Decision No. C24-0708-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24M-0261G

IN THE MATTER OF THE COMMISSION'S EXAMINATION OF GAS SYSTEM FORECASTING, MAPPING, AND COST BENEFIT ANALYSIS IN ACCORDANCE WITH DECISION NO. C24-0092 ADDRESSING THE INAUGURAL GAS INFRASTRUCTURE PLAN OF PUBLIC SERVICE COMPANY OF COLORADO.

INTERIM DECISION OF HEARING COMMISSIONER ORDERING THE FILING OF CERTAIN RESPONSIVE INFORMATION BY PUBLIC SERVICE COMPANY OF COLORADO

Issued Date: October 1, 2024

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I. BY THE COMMISSION

A. Statement

1. By Decision No. C24-0376, the Commission opened this Proceeding to examine Public Service Company of Colorado's ("Public Service" or the "Company") gas system forecasting, mapping, and cost benefit analysis in accordance with Decision C24-0092 issued on

February 23, 2024, in Proceeding No. 23M-0234G (the "GIP Decision"). The Commission designated Commissioner Megan M. Gilman as Hearing Commissioner pursuant to § 40-6-101(2), C.R.S.

2. This Decision sets requires Public Service to file certain information related to its upcoming GIP filing discussed below no later than October 23, 2024. Any stakeholder comments responsive to the Company's filing shall be filed no later than November 13, 2024.

B. Discussion, Findings, and Conclusions

3. By Decision No. C24-0376 issued on June 4, 2024, the Commission opened this Proceeding to examine Public Service Company of Colorado's ("Public Service" or the "Company") gas system load forecasting, mapping, and non-pipeline alternative cost benefit analysis ("CBA"). The three topics were identified in Decision C24-0092 issued on February 23, 2024, in Proceeding No. 23M-0234G ("GIP Decision") as areas in which the Commission wanted to see progress prior to the filing of the Company's next Gas Infrastructure Plan ("GIP"). The Commission designated Commissioner Megan M. Gilman as Hearing Commissioner pursuant to § 40-6-101(2), C.R.S.

4. Recommended Decision No. 24-0480-I explains the purpose of this Proceeding is to identify, develop, and express the Commission's expectations regarding certain substantive areas which the Commission identified as needing further development in the Public Service's most recent Gas Infrastructure Plan proceeding ("GIP"). This Miscellaneous docket ("M-docket") is intended as a venue to follow up on this and other issues in order to make interim progress prior to the filing of the Company's next GIP.

5. Pursuant to Rule 4552 of the Commission's Rules Regulating Gas Utilities, 4 *Code of Colorado Regulations* ("CCR") 723-1, Public Service will file its next GIP in 2025 ("2025 GIP") and thereafter every two years no later than May 1.

6. On July 18, 2024, Hearing Commissioner Gilman held a workshop in which the Workshop Participants presented and discussed, among other related topics, the magnitude and local aspects of the criteria listed in Rule 4553(b) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-1, in the Company's future gas load forecasts. Hearing Commissioner Gilman then held the second workshop on July 29, 2024, in which Public Service and invited stakeholders presented on and discussed existing system mapping data and capacities and Public Service's CBA methodology. On August 21, 2024, Hearing Commissioner Gilman held a third workshop that built on the discussion of the three topics, including discussion from experts outside of the Inaugural GIP process in targeted areas, and helped the Commission further develop expectations for the Company in advance of its next GIP filing.

a. Load Forecasting

(1) Discussion

7. In preparing its inaugural Gas Infrastructure Plan filed in Proceeding No. 23M-0234G, the Company largely utilized its historical forecasting practices. Feedback from stakeholders indicated concerns that the forecast produced by the Company forecasted with a bias toward indefinite system load growth and failed to accurately project residential use per customer and customer count growth.[1] Furthermore, stakeholders argued that the Company's current forecasting methodology, which relies on historical consumption data combined with an econometric model of customer growth and demographic data disaggregated to the county level

[1] Initial Comments of Advanced Energy United at 4; Conservation Advocates Initial Comments, 13-16.

using proportional population figures, "stands in stark contrast" with Commission Rule 4553(b), 4 CCR 723-1, which requires consideration of state and local building codes and suggests that the Company evolve to end-use, technology-based, and bottom-up modeling to better reflect these requirements as well as the meaningful high and low growth forecasts required in the GIP rules.[2]

8. The Company largely acknowledged that its forecasting methodology did not comply with Rule 4553(b) due to the timing of the first GIP following very shortly after the GIP rules were finalized.[3]

9. In Decision No. C24-0092, the Commission expressed an expectation "to receive a fully compliant forecast no later than the next GIP."[4] Furthermore, the Commission required Public Service to "include in its next GIP application a fully compliant forecast subject to any guidance provided in Proceeding No. 23A-0392EG. This must include full consideration of the factors listed [in Rule 4553(b) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-1], as well as localized forecasting, which appropriately considers the impact of those factors within the specific areas of the system such that they can be matched up with planned projects appropriately."[5] Additionally in Decision No. C24-0092, the Commission warned that if future GIP filings do not fully comply with the requirements of the Gas Rules, including if the Company proceeds with forecasting and planning methodologies that do not appropriately consider complexities of the transition, as identified in Rules 4553(b) and 4731(a)(1), "the Commission may consider additional appropriate avenues to encourage prudent and strategic infrastructure investment decisions and to ensure ratepayers do not cover the costs of imprudent

[2] Initial Comments of Advanced Energy United, 8-11.

[3] *See* Hrg. Trans. August 14, 2023, at 6:8-6:12 ("[t]his initial filing was meant to meet these rules requirements as much as possible, albeit on a short time frame given the GIP rules became effective roughly at the same time we filed in May of this year.")

[4] Decision No. C24-0092, ¶ ¶ 19-20, issued in Proceeding No. 23M-0234G, on February 23, 2024.

