Decision No. R25-0083

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.

RECOMMENDED DECISION ISSUING CERTAIN DIRECTIVES RELATED TO PUBLIC SERVICE COMPANY OF COLORADO'S UPCOMING GAS INFRASTRUCTURE PLAN FILING

Issued Date: February 5, 2025

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

2. This Decision sets forth certain requirements for the Company to adhere to in the preparation of its 2025 gas infrastructure plan filing.

B. Discussion, Findings, and Conclusions

1. Purpose and Procedural History

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 (the "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 Public Service's most

recent GIP proceeding. This Miscellaneous docket ("M-docket") is intended as a venue to follow up on these 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 annually.

6. By Decision No. R24-0480-I, issued on July 3, 2024, Hearing Commissioner Gilman set forth a workplan with discrete objectives and tasks for each of the three areas of focus ("Proceeding Workplan"). These tasks and objectives are discussed further in turn below for each forecasting, mapping, and CBA.

7. 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.[1] The workshop included participants from municipalities with significant building code and incentive programs, including the City and County of Denver ("Denver"); City of Boulder ("Boulder"); Colorado Energy Office ("CEO") who oversees state programs related to advanced building codes and statewide and federal incentives; and, the Company.[2]

8. Hearing Commissioner Gilman then held the second workshop on July 29, 2024[3], in which Public Service and invited stakeholders presented and discussed mapping, system

[1] The July 18, 2024 workshop was scheduled by Decision No. R24-0480-I, issued on July 3, 2024.

[2] The presentations from Denver, Public Service, and CEO are part of the Proceeding record on the Commission's e-filings site.

[3] The July 29, 2024 workshop was scheduled by Decision No. R24-0480-I, issued on July 3, 2024.

capacities and Public Service's CBA methodology. Among others, Western Resource Advocates ("WRA"), Advanced Energy United, CEO, Denver, Boulder, and the Company participated.[4]

9. On August 6, 2024, Hearing Commissioner Gilman issued Decision No. R24-0565-I, which required the Company, CEO, Denver, and Boulder to provide written responses to follow-up questions from the first workshop in order to aid in the understanding of available data and processes to improve gas load forecasting. CEO filed responsive comments on August 30, 2024. The Company filed responsive comments on September 3, 2024. WRA and Advanced Energy United filed responsive comments on September 5, 2025. Denver filed responsive comments on September 6, 2024.

10. On August 21, 2024,[5] 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.

11. By Decision No. C24-0708-I,[6] Hearing Commissioner Gilman identified further information that the Company was required to file in this Proceeding. This information related to all three focus areas of the Proceeding. On November 1, 2024, the Company filed information responsive to Decision No. C24-0708-I. Stakeholder responsive comments were received by Southwest Energy Efficiency Project ("SWEEP"), Natural Resources Defense Council, and WRA (jointly referred to as the "Joint Commenters"), jointly, on November 22, 2024. Responsive comments were also received by Advanced Energy United on the same date.

[4] The presentations from Boulder, CEO, WRA, and Public Service are part of the Proceeding record on the Commission's e-filings site.

[5] The August 21, 2024 workshop was scheduled by Decision No. R24-0582-I, issued on August 13, 2024.

[6] By the Errata issued on December 20, 2024, the decision number changed to R24-0708-I.

12. On December 12, 2024,[7] Hearing Commissioner Gilman held a final workshop at which Public Service presented on updates on its efforts related to forecasting, mapping, and CBA handbook development.[8]

13. By Decision No. R24-0937-I, issued on December 20, 2024, Hearing Commissioner Gilman identified several areas of follow-up questions for the Company. On January 10, 2024, Public Service provided responsive information to Decision No. R24-0937-I.

2. Load Forecasting

a. Discussion

14. Rule 4553(b) of the Commission's Rules Regulating Gas Utilities, 4 CCR 723-4, sets forth the forecast requirement for a gas utility's GIP. The utility is required to present low, base, 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 Clean Heat Plan ("CHP"). By rule, the utility must also indicate how its forecast incorporates, to the extent practicable, relevant external factors including, but not limited to: the effect of current or enacted state and local building codes; changes in the utility's line extension policies, and the associated impact on gas customer growth; 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 the price elasticity of demand.

[7] The December 12, 2024 workshop was scheduled by Decision No. R24-0779-I, issued on October 25, 2024.

[8] The presentation from Public Service presented at the December 12, 2024 workshop is part of the Proceeding record on the Commission's e-filing site.

15. In the Inaugural GIP Decision, the Commission concluded that further progress through a miscellaneous proceeding was necessary to ensure the Company's forecasts presented in the 2025 GIP are fully compliant with the Commission's regulations. The Company has largely acknowledged that it presented a forecasting methodology more consistent with historical practice that did not comply with Rule 4553(b) due to the timing of the first GIP.[9] The Commission stated that one purpose of this follow-on proceeding (*i.e.*, this Proceeding) will be to collect information regarding the Company's forecasting methodology and to discuss the parameters, logic, and other relevant facets of a gas system planning tool relevant to Public Service's service territory and customer base.[10] The Commission further emphasized the need for compliant forecasting in Decision No. C23-0397, issued in the Company's inaugural clean heat plan proceeding, Proceeding No. 23A-0392EG ("CHP Proceeding").

16. The Commission further concluded 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 decisions … [that] would likely include identifying opportunities to share the risk of investments that may become stranded or underutilized."[11]

17. The Proceeding Workplan identified several objectives related to gas forecasting in this Proceeding, including: (a) exploring the magnitude and local aspects of requirements

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[9] *See* Hr. Trans. August 14, 2023, in Proceeding No. 23M-0234G, 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.").

[10] *See* Decision No. C24-0092 at ¶ 24, in Proceeding No. 23M-0234G, on February 23, 2024.

[11] GIP Decision at ¶ 18.

identified in Rule 4553(b); (b) discussion of new or alternative load (throughput and demand) forecasting approaches with experts, including how the Company can implement these approaches; and (3) efforts 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.

18. The first workshop held on July 18, 2024, focused entirely on gas load forecasting. At this workshop and in follow-up comments, CEO provided information on building code improvements. Denver presented information on its 2022 Denver Energy Code revisions, and Boulder shared information on its strategies in place to reduce greenhouse gas emissions ("GHG"). Each of these areas of discussion are more fully described in Decision No. R24-0708-I.[12] The Company also presented on its forecasting methodology at the July 18, 2024 workshop and provided responsive comments on follow-up questions related to understanding 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.

19. In response to Decision No. C24-0708-I, the Company filed in this Proceeding its proposal for how it plans to approach forecasting for the 2025 GIP. Within its proposal, it provided a summary of how it plans to approach drivers of electrification, the range of forecasts required by Rule 4553(b), and its approach to the localized nature of GIP forecasting.[13]

20. As the Company describes it, its forecasting process involves several distinct phases. First, the Company develops an as-is view of capacity needs within sections of the system, described as "nodes". At each node, the Company uses actual monthly meter reads from the past

[12] *See* Decision No. R24-0708-I at ¶¶ 14-16.
[13] *See* Proposals regarding load forecasting, system mapping, and cost-benefit analysis, filed by Public Service on November 1, 2024 ("Company Proposal").

winter to determine the capacity needs of that section of the system utilizing the Customer Management Module ("CMM") within its hydraulic modeling software, SynergiGas. With the monthly meter read data, the Company, using its software, mathematically disaggregates the portion of the total monthly gas load that it determines likely occurred at the system peak, contributing to the required peak capacity of the system. The Company acknowledged that this method is based upon a fairly standard home that is entirely gas-heated and does not account for partially electrified homes that may use gas as a backup. This "as-is" forecast is essentially used to identify the current situation related to capacity within each section or node of the system. A forecast is then layered over top of the "as-is" data to determine the anticipated capacity situation in years to come for each segment or node of the system, which could be used to identify upcoming capacity needs.[14]

21. Rule 4553(b)(I) dictates that the Company must put forth a low, base, and high forecast with respect to gas sales and peak capacity. The Company has communicated that its forecasting methodology does not vary use or capacity needs per customer for existing customers, but does utilize differing customer counts, based upon the factors considered.

22. Several factors influence the sales forecast identified in the proposal. First, with respect to residential customers, the Company utilizes Energy Information Administration ("EIA") data to predict usage per new customer. The Company argues EIA data includes factors associated with building code improvements. The Company did not put forth any specific methodology or consideration of incentives as a factor in customer adoption of electrification technologies outside of the "beneficial electrification" described below. Second, with respect to large gas customers, the Company indicates that it will continue to use capacity check information for as part of the

[14] *See* Workshop Presentation, July 18, 2024.

forecasting process. Third, with respect to the price elasticity of demand for both residential and commercial customers, the Company suggests price elasticity is "pretty low" in the "0.1 range," though it acknowledges that customers have recently responded to periods of high prices by lowering their consumption.[15] .

23. Related to its forecast, the Company has developed new assumptions for electrification which were not represented in the Inaugural GIP. The Company distinguishes between what it terms as "Market Electrification" and "Beneficial Electrification." For Market Electrification, the Company utilizes an assumption based upon results to its 2022 Home Energy Use Study in which the Company surveyed a portion of its Colorado customers on various features of their homes including heating and water heating system types.[16] The Market Electrification factor only applies to the residential class. The Company indicated that newer homes (built between 2017-2022, the latest years subject to the survey) were less reliant on gas furnaces relative to the prior five-year period (73 percent vs. 84 percent for the earlier period). The Company incorporated the 73 percent furnace penetration on a going-forward basis for all years in the forecast period. In response to Decision No. R24-0937-I, the Company also provided information from a 2024 Home Energy Use Study and clarified that the results from the 2022 Home Energy Use Study do not include information for homes built in 2021 or 2022, so the recognized trend in heating system types discussed above occurred prior to 2021.

24. "Beneficial electrification," as the Company defines it, includes outcomes and goals specifically linked to adjudicated proceedings which have resulted in actions promoting electrification of heating, water heating and cooking loads, namely Proceeding No. 22A-0309EG

[15] *See* December 12, 2024, workshop at 1:36:30. https://www.youtube.com/watch?v=XnQg0KBln7M.
[16] *See* Home Use Energy Study Responses Attachments to Public Service January 10, 2025, Response to Decision No. R24-0937-I.

regarding demand side management ("DSM") and beneficial electrification ("BE") Strategic Issues and Proceeding No. 23A-0392EG, the CHP Proceeding. The 2024 Home Energy Use Study includes heating system types for only 11 total customers who began receiving service in 2021 (four customers), 2022 (three customers), 2023 (one customer), or 2024 (three customers).The data set contained in the 2024 Home Energy Use Study regarding heating appliances does not appear robust enough to be statistically significant or to use for the purpose of identifying trends. Given the significant interest and importance of gaining insights into changes in customer behavior and systems, a significantly more comprehensive method will likely need to be employed to understand penetration and trends related to heating equipment.

