STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

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In the Matter of a Commission Investigation into Gas Utility Resource Planning	**Docket No. G008, G002, G011/CI-23-117**

INITIAL COMMENTS OF THE CLEAN ENERGY ORGANIZATIONS

June 28, 2024

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INTRODUCTION

The Clean Energy Organizations ("CEOs," which consist of Fresh Energy, Minnesota Center for Environmental Advocacy, and Sierra Club) submit these Initial Comments in response to the Commission's May 7, 2024 request for comments. We have participated in the robust stakeholder process facilitated by the Great Plains Institute and are grateful for that opportunity and for others' participation as well. We also appreciate the opportunity to respond to the "straw proposals" submitted by the utilities on May 31, 2024 and to provide our own perspective on the questions posed by the Commission.

Below, we address five areas where we believe additional Commission guidance will be useful: (1) how the State's greenhouse-gas-emission-reduction goals should be included in the scope of gas integrated resource plans; (2) how the Commission can ensure that resources and proposed plans are compared on a consistent basis; (3) parameters the Commission can set to ensure accurate load forecasts; (4) how distribution system infrastructure costs and capacity expansion projects should be analyzed; and (5) how equity should be incorporated into gas resource plans and the gas planning process. For these areas, we have provided decision options for the Commission to consider.

DISCUSSION

I. Utilities Should Be Required to Explain How Their Preferred Plan Will Support and Serve the State's Greenhouse-Gas-Emission-Reduction Goals

In its March 27, 2024 Order, the Commission confirmed that "[t]he scope of integrated resource planning considers the State's economy-wide greenhouse gas reduction statutory goals."[1] These goals state that Minnesota endeavors to reduce its overall greenhouse gas emissions by 50% by 2030 using a 2005 baseline and to net zero by 2050.[2] The Commission did not, however, explain *how* utilities should consider these statutory goals in their integrated resource plans.

Nor did the utilities' straw proposals explain how integrated resource plans could serve the State's commitment to achieve these emission reductions. Xcel Energy was the only utility to raise Order Point 4 as one that could use clarification. But Xcel merely proposes a methodology to calculate emission reductions expected from its proposal.[3] It states that these calculations will enable consideration of the state's greenhouse gas emission reduction goals. While a methodology for calculating emissions will be helpful, we believe that the Commission must go further in its direction to utilities.

CEOs urge the Commission to adopt a decision option that would require utilities to include in their resource plans a narrative description of how the utility's preferred

[1] Order Establishing Framework for Natural Gas Utility Integrated Resource Planning at 7, ¶ 4 (Mar. 27, 2024) [hereinafter Phase I Order].

[2] Minn. Stat. § 216H.02, subd. 1.

[3] Xcel Energy Straw Proposal at 2 (May 31, 2024).

plan, including the 5-year action plan, will enable the utility to serve the State's greenhouse gas emission reduction goals, including achieving net zero emissions by 2050. Meeting these goals will require gas utilities to reduce greenhouse gas emissions from gas delivered to homes and businesses. In fact, reducing emissions related to heating and cooling of homes and businesses is a priority action identified in Minnesota's Climate Action Framework.[4] Gas utilities must plan for this transition if it is going to be accomplished in a timely, equitable, and cost-effective manner.

CEOs are part of a coalition of groups known as Clean Heat Minnesota that commissioned a study to examine pathways to decarbonize natural gas end uses in Minnesota.[5] The goal of the study was to better understand how heating and cooling for residential and commercial buildings could be decarbonized in the most cost-effective and equitable manner. As the study demonstrated, emission reductions can be achieved at higher or lower costs to utilities, ratepayers, and society.[6] "Overall, the results point to the importance of intentional utility planning, for both electric and gas utilities, to ensure customer costs do not increase uncontrollably and to minimize the risk to the utilities, their shareholders, and ratepayers."[7] Unless utilities map a clear course for achieving net zero emissions in their integrated resource plans, we risk a transition to a lower-carbon future that is more costly than necessary.

