



April 23, 2025

Ms. Lisa Felice  
Michigan Public Service Commission  
7109 W. Saginaw Hwy.  
Lansing, MI 48909

*Via E-File*

RE: MPSC Case No. U-21806

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Dr. Sol deLeon on behalf of Michigan Environmental Council and Sierra Club (Exhibit MEC-14 through MEC-15); and
- Proof of Service.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Christopher M. Bzdok  
[chris@tropospherelegal.com](mailto:chris@tropospherelegal.com)

CC: Parties to Case No. U-21806

**STATE OF MICHIGAN**  
**MICHIGAN PUBLIC SERVICE COMMISSION**

In the matter of the Application  
of **CONSUMERS ENERGY**  
**COMPANY** for authority to  
increase its rates for the  
distribution of natural gas and  
for other relief.

Case No. U-21806

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**DIRECT TESTIMONY OF**  
**DR. SOL DELEON**  
**ON BEHALF OF**  
**MICHIGAN ENVIRONMENTAL COUNCIL AND SIERRA CLUB**

**April 23, 2025**

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1     **I.   INTRODUCTION AND PURPOSE OF TESTIMONY**

2     **Q     Please state your name and occupation.**

3     **A**My name is Sol deLeon. My business address is 485 Massachusetts Ave., Suite 3,  
4            Cambridge, Massachusetts 02139. I am a Principal Associate at Synapse Energy  
5            Economics, Inc. I work primarily in Synapse’s consulting for future of gas utilities  
6            practice, and I also work in the related area of building decarbonization technology  
7            and policy.

8     **Q     Please describe Synapse Energy Economics.**

9     **A**Synapse Energy Economics is a research and consulting firm specializing in  
10           electricity and gas industry regulation, planning, and analysis. Our work covers a  
11           range of issues, including economic and technical assessments of demand-side and  
12           supply-side energy resources, energy efficiency policies and programs, integrated  
13           resource planning, electricity market modeling and assessment, renewable  
14           resource technologies and policies, and climate change strategies. Synapse works  
15           for a wide range of clients, including state attorneys general, offices of consumer  
16           advocates, trade associations, public utility commissions, environmental  
17           advocates, the U.S. Environmental Protection Agency, U.S. Department of  
18           Energy, U.S. Department of Justice, the Federal Trade Commission, and the  
19           National Association of Regulatory Utility Commissioners. Synapse’s staff  
20           includes over 35 professionals with extensive experience in the electricity and gas  
21           industries.

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1    **Q**    **Please describe your professional experience at Synapse Energy Economics**  
2           **and before beginning your current position at Synapse.**

3    **A**    I have over 25 years of experience in the energy industry, primarily in U.S. natural  
4           gas distribution utilities and international merchant electricity generation. I  
5           analyze gas utility applications and filings before state public service  
6           commissions, in addition to developing studies, reports, and other materials  
7           regarding gas utility investments, business models, ratemaking, depreciation,  
8           revenue requirements, and business risk. Prior to joining Synapse, I was a project  
9           manager at Washington Gas & Light Company, working on initiatives for  
10          corporate governance, renewable natural gas (“RNG”), and greenhouse gas  
11          (“GHG”) emissions reduction inventories. Before that, I worked for AES  
12          Corporation where I conducted risk analysis on commodity prices, interest rates  
13          and foreign exchange rates, developed models for derivative valuation and electric  
14          generating asset project valuation. I completed my Masters in Business  
15          Administration and my Doctorate in Liberal Studies at Georgetown University.  
16          My doctorate focused on energy transition and energy justice. My complete CV is  
17          attached as Exhibit MEC-14.

18   **Q**    **On whose behalf are you testifying in this case?**

19   **A**    I am testifying on behalf of Michigan Environmental Council and Sierra Club.

20   **Q**    **Have you previously testified before the Michigan Public Service Commission**  
21           **(“the Commission”)?**

22   **A**    No.

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1    **Q**    **What is the purpose of your testimony?**

2    **A**    The purpose of my testimony is to explain the impending energy transition and its  
3           impacts on ratepayers, and then to evaluate Consumers Gas (“Consumers” or “the  
4           Company”) planned capital investments within the context of the energy  
5           transition. I will also address the need to develop a long-term planning perspective  
6           and to introduce the value of using risk mitigation effectiveness measures as a tool  
7           to select and prioritize capital projects.

8    **Q**    **Are you sponsoring any exhibits in this proceeding?**

9    **A**    Yes, I am sponsoring the following exhibits:

- 10           • Exhibit MEC-14: CV of Dr. Sol deLeon
- 11           • Exhibit MEC-15: State Survey White Paper

12    **II.    FINDINGS AND RECOMMENDATIONS**

13    **Q**    **Please summarize your primary conclusions.**

14    **A**    My findings include the following:

- 15           • The future of natural gas will not be like the past or the present. Changes  
16           driven by climate policy, changing markets, and the availability of  
17           alternatives will have an impact on demand. Michigan has established  
18           policies and conducted regulatory processes that the Company could have  
19           used to inform its planning. In addition, the Company has developed its own  
20           climate objectives to support the state’s decarbonization targets. Thus, the  
21           Company has sufficient information to be taking prudent actions, as  
22           described in this testimony, to adapt to a changing future.

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- 1           • The Company’s lack of good planning practice makes imprudent  
2           investment likely.
  
- 3           • The Company has not made the appropriate evaluations to determine that  
4           the continued spending on gas distribution infrastructure is the best way to  
5           achieve goals of safety, affordability, and emission reductions.
  
- 6           • The Company does not undertake well-established practices to consider  
7           non-pipeline alternatives (“NPA”) to its capital investments.
  
- 8           • The Company’s approach to prioritizing leak-prone pipe for replacement  
9           does not account for the actions that need to be undertaken to meet the  
10          state’s GHG emission reduction goals or the Company’s scope 3 emission  
11          reduction targets, nor does it attempt to maximize the risk reduction of  
12          ratepayer spending.
  
- 13          • The Company has not initiated an NPA process within its long-term gas  
14          planning to ensure that investments meet affordability and clean energy  
15          objectives.

16   **Q    Please summarize your recommendations.**

17   **A    Based on my findings, I offer the following recommendations:**

- 18          • The Commission should find that the Company’s planning process is flawed  
19          because it does not incorporate planning for the energy transition. The  
20          Commission should direct the Company to update its practices to align with  
21          planning for the Company’s and Michigan’s climate objectives. This should

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1 include requiring the Company to include the forecasted yearly sales for  
2 each major customer class for the 10-year gas delivery planning horizon.

3 • The Commission should open a docket for the purpose of establishing a  
4 common framework and planning parameters, including consideration of  
5 NPAs and other alternatives, for the future of the natural gas system in  
6 Michigan.

7 • The Commission should require Consumers to evaluate NPAs in place of  
8 traditional gas infrastructure investments before the Company can seek cost  
9 recovery of those traditional investments. This should include evaluation of  
10 electrification as an alternative to service line replacement.

11 • The Commission should set forth minimum requirements for an NPA  
12 framework, including but not limited to benefit-cost analysis, project size,  
13 type of project, timeline for implementation, and alternatives to consider.  
14 The Commission should then launch an inclusive stakeholder process to  
15 develop the details of the NPA framework, with participation by all electric  
16 and gas utilities in the state along with other stakeholders.

17 • Consumers should provide much greater transparency regarding the  
18 tradeoffs between safety and affordability—on a regular basis and in its  
19 requests for approval to include expenditures in rate base—through  
20 probabilistic risk modeling and calculation of cost-effectiveness. This  
21 includes, but may not be limited to:

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- 1           ○ Reporting on transmission-level projects that demonstrates how  
2           Consumers utilizes cost-effectiveness, where applicable, to maximize  
3           safety impacts for the ratepayer dollars spent. Calculations and  
4           assumptions should be available to stakeholders upon request.
- 5           ○ Enhanced Infrastructure Replacement Program (“EIRP”) reporting  
6           should include risk ranking information (risk rank of asset remediated  
7           and total number of assets) and narrative descriptions regarding the use  
8           of risk ranking driving remediation for a particular project.
- 9           ● When probabilistic risk models are available for distribution assets starting  
10          in the next rate case, Consumers should do the following:
- 11          ○ Calculate and utilize total risk reduction and cost-effectiveness  
12          statistics as an important input into selecting appropriate projects and  
13          related remediations. Make cost-effectiveness statistics and all inputs  
14          and assumptions available to stakeholders upon request, including the  
15          ability to calculate risk reduction and cost-effectiveness for alternative  
16          projects and remediations.
- 17          ○ Ensure its EIRP reports summarize remediations examined, describe  
18          the cost-effectiveness of projects relative to alternatives, and indicate  
19          why the Company’s remediation was selected.
- 20          ● The Commission should require future rate case applications, starting with  
21          Consumers’ next rate case, to utilize probabilistic risk modeling and cost-  
22          effectiveness calculations to a much greater extent for all asset classes.

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1 Consumers should make this modeling available upon request to  
2 stakeholders and the Commission, including the following:

3 ○ Unless Consumers can demonstrate it is not possible, the Company  
4 should develop probabilistic risk models for use in the next rate case  
5 for all asset classes (distribution, storage wells, etc.).

6 ○ For each project proposed in the test year, Consumers should calculate  
7 the risk reduction, cost, and cost-effectiveness (measured as risk spend  
8 efficiency, or “RSE”) of its expenditures. The Company should make  
9 all workpapers available upon request, and include the source and  
10 calculation of key assumptions such as mitigation effectiveness, cost  
11 estimates, and other inputs.

12 ○ Consumers should provide an estimate of the impact that prior year’s  
13 expenditures have made to reduce risk on the system. Given the  
14 substantial ratepayer expenditures each year on the gas system to  
15 improve safety, the Company should describe what has been achieved  
16 to date and how much risk is left on the system relative to five years  
17 ago, ten years ago, etc.? If Consumers has prioritized the highest risk  
18 assets each year, I would expect diminishing returns for risk reduction.  
19 This information can only be ascertained with historical analysis of risk  
20 reduction achieved to date.

21 • The Commission should cap additions to plant in service in the projected  
22 test year at no more than 2024 investment levels, as illustrated in Table 1.

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1           Furthermore, the Commission should require Consumers to implement  
2           probabilistic risk models for EIRP and Vintage Service Program (“VSR”)  
3           before spending at levels that increase additions to plant in service above  
4           2024 levels. (See Table 8)

5   **III. ENERGY TRANSITION**

6   **Q    Could you please describe what you mean by the term “energy transition”?**

7   **A**The “energy transition” refers to the economy-wide transition to reduce GHG  
8           emissions by 80 percent or more by 2050 by moving away from an energy system  
9           of fossil fuel resources and toward an energy system of renewable and zero-carbon  
10          resources. The energy transition is underway in several jurisdictions across the  
11          United States as state agencies, public utility commissions, and utilities take action  
12          to support the achievement of the state’s GHG emission reduction objectives.

13 **Q    Are other jurisdictions taking actions to address the energy transition?**

14 **A**Many other jurisdictions are formally addressing issues related to the future of the  
15          natural gas system in a regulated context. For a detailed description of the future  
16          of gas dockets in 12 other jurisdictions including Massachusetts, New York,  
17          Maryland, the District of Columbia, Minnesota, Illinois, Colorado, Oregon, and  
18          California, refer to Exhibit MEC-15.

19 **Q    Please summarize the major implications of the energy transition for gas**  
20 **utilities based on experience in other jurisdictions.**

21 **A**As demonstrated by the regulatory proceedings in numerous other jurisdictions,  
22          utility commissions are increasingly recognizing that business-as-usual

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1 approaches to managing the gas system cannot continue if states are to achieve  
2 their emission reduction targets and maintain affordable rates. The major  
3 implications of the energy transition for gas utilities are:

- 4 • The future of gas consumption and gas utility asset utilization will not look  
5 like the past or present. Energy delivered by the gas system will fall  
6 substantially, and the building sector share of gas consumption will fall  
7 (Massachusetts, New York, Maryland).
- 8 • Business-as-usual approaches to accelerated leak-prone pipe replacement  
9 are not justified. Capital investments should not be made until they are  
10 shown to be superior to alternatives that incorporate repair, retirement, or  
11 NPAs such as efficiency and electrification (Massachusetts, New York,  
12 Maryland, Illinois). In addition, regulators are requiring higher levels of  
13 analysis to justify gas plans (New York) and more extensive reporting to  
14 justify gas capital investments (Illinois, Massachusetts, Colorado).
- 15 • The recovery of invested capital over a smaller volume of sales will mean  
16 higher gas distribution rates and increased competition from electricity. The  
17 extent of these gas rate increases can be reduced by changes to the utility's  
18 approach to capital investment, repairs, retirement, and depreciation  
19 (Massachusetts, New York).
- 20 • Utilities have a responsibility to undertake prudent planning and investment  
21 actions to adapt to the energy transition, taking into account the timeframe  
22 of that transition and how it relates to the lifetime of gas assets. Failure to

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1           make prudent capital decisions increases stranded-asset risk, which may be  
2           borne by customers and/or investors (Massachusetts, Maryland, Colorado).

3   **Q    Why is the energy transition relevant for this case?**

4   **A**As jurisdictions have started to plan for the energy transition and to model  
5           pathways to achieve net-zero emissions, available analyses have made clear that  
6           the transition requires broad reductions in gas consumption (see Exhibit MEC-15  
7           for a discussion of pathways analysis conducted in different jurisdictions) to meet  
8           emission reduction targets. The transition requires a reduction in the amount of  
9           fuel the gas utilities deliver to customers, and this will ultimately be reflected in  
10          changes in the Company’s rates and the Company’s overall competitive position  
11          compared to alternatives. The transition will impact the need to build out, repair  
12          and replace, depreciate, and generally plan and invest in the gas system, with fewer  
13          customers to shoulder this risk. Decision-making related to infrastructure  
14          investments must account for the energy transition. Gas distribution utilities such  
15          as the Company get their revenue from delivering gas to customers and recovering  
16          both the costs of the gas commodity and the costs of maintaining the extensive  
17          pipeline network used to transport it. Utilities have the opportunity to earn a fair  
18          return on prudent investments in assets that are used and useful.

19          As the energy transition progresses and gas sales decline, some gas utility assets  
20          will no longer provide service or will not be used and useful. These assets will  
21          therefore need to be removed from the rate base. That removal turns those  
22          investments into “stranded assets.” If the constructed stranded assets are not fully  
23          depreciated, the Company’s remaining customers or investors will bear the risk of

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1 those stranded costs. A rate case such as this one is where the prudence of a utility’s  
2 actions can be evaluated and its rates adjusted to account for the cost of capital,  
3 for changes in the assets which are used and useful, and for their useful lives. The  
4 energy transition impacts these factors and thus is relevant to this case.