[5] *Id*. at 19-20.

decisions … [that] would likely include identifying opportunities to share the risk of investments that may become stranded or underutilized."[6]

10. Furthermore, in Decision No. C24-0092, the Commission clarified its concept of geographical segmentation under Rule 4731(a)(I)(A) and Rule 4731(a)(I)(B) that the ideal level of granularity should be either: (1) pressure district; or (2) a geographically segregated and operated portion of the system between the level of regulator station and city gate. The Commission found that the Company's use of county-wide forecasting was inappropriately broad and potentially lumped together jurisdictions with varying factors that influence load and capacity. The Commission reiterated the requirement that district forecasts include customer count and peak demand by class for each geographic area or pressure district. The Commission further reiterated that the gas rules require the Company to separately model areas with unique local incentives or building codes that favor electrification, and overlay these areas over regions of system constraint and other factors relevant to system planning.[7]

11. In the Commission's decision on the Company's clean heat plan application,[8] the Commission stated its expectations that improvements to the Company's forecasting methodologies would occur in the Company's upcoming gas infrastructure planning application to be submitted in 2025 pursuant to Rule 4552(a), 4 CCR 723-4.[9]

12. In Decision No. R24-0480-1, the Hearing Commissioner communicated the following key objectives related to load forecasting: (1) Explore the magnitude and local aspects of requirements identified in Rule 4553(b); (2) Discuss new or alternative load (throughput and

[6] *Id*. at 18.
[7] *Id*. at 59.
[8] Public Service filed its clean heat plan application pursuant to § 40-3.2-108, C.R.S., on August 1, 2023, in Proceeding No. 23A-0392EG.
[9] *See* Decision No. C24-0397, ¶ 273, in Proceeding No. 23A-0392EG, issued June 10, 2024.

demand) forecasting approaches with experts, including how the Company can implement these approaches; and (3) Come to common understanding of ways the Company can move to compliance with Rule 4553(b) and timeline and identify if any additional guidance is necessary.

13. The first workshop held on July 18, 2024, focused entirely on gas load forecasting. The workshop included participants from municipalities with significant building code and incentive programs; Colorado Energy Office ("CEO") who oversees state programs related to advanced building codes and statewide and federal incentives; and the Company. The participants discussed potential impacts of building codes and programs as it relates to forecasting future gas throughput and capacity needs.

14. At the first workshop, CEO provided information on building code improvements and indicated that between the 2021 version of the International Energy Conservation Code ("IECC"), dropped the expected natural gas usage per residential unit between roughly 40-49 percent, depending on climate zone, compared to the 2006 version. Similarly, from the 2018 version to the 2021 version, the IECC modeled natural gas usage per residential unit to drop between roughly 8-19 percent, depending on climate zone. Commercial unit expectations were similar, with a modeled drop of roughly 29-48 percent from the 2004 to the 2019 version of ASHRAE 90.1[10] and roughly 4-8 percent drop from the 2016 version to the 2019 version of ASHRAE 90.1. CEO tracks code versions throughout the state and reported that 75 jurisdictions, covering 67 percent of the state's population, and notably many of the populated front range communities served by the Company, utilized the 2021 IECC. Approximately 3 percent of Colorado's population lives in jurisdictions that utilize energy codes older than 2015 (or have no

[10] ANSI/ASHRAE/IES Standard 90.1: Energy Standard for Buildings Except Low-Rise Residential Buildings is an American National Standards Institute standard published by ASHRAE.

energy code), but these are in rural areas which likely do not overlap with the Company's natural gas service territory. Of all residential unit construction permits reported in Colorado in 2023, CEO reports that 73 percent were in jurisdictions that were or are now utilizing the 2021 IECC. CEO also provided information on Colorado's Building Performance Standard Program, which applies to approximately 8,300 buildings over 50,0000 square feet statewide. Performance targets related to the Building Performance Standard are expected to affect buildings by deadlines in June 2027 and June 2031. CEO also reviewed federal incentives available for efficiency and electrification that are already available or coming to the Colorado market.

15. Also at the first workshop, the City and County of Denver ("CCD") presented information relating to the 2022 Denver Energy Code, which aims for all new buildings and homes to be zero emissions by 2030 with systemwide renewables. CCD highlighted that its High Impact Climate Code Amendments prohibit new commercial construction after January 1, 2024, to install fuel gas furnaces or fuel gas water heaters.[11] Additionally, CCD indicated that new modeling paths and prescriptive paths within its 2022 Denver Energy Code are intended to incentivize electrification within new commercial buildings. It shared that new residential buildings also have new modeling and prescriptive paths to incentive electrification and that new residential buildings must either pursue 50 percent renewables or electrification. For context, CCD reported between 1,889 and 2,368 new single-family, duplex, and townhomes are built per year over the last three years. For existing buildings, the Denver Energy Code requires a review of electrification options and partial electrification of space and water heating and cooling equipment upon system replacement in all existing commercial and multifamily buildings, when cost-effective, with the major implementation timelines all expected to be in place by 2027. In addition to building code

[11] *See* CCD slides uploaded in 24M-0261G on July 22, 2024.

changes, CCD also offers pilots and prescriptive rebates for commercial, multifamily and residential equipment with over 1,200 systems rebated since 2023 and 70 percent of the furnace replacements opting for cold climate heat pumps. Taken together, CCD expects a cumulative reduction by 2040 of 1,683.6 million therms of gas throughput by existing buildings within their jurisdiction by 2040 based on a 2020 baseline. CCD also presented observed trends in existing building data indicating from 2019 to 2023 an overall reduction of 10 percent in natural gas usage. In addition to enacted policies, CCD also provided details on a feasibility study to be completed first quarter of 2025 related to development of a Thermal District Network utilizing an ambient loop in Downtown Denver within the vicinity of the existing chilled water system and potential expansion opportunities outside of downtown. While still in the feasibility study phase, CCD estimates that a downtown ambient loop could reduce CCD annual gas consumption by as much as 41.9 million therms or 12 percent of the citywide usage. CCD identified that they have attempted to work with the Company related to modeling potential impacts and analysis of their policies, but have faced issues with data requests to the Company, with the Company often citing limited resources related to staff time and system functionality in denial of requests to share data.

16. The City of Boulder ("Boulder") also shared information beginning with their high-level strategies to reduce greenhouse gas ("GHG") emissions by 70 percent by 2030 and achieve net zero by 2035. To date, Boulder reports an 18 percent reduction in emissions compared to 2018 and a 37 percent reduction compared to 2005. Two-thirds of the community's emissions come from buildings, which are also a major contributor to front-range ozone. Since 2017, Boulder has required net zero operational energy for low-density residential new construction exceeding 5,000 square feet, which is roughly half of new homes developed in Boulder and primarily replacing existing buildings. Boulder reports that approximately 50 percent of these homes are

being constructed as all electric. In 2020, Boulder expanded this requirement to all homes exceeding 3,000 sq ft, and implemented new energy usage per square foot targets for commercial buildings, including multi-family residences, which include electric preferred provisions. Beginning in 2024, the Boulder Energy Code implements an all-electric appliance requirement for both residential and commercial new construction. Boulder has some exceptions for certain commercial and industrial uses, however, those are accompanied by electric preferred incentives. Boulder anticipates the next update to the code in 2027, and by 2030 to move to net zero emissions for all new construction. Boulder reviewed a variety of rebates they have available for upgrades to enable electrification through to specific appliances, including income-qualified rebates which cover 100 percent of project cost. Boulder also provided information on their community planning and zoning efforts to identify upcoming expected growth areas for development.

