of the process. Finally, while we are cognizant of Public Service's concerns regarding the timing of the first gas infrastructure plan filing, it is more appropriate for a utility to request a rule waiver if it finds it cannot include all the filing requirements in its first filing, rather than to address that through rule language.

81. *Filing Requirements*. Conservation Advocates also request the Commission establish a more defined process and role for intervenors in non-litigated proceedings. They point to the Commission's Rule regarding Generation and Transmission Associations in Rule 3605(a)(I) as a viable example for discovery procedures for informational gas infrastructure plan filings. Conservation Advocates recommend changes to Rule 4552(b)(II) that specifies that the Commission will set a calendar for written comments from parties to the proceeding and that

parties may conduct discovery on the filing and on any prefiled testimony submitted with the filing.[38]

82. We agree with Conservation Advocates that it is helpful to acknowledge through rule in a general manner, which can be supplemented in more detail through a decision in a gas infrastructure plan proceeding docket, that there will be some opportunity for discovery and written comments.

83. We also agree with Public Service that a miscellaneous proceeding (M-docket) opened by the Commission will be the best forum for the initial gas infrastructure plan filings.

84. *Cost Recovery*. Black Hills suggests the Commission should take this opportunity to allow concurrent recovery through a rider, especially for projects nearing construction for which total project cost estimates and associated annual revenue requirements have been provided.[39] Black Hills did not offer specific language to implement this.

85. We decline to adopt Black Hills' request on this matter. While a utility may always propose opportunities or new avenues for cost recovery, specific mechanisms for cost recovery for projects proposed through a gas infrastructure plan is beyond the scope of what was considered in this rulemaking.

### 10. Rule 4553: Contents of a Gas Infrastructure Plan

86. *System Mapping*. In CEO's RRR Application, it reiterates its request from earlier comment that the Commission should require utilities to present a system-wide map showing age and type of pipe in Rule 4553. CEO suggests the Commission incorporate this requirement

[38] Conservation Advocates RRR, p. 13.
[39] Black Hills RRR, p. 14.

because having this type of information available would help the Commission and stakeholders evaluate whether certain investments in future system planning are in the public interest. In the alternative, if the Commission continues to agree with utilities that they currently do not have information needed to produce system mapping, CEO asks the Commission to direct utilities to compile this information by a date certain—such as the date of a utility's first litigated gas infrastructure plan application.

87. CEO makes two main arguments regarding the importance of age and type of pipe information. First, it asserts that utilities likely already have this information because it is required by federal PHMSA standards. Second, it asserts that SB 21-108 requires the Commission to incorporate the most current federal regulations and that it allows the Commission to require mapping more stringent than federal standards. CEO also states that filings in other proceedings suggest that utilities may already have sufficiently sophisticated mapping systems to identify projects based on age or type of pipe.

88. The Commission recently issued a NOPR in 22R-0491GPS to implement SB21-108; this proceeding is before an administrative law judge. We do not have the record before us to implement mapping requirements to show age or type of pipe in this proceeding. CEO or others may consider providing relevant comments in the pipeline docket 22R-0491GPS, where the Commission is considering implementing similar requirements. Accordingly, we deny CEO's request at this juncture. However, the Commission expects that general and specific improvements in a utility's mapping capabilities, including the comprehension of pipeline material and age, due to separate GPS proceedings pursuant to 22R-0491GPS, or other efforts, should reasonably be incorporated into the utility's subsequent GIP filing in order to further the broad goals of the GIP process.

89. Black Hills requests that to alleviate the administrative burden, both Rule 4553(c)(I)(J) and Rule 4102(f)(X) should be modified to reflect that any maps provided by the utilities will be designated and treated as highly confidential without requiring utilities to incur the additional administrative burden and expense of preparing and filing a Motion for Extraordinary Protection for every filing.[40] We decline to make this determination by rule at this time that filing motions for extraordinary protection will be unnecessary. The Commission can rule on confidentiality efficiently within proceedings and with specific facts in front of it.

90. *Alternatives Analysis.* In their RRR Application, Conservation Advocates request that the Commission provide more specific criteria for the thresholds pertaining to projects that will require an alternatives analysis in litigated gas infrastructure plans. Conservation Advocates recommend the Commission adopt an unambiguous threshold for projects that require consideration of alternatives, instead of allowing the utility the discretion to only consider alternatives for limited number of projects. Conservation Advocates suggest modifications to Rule 4553(c)(I)(P) that would require a utility to conduct an alternatives analysis for all new business and capacity expansion projects that qualify as planned projects unless otherwise ordered by the Commission previously.

91. Public Service requests the opposite as Conservation Advocates: to limit the total number of alternatives analysis in fully adjudicated gas infrastructure plan proceedings based on the guidelines adopted for the informational filings (five projects for utilities over 500,000 customers, two projects for utilities between 50,000 and 500,000 customers, and one project for utilities less than 50,000 customers), unless otherwise ordered by the Commission. Public Service also suggests modifications to 4553(c)(I)(P) and 4553(c)(I)(Q) that would limit the alternatives

[40] Black Hills RRR, p. 14.

analysis in fully adjudicated gas infrastructure plan filings to capacity expansion projects. Public Service also proposes a new section 4553(c)(I)(Q) wherein the utility "shall report on alternatives evaluations with potential customers for any new business planned projects…" which has the effect of reporting on new business projects separately and outside the confines of the alternatives analyses.

92. The Commission rejects suggestions by both Conservation Advocates and Public Service to modify the number of alternatives analysis for fully-litigated gas infrastructure plan applications. The Commission deliberated on this issue thoroughly, and determined that the insights gained during the initial, non-adjudicated filings would provide valuable guidance for purposes of the fully-litigated applications. In essence, the Commission is taking a wait-and-learn approach to this issue, and nothing raised in the RRR applications persuades us to alter that approach.

93. *Stakeholder Participation.* The Commission established that utilities must collaborate with stakeholders prior to a gas infrastructure plan filing and hold one or more public workshops to educate and facilitate feedback from stakeholders prior to filing. Conservation Advocates suggest that the Commission clarify the requirements for public input prior to a gas infrastructure plan filing found in Rule 4553(a)(VII). They specifically suggest that the Commission require each utility to allow for written feedback for up to two weeks following each workshop and that a utility must summarize and respond to the feedback received at each workshop.[41] We agree with Conservation Advocates that requiring responses to stakeholder participation will make the process more meaningful and adopt Conservation Advocate's request in Rule 4552(d)(IV).