In the initial phase of this docket, utilities objected to the notion that integrated resource planning for natural gas utilities should require utilities to adopt plans that will meet the net-zero emission goal in 2050.[8] Utilities claimed that it was impractical to forecast out to 2050 in an accurate way. And utilities also pointed out that the State's climate goals are not mandatory and did not include a target specific to the gas sector.

It is true that the legislature has not broken down the State's economy-wide goals into sector-by-sector goals; meaning that there is no specific greenhouse gas reduction target calculated for each gas utility. But this does not change the fact that the State has set an economy-wide goal of net-zero emissions by 2050 and the task force charged with developing a framework to meet these targets determined that this would require significant reductions in building heating and cooling.[9] Accordingly, gas utilities must be

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[4] Minnesota's Climate Action Framework 50 (2022), https://climate.state.mn.us/sites/climate-action/files/Climate%20Action%20Framework.pdf.

[5] Sol deLeon et al., Minnesota Building Decarbonization Analysis; Equitable and Cost-Effective Pathways Toward Net-Zero Emissions for Homes and Businesses i (2024), https://drive.google.com/file/d/17GljHIUFVcb2RRxDDlBRWeqeXgnvre6f/view.

[6] *Id.* at ii.

[7] *Id.*

[8] Initial Comments of CenterPoint Energy Minnesota Gas at 8 (Nov. 30, 2023); Comments of Minnesota Energy Resources Corporation at 5 (Nov. 30, 2023); Initial Comments of Xcel Energy at 3-4 (Nov. 30, 2023).

[9] Minnesota's Climate Action Framework 50 (2022), https://climate.state.mn.us/sites/climate-action/files/Climate%20Action%20Framework.pdf. The framework sets goals of

planning for this transition if the transition has any chance of being equitable and cost-effective.

This begins with an order from the Commission requiring gas utilities to include a narrative description of how their preferred resource plans are consistent with the State's net-zero emission target. Ultimately, it is the Commission's duty to examine all proposed investments by the gas utilities through the lens of the State's greenhouse gas emission reduction goals. A sister Commission recently explained the Commission's duty to analyze gas integrated resource plans in light of climate goals thusly:

> [I]t is fair to say that a different lens will be applied to gas infrastructure investments going forward. The [Commission] will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving [the] Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. In this "beyond gas" future, we will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.[10]

This duty belongs to not just the Commission, but to all state agencies. For example, the legislature recently codified into the law the Department's duty to "prepare and defend testimony designed to ensure that the greenhouse gas reduction goals are attained on a schedule that keeps pace with the reduction timetable in section 216H.02, subdivision 1."[11]

It is contrary to law for the Commission to simply ignore the directive of the legislature. The legislature has set greenhouse gas reduction goals for the State. A governor-appointed task force has set specific goals. It is now up to the Public Utilities Commission to protect the public and ratepayers by implementing these directives. Requiring utilities to include a description of how their preferred plan serves the State's decarbonization goals falls squarely within the Commission's decision to approve, reject, or modify a utility's resource plan based on whether it protects the public interest and advances state policy.[12] The Commission cannot judge whether a plan is in the public

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reducing thermal greenhouse gas emissions by 20% by 2030 and 50% by 2035 from existing buildings.

[10] *Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals*, Mass. Dep't of Pub. Util. Docket No. 20-80-B, Order on Regulatory Principles and Framework at 14 (Dec. 6, 2023).

[11] 2024 Minn. Session Law ch. 126 (amending Minn. Stat. § 216A.07, subd. 3).

[12] Requiring utilities to include a description of how their preferred plan serves the State decarbonization goals also aligns with previous Commission orders. "[T]he Commission wants Minnesota utilities to prepare for foreseeable contingencies." *In the Matter of Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on*

interest if it cannot tell whether the plan aligns with the broader effort to avoid catastrophic climate changes.

Of course, as Xcel notes, a necessary first step to explaining how a preferred plan will accommodate the State's climate goals is to calculate the emissions that result from different possible futures, including a utility's preferred plan. Because of the high-global-warming potential of methane, CEOs assert that it is critical to include the best-available estimates of methane leakage in these emission calculations. This is already required for Xcel,[13] and should be required for the State's other gas utilities as well.