17. The Company presented background on its process to develop gas system forecasts. Importantly, it highlighted the difference, and potential divergence going forward, of forecasting for throughput versus design day peak hour demand (*i.e.,* the instantaneous capacity need of the system). The Company indicated that, in the specific case of a home moving to a cold climate air source heat pump which is backed up by supplemental gas heat, it did not expect any reduction in peak demand from that customer type. It highlighted that the underlying details and design of electrification projects will determine the impact and any potential reduction in Design Day peak hour gas demand. It also outlined the Company's process to create its forecast and evaluate upcoming projects and nonpipeline alternatives ("NPAs") for the 2025 GIP. Broadly, the Company describes its typical forecasting process where an as-is system usage is determined using historical monthly customer data and meter read files. Design Day peak hour gas consumption is estimated utilizing monthly gas customer meter reads, as advanced metering infrastructure is not utilized on

the gas system. That information, along with historical weather information is then uploaded into a program called "Synergi Gas" and linked to associated nodes, as appropriate, which provides a view of the system characteristics as of the previous winter. Then the Company adds on top a five-year monthly forecasts of customer growth by customer class, taking into account Colorado Department of Local Affairs population forecasts by county to determine the forecast by year and by county. This forecast is layered on top of the as-is condition and utilized to identify capacity needs. Capacity needs are identified through the use of Synergi Gas hydraulic flow modeling in representing the anticipated peak hour of gas consumption. The Company indicated that beginning in 2023, residential forecasts began including impacts of market electrification, including lower customer counts and usage per customer. It also indicated that it has made updates to include other recent changes, including the use of the Amended Preferred Portfolio within its clean heat plan application,[12] which was not the Commission-approved portfolio, but was utilized based on the timing in which they began development of its forecasts. The Company indicated that a reduction in the average use per customer is expected, however, does not necessarily translate to reduction in Design Day peak hour consumption. The Company generally described an intent for planned future improvements to forecasting, including more granular methodology that incorporates the impacts of localized codes and standards and line extension policy, and propensity to adopt models related to electrification. The Company also provided some data from early-stage implementation of beneficial electrification ("BE") in which the majority of BE retrofits to date are single family and are using gas as a backup space heating fuel, however, new construction is in large part using electricity, instead of gas, as a backup space heating fuel. However, according to the Company,

[12] Public Service filed its clean heat plan application pursuant to § 40-3.2-108, C.R.S., on August 1, 2023, in Proceeding No. 23A-0392EG.

even for those homes not utilizing gas as a backup space heating fuel, many appear to still be installing a gas line, perhaps for loads like fireplaces or stovetops. The Company's data also indicates that a higher percentage of new homes have heat pump water heaters than heat pump space heat. Participation in the BE retrofit rebates has predominantly occurred in Denver, with Boulder coming in second.

18. Following the workshop on July 18, 2024 (scheduled by Decision No. R24-0565-I), the Hearing Commissioner issued a set of follow up questions to better understand available data sources and any available trends related to customer adoption of electrified heating, backup energy sources, actual and predicted performance of electrified heating, and backup sources and gas capacity requests for new construction. Responses were provided to the Commission in late August from the Company, CEO, Advanced Energy United ("AEU") and Western Resource Advocates ("WRA"), jointly, and Denver.

19. Denver's response indicated several additional points beyond those comments provided at the first workshop summarized above. Denver sees thoughtful gas planning as key to many of its climate initiatives. Denver's all-electric new construction pilot program has supported 17 new construction projects, however they do not keep or track information on installations of gas furnaces/boilers, because they do not provide rebates on those items. The following is the most substantial information that Denver has compiled from its programs, however, several programs regarding new construction are new and do not yet have sufficient data to report. Denver is considering changes to its data collection practices so it can be helpful in providing some of the identified information in the future.

TABLE 1: *Existing Single Family, Denver Rebate Summary (Year 2024 is through September 3, 2024)*[13]

Year	ccASHP	ccMSHP	ASHP	MSHP	HPWH	sHPWH
2022	63	72	206	44	11	28
2023	209	272	67	37	21	94
2024	254	256	78	19	13	83

TABLE 2: *Existing Multifamily, Denver Rebate Summary (Year 2024 Is Through July 31, 2024)*[14]

Year	ccASHP	ccMSHP	ASHP	MSHP	HPWH
2023	2	2	2	0	0
2024	5	9	5	1	2

20. The joint response from AEU and WRA largely focused on some of their ongoing areas of concern. First, they expressed concern that, while some municipalities likely have valuable information and strategy to share in with the Company that could impact upcoming infrastructure, the Company appears to have declined some of the opportunities to coordinate. The expressed particular concern with this, as it relates to SB 23-1370, which will require a high level of coordination in "gas planning pilot communities." Second, they express concern that electrification rebates appear to be largely supporting dual-fuel buildings, even when gas is not being used as a primary or backup heating fuel, which leads them to concerns about affordability on the system due to capital expenditures growing much faster than throughput. They raise the potential to consider if the Commission should end both gas and electric line extension allowances for homes that continue to install a gas service line, in alignment with a policy now effective in California. Last, they point to several specific concerns around the cost benefit analysis, including

[13] Derived from CCD's Response to Questions from Workshop 1, filed September 6, 2024.
[14] Derived from CCD's Response to Questions from Workshop 1, filed September 6, 2024.

the appropriateness of the Ratepayer Impact Measure test, inappropriate assumptions for generation costs within the NPA CBA, the appropriateness of the inclusion of electric distribution system upgrade costs in the NPA CBA, and the Company's assumptions in calculating the peak electrical load associated with heat pumps.

21. CEO's response further elaborated on the expected Building Performance Standard process, but generally did not have specific information on rebate utilization or heat pump uptake to share at this time. CEO is working to identify any improvements in energy use and other building energy-related characteristics of homes within 2010 and 2020 studies to understand the impacts of strengthening energy codes over time and expressed an eagerness to share those results with the Commission once available.

22. At the third workshop held on August 21, 2024, Kevala presented on the importance of developing models for fuel switching and conservation behavior as a basis for bottom-up forecasting. They shared their mapping tools which allows for an analysis linking gas substitution and electricity resilience so that planners can better understand costs and benefits of gas line lifecycle replacement, including aggregating those costs and benefits with socioeconomic data. Kevala noted that there are opportunities to integrate these analyses utilizing existing data without "wait[ing] until you have all the data you want."