5 **Q What are Michigan’s emission reduction policies?**

6 **A** Executive Directive No. 2020-10, signed by Governor Whitmer in September  
7 2020, establishes a state-wide goal of achieving a 28 percent reduction in GHG  
8 emissions below 1999 levels by 2025, and reaching carbon-neutrality no later than  
9 2050.<sup>1</sup> To achieve these reductions, the Governor then ordered the creation of the  
10 Michigan Healthy Climate Plan in September 2020. The plan includes a roadmap  
11 to a 52 percent GHG emissions reduction in space heating for Michigan buildings.  
12 The plan elaborates further with respect to natural gas: “To complement immediate  
13 policy actions, the Plan recommends the state undertake a pathway analysis to  
14 assess options to achieve carbon neutrality from natural gas production,  
15 transmission, distribution, compression, storage, and end uses in a least-cost  
16 manner. This analysis should consider a full range of options for decarbonizing  
17 natural gas end uses, including energy efficiency, electrification, fuel switching to  
18 renewable natural gas and hydrogen, and other potential opportunities.”<sup>2</sup>

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<sup>1</sup> Governor Gretchen Whitmer, Executive Directive No. 2022-10, September 23, 2020, available at: [https://content.govdelivery.com/attachments/MIEOG/2020/09/23/file\\_attachments/1553296/ED%202020-10%20Carbon\\_Neutral\\_Goal.pdf](https://content.govdelivery.com/attachments/MIEOG/2020/09/23/file_attachments/1553296/ED%202020-10%20Carbon_Neutral_Goal.pdf).

<sup>2</sup> Michigan Healthy Climate Plan page 43.

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1    **Q**    **Do the natural gas utilities in Michigan have a role to play in meeting the**  
2           **state’s GHG emission targets?**

3    **A**    Yes, due to the reliance on natural gas for heating. Three-quarters of Michigan  
4           residents rely on natural gas for heating,<sup>3</sup> and in 2023 Michigan had the fourth  
5           highest natural gas consumption in residential and commercial sectors of any state  
6           in the United States.<sup>4</sup> According to the 2024 Michigan Healthy Climate Plan, the  
7           ‘built environment’ (which includes home and business heating) accounted for 16  
8           percent of statewide GHG emissions with industry consumption accounting for  
9           another 19 percent in 2021.<sup>5</sup>

10   **IV.    NATIONAL GAS DELIVERY PLAN AND CONSUMERS’ CLIMATE**  
11           **TARGETS**

12   **Q**    **Please describe the Natural Gas Delivery Plan and how the plan addresses**  
13           **Michigan’s GHG emission reduction objectives.**

14   **A**    The Natural Gas Delivery Plan (“NGDP”) presents the planned investments in  
15           natural gas infrastructure for the next 10 years. The framework for the investment  
16           plan considers the safety and reliability of gas supply and also factors in the  
17           changes needed to meet pipeline safety regulatory requirements.

18           The NGDP also includes the response of the Company to the decarbonization goals  
19           of Michigan. It includes a “strategic framework in response to the decarbonization

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<sup>3</sup> U.S. Energy Information Administration (EIA), Michigan State Energy Profile, updated October 17, 2024, available at: <https://www.eia.gov/state/print.php?sid=mi#51>.

<sup>4</sup> EIA, Natural Gas Consumption by End Use, released January 31, 2025, available at: [https://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_a\\_EPG0\\_vrs\\_mmcfa.htm](https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vrs_mmcfa.htm).

<sup>5</sup> Michigan Department of Environment, Great Lakes, and Energy (EGLE), Michigan Healthy Climate Plan: 2024 Report, December 2024, page 26, available at: <https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Reports/OCE/MHCP-2024-Report.pdf>.

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1 goals of the company’s natural gas customers and future carbon policy relevant to  
2 the utility.”<sup>6</sup> The NGDP includes a discussion of its commitment to “reducing  
3 greenhouse gas emissions across its systems associated with the energy  
4 consumption of its customers.”<sup>7</sup> The Company also mentions supporting  
5 Michigan’s MI Healthy Climate Plan with its goal to “achieve net zero greenhouse  
6 gas emissions from the entire natural gas production and delivery system,  
7 including customers and suppliers, by 2050.”<sup>8</sup>

8 **Q Does the Company have any GHG emission reduction goals?**

9 **A** The Company has established Scope 1 and Scope 3 targets.<sup>9</sup>

10 The Company established a goal to achieve net-zero Scope 1 methane emissions  
11 by 2030. The Company plans to achieve 80 percent of this reduction through near-  
12 term measures to reduce methane leaks from the system. This includes actions  
13 such as the reduction of distribution main and service leaks by replacing vintage  
14 pipe, reducing storage wellhead component leaks, and implementing compression  
15 blowdown venting procedures and transmission blowdown procedures. The  
16 balance of 20 percent is expected to be met through the procurement of carbon  
17 credits potentially through RNG.<sup>10</sup>

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<sup>6</sup> Direct Testimony of Company Witness Neal P. Dreisig, page 3 at 6.

<sup>7</sup> Dreisig Testimony, page 5 at 14.

<sup>8</sup> Ex A-42, Natural Gas Delivery Plan (NGDP), page 77.

<sup>9</sup> Scope 1 emissions are those directly resulting from the Company’s operations. This involves the reduction of fugitive methane and carbon emissions from the gas system. Scope 3 emissions are produced upstream and downstream of the Company; they include emissions that result from customers’ consumption of gas purchased from Consumers.

<sup>10</sup> NGDP, page 78.

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1 It also has a goal to reduce Scope 3 emissions by 20 percent by 2030 and to achieve  
2 net-zero carbon emissions by 2050. The Company clarifies that this “include[s] all  
3 emissions traced to natural gas purchases and activities by customers and  
4 suppliers, like those associated with burning natural gas to heat homes and  
5 businesses.”<sup>11</sup> The Company’s goal is to achieve the 20 percent reduction by 2030  
6 through Energy Waste Reduction (EWR or energy efficiency), RNG, carbon  
7 offsets and other new emerging decarbonization technologies such as hydrogen,  
8 clean synthetic fuels, electrification, and carbon capture.

9 While the Company highlights the voluntary program allowing customers to offset  
10 carbon emissions through RNG—noting that it would contribute to the state’s  
11 emission reduction targets—the Company admits that “[a]fter inception in April  
12 2024, no customers have been enrolled,”<sup>12</sup> and states that the program is expected  
13 to be operational in late 2025. This raises questions about the efficacy of this  
14 program in contributing to the achievement of the Company’s GHG emission  
15 reduction goals.

16 **Q Do you have any concerns that the Company does not have a more detailed**  
17 **decarbonization plan?**

18 **A** Yes. The Company has identified potential pathways to meet net-zero emissions  
19 by 2050. However, the Company has not provided any concrete plan to meet its  
20 Scope 3 targets, neither for 2030 nor for 2050. Despite findings from the state-  
21 wide decarbonization pathways analysis that support hybrid electric and gas

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<sup>11</sup> NGDP, page 79.

<sup>12</sup> Discovery Response MNSC-CE-0034

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1 heating,<sup>13</sup> the Company has stated that it “does not have current plans to deploy or  
2 support hybrid heating through 2030 and 2050.”<sup>14</sup> The Company has less than five  
3 years to achieve the 20 percent reduction in Scope 3 emissions and has only  
4 presented a list of actions and a waterfall chart;<sup>15</sup> it has not presented a more  
5 detailed execution plan that includes actual tasks that must be completed to achieve  
6 these lofty goals.

7 **Q Do you have any concerns about the inconsistency between the Company’s**  
8 **Scope 3 net-zero targets and the continued investment in natural gas**  
9 **infrastructure?**

10 **A** Yes. In the NGDP, the Company set an interim goal to help its customers achieve  
11 a 20 percent reduction in Scope 3 emissions by 2030. They also have a goal of net-  
12 zero emissions on or before 2050. The Company recognizes the immensity of the  
13 task, stating that “[r]eaching ‘net zero’ will require Consumers Energy to balance  
14 many diverse emission reduction opportunities with safe, reliable, and affordable  
15 energy delivery.”<sup>16</sup> Included in the list of items that will support the achievement  
16 of this goal are EWR or energy efficiency programs and electrification, which  
17 suggest a reduction or elimination of the use of natural gas.

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<sup>13</sup> According to the Company, hybrid heating “combines the heat content of natural gas with the efficiency of a heat pump. In this context, heat pumps would be used as much as possible; however, during the coldest winter months, natural gas furnaces would still be used to mitigate winter peak electric load.” (NGDP, p. 82)

<sup>14</sup> Ex MEC-3, Discovery Response MNSC-CE-0039. Witness Napoleon sponsors Ex MEC-3.

<sup>15</sup> See Figure 40 on page 80 of the NGDP.

<sup>16</sup> NGDP, page 79.

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1 As discussed in the next section, the Company’s emissions reduction targets  
2 coexist with contradicting plans for continued significant and elevated levels of  
3 investment in natural gas infrastructure. For one, Consumers is expecting  
4 continued customer growth through at least 2035, despite a historically declining  
5 number of new connections (please refer to the testimony of my colleague, Alice  
6 Napoleon, for more details on gas demand).<sup>17</sup> The Company is also planning to  
7 replace 1,760 miles of vintage, standard pressure, and Transmission Operated by  
8 Distribution pipe over the next 10 years with no plans to conduct leak repair or  
9 consider NPAs for serving demand in lieu of replacement.<sup>18</sup>

10 **Q Why is this a concern?**

11 **A** From 2026 to 2035, Consumers is proposing long-lived infrastructure investments  
12 that will be paid for by its customers for decades. This proposal is inconsistent  
13 with the Company’s Scope 3 emission reduction targets. The Company identifies  
14 several technologies that would contribute to meeting its Scope 3 objectives. The  
15 EWR/energy efficiency programs and increased electrification, in particular,  
16 should contribute towards a significant reduction in gas throughput and a reduction  
17 in gas customers. Thus, there is a risk that these new infrastructure investments  
18 will become stranded assets.

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<sup>17</sup> NGDP, page 60.

<sup>18</sup> NGDP, page 51.

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1    **Q**    **In the NGDP, what are the long-term factors that drive the future of the**  
2           **natural gas business?**

3    **A**    The Company identified four factors: safety, increasing regulation, changing  
4           supply and demand patterns, and an environmental focus.<sup>19</sup> The last factor has  
5           long-term implications. The Company elaborates, “[t]he impact of natural gas use  
6           on climate change through carbon emissions and methane emissions is becoming  
7           a focal point of environmentally conscious customers, regulators and other  
8           stakeholders as coal-based emissions from electric generation continue a  
9           downward trend.”<sup>20</sup>

10   **Q**    **Does the Company consider the energy transition in its gas planning, as**  
11           **presented in the NGDP?**

12   **A**    The Company discusses its Scope 1 and Scope 3 net-zero targets and the potential  
13           technologies that can be used to meet these targets. It also includes a section in its  
14           NGDP discussing the results of the decarbonization modeling undertaken in 2021.  
15           However, there is no evidence that the Company considered these when  
16           developing the near-term or long-term capital plan for the distribution system.

17           In contrast to discussions about the energy transition and the changing energy  
18           environment in which the Company will be operating, Consumers’ gas planning  
19           seems to assume the future will be the same as the past, with no departure from  
20           status quo. The NGDP includes a section with a 10-year focus on distribution  
21           assets, where the priority is to “[r]educ[e] system risk and methane emissions while

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<sup>19</sup> NGDP, page 11.

<sup>20</sup> NGDP, page 11.

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1 addressing system reliability and capacity. This will be accomplished by  
2 addressing aging or vintage infrastructure that is closest to the customers” and to  
3 “[r]emediate vintage distribution main, standard pressure main, and vintage  
4 services to meet 2035 completion date.”<sup>21</sup>

5 The planned investments in the distribution system are an extension of and  
6 completion of previously identified plans to replace pipe. The Company has not  
7 provided any indication that it considered other options, such as pipe repair or  
8 NPAs, that could be more suitable for a changing environment.

9 **V. OVERVIEW OF CONSUMER’S MAJOR INFRASTRUCTURE**  
10 **INVESTMENTS AND NATURAL GAS DELIVERY PLAN**

11 **Q Please describe how the natural gas infrastructure investments were**  
12 **determined in the NGDP.**

13 **A** A significant amount of investment in the distribution system is for the  
14 replacement of pipelines of vintage materials. The investments also include  
15 expanded monitoring though advanced leak detection methodologies and  
16 upgrading the remote data monitoring system.

17 The Company is planning to complete the vintage pipe replacement programs by  
18 2035, claiming that it balances safety, reliability, and affordability. Distribution  
19 programs aimed at replacing and expanding the distribution system make up  
20 almost 60 percent of Consumer’s cumulative projected investments through  
21 2034.<sup>22</sup>

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<sup>21</sup> NGDP, page 47.

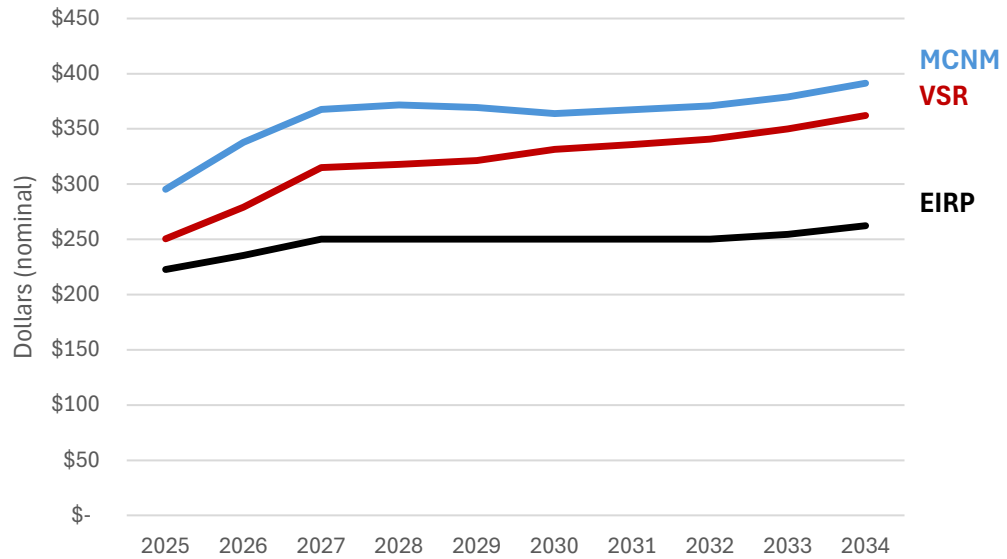
<sup>22</sup> Discovery Response MNSC-CE-0007\_Dreisig\_ATT\_1.