25. As discussed above, Rule 4553 requires the Company to provide a low, base, and high forecast. The Company described that it plans to run each forecast and identify, for each planned project, under which forecasting scenario such an investment would be required. For example, if a capacity investment was only needed for the high growth forecast, but not under the base or low forecast, such a difference would be readily identified within the GIP filing related to that planned project.

26. Public Service proposes that the "High Case" forecast will incorporate market electrification at the same rate as indicated from the 2022 Home Energy Use Study. As proposed, it would not include impacts of electrification from activities related to the approved DSM/BE SI Proceeding No. 22A-0309EG nor any impacts of electrification from activities related to the approved CHP Proceeding.

27. The Company proposes that its "Base Case" forecast will incorporate market electrification at the same rate as indicated from the 2022 Home Energy Use Study and beneficial

electrification at adoption levels targeted in the 2024-2026 DSM/BE Plan[17] and extended through the entire planning period. It would not include any impacts of electrification from activities related to the approved CHP Proceeding.

28. The Company proposes that its "Low Case" forecast includes market electrification at the same rate as indicated from the 2022 Home Energy Use Study, but only through 2026. After 2026, the Company assumes that no market electrification of this sort takes place, given implementation of the CHP incentives. As proposed, it would include impacts of the CHP Proceeding. However, it would include impacts of the Amended Preferred Portfolio, rather than the Commission-approved portfolio, as the Company claims the time necessary to prepare the forecast dictated use of the portfolio proposed by the Company prior to the conclusion of the proceeding. Generally, the "Amended Preferred Portfolio" proposed by Public Service in the CHP Proceeding resulted in approximately 20 percent less electrification, and associated CO_2 reductions, than the Commission-approved portfolio required in Decision No. C24-0397.[18] It was unclear whether the Company's proposed low forecast would include the DSM/BE SI beneficial electrification levels in addition to those specific to the CHP. In the December 12 workshop, Mr. Goodenough appeared to clarify that "DSM is included in all cases…" but the amount of DSM is unclear, and it is further unknown if aspects of BE also included in the DSM/BE SI proceeding are included or only DSM.

29. Several parties, including the Joint Commenters and Advanced Energy United, are supportive of the longer-term movement indicated by the Company to bottom-up forecasting that is more granular and localized. However, related to the 2025 GIP filing, they argue that the

[17] The Company's 2024-2026 DSM/BE Plan was approved in Proceeding No. 23A-0589EG through Decision No. C24-0671, issued on September 18, 2024.

[18] Comparison of budget and carbon dioxide emission savings from DRA-16 in Proceeding No. 23A-0392EG.

proposed forecasts are largely unreasonable. For example, Advanced Energy United questions whether the Company's proposal underestimates technological adoption generally and is concerned that the Company proposes to only include clean heat plan adoption levels in the "low" scenario. It also argues that the goals and directives in state, county, local laws should be considered in all scenarios, as they carry the full force of law.[19]

30. The Commission's Gas Rules establish requirements that a utility present the same forecasts in its GIP as was approved in the utility's most recent CHP. For that reason, Rule 4731(a)(I)(B), which resides in the Clean Heat section of the rules, references Rule 4553(b)(I) of the GIP rules in order to maintain the same forecasting methodology. Rule 4731(a)(I)(B) requires that: "Forecasts should be disaggregated by pressure district, unique planning zones requiring a distinct design peak demand condition, or other geographical segmentation, as appropriate."

31. In the Inaugural GIP, the Company's customer count forecast was developed by utilizing the state demographer's expectations for population growth distinguished by County.[20] The Company proposes to maintain that general approach for its 2025 GIP, but with improved County-level stratifications, which are developed using the recent relationship between customer growth and population growth in addition to population growth estimates. Longer term, the Company represents that it will develop a more localized, "bottom up" forecasting approach, which is widely supported by commenters. The Company did not specify the timeline of such changes.[21]

[19] Advanced Energy United Comments, filed on November 22, 2024, pp. 2-3.
[20] *See* GIP Decision at ¶ 59.
[21] Company Proposal, p. 22.

32. In its proposal, Public Service indicates that its development of peak hour gas growth forecast generally begins at the conclusion of the prior heating season, culminating in identification of expansion projects occurring in August through November, followed by nonpipeline alternative ("NPA") analyses running October through January. The Company generally articulates that its forecasting is already underway or complete for the 2025 GIP.[22]

33. While forecasting includes both capacity and sales figures, the Company's assumptions include a decline in sales, but little to no changes to design peak demand in electrification scenarios that include gas backup. Public Service bases this assumption upon a spreadsheet model submitted on September 3, 2024 in this Proceeding.[23] In identifying the modeled behavior expected by the Company, it makes several key assumptions including: that the heat pump and furnace cannot run simultaneously and that the heat pump capacity and ductwork are sized for the cooling load (and thus significantly undersized for the heating load). These assumptions result in a heating capacity of about one third of the furnace capacity. Further, the Company's use of the model appears to assume that all installed retrofit electrified heating with gas backup across the system would operate in the way indicated in the model.[24]

b. Findings and Conclusions

34. First and foremost, it is important to address the Company's indication that it either cannot or will not update forecasting based upon stakeholder feedback or outcomes of this Proceeding, due to the timeline it indicated in its presentations within this Proceeding. Further, it indicates that compliance with Rule 4553 will not occur for forecasting in the 2025 GIP filing. In the GIP Decision, the Commission ordered that "…Public Service shall file a forecast that fully

[22] Company Proposal, p. 8.
[23] Executable Attachment A, filed on September 3, 2024, in response to Decision No. R24-0565-I.
[24] Public Service Response to Decision No. R24-0565-I, filed on August 6, 2024, p. 5.

complies with Rules 4553(b) and 4731(a)(I) with or prior to its next GIP."[25] Further, the Commission identified that "[i]t is unclear how, if the Company is not taking appropriate factors into account, the Company can substantiate the need for specific projects."[26] Given all of this, we now find ourselves in a precarious situation given the timing in preparation for the 2025 GIP, the Commission's previously expressed requirement, and the Company's indications here regarding its forecasting methodology for the 2025 GIP. The Company's forecasting proposals presented in this Proceeding do not appear to be fully compliant with Rules 4553(b) and 4731(a)(I). It is notable that the Company has not communicated its inability to meet the requirements found in the Commission's Rules to the full Commission, nor has it filed a motion of any sort to address its anticipated failure to comply with the Commission's Order. In light of these considerations, it is inappropriate for the Hearing Commissioner to adjust expectations made by the full Commission, including those codified in the Commission's Regulations, for the 2025 GIP filing in any way. The Commission has previously pointed out risks associated with submitting a 2025 GIP that incorporates a non-compliant forecast, and I stand by those concerns.

35. The need for accurate and localized forecasting is critical. The Company's capital plans for its electric operations take a very optimistic view of increases in both sales and capacity needs on the electric system, in part to serve growing beneficial electrification loads. The Company has identified a projection of nearly $7.5 billion in capital investment needs in electric distribution infrastructure alone in the next 5 years.[27] If spending supporting wildfire mitigation, transportation electrification, and advanced grid intelligence and security ("AGIS") are removed, the request totals $4.9 billion related to other distribution system improvements, a

[25] GIP Decision, ¶ 24. The Commission reiterated this sentiment in Commission Decision No. C24-0397 at ¶ 273.
[26] *Id*.
[27] *See* Hr. Ex. 103 (Attachment ZDP-1), p. 101, filed on December 16, 2025, in Proceeding No. 24A-0547E.

portion of which is based upon expectations in the increase in beneficial electrification. This is in addition to approved or projected generation needs from the 2021 Electric Planning Proceeding (Proceeding No. 21A-0141E) and the 2024 Just Transition Plan (Proceeding No. 24A-0442E) filings totaling 107 billion in net present value capital additions[28] and approximately $3.5 billion in approved or requested transmission upgrades. Given the monumental growth the Company appears to be projecting for the electric operations, including for electrification of loads currently served by natural gas, one would hope and expect that there may be some commensurate savings represented in gas filings. Understandably, some of the impacts of increasing electrification on gas capacity may be harder to predict than impacts on sales, however, it is plain to see that continued growth in capacity on the gas system with anticipated declining sales points to a serious and growing economic problem for the overall system. Further, for its customers in Colorado, full investment and buildout of two redundant energy systems to serve high estimates of need on both systems may have crushing impacts on affordability. It is critical for the Company to reduce the lag associated with its forecasting processes. The Company suggests a timeline of 15 months (February 2023 through May 2025) from its last winter peak season to produce a forecast and embed such into its GIP evaluation. I am concerned that, if the Company cannot significantly reduce the lag in its forecasting and planning processes, to facilitate the 2025 GIP application, the Commission may have to hire an outside entity to conduct a proper forecast, rely on parties' expertise or do so internally to the best of our abilities. It is simply not acceptable to base highly impactful forecasting and hundreds of millions of dollars in capital additions for the gas system on broad generalizations and ultraconservative models. The Company does appear to recognize the

[28] *See* Decision No. C24-0052, ¶ 103, issued in Proceeding No. 21A-141E and Hr. Ex. 101 (Attachment JWI-2, Vol. 2), p. 160, in Proceeding No. 24A-0422E.

need to evolve its forecasting into a far more sophisticated and data informed operation. Its representatives showed up and participated in earnest in these efforts and communicated more of a willingness to move this effort forward within this Proceeding than I had previously heard. I appreciate the interest and efforts of those within the Company working to move these efforts along and aim to provide guidance to make these efforts as successful and useful as possible.

36. The first step in the Company's forecasting methodology is the development of "as-is" forecasting using historical monthly meter reads and hydraulic modeling on nodes of the system. Several key factors play into the "as-is" models developed in this manner. First and foremost are the design day criteria used to determine the extreme temperature for which the system sizing should be based. The Commission has opened a separate proceeding (Proceeding No. 23M-0092G) in which this issue is being studied. As discussed there, key questions remain including: (1) the appropriateness of the temperature inputs amid changes in the climate that trend warmer; (2) the precision or lack thereof related to the use of monthly meter reads to estimate the contribution to peak demand; and (3) the strain that new mechanical arrangements will put on the historical calculation approach. This Decision will focus more on future forecasts rather than the "as is" approach to determining design day (which is likely more appropriately followed up in Proceeding No. 23M-0092G). However, it is fair to say that significant questions and valid concerns about the "as-is" forecasting, which is the foundation upon which capacity needs are calculated, remain and likely will persist until this issue is more fully addressed. In the interim, the Company should track the most relevant data each heating season, especially in the most extreme cold events, to continually monitor and refine the accuracy of the estimates, based upon the most advanced real-time monitoring tools available on the system to proactively compare the anticipated

system flows to actual system flows at temperatures each year most similar to the peak design temperatures.