[41] Conservation Advocates RRR, p. 15.

94. Public Service requests limiting stakeholder participation in Rule 4553(a)(VII) to projects in the action period (it characterizes this as the first three years including the application year). Public Service contends that this approach would actually result in more manageable, targeted, and robust engagement for these projects.[42] We decline to limit stakeholder participation in the manner requested by Public Service. The record before us suggests that meaningful alternatives analysis typically occurs on a longer-term basis than a three-year period, and getting communities involved in planning at an early stage is imperative.

95. *Updates to Design Day Temperature.* Rule 4553(c)(IX) requires a utility to update the design day temperature assigned to unique segments of the utility system as part of its gas infrastructure plan filing. Public Service proposes to provide "the then-current" rather than "update" design day temperatures and adds "used for capacity planning."[43] Public Service argues that "this requirement does not align with the Company's practices (or determination of design day as noted earlier in this ARRR in the discussion regarding the proposed definition for "design day peak demand")".[44]

96. This section of the rules is designed to facilitate the Commission's comprehension of the conditions, and the development of those conditions, by which utilities plan their peak throughput requirements. Public Service suggests the gas infrastructure plan process should not be used to update those planning conditions, but only report on them. The Commission recognizes the data may not require updating. However, we reject Public Service's suggestion that the gas infrastructure plan would only require a reporting and not an update to the data or calculation

[42] Public Service RRR, p. 13.

[43] Public Services RRR, p. 13.

[44] *Id*.

approach, if necessary. Accordingly, we modify the rule language so that utilities are required to "provide and support the design day temperatures used for capacity planning."

97. *Planned Project Information.* Public Service requests several other changes to Rule 4553 related to planned project information that a utility must present in a gas infrastructure plan. First, Public Service requests that the Commission make two changes related to presentation of PHMSA regulations. We adopt and incorporate these changes in 4553(c)(1)(C) and 4553(c)(I)(K). Public Service also requests the Commission make minor changes to 4553(c)(I)(O) and 4553(c)(I)(R) which we incorporate in the attached.

98. *Existing Infrastructure Reporting.* Public Service requests the Commission add the phrase "if applicable and to the extent known" to Rule 4553(d) so that a utility is only required tor report to the extent it knows any information required in (I) and (II) related to customer-owned yard lines, hydrogen compatibility, and advanced leak detection, respectively. We decline to make this change which would make the overall existing infrastructure assessment reporting less meaningful.

### 11. Rule 4554: Interim Gas Infrastructure Plan Reporting

99. Public Service requests that interim filings under Rule 4554(a) should be due May 1 to align with regular filings which are also due on May 1.[45] We have incorporated this change in the attached Gas Rules.

### 12. Rule 4555: Approval of a Gas Infrastructure Plan

100. Public Service requests the Commission formalize language found in the Gas Rules Decision by also incorporating it in the Gas Rules. Specifically, Public Service requests that the

[45] Public Service RRR, pp. 15-16.

following statement from the Gas Rules Decision be added to Rule 4555: "The utility bears the ultimate responsibility to serve its customers reliably, and these rules should not interfere with or otherwise impede a utility's ability to meet that core obligation. Accordingly, if the utility needs to invest in infrastructure other than what is authorized through its approved gas infrastructure plan, it should do so and intend to fully justify the circumstances of such when it seeks cost recovery in a subsequent base rate proceeding."[46]

101. We do not find that adding this language to the Gas Rules is appropriate. The Commission's rules are intended to instruct the utilities how to comply with statute and Commission directives, and this language does not further that purpose. The statement in the Gas Rules Decision is for the purpose of context and explanation and not intended as rule language.

### 13. Rule 4726: Applicability

102. Rule 4726 establishes the applicability of the Clean Heat Plan Rules and specifies that they apply to all jurisdictional gas utilities. Black Hills requests that the Commission reconsider and strike Rule 4726(a) because SB 21-264 specifically references and defines "gas distribution utility," "municipal gas distribution utility," and "small gas distribution utility." However, the statute does not reference jurisdictional gas utilities. We find this change reasonable and therefore strike 4726(a) from the attached Gas Rules.

### 14. Rule 4727: Definitions

103. The Gas Rules Decision explained that implementing an informational period, action period, and total period approach furthers the goal of SB 21-264 that clean heat plans will aid the State of Colorado in achieving its greenhouse emission reduction goals by ensuring that

[46] Public Service RRR, p. 10.

each plan looks out at least to 2050. To that end, Rule 4527 includes a definition for each "clean heat plan action period," "clean heat plan informational period," and "clean heat plan total period."

104. Public Service requests that the Commission clarify that the Clean Heat Plan total period goes through 2050 unless 20 calendar years takes the plan filing past 2050 (in other words, for a 2031 Clean Heat Plan, the "total period" would go to 2051).

105. We confirm that Public Service's understanding is correct.

### 15. Rule 4730: Clean Heat Resources

106. In the Gas Rules Decision, the Commission adopted a modified version of CEO's proposal that allowed for utilities to count recovered methane credits generated since the last clean heat target year towards compliance with the next target, assuming the credit is only used once.[47] In its RRR, CEO states that "after further internal deliberations" it changed its position and no longer supports Rule 4730(a)(II)(D) which allows utilities to bank credits in years leading up to compliance years for use in demonstrating compliance with Clean Heat targets.[48] CEO states it was mistaken about the role of annual emission credits in mass-based targets because it contends that the statute requires emission reductions to occur in specific compliance years (*i.e.,* 2025 and 2030), so the utilities must demonstrate that they have reduced greenhouse gas emissions in those years. Despite concerns that this could reduce incentives to creation of a robust recovered methane market, CEO argues that following the purpose of the clean heat statute is of paramount importance in the Commission's rules.

[47] Gas Rules Decision, ¶ 309.
[48] CEO RRR, pp. 11-12.