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1 **Q Please characterize Consumers’ natural gas infrastructure investments.**

2 **A** Three major pipe replacement programs within the distribution category include  
3 the EIRP, VSR, and Material Conditioned Non-Modeled Program (MCNM). The  
4 Company is on track to spend \$3.6 billion in the next decade on the EIRP, VSR,  
5 and MCNM programs alone (see Figure 1).<sup>23</sup>

6 Figure 1. Distribution replacement program forecasted investment  
7



8

9 *Source: MNSC-CE-0007\_Dreisig\_ATT\_1.*

10 *Note: values are stacked to show cumulative program investment.*

<sup>23</sup> Discovery Response MNSC-CE-0007\_Dreisig\_ATT\_1.

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1           **i. Enhanced Infrastructure Replacement Program**

2   **Q   Please characterize Consumer’s Enhanced Infrastructure Replacement**  
3   **Program.**

4   **A**   Launched in 2012, the EIRP replaces distribution pipes made of vintage, leak-  
5       prone materials. The EIRP is the Company’s largest individual capital program,  
6       accounting for a fifth of cumulative projected investments through 2034.<sup>24</sup> In  
7       addition to replacing vintage pipes (defined as pipes made of cast iron, bare steel,  
8       threaded and coupled steel, and wrought iron),<sup>25</sup> Consumers intends to replace all  
9       low pressure pipe through the EIRP with the goal of eliminating its entire standard  
10      pressure system.<sup>26</sup> As of February 2024, there were 1,726 miles of vintage and  
11     standard pressure pipe slated for replacement under the EIRP.<sup>27</sup> The Company  
12     prioritizes segments of pipe using the Distribution Risk Analysis Model  
13     (DRAM).<sup>28</sup> Pipe repair is not part of the EIRP.<sup>29</sup>

14   **Q   Please describe historical EIRP activities.**

15   **A**   Refer to Table 1 showing historical miles of pipe replaced and capital expenditures  
16       under the EIRP since 2017. Since the start of the program in 2012, Consumer’s  
17       has spent \$1.6 billion on pipe removal and installation, in that time replacing  
18       roughly 980 miles of transmission and distribution pipe.<sup>30</sup> From 2012 to 2022,

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<sup>24</sup> Discovery Response MNSC-CE-0007\_Dreisig\_ATT\_1

<sup>25</sup> NGDP, page 48.

<sup>26</sup> NGDP, page 49.

<sup>27</sup> NGDP, page 51.

<sup>28</sup> Direct Testimony of Company Witness Kristine A. Pascarello, page 68 at 23.

<sup>29</sup> Discovery Response MNSC-CE-0579.

<sup>30</sup> Discovery Response MNSC-CE-0042\_Pascarello\_Attachment\_1 through 12.

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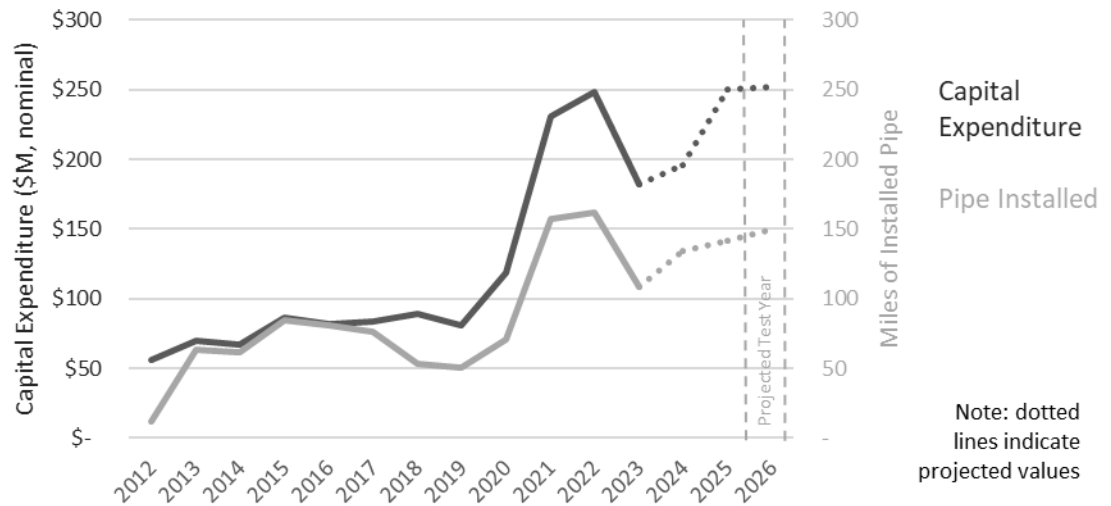
1 annual capital expenditures more than tripled; spending fell slightly in 2023, but  
2 Consumers' projected expenditures for 2025 and 2026 return to the same elevated  
3 levels from 2022 (see Figure 2).

4 **Table 1. EIRP Historical Pipe Replacement (nominal dollars)**

	2017	2018	2019	2020	2021	2022	2023
<b>Pipe Retired (miles)</b>	78.30	50.86	45.83	71.66	134.61	130.34	131.16
<b>Pipe Installed (miles)</b>	76.67	52.86	50.75	71.24	157.22	162.11	108.94
<b>Capital Expenditure (\$000)</b>	\$83,705	\$88,821	\$81,028	\$118,551	\$230,723	\$248,149	\$181,927
<b>Unit Cost (\$000/mile installed)</b>	\$1,092	\$1,680	\$1,596	\$1,664	\$1,468	\$1,531	\$1,670

5 *Source: MNSC-CE-0042\_Pascarello\_Attachment\_1 through 12.*

6 **Figure 2. Historical and Projected EIRP Expenditure and Pipe Installation**



7  
8 *Source: MNSC-CE-0042\_Pascarello\_Attachment\_1 through 12.*

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1     **Q     What are Consumers’ proposed investments for the EIRP?**

2     **A     Consumers is proposing to spend \$697.5 million over 3 years (2024-2026) to retire**  
3     **406 miles of old pipe and install 426.9 miles of new pipe through the EIRP.<sup>31</sup>**  
4     **Notably, the test year values show an almost 30% increase from \$195.6 million in**  
5     **2024 to a proposed \$251.4 million in the test year,<sup>32</sup> noting that the amount in the**  
6     **test year “supports the annual installed mileage required to ensure program**  
7     **completion by 2035.”<sup>33</sup>**

8     **Table 2. EIRP projected pipe replacement (nominal dollars)**

	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>Total</b>
<b>Pipe Installed (miles)</b>	134.60	142.00	150.30	426.90
<b>Capital Expenditure (\$000)</b>	\$195,587	\$250,300	\$251,600	\$697,487
<b>Unit Cost (\$000/mile installed)</b>	\$1,453	\$1,763	\$1,674	\$1,634

9     *Source: Exhibit A-84 (KAP-6).*

10             **ii.     Vintage Service Replacement Program**

11     **Q     Please characterize Consumer’s Vintage Service Replacement program.**

12     **A     Beginning in 2017, the VSR program eliminates services made of vintage**  
13     **materials such as copper or bare steel, and services for which the material is**  
14     **unknown.<sup>34</sup> Within this program, service replacements fall into one of three**  
15     **groups: In-Grid VSRs, Proactive-in-Grid VSRs, and Proactive Out-of-Grid VSRs.**

<sup>31</sup> Pascarello Testimony, page 49, Table 7; NGDP page 51.

<sup>32</sup> Pascarello Testimony, page 47 at 26.

<sup>33</sup> Pascarello Testimony, page 48 at 3.

<sup>34</sup> Pascarello Testimony, page 66 at 19.

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1           • In-Grid VSRs are vintage services attached to vintage mains that are being  
2           replaced within an EIRP project. The cost of these service replacements fall  
3           under the EIRP.<sup>35</sup>

4           • Proactive In-Grid VSRs are vintage services attached to non-vintage mains  
5           within the footprint of an EIRP project. The cost of these service  
6           replacements falls under the VSR program.<sup>36</sup>

7           • Proactive Out-of-Grid VSRs are vintage services located outside of an EIRP  
8           project; project costs fall under the VSR program.<sup>37</sup>

9           Vintage services might also be replaced outside of the VSR program, such as  
10          services replaced through the Material Condition Non-Modeled program, and  
11          others.<sup>38</sup>

12          Vintage services are currently prioritized based on a manual analysis process that  
13          considers factors such as leak rate, material age, and soil conditions; although the  
14          Company states that in 2025 it plans to transition to using the Distribution Risk  
15          Analysis Model (DRAM) which is currently used to analyze distribution pipes.<sup>39</sup>

16       **Q     Please describe historical VSR activities.**

17       **A     Refer to Table 3 showing historical VSR replacements and expenditures. The table**  
18       excludes service replacements carried out through the EIRP and through other

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<sup>35</sup> Pascarello Testimony, page 69 at 16.

<sup>36</sup> Pascarello Testimony, page 69 at 20.

<sup>37</sup> Pascarello Testimony, page 69 at 28.

<sup>38</sup> Pascarello Testimony, page 68 at 13.

<sup>39</sup> Pascarello Testimony, page 69 at 23.

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1 programs, it only includes service replacements associated with VSR expenditure.  
 2 The VSR program represents about half of the Company’s total service  
 3 replacements from 2017 to 2023.<sup>40</sup>

4 **Table 3. VSR historical service replacements (nominal dollars)**

	2017	2018	2019	2020	2021	2022	2023
<b>Proactive In-Grid and Out-of-Grid VSRs</b>	6,307	9,381	5,571	5,456	5,056	2,176	1,228
<b>VSR Program Spend (\$000)</b>	\$33,564	\$56,634	\$40,443	\$42,818	\$32,955	\$17,165	\$11,354
<b>VSR Unit Costs</b>	\$5,322	\$6,037	\$7,260	\$7,848	\$6,518	\$7,888	\$9,246

5 **Q What are Consumers’ proposed investments for the VSR program?**

6 **A** Table 4 shows the Company’s projected VSR replacements and expenditures  
 7 through 2026.

8 **Table 4. VSR projected service replacements (nominal dollars)**

	2024	2025	2026	Total
<b>Proactive In-Grid and Out-of-Grid VSRs</b>	2,875	4,194	5,913	12,982
<b>VSR Program Spend (\$000)</b>	\$18,666	\$27,978	\$43,689	\$90,333
<b>VSR Unit Costs (\$)</b>	\$6,493	\$6,671	\$7,389	\$6,851

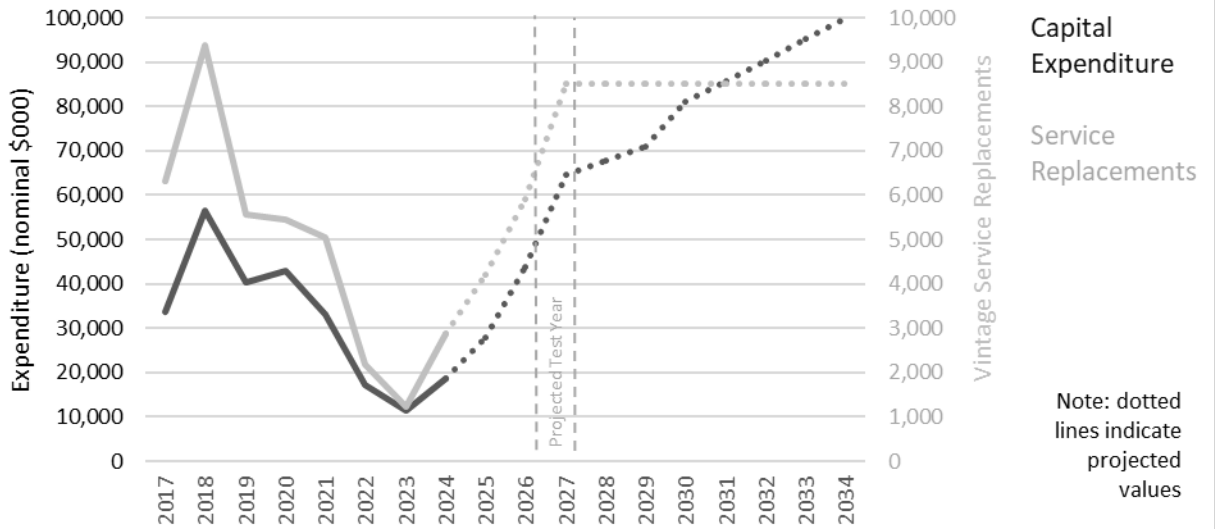
9 *Source: Pascarello Testimony, page 71.*

<sup>40</sup> Pascarello Testimony, page 71 Table 9; MNSC-CE-0040\_Pascarello\_Attachment\_1.

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1 Consumers’ projects an increased number of vintage service replacements in 2024,  
2 2025, and 2026, and through 2035.<sup>41</sup> The VSR program spend increases 128  
3 percent from \$18.6 million in 2024 to a projected \$42.5 million for the test year.<sup>42</sup>

4 **Figure 3. VSR service replacements**



5

6 *Source: Pascarello Testimony, page 71; MNSC-CE-0040\_Pascarello\_Attachment\_1;*  
7 *MNSC-CE-0007\_Dreisig\_ATT\_1.*

8 **iii. Material Condition Non-Modeled Program**

9 **Q Please characterize Consumers’ Material Condition Non-Modeled program.**

10 **A** This program replaces distribution main not covered by the EIRP. Under this  
11 program, pipes might be replaced due to emergent safety concerns, active gas  
12 leaks, compliance with regulation, and Company-initiated projects of certain

<sup>41</sup> Pascarello Testimony, page 71 Table 9; MNSC-CE-0040\_Pascarello\_Attachment\_1

<sup>42</sup> Pascarello Testimony, page 71 at 1.

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1 assets “which may not rank as highly in the Company’s risk modeling but whose  
2 replacements offer operational advantages to the Company and customers.”<sup>43</sup>

3 **Q How does the MCNM program differ from the EIRP?**

4 **A** Both the EIRP and MCNM program address risk-related needs of the system.  
5 Witness Pascarello explains that, as EIRP planning increasingly happens further  
6 out, the MCNM program gives the Company flexibility to address emergent needs  
7 of the deteriorating system as they arise.<sup>44</sup>

8 **Q Please describe historical MCNM activities.**

9 **A** Table 5 shows the Company’s historical expenditure, replaced pipe, and unit costs  
10 under the MCNM program. As stated in discovery, “There are zero miles of pipe  
11 repaired in this program.”<sup>45</sup>

12 **Table 5. MCNM historical replacements and expenditures (nominal dollars)**

	<b>2020</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>
<b>Pipe Replacement (miles)</b>	9.37	19.8	12.9	10	11.8
<b>Capital Expenditure (\$000)</b>	\$36,892	\$50,126	\$42,358	\$38,516	\$39,443
<b>Unit Cost (\$000/mile replaced)</b>	\$3,937	\$2,532	\$3,284	\$3,852	\$3,343

13 *Source: MNSC-CE-0578*

<sup>43</sup> Pascarello Testimony, page 50 at 24.