37. Rule 4553(b) dictates that the Company must put forth a low, base, and high forecast with respect to gas sales and peak capacity. An appropriate range of forecasts is a key foundational piece of the Gas Infrastructure Plan regime, since the need for future projects will largely be dependent upon the forecasts. In addition to its importance in determining project need and appropriateness of sizing projects, forecasting for sales and capacity will also be very important factors in identifying the relative economics of regions or segments of the gas system to evaluate non-pipeline alternatives and make other necessary regulatory evaluations to manage the future affordability of the system in ensuring it is properly sized. Based upon notable growth in the availability and market share of efficient electric heating options and policy levers pointing away from the continued use of gas as the predominant heating fuel, we have entered a time of significant uncertainty about the future of both sales and capacity needs of the system. This uncertainty comes with real concerns about how to right size the infrastructure and avoid any unnecessary investments to prevent saddling the system with higher fixed costs to spread across fewer customers and lower sales. Therefore, it is important that the low, base, and high forecasts provide a reasonable range of possibilities to evaluate investment needs under those different potential circumstances.

38. The Company's proposal put forth in its November 1, 2024 filing does not present a reasonable range of forecasts upon which to base the upcoming GIP because the Company's proposed approach ignores or improperly discounts enacted legislative policy, approved Commission plans, and broader market forces. While the Company recognizes the risk of underbuilding the system, leading to potential under-pressurization and loss of gas service, it does

not seem to acknowledge the potential mitigation strategies for that circumstance nor the significant risk that overbuilding may also cause. Given the significant uncertainty about the forecasting around gas loads going forward, overbuilding could present a clear and present risk of incurring costs for new assets which may become stranded or vastly underutilized well short of their depreciable or expected life, creating significant cost pressures for the system and its ratepayers. Gas loads do not materialize overnight nor without notice to the Company and the Company may be able to deploy strategies to manage the demand on the system, so it stands to reason that the Company has more options available to it to manage the timing and magnitude of changes in peak capacity than are considered. Recognizing a significant risk in either direction of failing to right-size the infrastructure, we must then focus on appropriate bounds for reasonable forecasting moving forward in an incredibly dynamic environment as it relates to policy and overall demand for the product.

39. The base forecast should include the most likely possible future. This should reasonably include enacted legislative policies, Commission rules, and Commission-approved plans and actions. The failure of the Company to include any impacts from the CHP Proceeding does not make the proposed Base forecast a reasonable basis upon which to plan. The Commission, along with its regulated gas utilities, are under a statutory obligation to reduce the greenhouse gas emissions from the distribution and end use of gas[29] and this Commission and stakeholders spent the better part of a year analyzing and debating the best path forward to do so in the CHP Proceeding. The base forecast here, which does not include any impact of the Clean Heat Plan, stands in stark contrast to filings made in the Company's electric Distribution System Plan (Proceeding No. 24A-0547E), in which the Company expects use of heat pumps for heating

[29] § 40-3.2-108, C.R.S. *et seq.*

to expand "to hundreds of thousands by 2030 to meet Colorado clean-energy goals."[30] The Clean Heat Plan represents $450.6M (including 15 percent budget flexibility)[31] in funding through 2027 to promote primarily beneficial electrification and DSM. It is unreasonable to think that as a base condition this effort will be entirely unsuccessful with no impact to either sales or capacity. Given that this is a legislatively required action and significant planning and funding are already allocated to it, the Company should include the anticipated savings attributed to both the DSM/BE SI and the CHP related to BE and DSM in its base forecast. The treatment of Market vs. Beneficial Electrification was not overwhelmingly clear, but it certainly stands to reason that the Company should include the most recent trends it has seen through Home Energy Use Studies or other appropriate research to continue to update trends in electrification occurring in the marketplace and incorporate that intelligence, ideally in a way that has data less than 5 years old, in its forecasting. The Commission will likely need to determine an appropriate assumption of market electrification (*i.e.*, electrification adoption occurring outside of Company programs) as part of our review and approval of the Company's 2025 GIP. Likewise, the inclusion of building code considerations appears to be overly general and not pertinent to the actual areas of study within the service territory. Further, the introduction of significant federal and local rebates and incentives promoting electrification have not been meaningfully considered nor has the Company appropriately addressed why their consideration would not be appropriate.

40. The high forecast, as presented, is also inappropriately high. In this Proceeding, the Company did not satisfactorily demonstrate how it includes BE and DSM initiatives likely to have the most impact on gas usage and capacity needs into its high forecast. While it is conceivable that

[30] Hr. Ex. 103(Attachment ZDP-1), p. 8, filed on December 16, 2024, in Proceeding No. 24A-0547E ("growing modern air-source heat pump ("ASHP") market is in the single-digit thousands today but may need to grow to hundreds of thousands of installations by 2030 to achieve Colorado's clean heat goals.").

[31] *See* 2024-2027 Clean Heat Plan, p. 12, submitted on October 21, 2024, in Proceeding No. 23A-0392EG.

these efforts may not meet their respective goals in full, especially at this early stage of their implementation, the Company put forward a limited explanation for how it incorporates BE and DSM into its high forecast. The Company should determine a high forecast which includes the approved and enacted initiatives around BE and DSM, but could consider a more pessimistic view of adoption, ideally informed by success or failure of other similar efforts or other relevant data sources that the Company believes could point to a reasonable lower bound of expectations as far as success of those efforts, so long as they are relevant to our context. Similar to the base forecast, the consideration of building codes appears overly general in the Company's high forecast proposal. In particular, it appears that the Company is assuming that all federal and local incentives have no impact on market electrification. The stakeholders to the instant Proceeding disagree with the Company's proposal. For example, stakeholders stated that the 2021 International Energy Conservation Code represents the "most significant changes in performance requirements" and is not captured in the Company's survey since the survey did not collect data after 2021.[32] Further, stakeholders, including Boulder and Denver, indicated their communities are experiencing increased electrification due to local building code changes otherwise unaccounted for in the forecasts.[33]

41. The low forecast proposal is also difficult to accept, as it appears to reference more of the Base Case – including implementation of the goals of the approved and enacted BE and DSM programs. It would appear that a low forecast should make more significant assumptions about building codes and uptake of federal and local incentives to present a view with lower forecasted capacity and usage than those only supported by a select number of policies and plans.

[32] *See* December 12, 2024 Workshop at 1:41:00 https://www.youtube.com/watch?v=XnQg0KBln7M.

[33] *See* City of Boulder's Workshop Presentation, Filed August 2, 2024, p. 19; City and County of Denver's Response to Questions, filed September 6, 2024, pp. 2-5.

42. The Company's proposed plan to evaluate for each forecast which of the projects identified in the GIP would be determined to be necessary appears to be a reasonable way to present the variation in system needs and buildout under the varied forecasts, especially given the significant uncertainty facing future capacity and sales.

43. The Company's plan for forecasting to only change the customer count, not usage per customer, does not seem to be a very accurate way to model for the variety of circumstances that the high, base, and low forecasts are intended to cover and could result in unintended consequences. It is unclear how the changes associated with partial electrification will be properly calculated. The Company's modeling presented in the CHP projected that 10 percent of residential single-family homes will have a fully electrified heating system by 2030 and that another 11 percent will have a hybrid system with a heat pump providing the primary heat with gas as a backup.[34] Given that only about half of the electrification the Company is projecting under the CHP by 2030 would be fully electrified, modeling only shifts in customer count ignore critical forecasting information. Indeed, there are even more extreme examples, whereas in Proceeding No. 22A-0309EG, the Company showed that a significant number of new homes with fully electrified heating were still getting a gas line, presumably for small auxiliary loads like a cooktop or fireplace.[35] This further points to a trend, not just in customer count, but in capacity and usage per customer which must be tracked and utilized in forecasting in order to paint a full and accurate picture.

44. Notably, in Decision No. R24-0708-I issued October 1, 2024, the Hearing Commissioner requested the Company to provide detailed information related to information

[34] Hr. Ex. 145 (Attachment DRA-16), in Proceeding No. 23A-0392EG.
[35] *See* Workshop Presentation, July 18, 2024, p. 12.

collected on the Company's Application for Gas and Electric Services. The application includes a field for entries of information including the new load's total gas load capacity (BTU/hr), as well as a breakdown of total gas load capacity by end use (BTU/hr). The Company's response indicated that this information is not always complete and could change by the time of construction. The response provided no data or analysis of new or potential customers, and was generally unsatisfactory given the wealth of information that could be gained related to new loads and their end use characteristics. The response also contradicts information previously filed in which the Company claimed it "does not use a standard loading assumption for new home service requests. Rather, the Company requires new service requests to submit an application which includes information on loading."[36] Given this clear contradiction, it is unclear how the Company estimates or gains insights into the expected peak capacity needs of new loads, as it has essentially denied both using an average modeled value and denied having actual data from each applicant that can be relied upon. Given the importance the Company places on understanding peak capacity needs and the significant changes that may be underway currently, the Company must make strides to ensure this information is completed in full in order for the application to be processed and prompt customers to update it if it is no longer accurate. The peak capacity need of new customers is a critical feature in planning the system and it is difficult to understand a strategy of using significantly more general information than the Company could reasonably have available. The Company should, therefore, ensure this critical information is complete in applications for new or upgraded service, have a process in place to incorporate updates to this information for applications already in progress, and record this information such that it can be analyzed to

[36] May 1, 2023 Response at p. 2, filed in Proceeding No. 23M-0092G.

determine relevant trends in total gas load capacity (BTU/hr) and gas load capacity by end use (BTU/hr) disaggregated by both customer class and geographic area.

45. The Homes Energy Use Study data appears somewhat useful in also understanding trends. However, as the Company clarifies in its January 10, 2025 filing, the 2022 data does not include homes built in 2021 or 2022, so the information being relied upon for the market electrification trend identified by the Company is at least 5 years old.[37] Notably, this is prior to many jurisdictions adopted the more stringent 2021 International Energy Conservation Code, and prior to the introduction of significant new local and federal incentives for electrified heating equipment. Further, the Company's use of the data anticipates only a flat line continuation of the latest values, in essence, holding steady 5-year-old data. In this way, it is possible that the Company is significantly underestimating the role of market electrification in its forecasting.

46. It appears that the Company and its forecasting could benefit by enhanced coordination with local municipalities. Local municipalities are often first to understand upcoming large developments, as well as their timing and details. They may also have valuable information about the impact that they expect their particular building codes and ordinances to have on efficiency and heating sources at the project, which could lead to more refined estimates by the Company. Prior to overlaying broad forecasting assumptions over large geographic areas, the Company should ascertain any relevant information from major municipalities about major gas loads that may be emerging or being eliminated. Likewise, significantly more information is needed about trends in electrification and backup systems. Municipalities and other entities who run programs or issue rebates related to electrification and mechanical systems could provide substantial help in tracking the prevalence of different system types, replacements, other system

[37] January 10, 2025 Supplemental Filing, at p. 4.

attributes to refine the Company's forecasting. In its response to Decision No. R24-0565-I, the City of Denver acknowledged that they could likely work with their other departments to better assist in tracking information that could be helpful.[38] Boulder also noted that they have data sets for the adoption of heat pumps that do not qualify for Company rebates.[39]

47. I encourage the Company and municipalities to work together to determine the most crucial information that could be gathered through these programs to help better inform the utility about trends and forecasting.