CEOs note that tools for accurately predicting methane leakage are becoming more accurate. M.J. Bradley & Associates, an ERM Group Company, has developed a tool that quantifies the life cycle greenhouse gas emissions of delivered natural gas.[14] The tool is designed to help utilities, regulators, and other stakeholders evaluate the emissions impact of different supply- and demand-side choices considered in gas planning processes.[15] It accounts for fugitive methane and combustion-related greenhouse gas emissions and relies on data publicly reported by local distribution companies to the U.S. Environmental Protection Agency (GHGRP; subpart W), as well as data from the National Energy Technology Laboratory, Energy Information Administration, Argonne National Laboratory's Greenhouse Gases and Energy Use in Transportation (GREET) model, Environmental Protection Agency Emissions and Generation Resource Integrated Database (eGRID), and the Environmental Defense Fund, Colorado State University, and other academic researchers. The tool estimates upstream emissions associated with production, gathering, boosting and transmission processes based on distance from the top two basins from which the local distribution company procures fuel, with

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Electricity Generation Under Minn. Stat. § 216H.06, Minn. Pub. Util. Comm'n Docket No. E-999/DI-22-236, Order Addressing Environmental and Regulatory Costs at 13 (Dec. 19, 2023).

[13] The Commission transferred Xcel's reporting of methane emissions from its performance-based regulation docket to its natural gas integrated resource planning docket. This includes "methane emissions from the Company's distribution system, upstream methane emissions, and methane emissions across the full fuel cycle." *In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Minn. Pub. Util. Comm'n Docket No. E-002/CI-17-401, Order Accepting 2021 and 2022 Reports, Suspending Decisions on Baselines and Targets, and Modifying Reporting Requirements at 6, ¶ 9 (Jan. 26, 2024).

[14] *Analytical Resource: Gas Company Climate Planning Tool,* ERM Sustainability Inst. (Jan. 10, 2022), https://www.sustainability.com/thinking/gas-company-climate-planning-tool/.

[15] ERM Sustainability Inst., Gas Company Climate Planning Tool: A Framework and Calculation Tool to Evaluate Supply- and Demand-Side Strategies, https://www.sustainability.com/globalassets/sustainability.com/thinking/analytical-resources/gas-company-climate-planning-tool_project-overview_may-2021.pdf.

customization options for gas share across these basins and applied emission factors. Gas utilities can use this tool in their integrated resource plans to estimate upstream emissions associated with procured fuel.

Proposed Decision Options

(1) Each integrated resource plan submitted by a gas utility must include a narrative description of how its preferred plan will support and serve Minnesota's greenhouse-gas-emission-reduction goals.
(2) Each integrated resource plan submitted by a gas utility must include the projected emissions that will result from its preferred plan and the other resource mixes considered. Projected emissions should include all emissions from distribution system operations and upstream emissions associated with purchased gas using recognized reporting protocols and available tools.

II. Comparing Resources on a Consistent Basis Requires Guidance from the Commission About How to Incorporate Costs

Order Point 6 of the Commission's March 27 Order states that "all resources must be evaluated on a consistent and comparable basis."[16] CEOs believe that additional guidance from the Commission about what components of resources should be included in such an evaluation would be helpful. First, we believe that utilities should be required to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison. Second, the Commission should clarify that utilities should include externalities in scenarios in the same manner that electric utilities do.

First, having a standardized cost comparison methodology is crucial when evaluating resource investments in the gas distribution system. This ensures that all options, whether it is stored liquified natural gas, traditionally delivered methane gas, renewable natural gas (RNG), geothermal energy, or efficiency measures, can be compared on a fair and consistent basis. The Environmental Defense Fund report, "Aligning Gas Regulation and Climate Goals," provides an example of such a methodology called the *all-in cost metric*.[17] This metric considers both fixed and variable costs, divided by the projected annual use, to give a comprehensive dollar per dekatherm ($/Dth) benchmark cost.[18] Including variable costs is essential because it captures the ongoing expenses associated with different resources, which can significantly impact their overall cost-effectiveness.