<sup>44</sup> Pascarello Testimony, page 52 at 6.

<sup>45</sup> Discovery Response MNSC-CE-0578.

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1    **Q    What are Consumers’ proposed investments for the MCNM program?**

2    **A**Consumers is proposing to spend over \$130 million on MCNM projects through  
3           2026.<sup>46</sup> This includes (but is not limited to) three Company-initiated projects:  
4           replacing 6 miles of wrought iron pipe (with plans to replace the entire remaining  
5           12 miles of the wrought iron system over the next four years), a \$38 million  
6           Maximum Allowable Operating Pressure (MAOP) compliance project on Line  
7           1010, and a high pressure waterway crossing.<sup>47</sup> The MCNM program spend  
8           increases 47 percent from \$38.3 million in 2024 to a projected \$56.2 million for  
9           the test year.<sup>48</sup>

10           **Table 6. MCNM projected expenditure (nominal dollars)**

	<b>2024</b>	<b>2025</b>	<b>2026</b>	<b>Total</b>
<b>Capital Expenditure (\$000)</b>	\$38,256	\$42,628	\$56,206	\$138,277

11           *Source: Exhibit A-82 (KAP-4), pages 1- 2;*

12    **Q    What can you say about the increase in gas infrastructure investment?**

13    **A**The test year capital expenditures for five programs is \$385.7 million, a 45 percent  
14           increase from \$266.3 million in 2023 and 35 percent increase from \$285.7 million  
15           in 2024.<sup>49</sup> The test year totals are a snapshot of a sustained high level of capital  
16           investment proposed by the Company (see Figure 4), leading to an increasing rate

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<sup>46</sup> Exhibit A-82 (KAP-4), page 2.

<sup>47</sup> Pascarello Testimony, page 56 at 15.

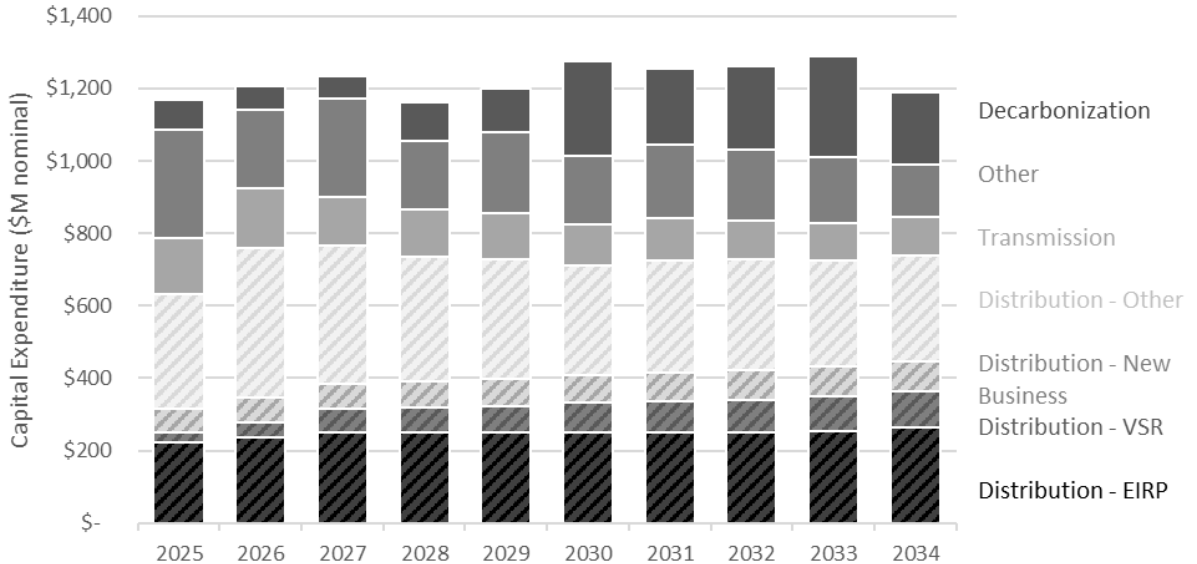
<sup>48</sup> Exhibit A-82 (KAP-4), page 1.

<sup>49</sup> Pascarello testimony, page 34 at 16.

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1 base. This level of spending, combined with sales the Company itself projects will  
2 decline and are likely to decline more than the Company projects.<sup>50</sup>

3 **Figure 4. Projected capital investment by program**



4  
5 *Source: MNSC-CE-0007\_Dreisig\_ATT\_1.*

6 **VI. RISK MODELING AND COST-EFFECTIVENESS TO MAXIMIZE**  
7 **SAFETY IMPACTS OF RATEPAYER EXPENDITURES**

8 **i. Overview of Risk Modeling and Cost-Effectiveness**

9 **Q How do you define cost-effectiveness in relation to safety-related programs?**

10 **A** In this context, cost-effectiveness analysis examines the level of risk reduction  
11 expected from alternative measures in comparison with the cost to deploy these  
12 alternatives. This type of analysis allows the utility and stakeholders to compare  
13 various mitigations against each other, such as replacement versus pipe lining,

<sup>50</sup> See Direct Testimony of Alice Napoleon.

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1 from both a safety impact and cost perspective, and can support evaluations  
2 regarding prudence.

3 **Q How can utilities model the risk of its gas system?**

4 **A** A probabilistic risk model utilizes historical data and subject matter expertise to  
5 estimate the likelihood of failure and consequence of failure for specific areas or  
6 pipeline segments. The multiplication of likelihood and consequence is the risk.  
7 Consumers acknowledges that probabilistic models “show great promise as a tool  
8 in more accurately assessing pipeline risk,” as compared to relative risk models.<sup>51</sup>

9 **Q How can a utility calculate the cost-effectiveness of various safety  
10 investments?**

11 **A** Cost-effectiveness, or risk spend efficiency (RSE), is calculated by dividing risk  
12 reduction of each mitigation alternative by cost. Ideally, for capital projects, costs  
13 should entail the full revenue requirement of an investment over the full  
14 depreciation life of the asset, discounted appropriately.<sup>52</sup> Risk reduction is  
15 calculated as the level of risk multiplied by mitigation effectiveness (percent  
16 reduction in likelihood and/or consequence), discounted appropriately in each  
17 year. Mitigation effectiveness can be determined based on historical data and/or  
18 subject matter expertise.

19 
$$RSE = Risk\ Reduction\ (Risk\ x\ Mitigation\ Effectiveness) / Cost$$

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<sup>51</sup> Direct Testimony of Company Witness Michael P. Griffin, p. 17 at 22.

<sup>52</sup> This allows for the comparison of O&M and capital mitigations. However, if the only mitigations available are capital investments with similar depreciation lives, the calculation of full revenue requirements is less important.

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1    **Q    What is the value of risk modeling and cost-effectiveness analyses?**

2    **A**Risk modeling and cost-effectiveness calculations allow stakeholders to examine  
3    the level of risk reduction expected from Consumers’ proposed remediations, the  
4    cost to achieve this, and an ability to assess alternatives that could better maximize  
5    risk reduction and minimize costs. These analyses provide transparency and  
6    insight into tradeoffs between risk reduction and affordability.

7    This type of transparency is currently lacking in Consumers’ application. The  
8    inability to assess tradeoffs between safety impacts and affordability means the  
9    Commission must rely on relatively vague utility proclamations without data-  
10   driven, analytical support that Consumers’ proposals are in the ratepayer interest.  
11   In the context of moving gas system planning away from business-as-usual to a  
12   more forward-looking approach, risk analysis is an important component to help  
13   reduce unnecessary or ineffective expenditures while still investing where  
14   necessary to ensure safe, reliable gas service.

15   **Q    What is the relationship between risk modeling, cost-effectiveness, and the**  
16    **energy transition?**

17   **A**As stated above, in the face of the energy transition, gas utility actions that avoid,  
18   reduce, or delay irreversible investments have particular value. Risk modeling and  
19   the examination of cost-effectiveness gives utilities, stakeholders, and regulators  
20   the tools to maximize risk reduction and minimize ratepayer spending on  
21   irreversible and long-lived investments. This helps to further the energy transition  
22   without compromising customer safety (and even making the system safer through  
23   a more granular understanding of risk). Quantitative estimates of risk reduction,

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1 cost, and cost-effectiveness of utility proposals and alternatives provide a rigorous  
2 way to explore tradeoffs between safety and affordability.  
3 The Company’s transmission asset risk model illustrates the importance of risk  
4 modeling for maximizing risk reduction and minimizing costs. For example, it  
5 shows that 80 percent of the current risk on the transmission system is contained  
6 within just over 9 percent of total transmission miles (208 miles).<sup>53</sup> This  
7 information can allow the utility and its regulator to properly target investment  
8 towards the highest risk assets.

9 **Q Should all utility programs calculate cost-effectiveness metrics?**

10 **A** There is a distinction to be made between “compliance” programs that are  
11 mandated by a law or regulation, and therefore have little-to-no flexibility for what  
12 measures to employ to remediate safety issues, and expenditures where multiple  
13 alternatives can be assessed (i.e. are “discretionary”). However, I note that the lines  
14 between these categories of programs are often unclear, which is why it is  
15 important to assess the risk reduction and cost-effectiveness of all utility programs.

16 **Q Do you have any examples of utilities that use risk modeling and cost-**  
17 **effectiveness in their decision-making?**

18 **A** Washington Gas (WGL), the gas utility in the District of Columbia, states that it  
19 utilizes risk models and cost-effectiveness to optimize investment and  
20 prioritization decisions:

21           Once the risk has been assessed for assets associated with each  
22           project, a parametric estimate of the cost for each project is

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<sup>53</sup> Statistics derived from Discovery Response U21806-MNSC-CE-0080\_Griffin\_CONF\_ATT\_1\_EB.

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1 produced. The Company then ranks projects to achieve the greatest  
2 reduction of overall risk per dollar invested. This basic prioritization  
3 may then be modified as appropriate to consider poor asset  
4 conditions observed directly by Company personnel, alignment with  
5 schedules for work compelled by others, and completion of work in-  
6 process.<sup>54</sup>

7 Furthermore, all California utilities must model risk to develop cost-effectiveness  
8 statistics for their gas inspection and investment programs. This framework was  
9 instituted in the wake of a 2010 pipeline failure in San Bruno, California, part of  
10 Pacific Gas and Electric’s (PG&E) service territory.<sup>55</sup>

11 **Q Have risk modeling and cost-effectiveness calculations influenced how the**  
12 **California Public Utilities Commission (“CPUC”) assesses utility**  
13 **expenditures?**

14 **A** Yes. In its decision on PG&E’s test-year 2023 rate case, the CPUC reduced  
15 PG&E’s proposed rate of 12 in-line inspection (ILI) upgrades per year to 4 per  
16 year, based on recommendations by an intervenor in that proceeding, The Utility  
17 Reform Network (“TURN”).

18 PG&E has not convincingly demonstrated that performing ILI  
19 upgrades at the rate of four segments per year would fail to meet the  
20 requirements of federal and state law and regulations, nor would it  
21 conflict with prior Commission decisions. Moreover, the lack of  
22 cost-effectiveness of ILI upgrades disfavors performing them at the  
23 pace requested by PG&E. TURN shows, for example, that the RSE  
24 [Risk Spend Efficiency] for PG&E’s proposal is 0.08, ranking the  
25 ILI Program 171st out of 247 programs for which PG&E calculated  
26 an RSE. This translates to a benefit-cost ratio of only 0.0159, or a

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<sup>54</sup> *Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Services*, Case No. 1180, Supplemental Direct Testimony of Kevin Murphy, November 4, 2024, p. 13.

<sup>55</sup> <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF>;  
<https://pstrust.org/map-of-major-incidents/sanbruno/>.

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1 benefit of 1.6 cents of risk reduction for every dollar spent.  
2 Compared to the costs and benefits of the combined external  
3 corrosion direct assessment and stress corrosion direct assessment  
4 costs every seven years (discussed below), it is unreasonable for  
5 ratepayers to pay for more than four ILI upgrades per year.<sup>56</sup>

6 The type of analysis discussed in this decision is not possible with the information  
7 provided by Consumers in this case.

8 **ii. Consumers Use of Risk Modeling and Cost-Effectiveness**

9 **Q Has Consumers developed probabilistic risk models to estimate the risk to**  
10 **customers of its assets?**

11 **A** Consumers developed a probabilistic risk model for transmission assets and  
12 Transmission Operated by Distribution assets. It is developing a model for storage  
13 wells which it expects to begin utilizing in 2025; the Company expects to develop  
14 a probabilistic distribution asset risk model by 2027.<sup>57</sup> The Company currently  
15 uses relative risk models for storage wells and distribution assets.<sup>58</sup>

16 Consumers acknowledges the importance of probabilistic risk modeling to  
17 accurately assess risk:

18 In the last several years probabilistic models have been developed,  
19 and show great promise as a tool in more accurately assessing  
20 pipeline risk. The use of a model that is entirely data driven provides  
21 a more accurate representation of the risks associated with pipelines.  
22 This in turn will allow the Company to more precisely mitigate risks

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<sup>56</sup> D. 23-11-069, Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company, 11/17/23, p. 88.

<sup>57</sup> Discovery Response MNSC-CE-0080, part (a).

<sup>58</sup> Discovery Response MNSC-CE-0080, part (a).

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1                    associated with its transmission system to improve customer safety  
2                    and reliability.<sup>59</sup>

3                    Additionally, Consumers states “[Pipeline and Hazardous Materials Safety  
4                    Administration] has identified the probabilistic risk model as a potential best  
5                    practice for pipeline operators over other risk models.”<sup>60</sup>

6                    **Q     What is your understanding of a relative risk model as compared with a  
7                    probabilistic one?**

8                    **A**     A relative risk model ranks assets within an asset class (e.g. transmission pipe,  
9                    distribution pipe, storage wells, etc.) based on certain characteristics (material,  
10                    location, etc.) but does not calculate a quantitative risk score using likelihood of  
11                    failure and consequence of failure. These models cannot examine cost-  
12                    effectiveness of remediation alternatives, nor can the risk across asset types (e.g.  
13                    distribution vs. transmission vs. storage wells) be compared against each other. By  
14                    contrast, a probabilistic risk model calculates a quantitative risk score that can be  
15                    used to understand the cost-effectiveness of alternative remediations and risk  
16                    across different types of assets.

17                    **Q     Does Consumers utilize cost-effectiveness information to support its cost  
18                    forecast and justify prior investment decisions?**

19                    **A**     In general, no. Consumers cannot calculate these statistics without a probabilistic  
20                    risk model. Consumers does not have a probabilistic risk model for distribution

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<sup>59</sup> Witness Griffin Testimony, page 17 at 22.