48. The Company's inclusion of the impacts of building codes is only very approximate, including data from a national source, without regard for specific building codes, especially those which may show an explicit or inherent preference for electric heating sources. The Company should identify major building code changes and implementation dates and associate those directly within its forecasting in localized areas. More recent information, like that which could be gained from new load applications, could help shed more light on the immediate impacts of recent building codes on new construction, especially as it relates to peak capacity and usage. It is not clear from the Company's Proposal if price elasticity of demand is being used for capacity or just sales. In its 2025 GIP application, the Company should further elaborate on its inclusion of the price elasticity of demand, including any mathematical relationship between price increases and sales that is or could be used. Further, if the Company is only considering behavioral change around sales related to increased prices, we could miss a larger trend. If prices continue to escalate, especially as sales decline, it is possible that capacity decreases could also follow, related

[38] *See* City and County of Denver's Responses to Commission Questions Issued in Interim Decision No. R24-0565-I, filed on September 6, 2024.

[39] *See* July 18, 2024 Workshop at 4:07:00 https://www.youtube.com/watch?v=Yyq0usnsOP0.

to customers choosing more cost-effective fuel choices. It is not clear if that is or can be modeled by the Company.

49. The emergence of homes that are primarily heated with electricity, but rely on gas as a backup fuel for the coldest days, presents a key challenge in forecasting. First, as the comments of Advanced Energy United identified, this situation could lead to increases in system capacity needs while sales decline, which, if widespread, could create major economic strains on the system. Second, this arrangement may lead to significant issues in the fairness of how customers who use the system in dramatically different ways are billed for the use of the product. Third, it can make the historical practices of disaggregating monthly meter read data to determine a building's peak usage based only on a monthly meter read more difficult and less accurate. Therefore, it is important to have appropriate assumptions about the behavior of a variety of mechanical configurations to understand this relationship. In order to make assumptions about the gas capacity needs in this situation, the Company is utilizing a spreadsheet model to quantify the gas capacity behavior of a home with primary electric air source heat pump heating and secondary gas backup heating. In response to Decision No. R24-0582-I, the Company provided additional details, including a written explanation and the executable model. Upon inspection of this information, it appears to be based on very conservative assumptions and is not likely to be reflective of every or even the majority of situations. The Company's model makes critical assumptions including: a system that does not allow the heat pump and furnace to run at the same time, a heat pump sized with less than half the heating capacity of the gas furnace, and use of the existing ductwork that they assume to be significantly undersized for the purposes of heating with a heat pump despite no delta T analysis. While the rather extreme constraints the Company placed on its model may represent some portion of retrofit installations of air source heat pumps, I agree

with Advanced Energy United that the Company must complete modeling to represent a "fuller range of potential outcomes."[40] Customers electrifying their heating with ductless units, ground-source heat pumps, air-to-water heat pumps for hydronic systems, appropriately sized new construction systems, or with more generously sized ducting than that considered by the Company in this limited example could be likely to have very different experiences, including contributions of the partial or full heating load by the heat pump, even in significantly cold conditions. While no one disputes that the efficiency of a heat pump will reduce as outdoor temperature drops, the Company does not provide compelling evidence to support why its base assumption that all contributions of the heat pump will be locked out at an outdoor temperature of 25 degrees °F or below and all heating loads at those times will rely entirely upon the gas backup would be a reasonable assumption for the Company to replicate for *all* assumed retrofits that utilize gas heating as a backup fuel. This could lead to a dramatic overestimation of the gas needs of these homes, both in terms of capacity, as well as usage. To the extent that the Company utilizes a worst-case rather than more average capacity need assumption for an individual home and then multiplies that singular result thousands or even hundreds of thousands of times over in forecasting, this could lead to a dramatic oversizing of infrastructure needs, increasing infrastructure costs for ratepayers and increasing the risk of stranded assets, some of which may never be necessary. The Company must endeavor to collect more data on the usage and capacity of these homes including under different mechanical system configurations. Third-party metering equipment, consultation with reputable labs and research firms, or other means must be used to refine the Company's assumptions around usage and capacity of homes utilizing gas as a backup

[40] Advanced Energy United Comments at p. 6.

to produce significantly more reliable and applicable information than is represented in the one modeled circumstance.

50. In the longer term, the Company has expressed an intent to move to significantly more informed and localized forecasting, described by it as bottom-up forecasting. It seemed likely from the dialogue at the last workshop that such forecasting would likely be in place by the 2027 GIP. I am pleased to see the Company moving in this direction and taking this initiative seriously, notwithstanding the other concerns within the Decision about the appropriateness of some major assumptions. As the Company builds the capacity to significantly modernize its forecasting methodology, it seems critical for the Company to identify what data collection or enhanced modeling is needed to ensure that refinements use the most appropriate and up-to-date information available. It would be a setback to spend time developing a new methodology only to not have the appropriate inputs and face further delays to actually implement the new methodology, so the Company should be working simultaneously to gain the insights and data it needs to input into the new methodology to ensure it meets expectations in a timely manner.

3. Mapping

a. Discussion

51. 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, Senate Bill 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.

52. In the Company's Proposal, it proposes to comply with the GIP mapping requirements through five measures: (1) Public Project-Specific Maps; (2) Confidential Project-Specific Maps; (3) Separate Highly Confidential Restriction (System-Wide Maps Meeting requirements of GIP Map Statute); (4) Separate Public System-Wide Map of distribution; and (5) Separate Public System-Wide map (entirety of system).[41]

53. The Company continues to raise security considerations that impact its ability to provide fully public mapping—it highlights that risks of public disclosure of sensitive mapping information is not hyperbolic and includes terrorism and security threats. It also delineates that the GIS data submitted per PSP Rule 11100 is not meant to be an extension of the GIP Rule mapping provisions.[42] The Company expects to file a GIS shapefile with the required attributes to the Commission's PSP and does not intend to file any of this information, unless explicitly required elsewhere, as part of the GIP filings.

b. Findings and Conclusions

54. As identified in previous decisions within this Proceeding,[43] commenters in the Inaugural GIP and the Commission 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 the investment needs, in order to plan the system as cost effectively as possible. Ideally, a reasonable view of upcoming system and capital planning would include some degree of technical and spatial awareness of the relationship of projects to each other to understand areas where investments might be pancaking in the future, which would be important to consider in any analysis of alternatives.

[41] Company Proposal, pp. 3-5.
[42] *Id*. at 38.
[43] *See e.g.,* Decision No. R24-0480-I at ¶ 8.

55. At the second workshop in this Proceeding, I had a conversation with the Company and stakeholders about the main objectives around the use of mapping and established the following areas of broad agreement as objectives that the 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.[44]

56. The Joint Commenters added a few specific objectives, including increased transparency into planned gas distribution investments, identify opportunities for equity-focused, cost-effective, and technically feasible NPAs, and lead to streamlined implementation of NPA projects, including zonal electrification at scale, with an emphasis on projects that benefit disproportionately impacted communities.[45] I agree with these aspects, as well, but also find that they largely overlap or are subsets of the already identified objectives. I find it inherent that the discussion on transparency and strategy in the original objective list include a significant focus on

[44] Following the workshop, in its written response to the interim decision, the Company expressed disagreement with this final concept. *See* Company Proposal, at p. 40.

[45] *See* Response Comments of Joint Commenters, filed November 22, 2024, at p. 8.

NPAs and disproportionately impacted communities, but appreciate the refinement provided by the Joint Commenters.

57. The Company's reiterated concerns about safeguarding of sensitive system information is a real concern that has been considered throughout this Proceeding. Careful consideration is required to understand the risk and reward with any release, even under confidentiality requirements, of system data. To be sure, we must also be aware how information will be immediately useful to the parties who would receive it to ensure that its release would advance the objectives listed above in a meaningful enough way on balance to warrant its release. It is also important to ensure that any protections or restrictions placed on access to such data and the technical expertise needed to interpret it are also considered in terms of ensuring that any release is actually useful in the context of a GIP proceeding and proper analysis of projects or potential project areas. That being said, there are very clear limitations providing this information only in list format or through only static maps which would significantly hamper the objectives above, all which are intended to ensure we are planning the system in order to serve ratepayers and pursue the state's policy objectives in the most optimized way possible. It is simply true that stakeholders will need to know more about the system than they have previously in order to properly represent their interests. My goal is to try to strike an appropriate balance in these important objectives.

58. In its proposal in response to Interim Decision R24-0708-I, the Company indicated that for confidential project-specific maps it is "exploring the possibility of allowing remote, secure, log-in to view the confidential planned project maps in an interactive, ESRI ArcGIS Online format, however it is unclear at this time whether such an interface can be solutioned prior to the

filing deadline for the 2025 GIP."[46] The Company also offers that the same may be available for Separate Highly Confidential Restriction – System-Wide Maps Meeting Requirement of § 40-3.2-104.4(3)(a), C.R.S. Otherwise, such viewing would only be available during the pendency of the GIP proceeding in person in the Company's office. However, upon viewing, the party could request and obtain highly confidential PDFs of certain sections. The Company identifies that "[a]ccess to the entirety of this map should be limited to parties to the GIP, and further limited to the Commission, State Agencies, Colorado municipalities/counties, and environmental advocates who routinely practice before the Commission."[47] This suite of options appears reasonable. The ability to remotely access the mapping tool would most appropriately serve the objectives identified by the group at the second workshop, summarized above. The Company should work in earnest to make this option available to parties as described in the Company's proposal for the 2025 GIP. Importantly, this will also help to refine the use of this information for parties to ensure we are meeting the broader goals of the GIP process.

59. The Join Commenters were generally supportive of the direction, but recommend some additional information be added to mapping to best serve the objectives. I will address each of those here:

a) ***The number and type of customers served by the project to help identify where electrification is most likely to be cost-effective***. For planned projects, I anticipate that this information will already be provided based on Rule 4553(c)(I)(K). The Rule does not necessarily require the information to be displayed on the map itself, which may be the nuance in the recommendation, but this information is expected to be readily available for each planned project nonetheless.

b) ***Available electric capacity in the project area***. Certainly, the integration of planning across both the gas and electric systems will be key to finding optimized solutions for ratepayers. Efforts are progressing quickly on both the gas and electric systems to develop and present more granular forecasting and system data to

[46] Company Proposal, pp. 43-44.
[47] *Id*. at 5-6.

provide precisely the kind of optimization that it appears the Joint Commenters are seeking, but I am not confident we are there at this point. Some of this may depend on the developments in Proceeding No. 24A-0547E, the Company's recently filed electric Distribution System Plan, where details about presentation of electric forecasting and infrastructure locations and loading may be further discussed. The Company has, on several occasions, and through its NPA CBA proposal, identified the importance of coordination of the infrastructure forecasts and needs, so I am confident they recognize that moving in this direction would be very helpful If the Company has available localized mapping of the electric system and its capacity, it would be very valuable for the Company to attempt to make that available through the same protections and avenues it expects for the gas infrastructure information. If not, the Company should aim to provide this sort of integrated information for the 2027 GIP.