107. Conservation Advocates request the same change as CEO and indicate they supports CEO's propose redline to rule 4730(a)(II)(D). Conservation Advocates assert that § 40-3.2-108(3)(b)(II), C.R.S. requires a clean heat plan to achieve the required level of emission reductions in the target year, which would prevent "banking" as allowed in the current rule. Conservation Advocates further supports this position by arguing that the interim year reporting requirements found in § 40-3.2-108(7)(b), C.R.S. do not contemplate credit banking, nor does the definition of "clean heat resource." Finally, Conservation Advocates argues that recovered methane credit banking would overcount actual emission reductions and weaken clean heat targets. Per Conservation Advocates' math, if a utility is allowed to bank credits, it effectively only needs one-fifth as many recovered methane credits to meet the recovered methane cap, and the total emission reduction would only be 18%, rather than 22%.[49]

108. The Commission originally adopted CEO's updated proposal in the Gas Rules Decision and with CEO's updated position expressed in its RRR filing, no participant in this Proceeding continues to support that approach. As such, we adopt CEO's proposal and reflect such in 4730(a)(II)(D) which now reads:

> 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.

109. We believe the legislature intended emission reductions to occur every year, not just in target years. Therefore, the Commission encourages utilities to provide suggestions to facilitate a stable, long-term market for recovered methane projects within their clean heat plan filings or elsewhere.

[49] Conservation Advocates RRR, pp. 16-19.

### 16. Rule 4731: Clean Heat Plan Application Requirements

110. *Forecasting*. Rule 4731(a) establishes the initial forecasts that a utility must present as part of a clean heat plan application. As we noted in the Gas Rules Decision, all long-term forecasting is presented in a utility's clean heat plan, but will also be utilized as part of a utility's gas infrastructure plan. Subparagraph (a)(I) requires a utility, for the low and high forecast, to 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. A utility must present 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.

111. In its RRR Application, Public Service requests several changes to Rule 4731(a)(I) which it contends makes the forecasting rule "manageable, actionable, and efficient."[50] First, it requests that the Commission modify the disaggregation rule for use in clean heat plans to have the disaggregation occur at a geographical segmentation level only, as opposed to using pressure districts or unique planning zones requiring a distinct design day. Public Service requests that the Commission require forecast disaggregation occur at a geographical segmentation level instead of using pressure districts. It states that while the concept of pressure district is applicable to localized gas capacity planning covered by the Gas Infrastructure Planning Rules, they are not applicable to the volumetric and sales forecasts required by clean heat plans. Public Service maintains that, rather than delineating forecasts by pressure, geographical segmentation for clean heat forecasts is more appropriate. Public Service argues this change will make the forecasting requirement more manageable for clean heat purposes. Second, Public Service requests that the factors accounted

[50] Public Service RRR, p. 21.

for in clean heat plan forecasting, listed in Rule 4731(a)(I)(E) be considered "in the aggregate."[51] Finally, Public Service requests that "gas supply" be added in Rule 4731(a)(I)(E), which provides that forecasts should include "other known factors affecting sales and capacity needs."[52] Public Service believes it is consistent with the thrust of the clean heat plan process, where clean heat plans focus on long-term system and supply issues and with the gas infrastructure plan process which focuses on shorter-term infrastructure needs. Public Service states that this clarification will ensure there is clarity about what type of "capacity needs" are potentially being considered in the context of forecasting.

112. As we stated in the Gas Rules Decision, continuity between forecasting performed for clean heat plans and gas infrastructure plans is important. Utilizing the same forecasts lessens some of the administrative burden of the filings and will create more consistent results from the respective processes. While we agree with Public Service that forecast disaggregation at the pressure district level is particularly important for gas infrastructure planning, we continue to believe it is also an appropriate level of geographic specificity for forecasting for clean heat plan purposes. Further, we find that the wording of Rule 4731(a)(I)(B) provides utilities enough flexibility already to implement forecasting at a specificity level that provides the Commission with the information needed to make decisions on clean heat plans and gas infrastructure plans while avoiding unnecessary specificity. With the exact timing and sequencing of proceedings also in flux, we find that the forecasting requirements are sufficiently flexible to develop and refine forecasting approaches through both the clean heat plan and gas infrastructure plan processes. We

[51] Public Service RRR, p. 22.
[52] Public Service RRR, p. 22.

therefore decline to make Public Service's requested change to remove pressure district from the forecasting requirements in Rule 4731.

113. We similarly decline to change in Rule 4731(a)(I)(E) that the factors listed should all be considered "in the aggregate" as requested by Public Service. To make such a change would remove needed specificity on a geographic basis for forecasted future changes. With respect to Public Service's suggestion to refer to forecast factors "in the aggregate," we find this modification appropriate for line extension policies. However, with respect to other factors required, the Commission rejects Public Service's suggestion. If a utility is to conduct an aggregation of such information, for example, local building codes, it must also comprehend the individual components in order to conduct such an aggregation. The Commission finds that the records in future CHP applications will benefit from the provision of the detailed information rather than an opaque aggregation that requires further investigation.

114. We agree with Public Service that specifying "gas supply" capacity needs are a reasonable clarification and reflect such in Rule 4731(a)(I)(E)(v). We also add the clarification requested in 4731(f) to ensure that green hydrogen projects proposed in coordination with the State of Colorado, to secure benefits under a federal law, are exempt from Rule 4731(f).

115. *Cost Recovery*. Rule 4731(g) implements § 40-3.2-108(6)(b), C.R.S., and allows a utility to propose a rate adjustment clause that provides for recovery of the utility's clean heat plan costs, or any costs prudently incurred to meet additional emission reduction requirements under § 25-7-105(1)(e)(X.7), C.R.S. Public Service seeks a minor revision to Rule 4731(g)(I) for purposes of consistency with § 40-3.2-108(6)(b), C.R.S., and adds that the Commission may approve a

utility's proposed rate adjustment clause "or structure."[53] We find this change reasonable and adopt it as reflected in the attached Gas Rules.

### 17. Rule 4734: Small Utility Clean Heat Plan

116. CNG requests the Commission clarify its expectations on the filing of a small utility clean heat plan pursuant to Rule 4734. CNG requests clarification that as a utility with less than 90,000 retail customers in Colorado, the filing of a clean heat plan under Rule 4734 or otherwise is not required but is at the option of the utility. Second, with regard to Rule 4734(a), CNG seeks clarification that if a small clean heat plan is filed, it may set a target for 2025 or 2030, but need not both, in the first plan.