<sup>60</sup> Witness Griffin Testimony, page. 17 at 5.

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1 system or asset classes such as storage wells. So for distribution-level assets it  
2 cannot justify investments based on cost-effectiveness.

3 For transmission-level assets, the Company states it *prioritizes* inspection by  
4 likelihood of failure and overall risk, as calculated by its probabilistic risk model  
5 of transmission assets.<sup>61</sup> Additionally, for certain programs, the Company states  
6 that it utilizes risk modeling results to prioritize selection of its projects. For  
7 example, the Asset Relocation Transmission Program prioritizes “[s]egments  
8 showing a higher overall risk reduction as a result of increased depth of cover  
9 [which] are graded as higher priority within the Asset Relocation Program.” That  
10 said, the Company allows itself considerable flexibility to deviate from  
11 remediating the highest risk projects, stating “[p]rioritization may also be adjusted  
12 based on availability of transmission pipeline outages, continued coordination  
13 with local municipalities or governing authorities for civic-related work, and  
14 anticipated future replacement under another program (such as TED-I).”<sup>62</sup>

15 When asked whether it utilizes cost-effectiveness to determine what pipelines or  
16 mitigations to target during the rate case period, the Company responded:

17 No, Consumers Energy does not perform cost-effectiveness or RSE  
18 metrics. The Pipeline Integrity program falls under [Pipeline and  
19 Hazardous Materials Safety Administration] requirements to  
20 perform on a reoccurring basis.<sup>63</sup>

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<sup>61</sup> Witness Griffin Testimony, page. 14 at 10.

<sup>62</sup> Witness Griffin Testimony, page 9 at 2.

<sup>63</sup> Discovery Response MNSC-CE-0081.

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1    **Q    Can you provide an example of issues with specific safety programs?**

2    **A    As an example, Consumers provides regular reports detailing work accomplished**  
3           in the EIRP, a major expense for gas ratepayers every year. In its reporting on the  
4           program, Consumers is obligated to provide the “risk ranking for all projects.”  
5           However, at least in the publicly available reports available to stakeholders, the  
6           Company rarely does this. As stated above, it also does not examine the cost-  
7           effectiveness of alternatives to support its expenditures. Table 7 shows the first  
8           five reasons given by the Company for EIRP projects in 2023, demonstrating the  
9           lack of risk ranking and cost-effectiveness information provided in these reports.

10           **Table 7. Consumers’ stated reason for selection of EIRP projects**

<b>Risk Rank / Selection Reason</b>
20" Line 100A, built in 1949, has reached the end of its useful life. Phase 1 of the Mid-Michigan project has replaced ~30 miles of 20" steel piping with new 36" steel piping from Chelsea to Williamston.
Install 20" PLD on 2700/600 to protect the MAOP difference
Removal of TDW hot tap tee on Line 2020
Replace actuator on valve 605T12W and update to RCV
Site reaching the end of its design life. Project completed in conjunction with mid-Michigan pipeline project. Added modern filter/separator to enhance gas quality and protect downstream facilities and customers.

11           *Source: U21806-MNSC-CE-0079\_GRIFFIN\_ATT\_1\_to\_6, tab “2023 Att 8*  
12           *Transmission.”*

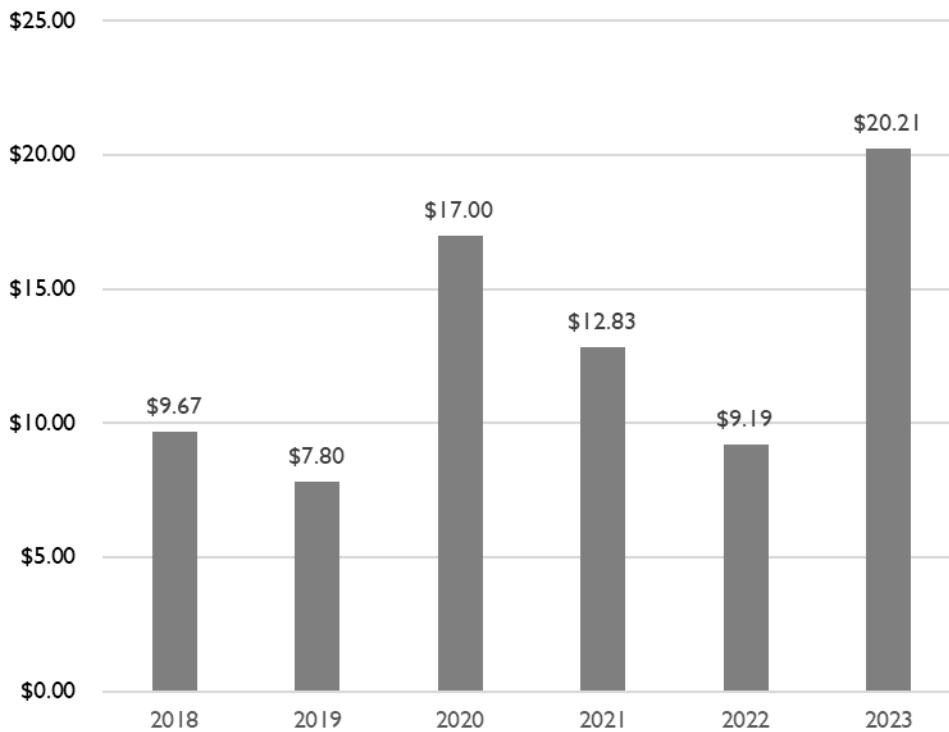
13           It is not my testimony that these, or other EIRP projects, were not necessary or  
14           prudent, as I have not conducted analysis at the project level. It is my testimony  
15           that the selection of projects under the EIRP program is not transparent from a risk

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1 reduction and cost-effectiveness perspective, which makes it impossible to assess  
2 the prudence of these investments.

3 A high-level analysis of the EIRP program’s cost-effectiveness from 2018–2023  
4 underscores why it is critical for cost-effectiveness to play a substantial role in the  
5 selection of projects. In Figure 5 below I calculated the dollars per leak remediated  
6 in each year. Leaks remediated in each year are therefore used as a proxy for  
7 reduced risk by that year’s EIRP investments.

8 **Figure 5. Dollars per leak remediated 2018–2023 (\$ million, nominal)**



9  
10 *Source: 2018-2023 EIRP Reports, expenditures and leak remediated on the distribution*  
11 *system. Links to the reports provided in Consumers response to U21806-MNSC-CE-0079.*

12 First, I observe that this program is expensive, costing ratepayers \$20 million *per*  
13 *leak* in 2023. Second, if Consumers EIRP program were targeted to remediate the  
14 most risk (as measured by leaks) at least cost, I would expect earlier years of

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1 program implementation to be much more cost-effective (lower expenditures per  
2 leak remediated) compared to later years (higher expenditures per leak  
3 remediated). While there is no clear pattern in Figure 5, the data is largely not  
4 consistent with this expectation, with the exception of a comparison of 2018 and  
5 2023. However, work accomplished in 2022 was 18 percent *more* cost-effective  
6 than 2018, while 2020 and 2023 had similar cost-effectiveness results. Therefore,  
7 based on the data I reviewed, including the EIRP reports and the analysis above,  
8 it is unlikely that the EIRP program has maximized safety impacts for the ratepayer  
9 dollars spent in each year.

10 **iii. Assessment and Recommendations Regarding Risk Modeling and**  
11 **Cost-Effectiveness**

12 **Q What are your concerns with Consumers’ use of risk modeling and cost-**  
13 **effectiveness statistics?**

14 **A** The Company does not have probabilistic risk models to calculate cost-  
15 effectiveness statistics for the distribution system or individual assets such as  
16 storage wells, though it is working on these models. In the current case, however,  
17 there is no way to tell whether the Company is performing cost-effective work that  
18 is in the interest of ratepayers, nor is it possible to even calculate cost-effectiveness  
19 of alternatives for a majority of forecast spending.<sup>64</sup>

20 While the Company states that cost-effectiveness is a “factor” in its decision-  
21 making, it has not provided evidence of this, and it is thus not possible to ascertain

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<sup>64</sup> In 2025 and 2026, distribution-related expenditures comprise 54 percent and 63 percent of total expenditures, respectively, based on my review of U21806-MNSC-CE-0007\_Dreisig\_ATT\_1.

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1 the extent to which cost-effectiveness influences project selection.<sup>65</sup> Indeed, the  
2 Company would not provide estimates of mitigation effectiveness (discussed  
3 above) for the various remediations it considered, so I cannot confirm that the  
4 Company even considers cost-effectiveness.<sup>66</sup> Additionally, it is unclear that the  
5 EIRP program has adequately prioritized cost-effectiveness and risk reduction.

6 Further, while the Company appears to understand the importance and necessity  
7 of risk modeling to prioritize its programs and investments, its use of models to  
8 examine the cost-effectiveness of remediations is extremely lacking. In sum, the  
9 Commission and stakeholders have very little information to assess whether  
10 Consumers' use of ratepayer funding is efficient and effective at reducing safety  
11 risk to customers.

12 Due to these shortcomings, there is a concerning lack of transparency and support  
13 for past and future spending. Is the Company's proposal the most efficient use of  
14 ratepayer funds? Is Consumers prioritizing the right types of inspections and  
15 remediations to cost-effectively maintain the safety of its system? Could NPAs  
16 more cost-effectively mitigate safety risks? These basic questions get at the heart  
17 of what expenditures should be deemed "just and reasonable" in this case. Based  
18 on my review of materials provided, neither I nor the Commission can  
19 satisfactorily answer these questions.

---

<sup>65</sup> Discovery Response U21806-MNSC-CE-0285, part (a) says: "Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards."

<sup>66</sup> Discovery Response U21806-MNSC-CE-0282.

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1    **Q**    **What are your recommendations?**

2    **A**    First, Consumers should provide on a regular basis and in its applications for  
3           ratepayer funding far greater transparency regarding the tradeoffs between safety  
4           and affordability. This includes, but may not be limited to:

5                 • Reporting on transmission-level projects that demonstrates how Consumers  
6                     utilizes cost-effectiveness, where applicable, to maximize safety impacts for  
7                     the ratepayer dollars spent. Calculations and assumptions should be  
8                     available to stakeholders upon request.

9                 • EIRP reporting should include risk-ranking information (risk rank of asset  
10                    remediated and total number of assets) and narrative descriptions regarding  
11                    the use of risk-ranking driving remediation for a particular project.

12                • When probabilistic risk models are available for distribution assets starting  
13                    in the next rate case, Consumers should:

14                         ○ Calculate and utilize total risk reduction and cost-effectiveness  
15                             statistics as an important input into selecting appropriate projects  
16                             and related remediations. Cost-effectiveness statistics and all  
17                             inputs and assumptions should be made available to stakeholders  
18                             upon request, including the ability to calculate risk reduction and  
19                             cost-effectiveness for alternative projects and remediations.

20                         ○ Summarize in its EIRP reports remediations examined, cost-  
21                             effectiveness of projects relative to alternatives, and  
22                             explanations of why the Company's remediation was selected.

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1 Second, future rate case applications should utilize probabilistic risk modeling and  
2 cost-effectiveness calculations to a much greater extent for all asset classes. This  
3 modeling should be made available upon request to stakeholders and the  
4 Commission, including the following:

- 5 • Unless Consumers can demonstrate it is not possible, it should develop  
6 probabilistic risk models for use in the next rate case for all asset classes  
7 (distribution, storage wells, etc.).
  - 8 ○ For each project proposed in the test year, Consumers should  
9 calculate the risk reduction, cost, and cost-effectiveness (RSE) of its  
10 expenditures. All workpapers should be made available upon  
11 request and include the source and calculation of key assumptions  
12 such as mitigation effectiveness, cost estimates, and other inputs.
  - 13 ○ Consumers should provide an estimate of the impact prior year's  
14 expenditures have made to reduce risk on the system. Given the  
15 substantial ratepayer expenditures each year on the gas system to  
16 improve safety, Consumers should explain what has been achieved  
17 to-date, and how much risk is left on the system relative to five years  
18 ago, ten years ago, etc. If Consumers has prioritized the highest risk  
19 assets each year, I would expect diminishing returns for risk  
20 reduction. This information can only be ascertained with historical  
21 analysis of risk reduction achieved to date.

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- 1           • The Commission should cap additions to plant in service in the projected  
2           test year at no more than 2024 investment levels (see Table 8). Furthermore,  
3           the Commission should require Consumers to implement probabilistic risk  
4           models for EIRP and Vintage Service Program (“VSR”) before spending at  
5           levels that increase additions to plant in service above 2024 levels.

6           **Table 8: Recommendations - Test Year**

				<b>Recommendation: Capped at 2024 levels</b>
	<b>2023</b>	<b>2024</b>	<b>Test Year</b>	<b>Test Year</b>
EIRP	\$181,927	\$195,587	\$251,372	<b>\$195,587</b>
VSR	\$11,354	\$18,666	\$42,513	<b>\$18,666</b>
MCNM	\$38,516	\$38,256	\$56,206	<b>\$38,256</b>

7

8   **VII. ALTERNATIVES TO PIPE REPLACEMENT AND PATHWAYS TO**  
9   **MEETING NET-ZERO EMISSIONS**

10   **Q   Is Consumers considering leak repair as an alternative to pipe replacement?**

11   **A**Consumers is not considering leak repair for any proposed projects.<sup>67</sup> The  
12   Company has stated that it does not consider pipe repair for the EIRP<sup>68</sup> or the  
13   MCNM program.<sup>69</sup>

14   The Company has already produced an example of what kind of analysis should  
15   be conducted when considering alternatives to pipe replacement. For example, the  
16   Company completed a cost and risk analysis for Line 1010 to compare the cost of

<sup>67</sup> Discovery Response MNSC-CE-0578.

<sup>68</sup> Discovery Response MNSC-CE-0579.

<sup>69</sup> Discovery Response MNSC-CE-0578.

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1 pressure testing the existing pipe to test for MAOP compliance, with the cost of  
2 complete pipe replacement. While the Company decided to proceed with pipe  
3 replacement, the evaluation was conducted and made available to the public.<sup>70</sup>

4 **Q What are NPAs and why are they relevant to the energy transition?**

5 **A** NPAs are solutions that meet customer energy needs and are alternative to  
6 traditional infrastructure investments. Examples of NPA portfolio components  
7 include electrification, energy efficiency, and other measures that reduce or  
8 eliminate customers' demand for natural gas. NPAs can be temporary solutions to  
9 defer infrastructure replacement or long-term solutions that allow utilities to  
10 decommission assets. The benefits of NPAs include emission reductions and  
11 associated health benefits, avoided costs from traditional infrastructure  
12 investments, and reduced risk of future stranded assets. When faced with  
13 uncertainty, companies can reduce risk by retaining optionality and avoiding  
14 potentially unnecessary capital investments. In the face of the energy transition,  
15 gas utility actions which avoid, reduce, or delay irreversible investments have  
16 particular value.