By dividing the total cost by the expected annual volume of use, the all-in cost metric highlights the true expense of rarely used resources. For instance, building an

[16] Phase I Order at 7, ¶ 6.
[17] Environmental Defense Fund, Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators 19-20 (2021), https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf.
[18] *Id.*

entire distribution system for use on just a few days each year will appear more expensive than more frequently utilized efficiency measures. This approach ensures that investments reflect their actual value and utility, promoting more informed decision-making.

Second, CEOs agree with the utilities that they should use the environmental externality values from Docket 14-643, which are now aligned with the federal social cost of carbon values.[19] CenterPoint points out that the equivalency factor to translate the social cost of carbon into a social cost of methane, for example, is different in Energy Conservation and Optimization (ECO) plans than it is in Natural Gas Innovation Act (NGIA) plans.[20] CEOs recommend that the Commission clarify that the NGIA equivalence factor should be used in gas IRP dockets. The factor used in ECO is based only on combustion, whereas the factor in NGIA considers lifecycle emissions, which is a more accurate representation of global warming potential for a gas like methane, which is a potent greenhouse gas when leaked directly into the atmosphere, not just when combusted.

In addition to clarifying that the Commission-approved externality values are the appropriate values to use, the Commission should provide some guidance about *how* those values should be incorporated into analyses. In December 2023, the Commission issued an Order in the regulatory cost of carbon docket that clearly explained the theoretical underpinnings of incorporating both a regulatory cost estimate and an externality value in resource plan modeling.[21] The fundamentals of how to use these values to compare electric resource plans apply with equal force to gas resource plans. The main difference at this point between electric and gas resource planning is that it is not clear what modeling software or other cost-benefit comparison methodology the gas utilities will be using to conduct their evaluations of resources. But the Commission should make clear that gas utilities are expected to incorporate externality values in gas resource planning in the same manner that electric utilities incorporate them into electric resource planning to the greatest extent possible.

<u>Proposed Decision Options</u>

(3) The Commission should require utilities to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison.

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[19] Xcel also proposes that life cycle emission factors for different resources calculated in the context of NGIA plans can be used in integrated resource plans to compare the emission intensity of different resources. CEOs agree with this suggestion.

[20] Straw Proposal of CenterPoint Energy Minnesota Gas at 3, n.2 (May 31, 2024).

[21] *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subdivision 3*, Minn. Pub. Util. Comm'n Docket No. E-999/CI-14-643, Order Addressing Environmental and Regulatory Costs at 13 (Dec. 19, 2023).

(4) The Commission should clarify that utilities should include externalities in scenarios in the same manner that electric utilities do to the greatest extent possible.

III. The Commission Should Set Parameters to Ensure Accurate Load Forecasts

Order Points 39 through 40 of the Commission's March 27 Order specify that utilities shall provide utility load and customer forecasts in their resource plans and a high, medium, and low load forecast, along with relevant assumptions, respectively.[22] We recommend that the Commission adopt additional requirements for utility load and customer forecasting. These requirements should be informed by Colorado's Gas Infrastructure Plan rules, which state:

> A utility filing under this rule shall indicate how its forecast incorporates, to the extent practicable, relevant external factors including, but not limited to:
>
> (A) the effect of current or enacted state and local building codes;
> (B) changes in the utility's line extension policies, and the associated impact on gas customer growth;
> (C) building electrification programs or incentives offered by the local electric utility or local or federal entities that overlap with the utility's gas service territory; and
> (D) the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).[23]

<u>Proposed Decision Option</u>

(5) Each integrated resource plan submitted by a gas utility must indicate how the utility load and customer forecasts incorporate, to the extent practicable, relevant external factors including, but not limited to: (1) the effect of current or enacted state and local building codes and standards; (2) building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory; (3) the effects of rate design and/or demand response programs; (4) changes in the utility's line extension policies, and the associated impact on gas customer growth; and (5) the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).

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[22] Phase I Order at 10-11, ¶¶ 39-40.
[23] Rules Regulating Gas Utilities, 4 Colo. Code Regs. § 723-4-4553(b)(2).