c) ***Area income, in addition to DI community designation, to help focus projects on low-income households.*** If the Company has access to such an information overlay for its service territory, I would encourage its inclusion in GIP maps, however, I would stop short of requiring them to perform a new exercise to obtain this information at this time prior to the 2025 GIP, if it is not already available to the Company. While I appreciate the nuance that even within DI communities, it may be helpful for us to target programs in lower income areas, at this early stage, there may be several competing objectives and variables, so it is not clear it would or should immediately drive choices about NPA implementation or analysis. However, I agree with the sentiment that adding this information to mapping, if available, could help inform our efforts.

d) ***Availability of supportive local government or community partners, to support robust community engagement***. I agree with the Joint Commenters that having a supportive local government or organization to aid in NPA efforts could be key to success. However, it is not immediately clear what metric or details would appear on the map. Perhaps the best indication of strong local support is a local rebate promoting DSM or electrification or an organization providing energy outreach and services. In order to include the proper aspects into forecasting, the Company should essentially be updating and mapping the existence of local rebates in order to comply with Commission Rule 4553(b)(II) regarding forecasting, although I am not confident that is how it is being done or planned to be done. It stands to reason that understanding the boundary area of these additional layers of support could be very helpful to successful planning and implementation of an NPA. I encourage the Company to evaluate what of this information will already need to be identified to meet the forecasting requirements and to try to incorporate presentation of the boundary areas of that layered support on any mapping.

e) ***Preliminary "hydraulic feasibility" assessment to provide initial insight into where pipeline retirement is or is not a viable option***. Rule 4553(c)(I)(K) will ideally be helpful here in identifying the number of customers served by or downstream of the pipeline segment. However, I understand that is not as fulsome as what is being suggested here, which could allow parties to better understand if there are other technical options available, besides replacement, within the hydraulics and operation of the system, which could include taking certain segments out of service based on an ability to bypass them. I see tremendous value in gaining more insight into the hydraulics and physical options available within the infrastructure, but doing so in a measured way that could limit such analysis and in-depth information as to the function of the system to a party readily able to interpret the information being provided. Below I provide direction on implementation of a new role in evaluation from an independent hydraulic expert, which I believe serves the purpose being proposed here in a reasonable way.

f) ***Pipeline risk factor or project lead-up time, to understand if there is enough time to implement an NPA***. I expect that the planned project identified by the Company will thoroughly identify the anticipated timeline related to the need of the project. The timing of NPA solutions is still in its early stages, but I expect that a robust NPA analysis will contain sufficient information to estimate the timeline needed to implement the NPA. I am not confident anything additional should be required in this area at this time.

g) ***GHG emissions reduction potential of an NPA project, to help map users assess its decarbonization benefits***. In order to calculate the CBA for the NPA, the Company is expected to include in such analysis the expected emissions reductions from the distribution and end use of the gas, as well as any expected additions from the long-run marginal emissions on the electric system. In that respect, I expect this information to be readily accessible elsewhere – within the NPA CBA calculation – and am not clear what presentation of the GHG emissions reduction on the map would gain in the evaluation of the NPA, which cannot be ascertained from consulting the CBA for the same project.

60. I also recognize that many of the Joint Commenters' suggestions are focused around prioritizing the NPA opportunities which may maximize benefits and have the opportunity to be the most successful. At this early stage, we have only seen a few NPAs proposed thus far, but it stands to reason that once a significantly broadened number of projects are evaluated, the Company and parties should have some method or matrix with which to screen or prioritize projects if pursuit of all of the viable NPAs may be too difficult in the short term. I agree for the likely need for such prioritization and recommend stakeholders work with the Company to ensure that we have an organized and well-reasoned approach to a broader consideration of NPAs.

61. The Joint Commenters also recommend maps would be helpful if made available to community-based organizations and local governments who are not regularly involved in gas

planning regulatory proceedings, as they may be critical partners for NPA implementation. This is a helpful flag to ensure that the right entities and partners are involved to enhance the success of any NPA, however, may be premature at this phase. Since the main premise is that these entities would not be parties, it is not reasonable to order anything specific related to the 2025 GIP filing now with regard to them. However, it is reasonable that upon planning and implementation of a NPA, the Company will very likely need to have a close relationship and open communication with community-based organizations and local communities to help with outreach and significantly improve the chance of success of a project. Therefore, the Company should already be considering, after the selection of NPAs coming out of the next GIP, how it will appropriately share information to keep the community apprised and involved and to create a meaningful partnership to enhance the success of a project.

i. Hydraulic Modeling

62. CEO brought up the possibility of inclusion of hydraulic modeling and mapping.[48] The Company expressed significant concerns related to the sharing of hydraulic models.[49] However, there is still validity to CEO's concern that to truly understand upcoming system needs may require some knowledge or insight into the hydraulic models which underpin a significant portion of the upcoming investment in the system. This concern is further amplified by the very limited view of expected upcoming Company investment put forth in its Inaugural GIP filing. In that proceeding, commenters expressed significant concern that the projects included by the Company in the GIP included only a tiny fraction of historical annual capital spending.[50] Likewise, there was concern that delayed identification of projects, including capacity expansion projects,

[48] *See* July 29, 2024 Workshop at 1:33:00 and 2:28:00 https://www.youtube.com/watch?v=HJIdRhBTbZc.
[49] *Id*. at 2:31:17.
[50] *See* GIP Decision at ¶ 65.

would likely limit the tools available to effectively evaluate and implement non-pipeline alternatives in order to avoid the investment, even if such alternatives may be more cost effective than the traditional infrastructure solution. I share the concerns on these accounts. Information that appears to be missing or incomplete within the GIP could stymie efforts to implement cost-effective NPAs, leading us down a more expensive path, so the additional insights and understanding that more detailed system-wide mapping could give are compelling. I generally agree with CEO that the hydraulic models used by the Company in its system analysis contain a wealth of information which may get to the heart of many of these issues. However, I agree with the Company that the risk of dissemination of this information is likely high – higher than that of static maps which show far less system information – and it is unclear that standard parties to a GIP proceeding would have the expertise or wherewithal to appropriately analyze this highly specialized tool, which may make the risk-reward relationship of making that information widely available less appealing. In order to address the goal and concerns here, a new pathway would provide the most benefit. The Commission should utilize an independent gas expert with knowledge in hydraulic modeling to review the Company's models in its office alongside its professionals in the Company who regularly utilize the software. This independent expert would be able to review the system and projects identified by the Company with several key goals: to evaluate at a high level the apparent need or technical alternatives to projects identified by the Company, to spot capacity constrained areas that may not have otherwise been identified because a precise project has not yet been scoped and to generally increase the Commission's understanding of the projects identified in the next GIP. Similar to an Independent Engineer or Independent Transmission Analyst use in other proceedings, this position would be provided cost recovery through the utility likely through the GIP, but would work at the direction of the

Commission. Additional scope and direction will be part of the early procedural discussion in the Company's GIP application proceeding. At this juncture, I envision that the consultant would be provided access to the hydraulic modeling on a confidential basis, and then would be able to present publicly at a technical conference or similar on its analysis of the Company's hydraulic modeling. That public report could be addressed by the Company and stakeholders through testimony in the adjudicated process.

63. The Company is also obligated to include information in the GIP about any pipe that may need to be upgraded or replaced in the next ten years pursuant to § 40-3.2-104.4(3), C.R.S. However, the Company does not appear confident it can readily identify such needs over the timeframe identified in the statute, commenting that it "does not generally plan for pipe upgrades/replacements beyond its five-year planning and budgeting cycle…"[51] that only committing that the Company may be able to identify some needs further out. The implementation of an independent hydraulic expert could also help to narrow this gap between the Company's stated abilities and the statutory expectations by helping to flag areas of capacity concern further in advance, in the situation where those are not already identified by the Company in the GIP filing.

4. Cost-Benefit Analysis

a. Discussion

64. Pursuant to Rule 4553(c), Public Service produced a cost benefit analysis for the consideration of non-pipeline alternatives. In the GIP Decision, the Commission concluded that the Company's first CBA was "a good first step as experience with alternatives analysis grows."

[51] Company Proposal, p. 46.

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 this miscellaneous Proceeding.

65. At the July 29, 2024 workshop several participants, including WRA, CEO, and the Company, presented on potential improvements and options for the cost-effectiveness analysis to be used in GIPs. At a follow up workshop, held on August 21, 2024, E4TheFuture and Energy Future Group also presented on certain suggested modifications.

66. On November 1, 2024, the Company filed its proposal for CBA and its draft CBA handbook into this Proceeding. The Company contends that the CBA handbook is the result of a stakeholder process and that the most recent version incorporates much of the feedback received in this Proceeding. The Company commits to an updated version to be filed in its upcoming GIP.[52]

67. At a high-level, the Company's CBA utilizes the Company's WACC as the cost discount rate, a 2.5 percent discount rate for benefits, and calculates using nominal dollar values and discount rates. The CBA handbook includes a section on "relevant cost-effectiveness tests;" a CBA "framework and methodology;" and an explanation of analysis assumptions made as well as costs inputted.

b. Findings and Conclusions

(1) Type of Cost Effectiveness Test

68. This Proceeding allowed for some meaningful progress around cost benefit analysis frameworks and appropriate data sources for inputs. I very much appreciate the Company filing documents and creating the CBA Handbook in a way that allows these documents to be shared publicly. Below I analyze and provide guidance on the Company's proposed CBA proposals.

[52] Company Proposal, pp. 48-49.

69. The Company included several factors in its CBA analysis for which I do not at this point have guidance on. However, parties are welcome to address these points in the upcoming adjudicated GIP proceeding.

70. Before getting into the details of what costs, benefits and specific inputs are most reasonable to include in the 2025 GIP NPA analysis, I think it is worth recognizing that there are several different lenses through which to view cost effectiveness. The Commission has recognized this in past proceedings.[53] It would be ideal for the Commission to, in a larger effort, develop a Colorado-specific cost effectiveness test, as advocated by CEO, that can be used across proceedings and properly identify the most useful costs and benefits to be considered, as well as reasonable data sources for those inputs. This could lead to a methodology that would provide consistency across proceedings and remove significant controversies that arise in each proceeding about what should be included and where those inputs should draw from. However, such an effort is not currently underway. In the interim, the most effective way to properly analyze and consider the differing opinions on both the specifics of what costs and benefits should be included, as well as the actual inputs themselves is for the cost benefit analysis to be done in an executable format that allows any user to toggle on or off any specific costs or benefits, as well as to edit the input value for each specific cost or benefit. This will readily allow different perspectives on the cost effectiveness to be calculated to compare and contrast under what assumptions and considerations the NPA may or may not be cost effective. In addition to making it an executable format, the Company should endeavor for the document to be publicly available. It is crucial for stakeholders, municipalities, and other interested groups to be able to understand the cost effectiveness of

[53] *See e.g.*, Decision No. C23-0413at ¶ 126, issued in Proceeding No. 22A-0309EG (Ordering the Company to file a utility test as well as an mTRC test in its next Strategic Issues filing); Decision No. C24-0397 at ¶ 60, issued in Proceeding No. 23A-0392EG (Ordering presentation of the UCT and mTRC as well as the Ratepayer Impact Measure, in the next clean heat plan filing).

alternatives in a transparent format and for the results to be able to be discussed publicly by both intervenors and the Commission itself.