17 **Q Has the Company discussed implementing any NPAs?**

18 **A** The Company does not address NPAs in its application nor has it proposed any  
19 NPA projects in its capital investment plan. To date, the Company has only  
20 completed an initial screening criterion which identified Kalamazoo, Lansing, and

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<sup>70</sup> Pascarello Testimony, page 56 at 23.

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1 Flint as “the top communities to investigate further for an initial feasibility data  
2 assessment”<sup>71</sup>

3 **Q Consumers claims that affordability is a main objective of the NGPD. Are**  
4 **there other actions it can do to address affordability?**

5 **A** Consumers claims that affordability is one of the key objectives of the NGPD.  
6 However, in the planning for the gas infrastructure investment, there is no evidence  
7 that the Company evaluated alternatives such as leak repair or NPAs that could  
8 reduce the need for pipeline replacement and thus be a lower-cost alternative to  
9 continued gas investments.

10 **Q Is it reasonable or prudent for the Company to make investment decisions**  
11 **without evaluating alternatives, such as pipeline repair or NPAs?**

12 **A** No. By failing to evaluate alternatives, the Company runs a high risk of spending  
13 more money than is necessary to achieve the safe and reliable gas system that it is  
14 obligated to maintain and operate. Because the Company has provided no records  
15 of any cost-effectiveness or other evaluations conducted to determine the most  
16 appropriate investment, it is essentially asking for approval billions of dollars of  
17 capital investments without substantive justification that they were truly  
18 necessary.

19 **Q Does this complete your direct testimony?**

20 **A** Yes, it does.

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<sup>71</sup> Discovery Response MNSC-CE-0030.



## **Dr. Maria Soledad (Sol) deLeon, D.L.S., Principal Associate**

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### **PROFESSIONAL EXPERIENCE**

**Synapse Energy Economics, Inc.**, Cambridge, MA. *Principal Associate*, January 2023 – Present

- Analyzes gas utility applications, as well as studies, reports and other evidence regarding gas utility investments, business models, ratemaking, depreciation, revenue requirements, and business risk.
- Sponsors testimony and performs analysis related to impact of climate regulation on utilities.
- Researches policies and practices regarding rulemaking related to renewable portfolio standards.
- Provides expert analysis, ongoing stakeholder support, and consulting services in regulatory proceedings regarding the future of natural gas local distribution utilities, including issues such as long-term planning for infrastructure investment, risk evaluation, and decarbonization strategies.

**WGL Holdings (Washington Gas)** Washington D.C. *Manager, Strategy & Innovation*, December 2019 – December 2022, *Manager, Strategy & Business Development*, March 2017 – December 2019

- Defined and successfully proposed GHG emission reduction targets. Project managed development and completion of regulator-required climate strategy reports, involving external consultants and internal subject matter experts.
- Established and implemented a governance process for strategic initiatives. Created templates for business plans, project charters, and status updates for proposed strategic projects.
- Established information capture process for regulatory and executive reporting of emission reduction initiatives, including status of budget, scope, schedule, and projected benefits.

**AES Corporation**, Arlington, VA. *Risk Manager*, January 2009 – January 2016, *Project Manager, Wind Development*, April 2008 – December 2008, *Risk Analyst*, March 2006 – March 2008

- Managed global Hydrology Risk Committee quantifying risks and reporting to executive leaders on hydrology and climate mitigation strategy to reduce impact on initiatives and earnings projections.
- Streamlined process for derivatives valuation and audit support, reducing quarterly reporting preparation by 400% and saving 10,000+ labor hours. Managed derivative approval process for projects in Latin America, and Asia.
- Supported business development and negotiations for greenfield wind farms and project pipelines by building and maintaining financial models.
- Mapped South American and Asian subsidiaries' structures and cash flows to identify material risks and develop interest rate and foreign exchange hedging strategies protecting enterprise value.

- Developed valuation models for futures, forwards and options for power, commodity, FX, and interest rate; identified and evaluated transaction risks, and performed ad hoc market risk analysis.

**Energy and Environment Analysis, Inc.**, Arlington, VA. *Energy Analysis*, August 2002– March 2006

- Built first-ever demand forecasting model of U.S. propane industry, fundamentally changing strategic decision-making across the propane industry.

**PG&E National Energy Group**, Bethesda, MD. *Intern, Asset Management*, June 2001– December 2001

- Fixed financial models for power plant valuations and financial models for 5,000-megawatt contract portfolio; corrected errors in 5 critical models which were reinstated for internal forecasting and reporting.

**Trans Asia Power**, Manila, Philippines, *Senior Project Analyst, Business Development*, March 1997 – August 2000

- Employee #4 of energy start-up. Identified projects for development. Company representative in nationwide launch of electricity spot market, implemented in company and trained other users.

## EDUCATION

**Georgetown University**, Washington, D.C.

Doctorate in Liberal Studies, Energy Transition and Energy Justice

Master of Business Administration, McDonough School of Business

**Ateneo de Manila University**, Quezon City, Philippines

Bachelor of Science, Management Engineering, AB Economics

## TESTIMONY

**Connecticut Public Utilities Regulatory Authority (Docket No. 24-12-01)**: Direct testimony of Dr. Asa Hopkins and Dr. Sol Deleon in the Application of Yankee Gas Services Company D/B/A Eversource Energy to Amend Its Rate Schedules. On behalf of the Connecticut Office of Consumer Counsel. March 13, 2025.

**New Mexico Public Regulation Commission (Case No. 22-00309-UT)**: Direct testimony of Sol Deleon in the Matter of New Mexico Gas Company, Inc.'s Application for the Issuance of a Certificate of Public Convenience and Necessity to Construct a Liquefied Natural Gas Facility. On behalf of the Office of the Attorney General. October 27, 2023.

**Illinois Commerce Commission (Docket No. 23-069)**: Direct testimony and rebuttal testimony of Sol Deleon in The People's Gas Light and Coke Company's Proposed General Increase in Rates for Gas Delivery Service. On behalf of the City of Chicago. May 9, 2023.

## TESTIMONY ASSISTANCE

**Maryland Public Service Commission (Case No. 9692):** Direct testimony of Asa Hopkins regarding the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People’s counsel, August 25, 2023.

**Maryland Public Service Commission (Case No. 9692):** Direct testimony of Courtney Lane regarding the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People’s counsel, August 25, 2023.

**Nova Scotia Utility and Review Board (Matter No. N10960):** Direct testimony of Eric Borden regarding Eastward Energy Incorporated’s schedule of rates, tolls, and charges pursuant to Section 21 of the Gas Distribution Act. On behalf of the Counsel to the Nova Scotia Utility and Review Board. April 12, 2023.

**New York Public Service Commission (Case 22-G-0610):** Initial comments of the Natural Resources Defense Council regarding the Long-Term Gas System Plan of National Fuel Gas Distribution Corporation. March 13, 2023.

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DeLeon, S., A. S. Hopkins, A. Napoleon, S. Schadler, D. Karabakal. 2025. *Regulatory Approaches to Gas Utility Futures: Survey of Proceedings, Policies, and Analyses Across Jurisdictions*. Synapse Energy Economics.

*Resume updated April 2025*

# Regulatory Approaches to Gas Utility Futures

Survey of Proceedings, Policies, and Analyses

Across Jurisdictions

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# 1. INTRODUCTION

The decarbonization of the building and industrial sectors will affect gas consumption, affect gas utilities, and require changes in regulation and business models. This transition is in its early stages, and there are numerous competing visions for how to resolve the resulting challenges. Responses to these challenges will vary among states, and utilities and will be driven by history, climate, the state of the gas system, and public policy choices. In a growing number of states, policymakers, regulators, and utilities are analyzing building and industrial decarbonization and the resulting impact on gas utilities and their customers. This white paper surveys the legislative, executive, and regulatory landscape of greenhouse gas (GHG) emission reduction targets, describes the analysis conducted to guide policy making as the energy transition evolves across U.S. states. It draws insights, identifies gaps, and highlights emerging best practices from those processes.

In this paper, we survey selected jurisdictions, moving from northeast to southwest across the United States. For each state, we provide an overview of relevant activity and list key regulatory proceedings. Then we briefly describe actions on key issues regarding the future of gas utilities in light of the energy transition. Where analysis has been conducted, we describe the analysis and summarize its results. We also discuss how each regulatory commission has addressed the following key issues: long-term gas planning, gas capital investment, line extension policies, and non-pipeline alternatives (NPA).

# 2. MASSACHUSETTS

*Massachusetts has adopted a statutory net-zero GHG emissions requirement for 2050, as well as sectoral emissions limits for 2025 and 2030. The State conducted a 2050 Roadmap study to lay out pathways to achieve its net-zero objective. This Roadmap study identified an “All Options” pathway as the most promising path forward. This pathway used electrification as the primary mechanism for decarbonization of both the transportation and buildings sectors. The Clean Energy and Climate Plan (CECP) for 2025, 2030, and 2050 provides detailed actions to help the state reach interim emissions limits and sublimits established in the 2050 Roadmap.<sup>1</sup>*

*The Massachusetts Department of Public Utilities (MA DPU) created Docket 20-80 following a request by the Attorney General’s Office to investigate the impact on the continuing business operations of local gas*

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<sup>1</sup> Massachusetts Executive Office of Energy and Environmental Affairs. Massachusetts Clean Energy and Climate Plan for 2025 and 2030. 2020. Available at: <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030>.

Massachusetts Executive Office of Energy and Environmental Affairs. Massachusetts Clean Energy and Climate Plan for 2050. 2022. Available at: <https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050>.



*distribution companies as the Commonwealth achieves its target 2050 climate goals.<sup>2</sup> The MA DPU reviewed this request and opened the docket “to examine the role of Massachusetts gas local distribution companies (LDC) in helping the Commonwealth to achieve its 2050 climate goals.”<sup>3</sup> The DPU set out to explore strategies to meet emissions objectives while considering ratepayers’s interests, safety, reliable gas service, and “potentially recasting the role of LDCs in the Commonwealth” as part of a project to develop “a regulatory and policy roadmap to guide the evolution of the gas distribution industry.”<sup>4</sup>*

## 2.1. KEY REGULATORY PROCEEDINGS

- **Docket No. 20-80:** Investigation by the MA DPU on its own Motion into the role of gas LDCs as the Commonwealth achieves its target 2050 climate goals
  - **Order 20-80-B:** Order on Regulatory Principles and Framework, December 6, 2023
- **Gas System Enhancement Plan (GSEP):** Each gas LDC must submit, annually, to the MA DPU a plan to replace its aging, leak-prone gas pipeline infrastructure. **The dockets are D.P.U. XX-GSEP-02** *The Berkshire Gas Company*; **D.P.U. XX-GSEP-03** *Boston Gas Company d/b/a National Grid*; **D.P.U. XX-GSEP-01** *Fitchburg Gas and Electric Light Company d/b/a Until*; **D.P.U. XX-GSEP-04** *Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty*; **D.P.U. XX-GSEP-05** *Eversource Gas Company of Massachusetts d/b/a Eversource Energy*; **D.P.U. XX-GSEP-06** *NSTAR Gas Company d/b/a Eversource Energy*
- **Climate Compliance Plan Dockets:** **D.P.U. 25-40** *The Berkshire Gas Company*; **D.P.U. 25-41** *Boston Gas Company d/b/a National Grid*; **D.P.U. 25-42** *Fitchburg Gas and Electric Light Company d/b/a Until*; **D.P.U. 25-43** *Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty*; **D.P.U. 25-44** *Eversource Gas Company of Massachusetts d/b/a Eversource Energy*; **D.P.U. 25-45** *NSTAR Gas Company d/b/a Eversource Energy*

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<sup>2</sup> Massachusetts Office of the Attorney General, Petition of the Office of the Attorney General, pursuant to G.L. c. 12, Section 11E, 10; and its common law authority to act in the public interest, Requesting an Investigation, pursuant to the Department of Public Utilities’ authority under G.L. c. 164, section 76, 105A into the impact on the continuing business operations of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals, D.P.U. Docket 20-80, June 4, 2020, available at: <https://eeaonline.eea.state.ma.us/dpu/fileroom/#/dockets/docket/11789>.

<sup>3</sup> Massachusetts Department of Public Utilities, *Order on Regulatory Principles and Framework* (“Order 20-80”), Docket DPU-20-80, December 6, 2023, page 4, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602>.

<sup>4</sup> Ibid.



## 2.2. ACTIONS ON KEY ISSUES

The following is a summary of key activities and determinations from Massachusetts' investigations into future of gas topics.

### Gas Planning

- Gas LDCs are required to file Climate Compliance Plans every five years that discuss their progress toward achieving state emission reduction goals.

### Accelerated Pipe Replacement

- The Gas System Enhancement Plan (GSEP) working group developed recommendations for legislative and regulatory changes to align GSEP activities with other state policies.

### Alternatives to Natural Gas

- The Gas LDCs proposed an NPA Framework that will be integrated into its planning processes to evaluate alternatives to traditional pipeline investment. In developing the NPA Framework, the gas LDCs engaged with stakeholders by establishing an NPA Working Group, a Technical Subcommittee, and a Community Focus Group.

### Line Extension Policy

- The DPU proposed a draft policy that would eliminate line extension allowances except in certain circumstances.

## 2.3. EXISTING ANALYSIS

### 2.3.1. DOCKET 20-80 ANALYSIS

#### **Consultant Reports**

The MA DPU directed the gas LDCs to engage consultants to analyze strategies to achieve net-zero emissions, adding greater detail and alternative approaches to those captured in the state's Roadmap study. In their Request for Proposals to hire the required consultant(s), the LDCs added to the scope of the study by including a commitment to develop recommendations for new business models and other actions that can be implemented in the near term to contribute to achieving the net-zero target by 2050, with flexibility to adjust over time as technologies evolve. This addition to the scope, led by the utilities, ensured that the consultants would do more than simply analyze the societal energy transition; they would also examine the pathway results' financial and regulatory implications on the utilities.

The consultants' analysis built upon the state's 2050 Roadmap and added detail not captured by the Roadmap. For example, the Roadmap did not differentiate between hybrid/dual-fuel heat pump



adoption and whole-building adoption, whereas the consultants' study made this distinction. The consultants produced multiple reports from the results of their analysis, including Net Zero Enablement Plans for each LDC, a Pathways Report with a technical analysis of the decarbonization pathways, and a Regulatory Designs Report considering alternative regulation to support the transition.<sup>5</sup>

The consultants' *pathways* analysis<sup>6</sup> included considerations about rate base and revenue requirements over time, customer costs, and quantification of the impacts of targeted electrification to allow asset retirement.