IV. The Commission Should Set Parameters to Ensure a Robust Expansion Alternatives Analysis

Order Points 51 through 54 of the Commission's March 27 Order outline the scope for the expansion alternatives analysis.[24] These analyses should be further defined by prescribing a 3-step framework for the consideration of alternatives, as described in a report on non-pipeline alternatives[25] prepared by Strategen:[26] a preliminary screening, the development of resource portfolios, and the evaluation of portfolios. The report describes these three steps as follows: First, the preliminary screening of forecasted infrastructure investments identifies projects for alternatives analyses that are more likely to be feasible and executable based on safety, cost, and timing. Next, to assess whether an alternatives project is technically viable, a utility procures and assembles eligible resources into a portfolio. Finally, a utility evaluates the alternatives portfolio using a benefit-cost test, qualitative vendor criteria, and equity analysis.

A. Preliminary Screening

The first step in the process is to screen potential capital projects for suitability for an expansion alternatives analysis. Order Point 51 states that "[u]tilities shall incorporate infrastructure costs related to resource expansion or new resources above an investment threshold to be established at a later date into the resource analysis and selection process."[27] The consideration of non-pipeline alternatives should be integral to decisions regarding capacity expansion projects at any level of investment. However, since only two to three significant upcoming capacity expansion projects are to initially be subject to a full expansion alternatives analysis per Order Point 54 of the Commission's March 27 Order, the CEOs are supportive of employing a reasonable threshold for gas utilities' initial resource plans. Utilities should aim to employ a cost threshold that casts a wide net of projects for consideration of alternatives analyses for initial resource plans. It is important to tailor the project cost threshold to the size of the utility: too high of a threshold and there will not be enough eligible projects, and too low of a threshold may result in the inefficient use of resources.[28]

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[24] Phase I Order at 11-12, ¶¶ 51-54.

[25] "Non-pipeline alternative" means programs, equipment, or actions that avoid, reduce, or delay the need for investment in certain types of new gas infrastructure and may include energy efficiency, demand response, and beneficial electrification.

[26] Ron Nelson, et al., Strategen Consulting, Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado (2023), https://eta-publications.lbl.gov/sites/default/files/non-pipeline_alternatives_to_natural_gas_utility_infrastructure_2_final.pdf [hereinafter Strategen NPA Report].

[27] Phase I Order at 11, ¶ 51.

[28] Strategen NPA Report at 16.

Other states also employ cost thresholds for alternatives analyses. Colorado gas utilities must consider non-pipeline alternatives when the proposed projects exceed a minimum cost threshold, which depends on the size of the gas utility:

> "Planned project" means any planned facility or an extension of an existing facility, or a defined programmatic expense with a defined scope of work and associated cost estimate that exceeds $3 million in utility capital investment in 2020 dollars, or $2 million in utility capital investment in 2020 dollars for gas utilities with less than 50,000 full-service customers, as adjusted annually for inflation.[29]

New York does not have a defined cost threshold but determines the level of scrutiny for a project based on cost. Generally, the utilities in the state have identified that proposed projects that cost less than $2 million are considered small, and subject to less scrutiny than proposed projects that exceed $2 million.[30]

We encourage utilities to not strictly prohibit safety and reliability projects from consideration for alternative analyses, although we acknowledge that it is not a requirement that utilities consider such projects for alternatives analyses based on Order Point 55 of the Commission's March 27 Order.[31] Even if not required, some safety and reliability projects can be more effectively addressed with non-pipeline alternatives. For example, New York requires gas utilities to examine non-pipeline alternatives analysis as an option to avoid replacing leak-prone pipes.[32] Given that CenterPoint is currently planning to invest over one billion customer dollars to replace existing gas main pipelines over the next three decades,[33] it is essential that an analysis of non-pipeline alternatives be considered for these planned projects.

<u>Proposed Decision Option</u>

(6) Utilities shall employ a cost threshold that casts a wide net of projects for consideration for alternatives analyses for initial resource plans.