(2) Findings and Conclusions

23. Following months of convening and information collection, it is an appropriate time to focus more acutely on the Company's plans going forward. To that end, the Hearing Commissioner requests proposals from the Company regarding both its plans for the 2025 GIP, as well as for longer-term improvements to its forecasting approach. After receipt of the proposals,

stakeholders will be asked to provide comments on the proposals. Ideally, this process will bring expectations for the forecasts closer together in advance of the 2025 GIP submission.

24. Public Service shall file a proposal for its plans regarding the process, assumptions and presentation of forecasting in the 2025 GIP. The proposal should specifically include, but not be limited to, the following details:

- A description of the capacity and throughput forecasting process that the Company intends to follow for the 2025 GIP, including specifically any deviations or modifications from past practice in completing load forecasts;
- A description and maps identifying the locational areas or groupings for which the Company will utilize unique factors for forecasts, including an explanation as to why those areas were grouped together, including any unique data or characteristics to develop the forecast;
- A description of any information the Company intends to include with its forecasting to support its assumptions, especially around localized load growth;
- A description on how each aspect of Rule 4553(b) 4 CCR 723-1 was incorporated into the forecasting and applied, as appropriate, to specific geographic areas including the influence of:
  - Building codes and policies;
  - Local, state and federal incentives; and
  - Price elasticity of demand;
- A description and example of how the Company intends to display information on localized forecasts for throughput and capacity and the underlying assumptions within its 2025 GIP filing; and
- A narrative on any input the Company has solicited or received (or expect to prior to the 2025 GIP) regarding development patterns or expectations in specific geographic areas, which have helped shape the forecasting, including any interaction with municipalities.

25. In addition to addressing forecasting plans and improvements related directly to the 2025 GIP, the Company should also provide information on future improvements to its forecasting methodology and process, which may play out over a longer-term time period. The proposal should specifically include a clear view of how the Company envisions future evolutions of its forecasting

methodology, along with timelines for any planned improvements, if known or estimated. This longer–term view should include, but not be limited to, the following details related to improvements beyond the 2025 GIP:

- Details surrounding the Company's plan to continually improve its forecasting methodology in compliance with Rule 4553(b), specifically addressing each category of information required to be included in the forecast in accordance with the Rule language;
- A description of the locational areas or groupings for which the Company anticipates developing unique forecasting characteristics in future rounds of the GIP to continue to refine its locational specificity with regard to infrastructure needs;
- A narrative on any process the Company envisions to solicit and incorporate information on development patterns or expectations in specific geographic areas, including through local building departments, recent new service applications, rebate program data or other means; and
- A narrative on any plans the Company has to utilize customer usage data, information contained within new applications, locational tracking of BE or DSM rebates, and outcomes of Clean Heat and other proceedings to trend or assess potential changes in throughput and capacity based on customer behavior. Please include any tracking or information sources that are planned to be analyzed to more thoroughly understand the capacity needs, and contingent factors, related to gas as a backup to air source heat pumps.

b. Mapping

(1) Discussion

26. Throughout the GIP Rulemaking, in Proceeding No. 21R-0449G, and subsequently in the Inaugural GIP and recent legislation, the issue of mapping and system data was raised multiple times.

27. Under Commission Rule 4553(a)(V), the Company must provide one or more system maps indicating the general locations of individual planned projects and indicate whether planned projects are located within disproportionately impacted communities. Furthermore, SB 23-291, codified at § 40-3.2.104.4(3), C.R.S., requires an investor-owned utility to provide, as

a part of GIP filings, a map showing system-wide locations, ages, materials or types of gas distribution system pipes consistent with 49 C.F.R. § 191 and § 40-2-115(1)(d), C.R.S.

28. As a part of the consideration of the Company's inaugural GIP, the Commission agreed with stakeholders that additional guidance on mapping requirements is necessary prior to preparation of the Company's 2025 GIP filing.[15] Commenters in the Inaugural GIP had generally recognized that system mapping could be key to understanding areas of the system facing upcoming capacity constraints or other upcoming investments, including understanding the geographic relationship of those investment needs, in order to plan the system as cost effectively as possible. In the same decision the Commission, "encourage[d] full consideration of CEO's proposal to include census tract level mapping and the potential for hydraulic models and other information"[16] as a part of the follow-on miscellaneous proceedings docket and expressed optimism that interactive system maps will "quickly evolve" to include pipe age and material, locations of capacity constraints, customer-owned yard lines, failed meter lots, and upcoming expenditures.

29. In Decision No. C24-0172,[17] the Commission modified the Commission's Rules Regulating Pipeline Operators and Gas Pipeline Safety, 4 CCR 723-11 ("Gas Pipeline Safety Rules") to mandate Company disclosure of certain GIS data to the Commission's Pipeline Safety Program, effective May 5, 2024. Specifically, Commission Rule 11100(c)(II) requires, to the extent available, disclosure of GIS data, including: the spatial location of the pipeline; operator name; fluid type; designation of pipeline as transmission, distribution, or gathering; National Pipeline Mapping System data for transmission pipelines; whether the pipeline is abandoned; the

[15] *See* Decision No. C24-0092, ¶ 147, issued in Proceeding No. 23M-0234G.
[16] Decision No. C24-0092, ¶ ¶ 148-150, issued in Proceeding No. 23M-0234G.
[17] Decision No. C24-0172, issued in Proceeding No. 22R-0491GPS, on March 19, 2024.

maximum allowable operating pressure; the testing pressure; pipe description; corrosion protection description; and HCA/MCA status. Commission Rule 11100 requires the Commission's Public Safety Program Chief to establish a publicly accessible online map viewer for certain system GIS data specified in Section 11100(c)(II) at scales less than or equal to 1:6,000, with an exception that any data filed confidentially must be filed with a publicly accessible version at a scale greater than or equal to 1:24,000.[18] Section 11100(c)(III)(B) allows a local government to reproduce publicly available data and sets forth a process for a local government designee to view confidential information subject to executing a confidentiality agreement.

30. In Decision No. R24-0480-1, the Hearing Commissioner communicated the following key objectives related to system mapping:

- Comprehend the Company's current system mapping capabilities relative to statutory and regulatory requirements;
- Clearly identify guardrails for public information based on safety and security concerns;
- Identify and prioritize the uses of system mapping and information that is necessary and who will likely need to access it; and
- Identify information to be shown on mapping, scale and method for providing mapping, as well as timeline.