The consultants' follow-on *regulatory* analysis<sup>7</sup> elaborated on options and approaches available to address the issues raised in the pathways analysis. The regulatory analysis included recommendations to minimize or avoid gas infrastructure projects to reduce costs that need to be recovered from gas system customers, to coordinate electric and gas system planning, to review line extension policies and practices, to align infrastructure cost recovery with utilization, and to analyze the cost impact of different cost recovery approaches.

### **Order 20-80-B**

In 2023, the DPU issued an Order on Regulatory Principles and Framework (Order 20-80-B) which contained findings about the consultants' reports and conclusions about the 2050 Roadmap and the CECP's implications for the gas system.<sup>8</sup> The DPU concluded that renewable natural gas (RNG) did not meet the Department's least-cost supply planning standards and that there are insufficient stocks to support pathways dependent on RNG.<sup>9</sup> Similarly, the order states that only targeted end uses may rely on hydrogen.<sup>10</sup> The DPU rejected the consultants' recommendation that the gas utilities should promote hybrid electrification. Instead, the DPU stated that no additional ratepayer dollars can be used for hybrid heating systems and funds should be directed to targeted electrification and networked geothermal (The DPU noted that it did not believe it had the authority to reject hybrid heating outright).<sup>11</sup> Further,

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<sup>5</sup> Massachusetts Department of Public Utilities, *Order on Regulatory Principles and Framework* ("Order 20-80"), Docket DPU-20-80, December 6, 2023, page 10, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602>.

<sup>6</sup> E3 and Scott Madden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report: Technical Analysis of Decarbonization Pathways*. March 18, 2022. Available at: <https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Regulatory%20Designs.pdf>.

<sup>7</sup> E3 and Scott Madden. *The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals Independent Consultant Report: Considerations and Alternatives for Regulatory Designs to Support Transition Plans*. March 18, 2022. Chapters 4 and 5. Available at: <https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Regulatory%20Designs.pdf>.

<sup>8</sup> Massachusetts Department of Public Utilities, *Order on Regulatory Principles and Framework* ("Order 20-80"), Docket DPU-20-80, December 6, 2023, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602>.

<sup>9</sup> Order 20-80, page 2.

<sup>10</sup> *Id.* at 84.

<sup>11</sup> *Id.* at 81.



the DPU requires LDCs to prove that they have adequately considered NPAs (such as electrification, thermal network systems, energy efficiency, and demand response) before determining to replace part of the gas system.<sup>12</sup> The DPU indicated its focus on a pathway with less reliance on the gas system going forward than anticipated initially by the 2050 Roadmap and CECPs.

Order 20-80 requires LDCs to take the following next steps:

- File Climate Compliance Plans every five years beginning April 1, 2025 (more details below) as well as a Climate Act Compliance Term Report that indicates the LDC's progress toward achieving emissions reductions.<sup>13</sup>
- Review and report on current line extension practices and policies including historical number of new customer connections to the gas system, no-charge line extension allowances, and methods for calculating customer contributions in aid of construction.<sup>14</sup>
- Forecast the potential magnitude of stranded investments and the impacts of alternative depreciation methods.<sup>15</sup>
- Propose at least one targeted electrification demonstration project that decommissions an area of the gas system in coordination with the relevant electric distribution company.<sup>16</sup>

### ***NPA Frameworks***

Following Order 20-80, stakeholders and LDCs formed a working group to discuss NPAs. In the working group, LDCs proposed an NPA Framework that integrates NPA evaluation into their existing gas planning processes. Using this framework, NPA projects will be reviewed as alternatives to replace or delay traditional investments in pipe replacement, new customer connections, capacity expansion, and other types of investments. The proposed NPA evaluation process includes initial viability testing, system feasibility review, benefit-cost analysis, and more.

### ***Climate Compliance Plans***

The DPU's 2023 Order in Docket 20-80 directs LDCs to file Climate Compliance Plans (CCP) every five years. The LDCs filed their first CCPs on April 1, 2025. According to Order 20-80, CCPs are intended to demonstrate how each LDC will comply with Massachusetts' emission reduction requirements,

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<sup>12</sup> Id. at 97-98.

<sup>13</sup> Id. at 135.

<sup>14</sup> Id. at 99.

<sup>15</sup> Id. at 101.

<sup>16</sup> Id. at 87.

expanding on the LDC's previous Net Zero Enablement Plans developed by consultants.<sup>17</sup> The DPU stated that it anticipates CCPs will "serve as actionable, enforceable plans for future actions, not merely a summary of existing plans and processes."<sup>18</sup> Order 20-80 requires CCPs to demonstrate how each LDC proposes to (1) contribute to the prescribed GHG emission reduction sublimit for Scope 1 and Scope 3 emissions,<sup>19</sup> (2) satisfy customer demand safely, reliably, affordably, and equitably with available technology, (3) use demonstration projects to identify investment alternatives, (4) incorporate evaluation of previous metrics, and (5) implement recommendations for future plans.<sup>20</sup> LDCs must also include a discussion on six key principles recommended by the Massachusetts Department of Energy Resources: consistency with already existing targets and orders; inclusion of actions that are concrete, quantifiable, and measurable; inclusion of metrics to track progress; adherence to a standardized format; inclusion of equity analysis for Environmental Justice populations; and stakeholder accountability and transparency.<sup>21</sup>

Additionally, within the nine months following each CCP deadline LDCs are required to file a Climate Act Compliance Term Report—an informational filing that indicates whether the LDCs achieved the required level of emissions reductions.<sup>22</sup>

### ***Line Extension Policy***

In Order 20-80, the DPU directed LDCs to review their line extension policies and practices to investigate the number of free line extensions provided to customers annually, calculation methods and assumptions for new customers' contributions in aid of construction (CIAC), and alignment with state policies. The DPU directed LDCs to report the findings from their investigation by August 13, 2024, followed by an opportunity for stakeholder comment until October 11, 2024.<sup>23</sup> Groundworks Data analyzed each LDC's line extension filings and published a report comparing LDCs' approaches to calculating CIACs, number of extensions completed annually, level of investment in line extensions, and

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<sup>17</sup> Id. at 134.

<sup>18</sup> Massachusetts Department of Public Utilities, Memorandum re: LDC Climate Compliance Plans, January 24, 2025, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/fileroom//19882689>.

<sup>19</sup> According to the EPA, scope 1 emissions, or 'direct emissions' are from sources that an organization owns or controls, like natural gas-fired boilers, vehicle fleets, and business operations. Scope 3 emissions are indirect emissions caused by the organizations including waste, business travel, and emissions from the upstream transportation and downstream distribution of natural gas. (Environmental Protection Agency, "Simplified Guide to Greenhouse Gas Management for Organizations," April 2024, available at: [https://www.epa.gov/system/files/documents/2022-09/Simplified\\_Guide\\_GHG\\_Management\\_Organizations.pdf](https://www.epa.gov/system/files/documents/2022-09/Simplified_Guide_GHG_Management_Organizations.pdf).)

<sup>20</sup> Massachusetts Department of Public Utilities, Order 20-80 at 135.

<sup>21</sup> Massachusetts Department of Public Utilities, Memorandum re: LDC Climate Compliance Plans, January 24, 2025, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/fileroom//19882689>.

<sup>22</sup> Id. at 135.

<sup>23</sup> Massachusetts Department of Public Utilities, Line Extension Policies of Gas Local Distribution Companies, June 14, 2024, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/fileroom//19211932>.

more.<sup>24</sup> The DPU reviewed LDC and stakeholder filings and proposed a draft line extension policy that would require new customers to pay for the entire cost of the connection except in special circumstances.<sup>25</sup> Stakeholders had the opportunity to comment on the draft policy and reply through the end of March 2025.<sup>26</sup>

### 2.3.2. GAS SYSTEM ENHANCEMENT PLANS

In Massachusetts, LDCs replace aging pipe through their individual GSEPs. As required by statute, the DPU convened a stakeholder group to review the GSEPs and develop recommendations for legislative and regulatory changes that might be needed to align GSEP activities with other state policies. The stakeholder group developed a report of recommendations for revising the GSEP provisions.<sup>27</sup> Recommendations include adding considerations for pipe repair and retirement, incorporating language that creates opportunities for NPAs, and more.

## 3. NEW YORK

*The Climate Leadership and Community Protection Act (CLCPA), passed in 2019, establishes statewide GHG emission reduction targets of 40 percent by 2030 and 85 percent by 2050 relative to 1990 levels.<sup>28</sup> The CLCPA created a Climate Action Council tasked with producing a Scoping Plan that outlines sector-specific strategies for meeting CLCPA targets. The Scoping Plan calls for a well-planned, strategic downsizing of the gas system, reductions in statewide fossil gas use by at least 33 percent by 2030 and by 57 percent by 2035, and dramatic increases in electrification.<sup>29</sup>*

*The New York Department of Public Service (NY DPS), which is led by the Public Service Commission (NY PSC) regulates the gas and electric utilities in New York. The NY DPS created case number 20-G-0131 covering all of the activities related to a modernized gas planning process. Under this docket, the Commission instructed DPS Staff and the major LDCs to conduct analysis and develop reports described*

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<sup>24</sup> Groundwork Data, *Pipeline Extension Allowances & the Transition Beyond Gas*, October 7, 2024, available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/fileroom//19728476>.

<sup>25</sup> Massachusetts Department of Public Utilities, *Procedural Notice and Request for Comments Regarding Policies and Practices for Proposed Line Extension Allowances and Contributions in Aid of Construction for Gas Local Distribution Companies*, February 5, 2025, Available at: <https://fileservice.eea.comacloud.net/FileService.Api/file/fileroom//19883930>.

<sup>26</sup> *Id.* at 5.

<sup>27</sup> Gas System Enhancement Plan Working Group, *Final Report and Recommendations*, January 31, 2024, available at: <https://www.mass.gov/doc/gsep-working-group-final-report-and-recommendations-13124/download>.

<sup>28</sup> NY State Senate Bill S6599. NY State Senate. June 18, 2019.

<sup>29</sup> New York State Climate Action Council, *New York State Climate Action Council Scoping Plan*: Chapter 18: Gas System Transition, 2022, page 350, available at: <https://climate.ny.gov/resources/scoping-plan>.

below. This action was triggered by the state GHG emission reduction targets pursuant to the CLCPA and the gas moratorium declared by certain New York gas utilities.

### 3.1. KEY REGULATORY DEVELOPMENTS

- **20-G-0131:** The New York Department of Public Service created case number 20-G-0131, Proceeding on the Motion of the Commission in Regard to the Gas Planning Procedures, to address issues related to the future of gas.
  - **Order Adopting Gas System Planning Process (“Gas Planning Order”)- May 12, 2022**
- **22-M-0149:** The New York Public Service Commission created case number 22-M-0149 to track and assess the advancements made towards meeting CLCPA mandates and provide policy guidance for the additional actions needed to help achieve the objectives of the CLCPA.
  - **Order on Implementation of the Climate Leadership and Community Protection Act – Case No. 22-M-0149 - May 12, 2022.** This Order directed the gas utilities to propose a GHG study to analyze the scale, timing, costs, risks, uncertainties, and bill impacts associated with significant reduction in GHG emissions.

### 3.2. ACTIONS ON KEY ISSUES

#### Gas Planning

- New York gas utilities are required to file long-term gas plans every three years that present possible strategies for achieving state emission policies.

#### Accelerated Pipe Replacement Programs

- Most New York utilities have accelerated pipe replacement programs – these are not explicitly addressed in the Gas Planning Order, however some utilities such as Con Edison evaluate accelerated pipe replacement projects for NPA opportunities.

#### Alternatives to Natural Gas

- The Gas Planning Order required LDCs to file NPA suitability criteria, NPA cost recovery, and NPA incentive mechanisms, discussed further below.
- Consolidated Edison in particular has made notable progress toward integrating NPA evaluation into its planning processes and executing NPAs.<sup>30</sup>

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<sup>30</sup> Consolidated Edison Company of New York, Inc. *Non-Pipes Alternatives Annual Expenditures & Program Report*, November 18, 2024, Case 22-G-0065, available at:

## Line Extension Policy

- DPS Staff proposed modifications to 16 New York Code of Rules and Regulations Part 230, known as the “100 foot rule”, to limit the length of no-charge customer line extensions and to shift more of the costs of line extensions to applicants instead of ratepayers.

### 3.3. EXISTING ANALYSIS

#### 3.3.1. GAS PLANNING ORDER, CASE 20-G-0131

In May 2022, the PSC adopted with modifications DPS Staff’s Gas System Planning Process Proposal.<sup>31</sup> The PSC’s Gas Planning Order establishes frameworks to investigate a range of topics related to long-term gas system planning. The Order creates numerous filing requirements for LDCs including long-term gas plans, NPA frameworks, NPA cost recovery and incentive mechanisms, and depreciation studies. Outside of these filings, the Gas Planning Order also addresses line extension policies, the avoided cost of gas, and other topics.

#### ***Long-Term Plans (LTP)***

The commission required each LDC to complete a long-term plan every three years exploring scenarios based on different natural gas sales forecasts that ensure compliance with state policies.<sup>32</sup> According to the Gas Planning Order, LTPs should provide a 20-year outlook on natural gas supply and demand and investment plan. LDCs must consider energy efficiency and NPAs as part of their plans, including an NPA-only (no new gas infrastructure) scenario unless they can present sufficient evidence that such a scenario is not feasible. The plans must evaluate and compare these alternatives using benefit-cost analysis, bill impact analysis, and emissions impacts.

At this point, all New York LDCs that are required to file initial LTPs have done so. LTP filings follow a similar structure, where LDCs present a handful of scenarios and a portfolio of strategies and investments for achieving emission reductions under each scenario. With some variation, LTP scenarios typically include a business-as-usual scenario, a high electrification scenario where all but a few hard-to-electrify customers convert to electrification, and a hybrid scenario which combines full and hybrid

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<https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=22-G-0065&CaseSearch=Search>.

<sup>31</sup> State of New York Public Service Commission, *Order Adopting Gas System Planning Process*, Case 20-G-0131, May 12, 2022, available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131>.

<sup>32</sup> Id.



electrification, energy efficiency, and low-carbon fuels. LDCs present a portfolio of investments for each scenario and compare the cost-effectiveness of each scenario.

The PSC issued orders on National Fuel Gas<sup>33</sup> and Consolidated Edison's<sup>34</sup> LTPs. These orders acknowledged the plans but did not accept them; further, they required compliance filings and changes to the LDC's future LTPs. The PSC directed both utilities to file a proposal for a demand response program, develop NPA implementation plans, and disclose specific information about their energy efficiency programs. It ordered National Fuel Gas to cease gas expansion activities in its Gas network Enhancement program, develop a benefit-cost analysis handbook, develop a pilot project to compare hybrid heating options, and more. The PSC ordered Consolidated Edison to provide a no-gas-infrastructure scenario, perform an optimization process to identify a preferred pathway, and include an electric load forecast from electrification in its LTP; as well as report the impacts of the initial LTP on disadvantaged communities, file a bill impact analysis that reflects reduced gas usage over 20-years for each customer class, and provide a definition for hard-to-electrify customers.