71. In section 2 of its CBA Handbook, the Company states that "[t]he Colorado Public Utilities Commission requires a modified total resource cost test…" While it is accurate that Rule 4752(n) requires a modified total resource cost test ("mTRC"), in the case of a utility's DSM, there is no reference in Colorado statute, nor in the Commission's Rules, that dictate that mTRC is, by default, the appropriate cost test for evaluation of NPAs. While consistency is a laudable goal for cost effectiveness tests across proceedings, it is possible that the mTRC as a sole focus has flaws that the Commission does not wish to replicate or transfer into the NPA evaluation and planning process. The Company's indication that the Commission requires this test, in reference to the NPA evaluation, is a reference that is either misplaced or misunderstood by the Company. This Proceeding should be considered by the Company and stakeholders to be the most instructive and detailed examination of the appropriate factors and references.

72. The Company is free to present whatever cost effectiveness test or analysis it wishes; however, I am not entirely confident that the Commission will find significant value in the expanded rates impact measure ("ERIM") test that the Company insists on putting forward. The Company's logic, explained on page 5 of the CBA Handbook, indicates that the Company finds the expanded, modified total resource cost ("EMTRC") lacking because the NPA projects, and therefore participants, are not spread evenly across the service territory. It is a fact that the constrained areas will be in certain areas of the system, rather than spread evenly. However, the Company's inference that the costs associated with doing infrastructure work in the constrained area would only be borne by the localized customers in the constrained areas is lacking any apparent basis. System impacts and investments in the system have a long history of being

socialized across the entire customer rate base, including customers far afield from those within the area incurring the investment. Therefore, the Company's concept that non-participating customers may be at some disadvantage with other cost tests is strained, as, in the current system, all customers bear the cost of infrastructure, even those costs for which they have no personal or technical contribution to the need.

73. Since there is the potential for impacts to gas only, electric only, and combined gas-electric customers, any analysis should be split to allow for impacts on each set of ratepayers to be identified independent of the others.

74. As identified by the Joint Commenters, there is no requirement, either explicit or implicit, that NPAs reach a cost-benefit ratio of 1.0 using the primary cost test.[54] I agree that there are several factors including the risk for stranded assets, the uncertainty of gas commodity costs, particularly in extreme weather, locational characteristics and unquantified health impacts, which could be considered in addition to an indicative CBA when evaluating NPAs.

(2) Specific Input Values:

(a) Capital Cost of Gas Infrastructure Projects

75. This input is foundational to the calculation, likely representing the single biggest entry in the analysis, so accuracy is critical. As indicated in the Company's supplemental direct testimony in Proceeding No. 24AL-0049G ("Gas Rate Case") the Company has consistently spent more than estimated for new and replacement gas pipeline projects.[55] This raises serious questions about if the infrastructure costs included in a CBA are likely to be chronically underestimated. Although outside the scope of the CBA, it is notable that cost overruns can cause projects that fall

[54] Joint Response Comments, filed on November 22, 2024, pp. 12 and 22.

[55] Hr. Ex. 120 (Supplemental Direct Testimony of A. Ray Gardner), p. 15, filed on May 30, 2024, in Proceeding No. 24AL-0049G.

modestly below the dollar threshold to be reported as a GIP project to, in fact, become projects that should have been reported. This situation may be foreseeable if the cost overruns are regular enough that they can essentially be expected. To refine our understanding of the relationship between the Company's estimated costs and actual project costs, the Company should regularly track the estimated cost of each project and the actual cost, with notes about any particular areas of work that caused the actual project to vary from its estimates. As discussed below, the Joint Comments from SWEEP and NRDC recommend use of the actual revenue requirement for the project to ensure all relevant costs associated with the project are considered. SWEEP and NRDC put forth compelling reasons for the actual revenue requirement to be used, including in the instance of an NPA delaying a project or other more nuanced outcomes, which would be best reflected by using the actual costs that will flow through to ratepayers.

(b) Net Salvage Value of Gas Infrastructure Projects

76. The Company notes it is in the process of incorporating assumptions related to net salvage into the Handbook, however, those have not been included at this time.[56] I find confusing the description of the Company's proposal related to the topic of net salvage value, considering the Commission's directive that such a value be included in the cost of the traditional infrastructure project.[57] The Company expresses challenges around the "level of granularity" and indicates that individual projects can have significantly different costs of removal, leading to different salvage rates, and the absence of forecasted inflation rates in any net salvage rate. These concepts are challenging for several reasons. First, while it is easy to understand that different projects will likely have different actual decommissioning costs, I have elected not to utilize the terminology of

[56] Company Proposal, p. 49.
[57] *Id*. at 50.

"cost of removal" put forth by the Company intentionally, as it is my understanding based on the Company's testimony in its Gas Rate Case that nearly all projects - "in excess of 99 percent" - in the recent past have been retired in place, as opposed to physically removed.[58] In that proceeding, the Company put forth terminology referring to "decommissioning" as the broad idea of taking a pipe out of service, which then breaks down into "removal" as the physical removal of the pipe and "retiring in place" as the act of purging and capping the infrastructure.[59] Therefore, I find the use of the term "cost of *removal*" here particularly confusing, as little if any of the infrastructure may be physically removed. With that said, it is reasonable to assume that different assets in different situations may have actual costs of decommissioning that vary. However, if we intend to look at the most likely cost to ratepayers, as I believe we do, it is important to acknowledge that, independent of the actual cost of decommissioning which may come decades in the future, the first time a new asset appears in rate base it includes the negative net salvage value assigned from that rate case. In essence, the negative net salvage value increases the depreciation collected by the Company throughout its entire life in service. So, while the actual decommissioning cost in 30-50 years may result in something different, the cost we know will be passed along to ratepayers from the beginning is that approved negative net salvage value. It is unclear why the Company would advocate for the Commission to approve this generalized, system average approach for the purpose of collecting the funding for decommissioning in real time, but not stand behind such an approach here. So long as the Company still intends to collect the negative net salvage value from assets when they are placed in service, it seems obvious that we have a reasonable value to be used here – the value already being billed to customers.

[58] *See* Hr. Ex. 121 (Supplemental Direct Testimony of Mark P. Moeller), pp. 8 and 10, filed on May 30, 2024, in Proceeding No. 24AL-0049G.

[59] *Id*. at p. 9.

77. Second, the Company points to a challenge in the inflation involved with decommissioning of an asset many years in the future, given that the CBA tool it has proposed calculates costs and benefits on a net present value basis. As described in Proceeding No. 24AL-0049Ga significant driver of the estimated net salvage rates is the very assumption about inflation of labor and materials needed to execute the decommissioning at a date relatively far into the future.[60] While the Company puts forth a potential approach to correct back to present value net salvage, it is not clear why such an approach is appropriate.

78. The proposal put forth by the Joint Commenters to use the full revenue requirement of the infrastructure project likely solves for many of these issues, including the inclusion of the negative net salvage expense. They properly assess that this approach would provide a more complete view of the infrastructure project costs, including an ability to model a delay in a project, rather than full removal.

79. The Company also offers that the net salvage value of new electric infrastructure should also be included in the calculation. The Company could also consider looking at a revenue requirement approach to electric infrastructure that could include net salvage values for those assets, as well, to ensure we have an appropriately inclusive calculation. However, it is unclear if the unrealized upstream costs associated with either the electric or gas systems must be treated the same as the immediate and scoped gas infrastructure project that is actually being evaluated, so this incongruency may ultimately be a minor concern.

[60] *See* Hr. Ex. 114 (Direct Testimony of Mark P. Moeller), p. 25, filed on January 29, 2024, in Proceeding No. 24AL-0049G.

(c) Incentive Cost

80. The Company indicates "[p]rogram incentive cost will include incentives provided through federal, state, or utility incentive programs."[61] The Company's language about including the other incentives in the program incentive cost may be contrary to my expectations. To be clear, the incentives offered by those other than the utility should be included in full and should be removed or be able to be removed from the assumed participant cost of the measure for which the incentive is applicable in accordance with the comments received from the Joint Commenters. I do not agree with the concept of including incentives coming from outside of the utility as part of the incentive cost specific to the NPA portfolio. While it is true that customers are indirectly paying for many of these incentives either through federal taxes or other local programming, these are not incentives at issue in this Proceeding and come in as a net savings to customers who choose to utilize the benefits of those programs. There is functionally no option to avoid paying for these incentives, so to count them as a cost specific to an NPA is inaccurate – they represent a benefit by decreasing the cost of certain NPA measures and that situation should be reflected or, at a minimum, the executable CBA calculator should allow a user an obvious way to readily make this change.

(d) Participant Cost

81. The Company indicates "participant cost will include the cost to the consumer of purchasing an NPA measure or technology, net of any federal, state, or utility incentives provided." It is notable that there are other incentives available through local sources, like the City and County of Denver, which should be part of this list. Also, "utility incentives" should include incentives offered by other utilities, to the extent those programs overlap in the NPA project area.

[61] Attachment 2 to Company Proposal at p. 1, filed on November 1, 2024.

For example, if the Company serves only gas in an area and the local electric utility provides rebates for certain NPA measures, such incentives should be considered in lowering the participant costs for those measures in that area. Additionally, the Company should include a discounting of the cost for participants based upon the average age of existing equipment. The Company argues that it "will likely have to incentivize participants with functioning equipment who do not otherwise need to replace their gas-fired equipment…"[62] Such an argument is short-sighted, as a substantial amount of that equipment may be in the latter half of its life. While I agree that it is likely more difficult to incentivize a customer to change out functioning equipment, treating them as a monolith is impractical. For customers whose equipment is nearing the end of its useful life, there is likely an understanding of the benefit of proactively changing out the equipment to avoid failure and that homeowner or building owner will soon face an expense for replacement of that equipment independent of the fuel used to feed it. Therefore, an appropriate discounting based on average age of existing equipment would properly acknowledge that customers inevitably have a cost to change out equipment and to pretend otherwise is inaccurate and improperly assigns more participant costs to an NPA than is appropriate.

82. In the CHP Proceeding, the Company's model appears to indicate the addition of a presumed financing cost to customers for new mechanical equipment at the Company's WACC for 15 years as a participant cost.[63] While no such assumption has been specified here, it is unclear if the approach will be similar or different. This assumption is quite challenging unless it is supported with data to show why it is a reasonable assumption or commonplace for a homeowner to utilize this type and length of financing for such a purchase.

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[62] *Id*.
[63] *See* Hr. Ex. 116 (Rebuttal Testimony of Jack W. Ihle), p. 85, filed on March 11, 2024.

(e) Administrative Cost

83. I understand that there are real administrative costs to run an NPA program. There are also likely administrative costs to complete a traditional infrastructure project, including notifications, coordination with other utilities, and municipalities and other efforts. The administrative costs of both options should be included to the extent they can be reasonably estimated and any major assumptions about the costs should be explained in the CBA handbook or accompanying documentation. The Company should justify and more thoroughly categorize its blanket assumption of an administrative cost of 20 percent of the estimated total cost of NPA measures. Also, the Company should indicate any expected changes in administrative costs as the Company gains more understanding and experience related to NPA measure implementation.