117. Pursuant to § 40-3.2-108(4), C.R.S., clean heat plans must be submitted by all "gas distribution utilities" which is defined as those serving more than 90,000 customers. Pursuant to § 40-3.2-108(a), C.R.S. a "small gas distribution utility" may file a clean heat plan under the process for "gas distribution utilities" or it may file a clean heat plan pursuant to the small utility emission reduction plan section in § 40-3.2-109, C.R.S., which is implemented through Commission Rule 4734. A small gas distribution utility, such as CNG, does not need to file a clean heat plan pursuant to either Rule 4734 or otherwise. However, if a small gas distribution utility chooses to file a clean heat plan, it need not file a small gas distribution utility clean heat plan under Rule 4734 if it prefers to use the process in Rule 4730 for gas distribution utility clean heat plans instead. For plans filed under Rule 4734, it must propose a clean heat target for both 2025 and 2030 at once pursuant to the requirements in Rule 4734(a) and § 40-3.2-109(b)(I), C.R.S.

[53] Public Service RRR, p. 21.

### 18. Rule 4753: DSM Plan

118. Black Hills requests that a DSM plan for utilities that are allowed to combine DSM plans with DSM strategic issues applications pursuant to statute be allowed to cover a 4-year period. The Gas Rules Decision stated that no one opposed a change to a 2-year filing cadence (proposed by Public Service), but Black Hills states in its initial filings it suggested a 4-year DSM plan filing cadence.[54]

119. Black Hills asserts that modifying Rule 4753 to allow smaller utilities to file DSM Plan filings every four years aligns with the statutory carve out that the Commission may establish energy savings targets, expenditures, cost-recovery mechanisms, and bonus structures for utilities with fewer than two hundred fifty thousand customers in the same proceeding in which the DSM Plan is submitted for approval.[55]

120. We reject Black Hills' request to set a 4-year filing cadence for DSM plan filings in Rule 4753. We believe that a 2-year filing cadence, with DSM strategic issue filings every four years, reflects a reasonable approach. While the Commission may establish the energy savings targets, expenditures, cost-recovery mechanisms, and bonus structures for utilities in a DSM plan filing, doing so every four years with a typical DSM plan filing every two years will ensure that policy determinations from a strategic issues filing are implemented in a timely manner.

121. Public Service points out that the Gas Rules Decision misstated that cost-effectiveness will be measured at the DSM program level, while Rule 4753(o)(IV) says it will be measured at the portfolio level.[56] We affirm that the decision reached by the Commission is that

[54] Black Hills RRR, p. 17.
[55] § 40-3.2-103(2.5), C.R.S.
[56] Public Service RRR, p. 25.

cost-effectiveness will be measured at the portfolio level. To the extent that the Gas Rules Decision misstated this, we grant Public Service's RRR request.

122. Rule 4753(h)(IX) requires utilities to provide, as part of its DSM plan, "a narrative discussion showing that the DSM measures and programs, particularly in new construction, do not discourage otherwise economic beneficial electrification." Public Service argues that this essentially creates a burden for all DSM programs to overcome, when DSM programs should be evaluated on their respective metrics understanding they are an important contributor, and one of the tools that can be deployed now, to reduce emissions on LDC systems.[57] Black Hills argues similarly that as a gas-only utility, it does not offer beneficial electrification and cannot provide electric service to customers. It reiterates its duty to serve and requests the Commission add "if applicable" to 4753(h)(IX).[58]

123. We continue to find that an analysis showing that DSM measures and programs are not discouraging economic beneficial electrification in new construction is an important analysis and consideration when approving DSM plans. We decline to remove this provision from the Gas Rules.

### 19. Rule 4754: Annual DSM Report

124. The Gas Rules Decision adopted a proposal by the City and County of Denver to require reporting of DSM program participation levels by the census block or zip code. Public Service requests the Commission eliminate the option to report by zip code when restrictions apply at the census block group. Public Service requests the zip code option be eliminated because it

[57] Public Service RRR, p. 27.
[58] Black Hills RRR, p. 18.

believes the use of census block groups is more appropriate than zip codes.[59] Black Hills suggests eliminating the concept entirely. It contends that this requirement would be burdensome for utilities and likely result in erroneous data given the lack of required detail in census block data.[60]

125. We reject both Public Service's and Black Hills' requests on this issue. Rule 4754(a) already reflects that reporting on a zip code basis is only one option and not required, so keeping it retains flexibility in rule. Further, we note that reporting by census block was a proposal put forth by the City and County of Denver, who proposed this reporting would support municipal efforts and help ensure funds are being equitably distributed, which are helpful goals.

### 20. Rule 4756: General Provisions Concerning Cost Allocation and Recovery

126. Rule 4756(d) implements § 40-3.2-103(5)(b), C.R.S. in the Gas Rules. Public Service requests two changes to the decoupling provision found in Rule 4756(d) which it asserts are required to align the rule provision more closely with the statutory provision. First, it recommends removing "or other appropriate decoupling metric" because it states the statute specifically cites "revenue per customer" as the relevant metric. Second, it requests the Commission add the phrase "nor shall the Commission reduce a gas utility's return on equity based solely on approval of a revenue decoupling mechanism" to Rule 4756(d)(II) because § 40-3.2-103(5)(b)(III), C.R.S., contains this prohibition.[61] We find it appropriate to implement Public Service's first request and therefore eliminate "or other appropriate decoupling metric" from the attached Rule 4756(d). However, while Public Service is correct that § 40-3.2-103(5)(b)(III), C.R.S., contains the prohibition that the Commission shall not reduce a gas

[59] Public Service RRR, p. 22.
[60] Black Hills RRR, p. 19.
[61] Public Service RRR, pp. 23-24.

utility's return on equity based solely on approval of a revenue decoupling mechanism, this is an unnecessary addition to the Gas Rules which regulate gas utilities and not the Commission.

### 21. Rule 4760: Gas DSM Bonus (G-DSM Bonus)

127. Rule 4760(i) provides that "[a]ny 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." Public Service argues this rule implicates the same issues as 4753(h)(IX), and in practice may encourage less efficient construction by creating a counterfactual that lacks consistency with the one considered by developers and builders. Public Service requests both provisions be removed from the Gas Rules.