For initial resource plans, there will be an intermediate step after the preliminary screening of eligible projects to determine the handful of projects to be considered for expansion alternatives analysis in utilities' initial plans. This is because Order Point 54 of the Commission's March 27 Order states that utilities shall identify two to three significant upcoming capacity expansion projects in each utility resource plan for a full

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29 Rules Regulating Gas Utilities, 4 Colo. Code Regs. § 723-4-4551(f).
30 Strategen NPA Report at 16-17.
31 Phase I Order at 12, ¶ 55.
32 Strategen NPA Report at 17-18.
33 Caitlin Eichten et al., Fresh Energy, Hidden Beneath Our Feet: Minnesota's Growing Decarbonization Challenge 20 (2024), https://fresh-energy.org/wp-content/uploads/2024/04/White-Paper-Minnesotas-Decarbonization-Challenge-040824.pdf.

alternatives evaluation. The CEOs agree with Xcel and CenterPoint that the resource plan should include a discussion of the rationale for the projects selected for an expansion alternatives analysis.[34] For projects above the investment threshold for the expansion alternatives analysis, a utility should provide a full alternatives evaluation or justify why the project was not selected for a full alternatives evaluation. A recent report from RMI and National Grid finds that prioritization of non-pipeline alternatives projects should weigh a broad set of criteria, including gas asset risk and hydraulic feasibility, electric capacity, benefit-cost criteria, number and type of customers, customer propensity for new technology adoption, equity, and community factors.[35] We also request that utilities include stakeholders in discussions regarding the selection of projects for the expansion alternatives analysis and include a summary of these discussions in their resource plans along with the discussion of rationale.

Proposed Decision Options

(7) For projects above the investment threshold for the expansion alternatives analysis, a utility shall provide a full alternatives evaluation or justify why the project was not selected for a full alternatives evaluation.
(8) Each utility must include a summary of its discussions with stakeholders regarding the selection of projects for the expansion alternatives analysis.

B. Portfolio Development

After the utility has conducted its preliminary screen and determined the projects to be considered for alternatives in utilities' initial plans, the next step of the process is the development of the resources portfolio for the alternatives analysis. Strategen identifies two key considerations for the development of the resource portfolio:

1. Eligible resources: Resource portfolios should align with state climate targets. Demand-side solutions, including energy efficiency and electrification, produce the most societal benefits, but supply-side resources can be beneficial on a short-term basis.
2. Project Solicitation Mechanism: Identifying a preference for competitive procurements to determine project costs, feasibility, and acquisition reduces resource costs, particularly for large projects.[36]

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[34] Straw Proposal of CenterPoint Energy Minnesota Gas at 4 (May 31, 2024); Xcel Energy Straw Proposal at 6 (May 31, 2024).
[35] Abigail Lalakea Alter et al., RMI & National Grid, Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization (2024), https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf.
[36] Strategen NPA Report at 5.

C. Portfolio Evaluation

In the third step of the process, eligible resource portfolios are evaluated based on quantitative and qualitative criteria to compare resources and determine a proposed resource portfolio. This can include an evaluation of cost-effectiveness, third-party qualifications, and equity considerations.

Order Point 54 of the Commission's March 27 Order states that "for initial utility resource plans, utilities shall identify two to three significant upcoming capacity expansion projects in each utility resource plan for a full alternatives evaluation."[37] The CEOs believe there is a need to define what is required for a full alternatives evaluation for the expansion alternatives analysis in gas resource plans. We recommend that these requirements be informed in part by the requirements for new business and capacity expansion projects in Colorado's Gas Infrastructure Plans:

> for a quantity of new business and capacity expansion projects, given the criteria established by the Commission in accordance with subparagraph 4552(b)(I)(A) through (C), the utility shall present an analysis of alternatives, including non-pipeline alternatives, costs for those alternatives, and criteria used to rank or eliminate such alternatives.
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> (i) An analysis of alternatives shall consider, at a minimum:
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> (1) one or more applicable clean heat resources consistent with the utility's most recently approved clean heat plan, pursuant to rule 4732, demand side management plan, pursuant to rule 4753, or beneficial electrification plan, as applicable;
> (2) a cost-benefit analysis including the costs of direct investment and the social costs of carbon and methane for emissions due to or avoided by the alternative, and other costs determined appropriate by the Commission; and
> (3) available best value employment metrics associated with each alternative, as defined in paragraph 4001(h), including a projection of gas distribution jobs affected by the alternative and jobs made available through the alternative, opportunities to transition any affected gas distribution jobs to the alternative, pay and benefit levels of the affected gas distribution jobs and the jobs available through a transition opportunity, and how employment impacts associated with each alternative could affect disproportionately impacted communities.