31. At the second workshop in this Proceeding held July 29, 2024, WRA reiterated that the Company should provide "high resolution" system maps in an electronic, searchable format available to the parties in a GIP proceeding under a non-disclosure agreement. WRA argued that these guidelines align with tools included in PG&E's Gas Asset Analysis Tool that allow the relevant utility, commission, and stakeholders to evaluate non-pipeline alternative analyses on longer time horizons and provide enough detail to conduct hydraulic feasibility studies of

[18] *See* Commission Rules Regulating Pipeline Operators and Gas Pipeline Safety ("Commission Gas Pipeline Safety Rules"), Rule 11100(c)(II)(A) 4 CCR 723-1.

removing a pipeline from service. Specifically, WRA advocated for the disclosure of the following pipeline data by the Company: age, material, specific segments that may need to be replaced within 10 years, electric capacity information, mean customer income by geographic area, renter prevalence by geographic area, and disproportionately impacted communities. WRA detailed its views on how joint mapping of natural gas and electric distribution systems would allow the Commission and stakeholder to investigate the relative capacity available for natural gas versus electric service in different geographic areas, particularly for new construction, as well as aiding in the identification of non-pipeline alternative projects.

32. Also at the second workshop, CEO recognized existing mapping requirements across state statutes, including the aforementioned Commission Gas Pipeline Safety Rule 11100(c), as well as Gas Rule 4553(a)(v) and Gas Rule 4553(c)(I)(J). Furthermore, CEO expressed interest in better understanding how the Commission and stakeholders can better utilize hydraulic modeling, and the data contained therein to better inform oversight and accuracy of GIP forecasts.

33. The Company provided its understanding of the GIP Rule mapping requirements, including new requirements established by SB 23-91 (§40-3.2-104.4 (3), C.R.S.) and federally required annual reporting required by 49 CFR 191. Further, the Company laid out its obligations to support the National Pipeline Mapping System Public Map Viewer, which details the locations of gas transmission and hazardous liquid lines at a map scale of 1:24,000, and does not contain distribution or gas gathering pipelines. The Company also detailed its and the Commission's obligations under Rule 11100(C) of the Commission's Pipeline Safety Rules. Public Service raised "significant concerns" for cybersecurity, physical security, and reliability associated with the disclosure of detailed GIS maps that show detailed system attributes. The Company detailed the

way in which it utilizes its GIS system and the key attributes it holds therein, including nominal diameter, material, coating, manufacturer, install method, joint trench, crossing type, ownership, status, install date, wall thickness, installed length, maximum allowable operating pressure ("MAOP"), standard dimension ratio ("SDR"), specified minimum yield strength ("SMYS"), pressure, system number cathodic protection system, gopher pipe, MAOP system, tap distance, product, type, operator, MOP, established MAOP, system MOP, piggable, inside diameter, line loop MAOP, operating pressure, percent SMYS, internally coated, longitudinal seam, toughness, manufacturer, coating date installed, cathodic protection, nominal diameter, pipe grade, and previous liquid line. However, the Company notes that its GIS system has limitations, including that data attributes for some pipeline segments may only exist in paper records. It also cautioned that reproduction of data held in its GIS system creates misinterpretation risks or risk of misuse of the data. Company representatives detailed the GIS-housed attributes used in its hydraulic modeling and integrity management program, and said the Company is actively researching additional planning tools to support NPA analyses, targeted electrification, Net Zero Vision and Clean Heat Plan implementation, and capital investment optimization. The Company presented three suggested next steps on mapping for the Commission and stakeholders to consider: (1) collaborate on how to meet new statutory mapping requirements for the 2025 GIP while maintaining limited access to sensitive infrastructure data; (2) determine ultimate objectives for a mapping tool used in connection with the GIP; and (3) agree on achievable next steps recognizing that the envisioned mapping tool will take time.

34. Also, at the second workshop, Hearing Commissioner Gilman led a whiteboard discussion engaging with the Company and other workshop participants in order to start conversations and to work towards a common understanding on: (1) objectives on what gas system

mapping should allow or enable; (2) near term steps on how the Company can comply with SB 23-291 requirements for the 2025 GIP; (3) what data sources the company currently possesses in its GIS/shapefile; and (4) to whom the data should be available.

35. The discussion resulted in initial, informal agreement on the objectives associated with providing and utilizing improved system mapping. Among the objectives discussed, the Company expressed a need for prioritization within the list of objectives for implementation. Broadly, the group provided feedback that gas system mapping should allow or enable (in no particular order):

- Meeting the state's emission reduction targets in an equitable way;
- Coordination and optimization of beneficial electrification efforts;
- Minimizing or optimizing overall gas and electric infrastructure system investments, including managing costs of a gas transition on the gas utility;
- Local governments to have visibility into system planning;
- Reduction of information asymmetry between the Company and stakeholders in planning proceedings;
- A focus on the most useful information to minimize costs and security concerns associated with providing more information than is needed to achieve objectives;
- A valuable tool in developing the overall strategy of the gas utility; and
- Interactive/GIS basis for mapping is an important functionality in the ultimate mapping solution, with an understanding that getting to an ideal solution may take some time.

36. The Company and several stakeholders appeared to agree that mapping provided in the GIP could be available to intervenors under confidentiality terms and should be moving to an interactive, GIS basis. There was not an overwhelming sense that the information was useful or necessary to be provided in a public format, especially given the Company's security concerns related to full-scale public access, and that inclusion of the information for parties in a proceeding would allow for constructive conversation on the details of a project or areas of the system without

significantly increasing access to information, which could have security implications. Additionally, there was general agreement that information/system data required for the GPS rulemaking should reasonably be included in GIP filing, as well.

37. At the August 21, 2024 workshop, Catherine Elder from Aspen Environmental Group provided background and insights into the uses of hydraulic modeling, especially as it relates to system capacity planning. Also at the workshop, the Company expressed significant concerns about sharing hydraulic map data and stated it was not immediately clear how the raw information would be useful to stakeholders who do not have specific expertise in the hydraulic modeling software. Also, Dan Shea from CCD provided a perspective regarding the interrelationship of HB 24-1370 and the GIP process, in terms of identifying information that municipalities would need to identify neighborhood-scale alternative projects. Given the timeline anticipated by the legislation, access to actionable data with reasonably detailed data about specific sections of the system within their jurisdiction, is anticipated to need to be part of the 2025 GIP filing. The Company also provided some information at the third workshop, primarily related to their process and information input used in their forecasting, specifically around the integration of customer data into gas hydraulic models. They expressed significant concerns around making hydraulic modeling data publicly available, because they feel the level of information about system operations that would be available would pose a security risk.

(2) Findings and Conclusions

38. Following months of convening and information collection, it is an appropriate time to focus more acutely on the Company's system mapping efforts going forward. To that end, the Hearing Commissioner requests proposals from the Company regarding both its plans for the 2025 GIP, as well as for longer term improvements. After receipt of the proposals, stakeholders will be

asked to provide comments on the proposals. Ideally, this process will bring expectations for the system mapping closer together in advance of the 2025 GIP submission.