128. We decline to remove this provision from the Gas Rules. It is important for the Commission to have information available to consider impacts of gas DSM programs on overall gas usage. This requirement simply requires utilities to provide relevant information, does not require the utility to make an evidentiary showing, and as such does not prevent a utility from receiving a bonus as a result of the outcome of the narrative discussion.

### 22. Rule 4761: Filing of DSM Strategic Issues Applications

129. CNG seeks clarification from the Commission as to the expectations with respect to timing of the Company's DSM plan. In its RRR Application, CNG states that while it intends to file a strategic issues application by the end of 2022,[62] it will not be able to include the requirements of Rule 4761 in its filing. CNG prefers to file its new DSM Plan and a supplement to its Strategic Issues that includes the details required by rule 4761(b) on July 1, 2022. If the

[62] Proceeding No. 22A-0577G

Commission finds this approach acceptable, CNG seeks clarification as to whether another request for an extension is needed, or whether the need for the extension is superseded by the rule permitting the Plan to be filed on July 1.

130. Black Hills encourages the Commission to allow some flexibility with respect to the DSM filings that they characterized as likely to be rushed to be completed and filed no later than December 31, 2022. Black Hills is intending to file a strategic issues proceeding in April 2023 along with its next DSM plan. It states that it is illogical to require Black Hills to file a stand-alone strategic issues filing only a few months before its next regularly scheduled DSM plan filing.[63]

131. Black Hills, CNG, and Atmos each filed on December 30, 2022, their respective DSM strategic issues applications.[64] The timing and status of those applications is unclear, as is the timing that the final Gas Rules will go into effect. If a rule waiver is necessary, it is premature to discuss at this juncture, and the more appropriate forum would likely be within the utility's respective strategic issue proceedings. Similarly, requests by the utility for more time or for direction on filing deadlines are more appropriately handled outside the rulemaking proceeding.

[63] Black Hills RRR, p. 20.

[64] Proceeding No. 22A-0580G, 22A-0577G, 22A-0579G, respectively.

## II. ORDER

### A. It is Ordered That:

1. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Black Hills Colorado Gas, Inc., is granted in part and denied in part, consistent with the discussion above.

2. The application for rehearing, reargument, or reconsideration of Decision No. C22-760 filed on December 21, 2022, by Natural Resources Defense Council, Western Resource Advocates, and Southwest Energy Efficiency Project, jointly the "Conservation Advocates," is granted in part and denied in part, consistent with the discussion above.

3. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by the Colorado Energy Office, is granted in part and denied in part, consistent with the discussion above.

4. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Colorado Natural Gas, Inc., is granted in part and denied in part, consistent with the discussion above.

5. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by the Atmos Energy Corporation, is granted in part and denied in part, consistent with the discussion above.

6. The application for rehearing, reargument, or reconsideration of Decision No. C22-0760 filed on December 21, 2022, by Public Service Company of Colorado, is granted in part and denied in part, consistent with the discussion above.

7. Amendments to the Commission's Rules Regulating Gas Utilities, 4 Code of Colorado Regulations (CCR) CCR 723-4, contained in legislative (i.e., strikeout/underline) format as Attachments and final format as Attachments B are adopted, and are available through the Commission's Electronic Filings system at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=21R-0449G

8. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding the constitutionality and legality of the rules as finally adopted. A copy of the final, adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in The Colorado Register by the Office of the Secretary of State

9. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

10. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING February 1, 2023.**

(S E A L)

ATTEST: A TRUE COPY

G. Harris Adams,
Interim Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

Commissioners

COMMISSIONER JOHN GAVAN'S
TERM EXPIRED FEBRUARY 3, 2023.

# 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 ~~rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing~~ the manner of regulation over jurisdictional gas utilities, ~~master meter operators, and~~ 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) ~~and/~~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~~d~~) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).

(g~~e~~) "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~~f~~) "Commission" means the Colorado Public Utilities Commission.

(k~~g~~) "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~~h~~) "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~~i~~) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.

(n~~j~~) "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~~k~~) "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~~l~~) "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~~m~~) "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~~n~~) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

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

(y~~q~~) "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~~r~~) "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~~s~~) "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 ~~and/~~or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.

(bb~~t~~) "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~~u~~) "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~~v~~) "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~~w~~) "Mcf" means 1,000 standard cubic feet.

(gg~~x~~) "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.

(~~y~~jj) "Non-standard customer data" means all customer data that are not standard customer data.

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

(mm~~bb~~) "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~~n~~ 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.

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

(ss~~ee~~) "Sales customer" or "full service customer" means a customer~~person~~ who receives sales service from a utility and is not served under a utility's gas transportation service ~~rate schedules~~at that same meter.

(tt~~ff~~) "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~~gg~~) "Security" includes any stock, bond, note, or other evidence of indebtedness.

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

(ww~~ii~~) "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~~jj~~) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.

(yy~~kk~~) "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~~ll~~) "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~~mm~~) "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~~nn~~) "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~~oo~~) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.

(ddd~~pp~~) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.

(eee~~qq~~) "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.

~~(rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.~~

(fff~~ss~~) "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~~tt~~) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(hhh~~uu~~) "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~~II~~) appeal of a local government land use decision, as provided in rule 4703; or

(XVII~~IV~~) 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 ~~three~~ 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~~IV~~) records concerning demand side management, pursuant to rules 4750 through 4761~~0~~; 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. ~~If the utility maintains a website, it shall also maintain its c~~Current and complete tariffs shall also be available on a utility's~~on its~~ 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 ~~pursuant to~~in accordance with this rule. ~~The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business.~~ 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~~b~~) 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 ~~paragraphs~~ rule 4002~~(b) and 4002(c)~~;

(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) a description of the proposed facilities to be constructed;~~

~~(IV) estimated cost of the proposed facilities to be constructed;~~

~~(VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and~~

(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~~II~~) 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, ~~as applicable, information on alternatives studied,~~ 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 ~~natural gas energy~~ or receiving ~~natural~~ gas ~~energy~~ 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 ~~insure~~ 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 ~~insure~~ 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 ~~and/~~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~~e~~, 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 ~~low-income~~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 ~~municipally~~ 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 ~~natural~~ gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which ~~natural~~ 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 ~~natural~~ 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 ~~natural~~ 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 ~~s~~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 ~~natural~~ 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 ~~natural~~ gas consumption in PIPP participants' homes;

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

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[indicates omission of unaffected rules]

**4506. – 452~~499~~. [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~~4506~~. – 4599. [Reserved].**

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[indicates omission of unaffected rules]

**4708. – 4724~~4749~~. [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 ~~that~~ was retired in ~~prior to~~ 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~~08~~. – 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~~5~~, 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 ~~natural~~ 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 ~~natural gas utilities~~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~~b~~) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.