(f) Generation capacity

84. Stakeholders generally applaud the move to marginal generation capacity cost impacts. The Company's proposal to assume that the NPA measure's impact on electric peak demand is "comprised by multiplying the peak hour demand gas reduction by the assumed baseline gas equipment efficiency and then converting to electricity by dividing by the assumed efficiency of 1.0 during peak hour (electric resistance backup),"[64] has not been substantiated. This fails to include any contribution by the heat pump and no diversification of loads through intelligent controls or programming, which is an unlikely circumstance, given that these loads are more likely than not to be internet-connected and highly controllable, including through means like demand response programming, tariffs, virtual power plants ("VPP"s) and other tools. This myopic view of system impacts likely overestimates the impact in a way that would disadvantage NPAs in the cost benefit analysis. These issues should continue to be explored to ensure that the peak capacity

[64] Attachment 3 to Company Proposal at p. 9, filed on November 1, 2024.

impact represents a diversity of mechanical system operations at system peak and a realistically managed, rather than ultraconservative, view of the combination of these loads. In the executable CBA tool, the Company should allow users to model some diversification in the peak load, which could be achieved by any of the described tools, for the purpose of estimating the cost impact of additional generation, transmission and distribution expenses. The proposal to utilize the lowest cost generation capacity option identified in the Xcel Encompass modeling sounds appropriate and should include the most recent available price information as bidding and procurement continue. Since the generation capacity is unlikely to be added immediately or cause an independent solicitation, there may be a net present value component that should be considered to properly address the timing of this anticipated expense, relative to the timing of the traditional infrastructure project.

85. It is also important to note that the Company's Just Transition Solicitation ("JTS") Proceeding (Proceeding No. 24A-0442E) assumes significant levels of future electrification within the forecasts. As such, the Company is currently before the Commission projecting transformative additions to generation capacity, independent of any specific NPA projects. In part, the Company has argued in that proceeding that electrification of buildings is likely to be a component of the expected need for additional generation. Electrification of buildings may be caused by many drivers, with NPA projects, specifically, likely being a more subtle force in the greater system than market forces or larger policy initiatives. This may make it difficult to determine the actual costs that should be allocated to NPAs for a broader shift and profound capital needs related to generation that are already being anticipated by the Company. Over time, it may make sense to track trends in electrification to determine what result is likely to occur, in terms of electrification of former gas loads, to identify what portion of the electrification associated with an NPA is truly

additional to what was most likely to occur anyway. At this early stage, the Company's proposal is to essentially allocate all electrification impacts caused in the NPA area as a cost of the NPA project. It is not clear, given what is projected in other proceedings if this is a valid assumption.

86. In the description, the Company refers to these costs being assessed when "the alternative portfolio results in a net increase in electric load during the system peak."[65] It is not clear if the Company is referring to the gross or net system peak in this description.

(g) Transmission Capacity Cost Impacts

87. The Company explains that "Transmission Capacity cost impacts occur when NPA measures implemented as part of an alternative portfolio result in system peak load that increase the transmission capacity required to transport electricity safely and reliably."[66] It is not clear by the description if this is based upon gross load capacity or net load capacity. It is also not clear how the locational nature of an NPA might factor into the determination as a need for additional transmission. NPAs are expected to be locally confined and, therefore, could have different impacts on transmission needs based on their location. Therefore, locationally specific characteristics should also be considered to the extent that is possible.

88. The Company proposes to make the same assumptions around electric peak demand impact for the transmission system as on the generation, assuming an efficiency of 1.0 (electric resistance) and a pancaking of all loads at the same time. I have the same concerns with this approach as indicated in the Generation section and expect the executable CBA tool would have a feature to allow a user to model some reduction in peak load or diversification based on the suite of tools available to avoid the worst-case scenario of load pancaking.

[65] Attachment 2 to Company Proposal at p. 1, filed on November 1, 2024.
[66] *Id*. at 9.

89. Likewise, it is unclear if the Company has analyzed the difference in winter and summer peak capacity on the transmission system, due to the addition of loads at lower ambient temperatures, to ensure the calculations are properly adjusted to be appropriate for the anticipated timing of the new loads. It is my understanding that the Company's assumption on the new winter peak loads is that they will occur at the coldest possible outdoor temperature, when heating needs would be at a maximum. These temperature assumptions and any appropriate adjustments for wiring and equipment capacity should be more properly explained in the 2025 GIP to substantiate values being used in that proceeding.

90. The Company has $1.7B in transmission upgrades underway in the Colorado Power Pathways project[67] and recently filed an application for a certificate of public convenience and necessity ("CPCN") for $1.2B in additional upgrades that the Company argues are needed to serve the Denver Metro area.[68] To the extent that transmission needs being planned today are predicated on significant estimates of electrification, similar to generation, it is unclear if a portion of the electrifying load in an NPA would have already been assumed to electrify in the coming years and is, in essence, already baked into the significant transmission upgrades already underway or being sought before this Commission. Therefore, it is not clear if the assumption of allocating the full value of any NPA electrification that could result in a system peak load increase is appropriate.

91. Since the transmission capacity is unlikely to be added immediately or cause an independent transmission project, there may be a net present value component that should be considered to properly address the timing of this anticipated expense, relative to the timing of the traditional infrastructure project.

[67] Decision No. C22-270, ¶ 22, in Proceeding No. 21A-0096E.
[68] *See* Verified Application in Proceeding No. 24A-0560E, p. 13.

92. In the description, the Company refers to these costs being assessed if "an alternative portfolio results in a net increase in electric load during the system peak."[69] It is not clear if the Company is referring to the gross or net system peak in this description.

(h) Distribution Capacity Cost Impacts

93. The descriptions for the situation that would incur this expense vary from the CBA Handbook and the Company's Attachment 2 describing the different factors included in the CBA. The Handbook indicates that these are cost impacts where the alternative portfolio would result in an increase in the electric winter peak demand. However, Attachment 2 indicates that these costs would be assessed "if an alternative portfolio results in a net increase in electric load during the system peak."[70] It is not clear which circumstance the Company intends to use in this calculation. Notably, the generation and transmission cost impacts are based upon annual changes and peak capacities, rather than only a winter-specific peak. It is further unclear if either of the discussions of system peak or peak demand would refer to a gross or net peak.

94. The Company proposes to make the same assumptions around electric peak demand impact for the distribution system as on the generation and transmission, assuming an efficiency of 1.0 (electric resistance) and a pancaking of all loads at the same time. I have the same concerns with this approach as indicated in the previous sections and expect the executable CBA tool would have a feature to allow a user to model some reduction in peak load or diversification based on the suite of tools available to avoid load pancaking.

95. Likewise, it is unclear if the Company has analyzed the difference in winter and summer peak capacity on the distribution system and its major components, due to the addition of

[69] Attachment 2 to Company Proposal at p. 1, filed on November 1, 2024.
[70] *Id.*

loads at lower ambient temperatures, to ensure the calculations are properly adjusted to be appropriate for the anticipated timing of the new loads. It is my understanding that the Company's assumption on the new winter peak loads is that they will occur at the coldest possible outdoor temperature, when heating needs would be at a maximum. These temperature assumptions and any appropriate adjustments for wiring and equipment capacity should be more properly explained in the 2025 GIP to substantiate values being used in that proceeding.

96. The Commission has before it the Company's Distribution System Plan ("DSP") Proceeding (Proceeding No. 24A-0547E) application that anticipates roughly $7.52B in distribution system spending. This unprecedented level of expansion and improvement of the Company's distribution system is based, in some part, on the electrification of loads. While the Commission is still working through that forecasting and evaluate of its appropriateness in a separate venue, it is important here to recognize the potential for double-counting if the Company is already assuming significant electrification and requesting funding for such in other proceedings. Therefore, it is not clear if the assumption of allocating the full cost of any potential capacity upgrades attributed to electrification in an NPA is appropriate, given the Company's proposal for widespread system improvements, in part to support electrification more generally. In the Initial GIP, the Company suggested evaluating if upgrades were already included in a 5-year capital forecast in order to remove the cost responsibility for such upgrade from being attributed to the NPA. Such an approach has not been discussed in this proposal. However, given the sweeping nature of the upgrades proposed in the Company's recent DSP filing, such an analysis and removal of double-counting would be reasonable.

(i) Electric Commodity Cost Impacts

97. The treatment of this input as described in the CBA for Non-Pipeline Alternatives Handbook appears reasonable. Notably, if the replacement of a standard air-conditioner results in the replacement with a heat pump, the Company should also be modeling a benefit related to the cost savings of the Electric Commodity Costs at the summer system coincident peak to reflect this efficiency gain.

98. In response to my request to address that "[i]f 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."[71] the Company indicated "[t]he gas commodity price assumptions will be sourced from the Company's currently approved Demand-Side Management and Beneficial Electrification Plan. The aggregated value is not considered confidential."[72] I do not find the Company's answer to be fully responsive, given that the executable tool being requested herein may necessarily include annual, rather than aggregate values. The Company should utilize an appropriate publicly available proxy value, if needed, to avoid confidentiality concerns related to the entire executable tool. The Company did not specify if there are any other reasons the tool may be considered confidential, so my understanding is that it will be designed to be publicly available.

(j) Ancillary Service Cost

99. The Company proposes to make the same assumptions around electric peak demand impact for the transmission system as on the generation, assuming an efficiency of 1.0 (electric resistance) and a pancaking of all loads at the same time. I have the same concerns with this

[71] Decision No. R24-0708-I at p. 34 fn. 37.
[72] Attachment 2 to Company Proposal at p. 3, filed on November 1, 2024.

approach as indicated in the Generation and Transmission section and expect the executable CBA tool would have a feature to allow a user to model some reduction in peak load or diversification based on the suite of tools available to avoid load pancaking..

(k) Winter Mitigation Cost

100. As the Commission previously identified the use of liquified natural gas ("LNG") or compressed natura gas ("CNG") within an approved NPA could represent a reasonable way to assist in deferral, delay or avoidance of a traditional infrastructure project, this is an appropriate inclusion. However, in its Gas Rate Case, the Company identified that it has already purchased LNG equipment to use on its system.[73] Therefore, it is not immediately apparent that the reference in the Handbook to an annual winter lease payment will be applicable in each situation, as utility-owned equipment may already show up in rate base. The costs included for such a solution should represent the most appropriate based upon the lowest cost option available or already utilized by the utility – lease or ownership – of such equipment.