39. The Company shall file a proposal for its plans related to presentation and delivery of system mapping and characteristics for 2025 GIP which should specifically include, but not be limited to, the following information:

- Confirmation on the format of system maps that the Company anticipates providing, including if the maps will be available in GIS format or shapefile and what, if any, software would be needed by intervenors in order to access the information; and
- A description of the Company's intention related to the confidentiality designation it intends to seek and its intention to provide availability to intervenors who have executed a non-disclosure agreement.

40. The Company shall also provide additional information regarding its 2025 and longer-term system mapping efforts. The Company shall provide information regarding its plans for the following categories:

Attribute	**Included in 2025 GIP Shapefile? (Y/N)* If no, please provide anticipated timing of inclusion in future GIP filings. If information will be provided, but not in a Shapefile, please indicate how the information is intended to be presented.**	**Anticipated access level in 2025 GIP filing (public, confidential with NDA, only certain intervenor types, etc.) If designation only applies at a certain scale, please indicate.**	**Included in 2025 Rule 11100 filing? (Y/N) If no, please provide anticipated timing of inclusion in Rule 11100 filings.**	**Anticipated availability in 2025 Rule 11100 filing (public, confidential with NDA, only certain intervenor types, etc.) If designation only applies at a certain scale, please indicate.**
Pressure district or geographic area[19]				

[19] Requirements "Pressure District or Geographic Area" through "Electric Utility Service Provider found in Rule 4553 (c)(I)(J).

Existing regulator stations				
Proposed regulator stations				
Existing distribution piping				
Proposed distribution piping				
Existing transmission piping				
Proposed transmission piping				
Locations of disproportionately impacted communities				
Electric utility service provider[20]				
Locations of system-wide gas distribution pipes[21]				
Age of each gas distribution pipe				
Materials or types of each gas distribution pipe				
Pipes needing upgrades and/or replacement within 10 years with accompanying information about the need[22]				
Spatial location of each distribution and transmission pipeline[23]				
Operator name of each transmission and distribution pipeline				
Fluid type of each distribution and transmission pipeline				

[20] *Id*.

[21] Requirements "Age of each gas distribution pipe" to "pipes needing upgrades" found in SB 23-291, codified at §40-3.2-104.4 (3), C.R.S.

[22] *Id*.

[23] Attributes "Spatial location" through "Description of corrosion" from Pipeline Commission Gas Pipeline Safety Rules, Rule 11100(c).

Designation of pipeline as transmission, distribution, or gathering				
Additional data provided to the National Pipeline Mapping system (NPMS) by the operator (Transmission only)				
Abandoned status of all distribution and transmission pipelines**				
Testing pressure of all distribution and transmission pipelines				
Pipe description (i.e., nominal diameter, coating, standard dimension ratio, and material) of all distribution and transmission pipelines				
Description of corrosion protection (i.e., Galvanic, Rectified/Impressed Current, or NA) for all distribution and transmission pipelines[24]				
Identify as HCA/MCA on each segment for class location, as applicable, for all distribution and transmission pipelines				
* Note that the GIP rules require submitting "maps" which the company previously interpreted as "paper" maps, i.e PDFs, not shapefiles. There was apparent consensus during the 7/29 workshop that the maps submitted as a part of the 2025 GIP should be electronic shapefiles. ** as defined in 49 CFR 192.3 and inactive pipelines. Include abandonment and inactive dates as applicable, as defined in 49 CFR 192.727 inactive dates as applicable, as defined in 49 CFR 192.727				

c. Cost-Benefit Analysis

(1) Discussion

41. Pursuant to Rule 4553(c), Public Service produced a cost benefit analysis for the consideration of non-pipeline alternatives. In Decision No. C24-0092, the Commission concluded

[24] *Id*.

that the Company's first CBA was "a good first step as experience with alternatives analysis grows."[25] However, the Commission agreed that the CBA could be further developed and refined and to this end directed the Company to develop a CBA handbook as a part of the miscellaneous proceeding.

42. Also within Decision No. C24-0092, the Commission made certain specific findings with regard to the Company's CBA analysis, including:

- The miscellaneous proceeding should include evaluation of ways to better involve DI communities, including a CBA to a specific DI community, and the possibility of an adder for benefits that impact a specific DI community.[26]
- Within a CBA analysis, it is more appropriate to compare costs and benefits directly between the infrastructure option and the NPA option rather than considering them separately, which is how the Company conducted its analysis.[27]
- Methane emissions associated with leakage should be a part of the CBA, and the Company should pursue use of long-run marginal emissions rates rather than short-run emissions rates for electric loads.[28]
- The Company's CBA should include negative net salvage value, as in many cases, it adds a significant portion to the actual cost that will be incurred by ratepayers for an infrastructure investment.[29]
- The Company's CBA should include incentives from the Inflation Reduction Act and state tax credits.[30]
- The Commission reiterated the holding from Decision No. C23-0413 that the Company should assess DSM programs using the Utility test and provide feedback to the Commission.[31]
- The Commission determined that including electric system infrastructure needs resulting from an NPA are premature. The Commission stated '[i]t is not immediately clear that the five-year projections used for business as usual investments outside of NPAs fully evaluated growth rates and ambient electrification activities, especially

[25] Decision No. C24-0092, ¶ 111, issued in Proceeding No. 23M-0234G, on February 23, 2024.
[26] *Id*. at 111.
[27] *Id*.
[28] *Id*. at 112.
[29] *Id*. at 113.
[30] *Id*. at 114.
[31] *Id*. at 115.

> considering that several areas of the distribution system appear to need immediate infrastructure investment in order to meet growth as is."[32]

43. In its decision responding to the Company's Application for Rehearing, Reargument, or Reconsideration, the Commission denied the Company's request for reconsideration of negative net salvage value in the CBA for NPAs and reaffirmed the directive for the Company to include negative net salvage value of gas infrastructure in the Company's NPA evaluations submitted with the 2025 GIP. However, the Commission: (1) acknowledged there are complexities with the issue; (2) encouraged the Company to adopt an approach it determines appropriate and accurate; (3) encouraged the Company to support its approach with relevant expert testimony; (4) allowed the Company to apply negative net salvage symmetrically by including the negative net salvage value for electric infrastructure if in doing so results in more realistic and accurate CBA for required NPAs.[33]

44. In Decision No. R24-0480-1, the Hearing Commissioner communicated the following key objectives related to cost benefit analysis:

- Develop a consensus approach, but if not possible, recommendations, on a cost benefit framework and format.
- Clearly identify the costs and benefits that are expected in an NPA CBA, including any information on appropriate assumptions or data sources.
- Identify appropriate data sources and inputs, where possible, to narrow the field of items to be litigated in future GIP proceedings.
- Identify a pathway to avoid the entirety of the CBA from being considered confidential in upcoming GIPs to allow for maximum transparency and involvement from parties and the general public.