(d~~c~~) 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~~0~~, 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, ~~natural~~ 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; ~~measures, information~~ and services offered to customers to reduce ~~natural~~ 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.~~ In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility’s avoided production, distribution and energy costs; the participant’s avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. 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.~~

(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.

~~(q) “Sales customer” or “full service customer” means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility’s gas transportation service rate schedules.~~

**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)~~ file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year~~.

(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.~~ Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.~~

(e) By ~~May~~ July 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective ~~natural~~ 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. ~~Periodic~~ DSM Plan ~~Filing~~.**

Each utility shall ~~periodically~~ file, in accordance with paragraph 4752(e), a prospective ~~natural~~ gas DSM plan that covers a DSM period of ~~three~~ 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~~; the sum of these expenditures represents the utility's proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.~~;

(b) the utility's estimated ~~natural~~ 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~~d~~) 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~~e~~) 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~~f~~) 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);~~and~~

(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~~g~~) In its DSM plan, the utility shall address how it proposes to ~~target~~ prioritize DSM services and programs for income-qualified ~~to low-income~~ customers and customers in disproportionately impacted communities. ~~The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S.~~

(I) The utility may propose one or more ~~low-income~~ 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~~h~~) In proposing an expenditure target for Commission approval, ~~pursuant to § 40-3.2-103 (2)(a), C.R.S.,~~ 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~~, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater~~; and

~~(II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and~~

(II~~I~~) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to ~~natural~~ 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~~i~~) 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~~j~~) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.

(m~~k~~) 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~~l~~) 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~~m~~) 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 ~~non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows~~.

(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 ~~avoided emissions and other~~ societal benefits, shall be multiplied by a factor established by the Commission in the utility's strategic issues proceeding ~~1.05~~ to reflect the value of the ~~avoided emissions and other~~ societal and non-energy benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for ~~avoided emissions and~~ 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~~n~~) 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 ~~c~~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 ~~and Application for Bonus and Bonus Calculation~~.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report ~~and application for bonus~~.

(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~~participation levels and cost-effectiveness~~.

(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.

~~(f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.~~

~~(g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.~~

~~(I) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:~~

~~(A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;~~

~~(B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;~~

~~(C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;~~

~~(D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(I); and~~

~~(E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.~~

~~(II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(I), in order to earn a bonus.~~

~~(III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:~~

~~(A) The <u>Energy Factor</u> is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.~~

~~(B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.~~

~~(IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per $1 million expended, and the utility's actual savings is 18,000 dekatherms per $1 million.~~

~~The energy factor would be: 50 percent x (106 – 80), or 13 percent~~

~~The savings factor would be: 18,000/15,000 or 1.2~~

~~The resulting bonus percentage would be: 13 percent x 1.2, or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.~~

~~(h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:~~

~~(I) the costs and benefits associated with a low-income 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 low-income program is below 1.0; and~~

~~(II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.~~

~~(i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.~~

~~(j) 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.~~

**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) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.~~

(b~~c~~) 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~~d~~) 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 ~~the gas DSMCA~~ 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 p~~P~~rovisions.

(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 p~~P~~rovisions. 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) ~~Applications~~.**

(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 ~~application submitted~~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~~a~~) ~~G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754.~~ 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~~b~~) ~~Contents of G-DSM bonus filing.~~ 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) ~~gas~~ 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; ~~and~~

(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.

~~(c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.~~

(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~~d~~) ~~Accounting for G-DSM bonus.~~ 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~~e~~) ~~Prudence review and adjustment of G-DSM bonus.~~ 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~~1~~. – 4799. [Reserved].**

# 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].**

Decision No. C23-0117-E

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 21R-0449G

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IN THE MATTER OF THE PROPOSED AMENDMENTS TO THE COMMISSION'S RULES REGULATING GAS UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-4, RELATING TO GAS UTILITY PLANNING AND IMPLEMENTING SB 21-264 REGARDING CLEAN HEAT PLANS AND HB 21-1238 REGARDING DEMAND SIDE MANAGEMENT.

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**ERRATA NOTICE**

**COMMISSION DECISION ADDRESSING APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION**

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Errata Notice mailed: March 15, 2023
Original Decision No. C23-0117 mailed: February 24, 2023

1. Correct Section 4102(f)(X) on page 11 of the adopted rules attached as Attachment A to Decision No. C23-0117 by removing the words "that shows" so that Section 4102(f)(X) reads (in redline) as follows:

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

2. Correct Section 4102(h) on page 13 of the adopted rules attached as Attachment A to Decision No. C23-0117 by referring to Section 4102, not 4210 so that Section 4102(h) reads (in redline) as follows:

(h) In accordance with subparagraph 4552(d)(II), the utility may satisfy the requirements of rule 4102 in an application submitted pursuant to the Gas Infrastructure Planning Rules.

3. Correct Section 4550 on page 20 of the adopted rules attached as Attachment A to Decision No. C23-0117 by referring to gas distribution utilities, not jurisdictional utilities, so that Section 4550 reads (in redline) as follows:

> These rules foster the examination of capital investment of gas distribution 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.

4. The corrected rules are attached to this Errata Notice. Attachment A is the legislative (*i.e.,* strikeout/underline) formatted rules and Attachment B is the final formatted rules.

(S E A L)

STATE OF COLORADO ★ THE PUBLIC UTILITIES COMMISSION ★ NIL SINE NUMINE

ATTEST: A TRUE COPY

G. Harris Adams,
Interim Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

G. HARRIS ADAMS

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Interim Director

# 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 ~~rules describing the service to be provided by jurisdictional gas utilities and master meter operators to their customers and describing~~ the manner of regulation over jurisdictional gas utilities, ~~master meter operators, and~~ 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) ~~and/~~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~~d~~) "Basis Point" means one-hundredth of a percentage point (100 basis points = 1 percent).