(l) Incremental Gas Infrastructure Cost

101. There is not sufficient information within the Handbook or the Company's responsive comments to determine if this cost will be properly included in the 2025 GIP nor to determine if the Company's interpretation of this input matches my expectation. For NPAs, the Company proposes including the costs of a host of different unrealized upstream costs associated with the addition of more capacity needs on the electric system for all sections of the system, from distribution to transmission to generation. To ensure consistency in the approach and a comprehensive look at the costs and benefits associated with either traditional infrastructure or the NPA, in much the same way, the Company must include the costs (or benefits for an alternative)

[73] *See* Decision No. C24-0778 at ¶ 172, in Proceeding No. 24AL-0049G.

of unrealized upstream costs associated with the addition of more capacity needs on the gas system for all sections of the system for the traditional infrastructure scenario. This should include a proxy value for the general cost to add new gas transmission capacity and capacity at every stage upstream on the gas distribution system, similar to the approach for electric infrastructure. Such a value may best be presented as a $/Dth cost so it can readily apply to NPAs and loads of differing capacities. While the electric system currently peaks in the summer by a fairly wide margin, the gas infrastructure currently peaks at the exact timing that new gas load would also be expected to peak. In Proceeding No. 23M-0092G the Company explained that ambient temperature is the only significant driver of the system peak capacity needs, and that timing generally always aligns with the same morning hours. Additionally, while there are a host of demand response options available on the electric system, the Company has not yet reported any results from its sole gas demand response pilot and has not provided the Commission with any information to indicate they are aware of ways to vary the timing or magnitude of new gas loads. That said, it is clear that new gas loads would be highly likely to hit at the gas system's coincident peak, directly driving future gas capacity needs and capital investments, while that correlation of those heating loads on the electric system to its peak is not as obvious.

102. To the extent the Company finds it most appropriate to include a net salvage value in evaluation of the costs of unrealized upstream electric infrastructure needs associated with an alternative portfolio, the Company should also include a value for negative net salvage for the unrealized upstream gas infrastructure needs. However, I find the inclusion of the negative net salvage value to be the most appropriate and it should be included within the expected costs of the specific, scoped gas infrastructure project being evaluated. The inclusion of such a cost on these unrealized upstream costs for either the gas or electric systems is less obviously needed.

(m) Avoided Gas Commodity Benefits

103. To ensure the CBA can be publicly available, the Company should utilize gas commodity estimates that represent a third-party source's estimates and should not utilize confidential gas commodity estimates.

104. The Company does not propose including the cost for lost and unaccounted for gas as a percentage or in any other capacity within the gas commodity cost. However, the Company proposes to include line losses on the electric infrastructure for the alternative and also proposes to include the "incremental generation methane leakage cost" which occurs "as a result of the need to procure and rely on more fossil-fired generation as a result of an alternative portfolio."[74] Lost and unaccounted for gas is a widely recognized cost of providing gas service for which the Company regularly seeks and is provided cost recovery. Exclusion of this cost represents an obvious mismatch. The Company should include the costs, on the most recently approved percentage basis, of lost and unaccounted for gas in its avoided gas commodity benefit.

(n) Deferred Capital Expenditure Benefit

105. The Company proposes this entry to represent "the time value of money of capital expenditures that would otherwise have been spent absent the alternative portfolio."[75] The Joint Comments from SWEEP and NRDC dispute that a 2.5 percent discount rate does not appropriately account for the benefit of avoided gas distribution system capital infrastructure. Instead, they argue that the NPA analysis should be based on the full revenue requirement of the project, including the Company's return on equity and property taxes. The Company points to difficulties with this approach. The Company is free to propose different cost recovery proposals for NPAs within the GIP and could represent the revenue requirement of those proposals as options

[74] Attachment 2 to Company Proposal at p. 2, filed on November 1, 2024.
[75] Attachment 3 to Company Proposal at p. 13, filed on November 1, 2024.

within the executable CBA to allow the Commission and stakeholders to evaluate them and to provide a more straightforward comparison between the NPA and the traditional infrastructure solution. The Joint Commenters provide a compelling perspective that the Company's approach likely undervalues the savings associated with deferred capital expenditures. Utilizing the actual revenue requirement also provides a direct and accurate way for the Company to include the negative net salvage value, included in depreciation rates, as directed by the Commission in Decision No. C24-0233. I find that the Company should utilize the actual revenue requirement associated with the infrastructure project in order to appropriately capture the actual expected costs of the projects to be borne by ratepayers.

(o) Non-Energy Benefits

106. It is helpful that the Company proposes to use Enviroscreen demographics to determine the approximate number of IQ customers in an area, as it is well understood that actual participation in IQ programs likely only represents a fraction of those who may actually qualify.

(p) Net Revenue Impact

107. The Company only proposes use of this metric in the ERIM test. Since the electric and gas ratepayer bases vary, it is not clear that it is reasonable to include disparate impacts to both in one calculation as presented.

(q) Electric Reliability Cost

108. The Company proposes to include, but not quantify this cost. It is difficult to understand why a cost effectiveness test would include a cost associated with electric reliability due to incremental investments being required for the system to support the alternative portfolio development. I am concerned about the Company's proposal here for several reasons. First, the Company already includes quantification of electric infrastructure needs that it directly attributes

to electrification as a result of an NPA, so it is not clear why there is an unquantifiable additional cost associated with reliability that is not covered by the relatively conservative assumptions already included in the new system infrastructure needs. Second, the impact of a cost that is included, but not quantified is not well understood. The Commission and stakeholders would benefit from additional explanation as to the consideration of costs that the Company categorizes as included, but not quantified. Third, to the extent that the new electric loads, which are supported by the Company through deployment of an NPA are likely to be internet-enabled and highly controllable, it is not clear why Company support of deployment of such resources would not reasonably include some measure of load control to ensure that these new loads represent a benefit, rather than a detriment to the reliability and operation of the system. Since such capabilities are widely understood to be available, it is not clear why addition of such loads would lead to a reliability concern.

(r) Higher Utilization of Underutilized Assets

109. The Company excludes this metric. It is not clear if the higher utilization of assets is related to the Company's gas or electric system. However, I broadly understand that, at least in the short term, addition of heating loads to the electric system would add load, primarily to a time of year when the system is not at a peaking situation, likely improving the capacity factor of the electric system, in general. To the contrary, given the significant coincidence of heating loads with the gas infrastructure peak capacity needs and lack of tools, like demand response, to diversify the coincidence of the loads, it appears this category would primarily present as a benefit of an NPA portfolio in improving utilization of electric infrastructure year-round, but the Company's intent here was not clear.

(s) Incremental Generation Emissions Cost

110. The Company's proposal includes incremental generation emissions costs, which occur "as a result of an alternative portfolio resulting in increased customer electricity usage and the increased need for the amount of fossil-fueled electricity generation."[76]

111. As presented in this Proceeding, the Company's view of the cumulative electric load caused by electrification looks to be primarily based on a very limited case view of usage that may result based on presumed behavior of backup heating, if present, and operating characteristics like efficiency will likely factor into this calculation, as well. Those methodologies and behaviors likely need further refinement within the GIP to ensure this calculation is as appropriate as possible. I do not view the single residential model provided in this Proceeding to be reliable enough to build significant, widespread assumptions. As described in the GIP Decision, the Company should use long-run marginal emissions, rather than short-run emissions.[77] That distinction is not clear in the Company's proposal and should be made clear within the GIP filing.

(t) Avoided Methane Leakage Benefit

112. While it is certainly appropriate to include the benefit of avoided methane leakage, the Company's methane leakage rate could be challenged. The value being used is from one source and was selected by the Commission in a single proceeding. Stakeholders could bring forth more thorough information which allows for a more fulsome understanding of the total likely methane leakage rate, inclusive of behind the meter leakage. In defining the calculation for this value, the Company refers to the "measured annual consumption in default mountain system to calculate the

[76] *Id*. at 17.
[77] GIP Decision at ¶ 113.

annual energy savings."[78] It is not clear what the "default mountain system" is nor what input that implicates. The "default mountain system" reference used throughout the Handbook should be defined and clarified, as its purpose and underlying assumptions are not understood.[79]

(u) Avoided CO_2 Benefit

113. that the Handbook does not specify the Company's combustion efficiency assumption, which is likely a foundational input to the calculation of Avoided CO_2 based upon a reduction of the combustion of gas. The Company should specify this assumption and if any localized data on housing stock, including things like housing ages and building codes, should be taken into account, based upon the localized nature of an NPA.

(v) Incremental Generation Methane Leakage Cost

114. The Handbook contains very little information about the calculation associated with the Incremental Generation Methane Leakage Cost or its assumptions. I will note that the impact of this item may also rely upon the Company's assumptions about the operational characteristics and efficiency of heat pumps and their backup, if present, which are areas in which I have already expressed significant concerns. I note the Company does not quantify the methane leakage cost or the basis for the leakage rates and it is unclear what methodology the Company will use to identify the generation mix for all hours of the additional electric load.

(w) Air Pollutants

115. The Company proposes to include, but not quantify this metric. In Decision C24-0397, the Commission found merit in the consideration of "additional health benefits from reduced air pollution" when considering Clean Heat Portfolios. Additionally, the Commission

[78] Attachment 3 to Company Proposal at p. 18, filed on November 1, 2024.

[79] Attachment 2 to the Company Proposal notes that this term was used in error in certain sections. However, we are unclear if the term is used in error in the entirety of the Company's filings or just in the instance referred to in Attachment 2.

stated "[a]s suggested by Dr. Bilsback's testimony, any attempt to quantify the health benefits from reduced air pollution will in fact make a cost-effective portfolio even more cost-effective." The Commission also indicated that the Company "should attempt to quantify health benefits of respective portfolios in future clean heat plans…"[80] Similar to a Clean Heat Plan Portfolio, the NPA portfolios are also likely to rely upon the same measures including electrification and DSM and serve to offset gas usage. In this way, the same logic should be followed. There is a high likelihood that at least some of the indoor air pollutant impacts can be quantified and the Company should try to do so. Also, it is likely that the consideration of air pollutants and other health impacts would serve to boost the cost-effectiveness of an NPA solution, all other things equal.

(x) Workforce Impacts

116. The Company lists this aspect as "excluded" and states "[t]hese impacts are not applicable or included as part of the alternative portfolio development."[81] It is not clear how quantification or comparison of the workforce impacts would be estimated nor if it should be included in the cost effectiveness metric or in another, separate metric. However, to the extent that an NPA would include replacement of a traditional pipeline infrastructure project with a suite of measures inside homes and businesses, there are very likely to be some workforce impacts. Those impacts may be spread over more trades than have supported gas infrastructure work in the past. However, in the example of a thermal network, it is possible that the typical trades may be utilized in a different way in an NPA. Nonetheless, it may not be accurate to describe these costs as "not applicable", as they could be something considered by the Commission. Although, I note that if these impacts can be included within a cost effectiveness test is likely still an open issue.

[80] Decision No. C24-0397, in Proceeding No. 23A-0392EG, at ¶ 60.
[81] *Id*. at 20.

II. ORDER

A. It Is Ordered That:

1. In accordance with the discussion above, this Decision advances the development of and provides requirements for Public Service Company of Colorado's gas system forecasting, mapping, and cost benefit analysis in accordance with Decision C24-0092 issued on February 23, 2024, in Proceeding No. 23M-0234G for implementation in Public Service's next Gas Infrastructure filing, expected in May 2025.

2. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

3. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

> (a) If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S

4. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

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

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

MEGAN M. GILMAN

Hearing Commissioner