45. During the second workshop held on July 29, 2024, WRA presented key principles it believes a CBA of NPAs should reflect: (1) CBAs should compares costs and benefits against the status quo pipeline project; (2) costs of NPAs should be cited, up to date, and reflect state and

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[32] *Id*. at 116.
[33] Decision No. C24-0233, ¶ 12, issued in Proceeding No. 23M-0234G, on March 14, 2024.

federal incentives; (3) necessary electric assumptions should be transparent and incorporate exogenous demand trends; and (4) evaluated benefits should be comprehensive. Specifically, WRA recommended that in future GIP CBA calculations, the Company should: (1) include the avoided cost of a pipeline project as a NPA benefit; (2) ensure assumed equipment costs account for all applicable state and federal incentives; (3) clearly justify administrative cost assumptions; (4) clearly cite equipment costs. WRA also argued that although it is reasonable to assume a need for electric distribution upgrades for some NPA projects, it is inappropriate to assume that NPAs trigger generation upgrades in NPA CBA calculations. Lastly, WRA presented additional project characteristics it believes should be included as benefits in CBA calculations, including: (1) social cost of avoided carbon and methane; (2) avoided negative net salvage value of pipeline investments; and (3) avoided customer gas equipment costs.

46. Also during the July 29, 2024 workshop, CEO presented jurisdictional cost tests as an alternative to existing utility and total resource cost tests as a tool to better align CBA with state policy, namely the reduction of emissions. CEO discussed the Minnesota Benefit Framework, New York's BCA Handbook, and the National Standard Practice Manual as resources to aid in the development of unified cost test for Colorado that would apply to distributed energy resources, including within NPA projects proposed and evaluated in future GIP proceedings.

47. During the second workshop, Public Service updated participants on its efforts to develop a CBA Handbook as mandated by Commission's Inaugural GIP Decision, including how the handbook will detail the methodologies, calculations, data sources, and descriptions of the costs and benefits used in future GIP CBA calculations. It detailed new or modified cost and benefit components of its expanded, modified total resource cost ("EMTRC") primary cost effectiveness test and argued the need for a new, expanded rates impact measure ("ERIM")

secondary cost effectiveness test. Its presentation also included an appendix summarizing utility impact criteria to consider for each proposed test. Public Service claimed that Commission rules require the use of a modified total resource cost test ("mTRC") that accounts for societal benefits including carbon and methane emissions.[34]

48. During the third workshop held on August 21, 2024, E4TheFuture and Energy Futures Group gave a joint-presentation on potential improvements to the Company's NPA CBA calculations, including running a process reflected in the National Standard Practice Manual ("NSPM") to: (1) define fundamental CBA principles; (2) run a multi-step process to develop a primary cost-effectiveness test; and (3) give guidance for when and how to use secondary cost-effectiveness tests. As it relates to CEO's earlier suggestion, the presenters suggested a focus on policy and outcome aspects that are of specific importance to Colorado, to ensure that the cost test is reflective of the priorities and values of the state. As for outlining CBA principles, the joint presentation encouraged the Commission and Company to: (1) treat comparisons with other energy resources consistently within CBA analyses; (2) seek alignment on applicable policy goals; (3) ensure symmetry across costs and benefits; (4) account for relevant, material impacts based on applicable policies; (5) conduct forward-looking, long term analysis of incremental impacts of DER investments; (6) avoid double counting though clear definitions; (7) ensure transparency in presenting the CBA and results; and (8) conduct CBA separate from rate impact analyses. The joint presenters noted that the Commission directed Public Service to apply NSPM principles to the Distribution System Plan to apply to the Company's competitive procurement process in Proceeding No. 20R-0516E.[35] The joint presenters provided several critiques to the Company's

[34] The Commission's DSM Rules require the use of the mTRC, however the Commission's GIP Rules do not specifically indicate that this should be the cost test specifically used to evaluate NPAs.

[35] *See* Decision No. R21-0387, ¶¶ 103-105, in Proceeding No, 20R0516E, issued on July 8, 2021; Commission Rule 3535(a), 4 CCR 723-1.

proposed changes to its CBA methodology as presented during the workshop held on July 29, 2024. The joint presenters suggested the following: (1) investigating whether there is a state policy goal that requires the inclusion of participant impacts in the CBA tests; (2) further consideration of what state policies would cause government incentives to be treated as transfer payments, in that assigning transfer value as a part of electric energy or gas energy avoided cost calculations to ensure equal treatment of distributed DER generation incentives is likely completely impractical; (3) the Company deserves credit for fleshing out the range of impact categories to consider in its primary cost test; (4) the Company should consider the "option value" as a benefit in that the NPA could buy enough time until load growth starts to decline, rendering future incremental capacity costs unnecessary; (5) using different discount rates for costs and benefits does not make economic sense and seems highly problematic as the Company proposed discounting costs by weighted average cost of capital while discounting benefits by 2.5 percent; (6) ratepayer impact measure ("RIM") tests, like the secondary cost test the Company proposed, is not a cost effectiveness test, but rather reflects equity concerns in rates. Further, in areas like equity and job impacts, the presenters cautioned that there likely is not a straightforward way to consider these items in a primary test focused primarily on more readily quantifiable costs and benefits, but that secondary tests could be utilized to assess the performance in these areas.

49. The joint presenters included the following example information as to how costs and benefits could begin to be considered:

Type	Host Customer Impact	EE	DR	DG	Storage	Electrification
Host Customer	Host portion of DER costs	🔴	🔴	🔴	🔴	🔴
	Interconnection fees	○	○	🔴	🔴	○
	Risk	🟢	○	🟠	🟢	🟠
	Reliability	🟢	🟠	🟢	🟢	🟠
	Resilience	🟢	🟠	🟢	🟢	🟢
	Tax Incentives	🟢	🟢	🟢	🟢	🟢
	Host Customer NEIs	🟠	🟠	🟠	🟠	🟠
	Low-income NEIs	🟢	🟢	🟢	🟢	🟢

🟢 = *typically a benefit*
🔴 = *typically a cost*
🟠 = *either a benefit or cost depending on application*
○ = *not relevant for DER type*

(2) Findings and Conclusions

50. Following months of convening and information collection, it is an appropriate time to focus more acutely on the Company's plans regarding its proposed CBA methodology going forward. To that end, the Hearing Commissioner requests proposals from the Company regarding both its plans for the 2025 GIP, as well as for longer-term improvements. After receipt of the proposals, stakeholders will be asked to provide comments on the proposals. Ideally, this process will bring expectations for the NPA CBA closer together in advance of the 2025 GIP submission.