(g~~e~~) "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~~f~~) "Commission" means the Colorado Public Utilities Commission.

(k~~g~~) "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~~h~~) "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~~i~~) "Curtailment" means the inability of a transportation customer or a sales customer to receive gas due to a shortage of gas supply.

(n~~j~~) "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~~k~~) "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~~l~~) "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~~m~~) "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~~n~~) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

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

(y~~q~~) "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~~r~~) "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~~s~~) "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 ~~and/~~or its end-use customers, as authorized under its effective Colorado jurisdictional tariffs.

(bb~~t~~) "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~~u~~) "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~~v~~) "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~~w~~) "Mcf" means 1,000 standard cubic feet.

(gg~~x~~) "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.

(~~y~~jj) "Non-standard customer data" means all customer data that are not standard customer data.

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

(mm~~bb~~) "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~~n~~ 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.

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

(ss~~ee~~) "Sales customer" or "full service customer" means a customer~~person~~ who receives sales service from a utility and is not served under a utility's gas transportation service ~~rate schedules~~at that same meter.

(tt~~ff~~) "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~~gg~~) "Security" includes any stock, bond, note, or other evidence of indebtedness.

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

(ww~~ii~~) "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~~jj~~) "Standard customer data" means customer data maintained by a utility in its systems in the ordinary course of business.

(yy~~kk~~) "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~~ll~~) "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~~mm~~) "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~~nn~~) "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~~oo~~) "Transportation customer" means a person who, by signing a gas transportation agreement, elects to subscribe to gas transportation service offered by a utility.

(ddd~~pp~~) "Unique identifier" means customer's name, mailing address, telephone number, or email address that is displayed on a bill.

(eee~~qq~~) "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.

~~(rr) "Upstream pipeline" means either a natural gas pipeline or a LDC that provides gas to a LDC.~~

(fff~~ss~~) "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~~tt~~) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(hhh~~uu~~) "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~~II~~) appeal of a local government land use decision, as provided in rule 4703; or

(X~~IV~~VII) 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 ~~three~~ 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~~IV~~) records concerning demand side management, pursuant to rules 4750 through 4761~~0~~; 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. ~~If the utility maintains a website, it shall also maintain its c~~Current and complete tariffs shall also be available on a utility's~~on its~~ 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 ~~pursuant to~~in accordance with this rule. ~~The utility need not apply to the Commission for approval of construction and operation of a facility or an extension of a facility which is in the ordinary course of business.~~ 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~~b~~) 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 ~~paragraphs~~ rule 4002~~(b) and 4002(c)~~;

(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) a description of the proposed facilities to be constructed;~~

~~(IV) estimated cost of the proposed facilities to be constructed;~~

~~(VI) a map showing the general area or actual locations where facilities will be constructed, population centers, major highways, and county and state boundaries; and~~

(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 (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~~II~~) 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, ~~as applicable, information on alternatives studied,~~ 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 4102 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 ~~natural gas energy~~ or receiving ~~natural~~ gas ~~energy~~ 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 ~~insure~~ 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 ~~insure~~ 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 ~~and/~~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 certificationz~~e~~, 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 ~~low-income~~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 ~~municipally~~ 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 ~~natural~~ gas bills rendered to participants shall not exceed an affordable percentage of income payment. For accounts for which ~~natural~~ 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 ~~natural~~ 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 ~~natural~~ 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 ~~s~~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 ~~natural~~ 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 ~~natural~~ gas consumption in PIPP participants' homes;

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

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[indicates omission of unaffected rules]

**4506. – 452~~499~~. [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 gas distribution 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~~4506~~. – 4599. [Reserved].**

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[indicates omission of unaffected rules]

**4708. – 4724~~4749~~. [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 ~~that~~ was retired in ~~prior to~~ 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~~08~~. – 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~~5~~, 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 ~~natural~~ 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 ~~natural gas utilities~~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~~b~~) Each utility shall annually file an advice letter or application for cost recovery, as permitted herein.

(d~~c~~) 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~~0~~, 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, ~~natural~~ 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; ~~measures, information~~ and services offered to customers to reduce ~~natural~~ 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.~~ In performing the modified TRC test, the benefits shall include, but are not limited to, as applicable: the utility's avoided production, distribution and energy costs; the participant's avoided operating and maintenance costs; the valuation of avoided emissions; and non-energy benefits as set forth in rule 4753. 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.~~

(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.

~~(q) "Sales customer" or "full service customer" means a residential or commercial customer that purchases a bundled natural gas supply and delivery service from a utility but does not include customers served under a utility's gas transportation service rate schedules.~~

**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)~~ file an application pursuant to rule 4760 requesting approval of such bonus on or before April 1 of each year~~.

(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.~~ Alternatively, each utility may file a combined application on or before April 1 of each year seeking a G-DSM bonus, as well as an adjustment to the G-DSMCA, to be effective July 1 for a period of 12 months.~~

(e) By ~~May~~ July 1 of the final year of the currently effective DSM plan, each utility shall file by application a prospective ~~natural~~ 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. ~~Periodic~~ DSM Plan ~~Filing~~.**

Each utility shall ~~periodically~~ file, in accordance with paragraph 4752(e), a prospective ~~natural~~ gas DSM plan that covers a DSM period of ~~three~~ 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~~; the sum of these expenditures represents the utility's proposed expenditure target as required by § 40-3.2-103(2)(a), C.R.S.~~;

(b) the utility's estimated ~~natural~~ 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~~d~~) 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~~e~~) 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~~f~~) 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);~~and~~

(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~~g~~) In its DSM plan, the utility shall address how it proposes to ~~target~~ prioritize DSM services and programs for income-qualified ~~to low-income~~ customers and customers in disproportionately impacted communities. ~~The utility shall also address whether it proposes to provide DSM services directly or indirectly through financial support of conservation programs for low-income households administered by the State of Colorado, as authorized by § 40-3.2-103(3)(a), C.R.S.~~

(I) The utility may propose one or more ~~low-income~~ 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~~h~~) In proposing an expenditure target for Commission approval, ~~pursuant to § 40-3.2-103 (2)(a), C.R.S.,~~ 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~~, at a minimum, two percent of a natural gas utility's base rate revenues, (exclusive of commodity costs), from its sales customers in the 12-month calendar period prior to setting the targets, or one-half of one percent of total revenues from its sales customers in the 12-month calendar period prior to setting the targets, whichever is greater~~; and

~~(II) the utility may propose an expenditure target in excess of two percent of base rate revenues; and~~

(II~~I~~) funds spent for education programs, market transformation programs and impact and process evaluations and program planning related to ~~natural~~ 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~~i~~) 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~~j~~) The budget shall explain anticipated increases/decreases in financial resources and human resources from year to year.