[37] Phase I Order at 12, ¶ 54.

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

(1) the technologies or approaches evaluated;
(2) the technologies or approaches proposed, if applicable;
(3) the projected timeline and annual implementation rate for the technology or approaches evaluated;
(4) the technical feasibility of the alternative assuming full adoption of the technologies and approaches evaluated;
(5) the utility's strategy to facilitate the technologies or approaches evaluated; and
(6) an explanation of the methodology used to select which projects are presented with an alternative analysis, including discussion of the public review process required pursuant to subparagraph 4552(d)(IV).[38]

CEOs agree with these suggested minimum elements to include in an alternatives analysis. In addition, as mentioned above, including variable costs is essential because it captures the ongoing expenses associated with different alternatives, which can significantly impact their overall cost-effectiveness. Variable costs should also be included in the expansion alternatives analysis. The "infrastructure costs" included in these analyses should not be limited to capital costs only. Lastly, the Commission should require the utilities to explain how equity was considered as part of their analysis.

Moving forward, gas resource planning would benefit from the development of gas system mapping tools. According to a recent report by National Grid and the Rocky Mountain Institute, "PG&E has already developed an asset screening tool, featuring an integrated mapping of gas and electric systems with customer data. This tool has aided in early research on potential non-pipeline alternatives frameworks for California."[39] An integrated system mapping and planning tool such as this can empower the utility and partners to identify potential projects along multiple prioritization criteria, including equity considerations.[40] "PG&E's mapping tool has also helped cities gain insight for localized decarbonization planning."[41]

These distribution system maps can then be overlaid with maps of low-income, disadvantaged, and environmental justice communities to further advance equitable resource planning. Overlaying a map of proposed capital projects on a map of a priority population may allow for greater understanding of how the areas may be impacted by new infrastructure or non-pipeline alternatives solutions. "For example, Washington

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[38] Rules Regulating Gas Utilities, 4 Colo. Code Regs. § 723-4-4553(c)(1)(P).

[39] Abigail Lalakea Alter et al., RMI & National Grid, Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization 21 (2024), https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf.

[40] *Id.*

[41] *Id.*

state is developing disadvantaged community maps and asking the utilities to use these maps when planning their investments."[42] The CEOs are supportive of CenterPoint's plans to evaluate ways to incorporate public data and mapping tools for low-income residents or disadvantaged communities in this IRP process,[43] and encourage other utilities to do the same.

Proposed Decision Option

(9) A full alternatives evaluation, as required by Order Point 54 of the Commission's March 27 Order, shall include non-pipeline alternatives and/or non-natural-gas alternatives; costs and benefits of those alternatives including the costs of direct investment, variable costs, and the social costs of carbon and methane for emissions due to or avoided by the alternative; a thorough and transparent explanation of the criteria used to rank or eliminate such alternatives; and an explanation of how equity was considered.

(10) To integrate equity into alternatives analyses, utilities shall evaluate ways to overlay maps of proposed capital projects and resource acquisitions across maps of environmental justice and disadvantaged communities in the utilities' service areas.

V. Equity in Gas Resource Planning

The combustion of fossil fuels in buildings has been shown to harm human health and disproportionately burden vulnerable communities, including low-income households and communities of color.[44] Rising emissions from building sectors, notably particulate matter and NOx, contribute significantly to health issues and climate change.[45] Studies have highlighted the severe health impacts and substantial social costs

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[42] Strategen NPA Report at 34.

[43] Straw Proposal of CenterPoint Energy Minnesota Gas at 7 (May 31, 2024).

[44] Sasan Saadat et al., Rhetoric vs Reality: The Myth of Renewable Natural Gas for Building Decarbonization (Earth Justice & Sierra Club, 2020), https://earthjustice.org/feature/report-buildingdecarbonization; Taylor Gruenwald et al., Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States, 20 Int'l J. Env't Rsch. Pub. Health 1, 1-4 (2023), https://doi.org/10.3390/ijerph20010075.