51. The Company shall file a proposal related to its anticipate CBA for NPA projects for 2025 GIP and should specifically include:

- An update on the extent to which the Company has involved stakeholders in a process to develop a CBA Handbook, including what stakeholders have been involved, how many times the group has met and if there are any outcomes from the group's efforts.
- The Company's analysis on each of the following categories of costs and benefits (see chart beginning on page 32 below), including the Company's proposal for which should be included in a CBA for an NPA, appropriate discount rates, suggestion of one or more

appropriate data sources that could promote consistency and accuracy across proceedings.

- A calculation showing how the addition of net salvage value will be added to the project capital cost and a description of any modifications or complications related to the Company's chosen approach.

- If the Company proposes including incremental costs of electrification on the electric system, please provide a detailed narrative on how the Company will identify and calculate such incremental costs, including how these upgrade areas will be cross-referenced with the Company's plans related to the Distribution System Planning, Electric Resource Planning and transmission planning, which are expected to identify existing system needs. Also, identify how common assumptions on incremental cost can be used to establish consistency in the inputs made across the different proceedings.

- Please identify specific data inputs, calculations or outputs that the Company considers confidential and if there are any placeholders or other assumptions that could be made in order to produce a publicly available CBA.

- Provide information on what sources of information the Company plans to collect or consult in order to estimate the costs of electrification upgrades for customers, including if those costs will be presented as a gross cost or net of the assumed cost of new gas equipment. Also, identify if the costs of electrification upgrades for customers will be presented as net of local (if applicable), state and federal incentives available for the scopes of work being considered or if those incentives will be considered in any other way.

- Provide feedback to indicate the Company's position if the Commission were to undertake a process to evaluate the cost benefit and cost effectiveness framework more holistically, inclusive of many plan types which could benefit from a unified, but updated cost effectiveness framework that explicitly considers the state's policy framework and priorities.

- Please address if the Company intends to file a CBA Handbook prior to or along with the 2025 GIP, including any intended timing. If the Company has a draft or concepts for the Handbook, please provide them.

- Please identify if the Company plans to file an executable version of the CBA calculation related to each NPA considered in the 2025 GIP.

- Provide a description on how the Company suggests considering the costs and benefits of an NPA specific to any DI community that might be within the area of mitigation. Identify if the Company suggests any special treatment of those DI community costs and benefits within the CBA calculation or through a secondary test.

- Provide a description on how the Company suggests considering the costs and benefits of an NPA specific to labor impacts. Identify if the Company suggests any special treatment of those labor costs and benefits within the CBA calculation or through a secondary test.

- Instead of focusing on one, specific pre-made cost test or another, please evaluate each cost and benefit to determine if it is reasonable to consider each in a cost test that is more focused on the jurisdictional level. Complete the following table with responses in each of the four columns for each potential cost or benefit stream to clearly show the Company's plans for their next NPA CBA. Some data fields in the chart contain a specific prompt for certain detailed information to ensure that the Company's plans are clear within the response.

	Proposed to be included in cost benefit analysis (Y/N)	**Proposed Discount rate**	**Proposed data source(s), including if the values will be directly sourced or netted against any other factors**	**Notes about any special treatment or consideration**
Costs[36]				
Capital cost of gas infrastructure project				*For new business and capacity expansion projects, please identify if this cost includes any incremental capacity needs upstream of the project area, which have the potential to contribute to future capacity projects.*
Net salvage value of gas infrastructure project				
Incentive cost				
Participant cost				*Please specifically identify if the assumptions for participant cost will be net of any local, state, and federal incentives. Also address if the assumptions for participant cost will be net of the cost of replacement gas-fired equipment, as an alternative.*
Administrative cost				
Generation capacity				*Identify how the Company will determine when an NPA triggers new generation capacity need.*
Transmission capacity				*Identify how the Company will determine when an NPA triggers new transmission capacity needs*

[36] This list is derived from Public Service's presentation at CBA workshop.

Distribution capacity				*Identify how the Company will determine when an NPA triggers new distribution capacity needs.*
Ancillary service cost				*If the Company proposes inclusion of this cost, please identify how the Ancillary service cost would be determined specific to the NPA, rather than broader system needs.*
Energy cost				*Please provide additional details, including an example, on the calculation the Company details in its presentation from the Second Workshop Slides p.41, as well as elaboration on what it means to utilize consumption from a "default mountain system case."*
Incremental line losses				
Incremental long-run generation emissions cost				
Winter mitigation (if applicable)				*Please elaborate on criteria of when the Company anticipates it will include Winter Mitigation costs for an NPA portfolio vs assuming other NPA means can meet the need and vs classifying an NPA as infeasible due to not meeting demand needs.*
Incremental gas infrastructure costs (if applicable)				
Net revenue cost				*The Company described this as "the net impact on utility revenues through customer rates as a result of customers changing consumption of electric and gas services." Please identify how this is determined for both the electric and gas systems.*
Please identify any additional costs that may be included				
Benefits				

Avoided gas commodity cost[37]				*Please identify if this includes a value for any lost and unaccounted for gas, in addition to the quantity of gas consumption that is directly avoided.*
Avoided gas O&M cost				*Please identify the assumptions the Company will use, if any, to estimate savings on gas O&M as it relates to changes in infrastructure or reductions in throughput or peak capacity.*
Deferred capital expenditure benefit (if applicable)				*Please identify what criteria the Company intends to use to identify if an NPA will defer a new gas infrastructure project vs avoid the project. Also please identify how the Company intends to identify the years of deferral in that situation.*
Non-energy benefit				*Please identify if any additional air pollutant benefits, indoor or outdoor, will be considered or if they are assumed to be included in the proposed non-energy benefit value.*
Avoided methane leakage benefit				*Please identify if this includes a value for any lost and unaccounted for gas.*
Avoided CO2 emissions benefit				
Please define any additional benefits that could be included				

52. The Company shall provide the information detailed under each of the three categories above no later than October 23, 2024. Any stakeholder comments responsive to the Company's filing shall be filed no later than November 13, 2024.

[37] If the gas commodity forecasts are considered confidential, please also address a source for generic values that can be used for a public version in order to allow an executable version of the calculator to be public. If other factors would lead to the document being considered confidential, please identify those.

II. ORDER

A. It Is Ordered That:

1. Consistent with the discussion above, the Company is requested to file responsive information no later than October 23, 2024. Any stakeholder comments responsive to the Company's filing shall be filed no later than November 13, 2024.

2. This Decision is effective immediately upon its Issued Date.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Megan Gilman

Hearing Commissioner

ATTEST: A TRUE COPY

Rebecca E. White,
Director