(m~~k~~) 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~~l~~) 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~~m~~) 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 ~~non-energy benefits of avoided emissions and societal impacts shall be incorporated as follows~~.

(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 ~~avoided emissions and other~~ societal benefits, shall be multiplied by a factor established by the Commission in the utility's strategic issues proceeding ~~1.05~~ to reflect the value of the ~~avoided emissions and other~~ societal and non-energy benefits. The result shall be the modified TRC. A utility may propose for approval a different factor for ~~avoided emissions and~~ 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~~n~~) 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 ~~c~~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 ~~and Application for Bonus and Bonus Calculation~~.**

On the schedule set forth in rule 4752, the utility shall provide the Commission a detailed DSM report ~~and application for bonus~~.

(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~~participation levels and cost-effectiveness~~.

(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.

~~(f) The utility may file an application for bonus, pursuant to rule 4760. The application for bonus shall include the utility's calculation of estimated bonus applying the methodology set forth in this rule to the utility's actual performance.~~

~~(g) The Commission shall determine the level of bonus, if any, that the utility is eligible to collect on the basis of the information included in the report, pursuant to the bonus criteria and process set forth, below.~~

~~(I) The primary objective of the bonus is to encourage cost-effective energy savings. The amount of bonus earned, if any, will correlate with the utility's performance relative to the approved savings target (dekatherms saved per dollar expended) and the energy target. Assuming all other factors that affect consumption remain unchanged, effective DSM programs will reduce per customer commodity consumption, which may lead to revenue reductions for the utility. The utility may include in the bonus application a request for approval to recover a calculated amount of revenue that acknowledges the DSM program reduced the utility's revenue. The recovery amount for reduced revenue is separate from any bonus determined by the Commission and shall be calculated, as follows:~~

~~(A) the utility shall calculate a dollar per therm value that represents the utility's annualized fixed costs that are recovered through commodity sales on a per therm basis;~~

~~(B) the utility shall include in the DSM filing pursuant to rule 4753 a proposed dollar per therm value with the calculation methodology and supporting documentation;~~

~~(C) the recovery amount for reduced revenue shall be calculated by multiplying the dollar per therm value by the annualized number of therms saved and reported in the utility's annual DSM report for the plan year;~~

~~(D) the recovery of the reduced revenue amount shall be through the Demand-Side Management Cost Adjustment (DSMCA), over the same twelve month period in which any approved bonus amount is recovered, as set forth in subparagraph 4752 (b)(I); and~~

~~(E) for the purpose of inclusion in the above calculation, the annual report shall include the number of therms projected to be saved from the DSM programs in the twelve months following the end of the program year.~~

~~(II) As a threshold matter, the utility must expend at least the minimum amount set forth in subparagraph 4753 (h)(I), in order to earn a bonus.~~

~~(III) The bonus amount is a percentage of the net economic benefits resulting from the DSM plan over the period under review. The percentage value is the product of the two factors:~~

~~(A) The Energy Factor is determined by the percentage of the energy target achieved by the utility. The energy factor is zero plus 0.5 percent for each one percent above 80 percent of the energy target achieved by the utility.~~

~~(B) The Savings Factor is the actual savings achieved divided by the approved savings target. The actual savings achieved and approved savings target are each expressed in dekatherms saved per dollar expended.~~

~~(IV) The following is provided as an example of the bonus calculation, using these illustrative numbers: utility achieves 106 percent of its energy target; the utility's savings target is 15,000 dekatherms per $1 million expended, and the utility's actual savings is 18,000 dekatherms per $1 million.~~

~~The energy factor would be: 50 percent x (106 – 80), or 13 percent~~

~~The savings factor would be: 18,000/15,000 or 1.2~~

~~The resulting bonus percentage would be: 13 percent x 1.2, or 15.6 percent. Thus, 15.6 percent of net economic benefits would be the bonus amount.~~

~~(h) For the purposes of calculating the bonus, the costs and benefits associated with DSM programs targeted to low-income customers may be excluded as follows:~~

~~(I) the costs and benefits associated with a low-income 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 low-income program is below 1.0; and~~

~~(II) the expenditures and therms saved associated with a low-income DSM program may be excluded from the calculation of the Savings Factor if the therms saved per dollar expended for the low-income program is below the approved savings target for the overall DSM portfolio.~~

~~(i) The maximum bonus is 20 percent of net economic benefits or 25 percent of expenditures, whichever is less.~~

~~(j) 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.~~

**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) Fuel switching. Fuel switching from natural gas to other fossil fuel derived energy sources shall not be included in the gas utility's DSM program. Programs to save natural gas through switching to renewable energy sources such as solar heating and ground source heat pumps are allowed.~~

(b~~c~~) 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~~d~~) 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 ~~the gas DSMCA~~ 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 p~~P~~rovisions.

(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 p~~P~~rovisions. 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) ~~Applications~~.**

(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 ~~application submitted~~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~~a~~) ~~G-DSM bonus filing requirements. The utility shall file its G-DSM bonus application as part of the annual report submitted to the Commission on the timetable set forth in rule 4752. The utility may request a G-DSM bonus not to exceed the lower of 25 percent of the expenditures or 20 percent of the net economic benefits of the DSM programs, applying the bonus calculation procedure set forth in rule 4754.~~ 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~~b~~) ~~Contents of G-DSM bonus filing.~~ 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) ~~gas~~ 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; ~~and~~

(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.

~~(c) The Commission shall issue a decision approving, modifying, or disapproving a DSM bonus application within 90 days of the utility filing of the application. The Commission shall allow oral testimony and shortened discovery response times as necessary to expedite the schedule.~~

(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~~d~~) ~~Accounting for G-DSM bonus.~~ 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~~e~~) ~~Prudence review and adjustment of G-DSM bonus.~~ 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~~1~~. – 4799. [Reserved].**

# 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 (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 4102 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 gas distribution 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].**