[45] *Greenhouse Gas Emissions Data*, Minn. Pollution Control Agency (Sept. 29, 2023), https://public.tableau.com/app/profile/mpca.data.services/viz/GHGemissioninventory/GHGsummarystory (showing that the combustion of natural gas in buildings and industry in Minnesota contributed 22 million tons of greenhouse gas emissions in 2020); *Greenhouse Gas Equivalencies Calculator*, U.S. Env't Prot. Agency (July 21, 2023), https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator#results (calculating that 22 million tons of greenhouse gas emissions is equivalent to the emissions produced by 5 coal plants in one year).

associated with pollution from fossil fuel appliances.[46] Moreover, escalating natural gas prices and energy costs, exacerbated by events like geopolitical conflicts, pose financial challenges for many households. Effective decarbonization strategies should focus on reducing gas dependence, protecting vulnerable populations, and ensuring equitable access to affordable and clean energy solutions. The Commission should also enhance participation in decision-making processes by accommodating diverse community needs and improving transparency and accessibility in public utilities commission engagement.

To center equity in gas planning, the Commission should encourage utilities to focus on electrification. Shifting focus away from alternative fuels, which analyses show are more costly and risky compared to electrification, will better address historical disparities affecting low-income and BIPOC communities. The Commission should also explore policies necessary for equitable electrification of Minnesota's buildings, ensuring that pathways to decarbonizing buildings incorporate comprehensive evaluations of costs, benefits, and risks, including health and air quality. It is crucial to provide detailed planning information to the public and stakeholders to ensure transparency and understanding of assumptions, data, and methodologies. Additionally, there is a need for regulatory actions to manage both short-term and long-term solutions that ensure low-income households are not disproportionately impacted by the transition from gas to electrified systems.

CONCLUSION

CEOs propose the following decision options based on the preceding discussion:

1. Each integrated resource plan submitted by a gas utility must include a narrative description of how its preferred plan will support and serve Minnesota's greenhouse-gas-emission-reduction goals.
2. Each integrated resource plan submitted by a gas utility must include the projected emissions that will result from its preferred plan and the other resource mixes considered. Projected emissions should include all emissions from distribution system operations and upstream emissions associated with purchased gas using recognized reporting protocols and available tools.
3. The Commission should require utilities to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison.
4. The Commission should clarify that utilities should include externalities in scenarios in the same manner that electric utilities do to the greatest extent possible.

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[46] Eric. D. Lebel et al., *Composition, Emissions, and Air Quality Impacts of Hazardous Air Pollutants in Unburned Natural Gas from Residential Stoves in California*, 56 Env't Sci. & Tech. 15828–38, https://doi.org/10.1021/acs.est.2c02581.

5. Each integrated resource plan submitted by a gas utility must indicate how the utility load and customer forecasts incorporate, to the extent practicable, relevant external factors including, but not limited to: (1) the effect of current or enacted state and local building codes and standards; (2) building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory; (3) the effects of rate design and/or demand response programs; (4) changes in the utility's line extension policies, and the associated impact on gas customer growth; and (5) the price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).
6. Utilities shall employ a cost threshold that casts a wide net of projects for consideration for alternatives analyses for initial resource plans.
7. For projects above the investment threshold for the expansion alternatives analysis, a utility shall provide a full alternatives evaluation or justify why the project was not selected for a full alternatives evaluation.
8. Each utility must include a summary of its discussions with stakeholders regarding the selection of projects for the expansion alternatives analysis.
9. A full alternatives evaluation, as required by Order Point 54 of the Commission's March 27 Order, shall include non-pipeline alternatives and/or non-natural-gas alternatives; costs and benefits of those alternatives including the costs of direct investment, variable costs, and the social costs of carbon and methane for emissions due to or avoided by the alternative; a thorough and transparent explanation of the criteria used to rank or eliminate such alternatives; and an explanation of how equity was considered.
10. To integrate equity into alternatives analyses, utilities shall evaluate ways to overlay maps of proposed capital projects and resource acquisitions across maps of environmental justice and disadvantaged communities in the utilities' service areas.

Respectfully submitted,

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