Thus far the Commission has not clarified the relationship between LTPs and rate cases. However, in its 2025 rate case, Consolidated Edison discussed changes to its accelerated pipe replacement program where it will avoid replacing pipe in areas with a high likelihood of electrification (although it is not yet clear how the Company will identify these areas).<sup>35</sup>

### ***Depreciation Studies***

The NY PSC required the LDCs to complete a depreciation study to examine both the structure of accelerated depreciation and its potential impacts on ratepayers. The PSC required the LDCs to calculate the revenue requirement and bill impacts, under the following scenarios: (a) full depreciation of all new (2022 and after) gas plant by 2050, (b) full depreciation of all gas plant by 2050, and (c) 50 percent of gas customers exit the gas system by 2040 and that 10 percent of gas customers remain after 2050.<sup>36</sup> The results from National Fuel Gas' (NFG) study can be used as an example.<sup>37</sup> NFG modeled its 2050 rate

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<sup>33</sup> State of New York Public Service Commission, *Order Implementing Long-Term Natural Gas Plan with Modifications*, Case 22-G-0610, December 14, 2023, available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=22-G-0610&CaseSearch=Search>.

<sup>34</sup> State of New York Public Service Commission, *Order Regarding Long-Term Natural Gas Plan and Requiring Further Actions*, Case 23-G-0147, September 20, 2024, available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-g-0147&CaseSearch=Search>.

<sup>35</sup> Consolidated Edison, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Case 25-G-0073, available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=75508>.

<sup>36</sup> State of New York Public Service Commission, *Order Adopting Gas System Planning Process*, Case 20-G-0131, May 12, 2022, page 61, available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131>.

<sup>37</sup> National Fuel Gas Distribution Company, *Depreciation Study: Analysis of Gas Planning Scenarios*, November 7, 2022.



base under different scenarios. With the High Electrification scenario, straight-line depreciation (with current assumed asset life) would result in a rate base that is almost 4 times larger, compared to the rate base assuming accelerated depreciation. In this scenario, rate base in 2050 is over \$1,800 million, while with a units-of-production depreciation methodology, it would be over \$400 million. The difference in 2050 rate base is less stark under a medium electrification scenario. With straight line depreciation, it is estimated to be over \$1,600 million; using units of production-based depreciation, it is over \$1,200 million. While the results of the depreciation studies are informative, the LDCs have not incorporated depreciation findings into their LTPs.

### **NPA Framework**

In the Gas Planning Order, the PSC required LDCs to file NPA Suitability Criteria that defines small and large projects in terms of project cost thresholds and project lead time. Each LDC independently filed NPA Suitability Criteria in August 2022. The Gas Planning Order requires that small projects go through an expedited review process with streamlined economic and technical analysis, and employ known alternative solutions where feasible, while large projects undergo a full-scale NPA solicitation followed by a benefit-cost analysis.<sup>38</sup>

The Order also directed LDCs to file NPA cost recovery procedures and an NPA incentive mechanism. The NPA cost recovery procedure seeks to define a process through which NPA project costs will be recovered. The joint New York LDCs proposed treatment of NPA costs as regulatory assets and a 20-year amortization period.<sup>39</sup> The NPA incentive mechanism seeks to determine what share of NPA benefits should be allocated to shareholders and to ratepayers. The joint LDCs proposed that 30 percent of net benefits go to shareholders and 70 percent go to customers.<sup>40</sup>

### **Line Extension Policy**

In July 2024, Public Service Staff proposed modifications to Chapter 16 of the New York Code of Rules and Regulations Part 230, known as the “100 foot rule.”<sup>41</sup> Staff proposed to limit customers’ “entitlements” (essentially, the length of main or service that utilities provide to a new customer at no charge) to the minimum required by law and prohibit the pooling of entitlements for line extensions that serve multifamily buildings or developments with multiple units.<sup>42</sup> Utilities and stakeholders had

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<sup>38</sup> Id. at 37.

<sup>39</sup> Joint Local Distribution Companies. 2022. Joint Local Distribution Companies’ Proposal for Non-Pipeline Alternative Incentive Mechanism and Cost Recovery Procedures. August 10. Page 5. Case 20-G-0131. Available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131>.

<sup>40</sup> Joint Local Distribution Companies. 2022. Joint Local Distribution Companies’ Proposal for Non-Pipeline Alternative Incentive Mechanism and Cost Recovery Procedures. August 10. Page 2. Case 20-G-0131. Available at: <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131>.

<sup>41</sup> State of New York Department of Public Service, *Staff Straw Proposal Regarding Modification of 16 NYCRR Part 230*, July 16, 2024, Case 20-G-0131.

<sup>42</sup> State of New York Department of Public Service, *Staff Straw Proposal Regarding Modification of 16 NYCRR Part 230*, July 16, 2024, Case 20-G-0131.

the opportunity to respond to Staff’s proposal and utilities provided some data about their historical number of new connections, allowance lengths, and unit costs for constructing mains and services. Next, the PSC will review and make determinations about the proposed modifications.

## 4. MARYLAND

*In the Climate Solutions Now Act (CSNA) of 2022 (Senate Bill 528), Maryland’s General Assembly set a goal of a 60 percent reduction in GHG emissions by 2031 and net-zero statewide GHG emissions by 2045.<sup>43</sup> The CSNA came a few years after the passage of the 2019 Clean Energy Jobs Act (Senate Bill 516), which increased the total renewable energy requirement to 50 percent by the year 203.<sup>44</sup> Recent legislation also requires that, in supervising and regulating public service companies, the Maryland Public Service Commission consider “the preservation of environmental quality, the protection of the global climate from warming, and the achievement of the State’s climate commitments for reducing statewide GHG emissions.”<sup>45</sup>*

*In response to the establishment of state climate goals, the Maryland Public Service Commission (PSC), which regulates three investor-owned gas utilities (Washington Gas (WGL), Baltimore Gas & Electric (BGE) and Columbia Gas of Maryland), issued a notice seeking comments on the PSC’s statutory obligation to consider the achievement of the state’s climate goals in its duties. The Commission created Case No. 9707, in response to a petition from the Office of People’s Counsel (OPC), seeking public comment on establishing a docket for near-term priority actions and comprehensive long-term planning for Maryland’s Gas Companies.*

*After the passage of the CSNA, analyses of gas system decarbonization were published by BGE and OPC (see Future of Gas Studies, under Existing Analysis).*

### 4.1. KEY REGULATORY PROCEEDINGS

- **MD PSC Case No. 9692:** BGE’s 2023 Rate Case where the Commission opined on BGE’s infrastructure investment plan, advising BGE to prioritize risk reduction and cost effectiveness in light of the state’s emission reduction targets.<sup>46</sup>

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<sup>43</sup> *Maryland Senate Bill SB0528.* Maryland General Assembly. June 1, 2022.

<sup>44</sup> *Maryland Senate Bill SB0516.* Maryland General Assembly. October 1, 2019.

<sup>45</sup> *Order on Application for a Multi-Year Rate Plan.* Maryland PSC-9692. December 14, 2023. Pages. 83-84.

<sup>46</sup> *Order No. 90948 on Application for a Multi-Year Rate Plan.* Maryland PSC-9692, p. 119–132. December 14, 2023, page 242.



- **MD PSC Case No. 9704:** WGL’s 2023 Rate Case, where the Commission denied a large proportion of the utility’s requested rate increase but deferred ruling on larger gas planning issues to the Future of Gas docket requested by OPC.<sup>47</sup>
- **MD PSC Case No. 9707:** The Commission opened this docket in June 2023 in response to OPC’s petition to discuss issues related to near-term and long-term future of gas issues. OPC expected a decision from PSC on granting the petition in 2024, but as of March 2025 none has been made.<sup>48</sup>
- **Alternative Fuels Working Group:** This group is facilitated by Maryland Department of the Environment, with the first session occurring on March 20, 2025. Including members of the Building Energy Performance Standards and Clean Heat Rules proceedings, this working group seeks to incorporate stakeholder engagement to create an assessment framework for the alternative fuels and technologies to apply to state building decarbonization technologies.<sup>49</sup>

## 4.2. ACTIONS ON KEY ISSUES

### Gas Planning

- Case 9707 was established to address OPC’s petition about investigating near-term and long-term actions for gas utilities to align gas planning with state climate policies.

### Accelerated Pipe Replacement Programs

- In BGE’s 2023 rate case, the Commission required increased reporting requirements for aging pipe replacement projects.

### Alternatives to Natural Gas

- The Commission denied \$145 million of transmission pipe recovery in BGE’s 2023 rate case (No. 9692) because the utility did not properly consider NPA’s or the long-term future of gas.<sup>50</sup>

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<sup>47</sup> Leonard, T. 2023. “Maryland PSC Denies Large Portion of Washington Gas Light’s Rate Increase Request.” Maryland PSC. Available at: [https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request\\_12142023.pdf](https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request_12142023.pdf).

<sup>48</sup> Maryland OPC. *Gas spending update and long-term gas system planning petition*. Accessed April 22, 2025. Available at: <http://opc.maryland.gov/Consumer-Learning/Gas-and-Gas-Spending/Gas-Planning-Petition>.

<sup>49</sup> Maryland Department of the Environment. *Alternative Fuels and Technologies, Session 1*. March 20, 2025. Available at: <http://mde.maryland.gov/Documents/AlternativeFuelsandTechSession1.pdf>.

<sup>50</sup> Order No. 90948 on Application for a Multi-Year Rate Plan. Maryland PSC-9692, p. 143. December 14, 2023.



- In WGL’s rate case (No. 9704), the Commission required consideration of NPAs.<sup>51</sup>
- At a July 2024 public hearing as part of Case 9707, the Maryland Energy Administration recommended to the PSC that gas utilities be required to consider NPAs.<sup>52</sup>

### Line Extension Policy

- No notable action has been taken, but as part of its ruling on WGL’s 2023 requested rate increase (Case No. 9704) the Commission stated that line-extension policy should be addressed in the ‘Future of Gas’ proceeding requested by the OPC.<sup>53</sup>

## 4.3. EXISTING ANALYSIS

### 4.3.1. FUTURE OF GAS STUDIES

Maryland’s regulators have not required any studies as a part of the regulatory proceedings mentioned above; however, numerous reports have been published investigating different emission reduction pathways and their impacts on gas rates. The first study was conducted by E3 for the Maryland Commission on Climate Change in 2021, following the 2030 Greenhouse Gas Emissions Reduction Act. Two reports were released in October and November 2022, by E3 for BGE and Synapse for the OPC, respectively – published after the passage of the CSNA in June 2022.

#### ***Maryland Building Decarbonization Study (E3 for Mitigation Working Group)***

Released in 2021, the Maryland Department of Environment’s 2030 Greenhouse Gas Emissions Reduction Act (GGRA) Plan recommends reducing emissions from buildings using energy efficiency and by electrifying building heating systems. Under this plan, the Mitigation Working Group (MWG) of the Maryland Commission on Climate Change (MCCC) developed and issued the Building Energy Transition Plan.<sup>54</sup>

To inform this plan, Energy + Environmental Economics (E3) analyzed scenarios for achieving reductions in emissions to near net-zero levels for Maryland’s residential and commercial buildings by 2045. The

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<sup>51</sup> Leonard, T. 2023. “Maryland PSC Denies Large Portion of Washington Gas Light’s Rate Increase Request.” Maryland PSC. Available at: [https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request\\_12142023.pdf](https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request_12142023.pdf).

<sup>52</sup> Kauffman, K. 2024. “Maryland Energy Administration, PSC Staff Clash on Future of Gas.” *RTO Insider*. Available at: <https://www.rtoinsider.com/84742-md-psc-future-of-gas-hearings-round-2/>.

<sup>53</sup> Leonard, T. 2023. “Maryland PSC Denies Large Portion of Washington Gas Light’s Rate Increase Request.” Maryland PSC. Available at: [https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request\\_12142023.pdf](https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request_12142023.pdf).

<sup>54</sup> Maryland Commission on Climate Change. Building Energy Transition Plan: A Roadmap for Decarbonizing the Residential and Commercial Building Sectors in Maryland. Approved by the Mitigation Work Group on Oct. 13, 2021.



study was published in October 2021. In total, E3 modeled four scenarios, including the MWG Policy Scenario, which was found both to be the lowest-cost scenario and to reduce residential and commercial building emissions by 95 percent. This scenario reflects four core concepts and objectives, including: ensuring an equitable and just transition; shifting to fossil-free space and water heating for new construction; replacing almost all fossil heating systems in homes with heat pumps by 2045; and implementing an emissions standard that provides commercial buildings compliance alternatives.

### ***Integrated Decarbonization Strategy (E3, for Baltimore Gas and Electric)***

In response to the passage of the CSNA in June 2022, and ahead of filing for a multi-year rate plan in February 2023, BGE hired E3 to explore strategies to hit state GHG reduction goals in its service territory. The study, published in October 2022, considered three scenarios: Limited Gas, Hybrid, and Diverse.<sup>55</sup> The Hybrid and Diverse scenarios make use of a combination of electric and gas infrastructure to achieve decarbonization, with a different set of measures taken in each scenario. The Limited Gas scenario is primarily based on electrification and shifting away from gas.

**Policy Recommendations.** BGE provided regulatory and policy recommendations. These include:

- **Rate Design:** For gas customers, BGE recommends exploring subscription or other fixed-price methodologies that would allow the collection of gas infrastructure costs from hybrid customers with much lower volumes.
- **Renewable Natural Gas (RNG) Procurement:** Measures to allow for the procurement of these fuels, such as allowing utilities to offer voluntary RNG products, a renewable portfolio standard for gas, and inclusion of a social cost of carbon in gas supply planning or in a clean heat standard.
- **Accelerated depreciation:** The report notes that this may become a necessity as gas system utilization drops, resulting in a lower useful life for certain gas infrastructure. This report does not propose a methodology but points to proposals put forth by National Grid in Massachusetts and PG&E in California.
- **Redirection of incremental gas investment:** Involving changes to utility planning practices, such as more intensive coordination between electric and gas distribution planning.
- **Electric to gas benefit payments:** Establishment of transfer payments from the electric to the gas business to ensure the costs of the gas system are borne by those who benefit from the capacity and other benefits provided.

### **Alternatives**

- **Networked Geothermal.** Proposal to pilot a networked geothermal program. The report argues that this would require detailed engineering studies of networked geothermal potential in the state, demonstration projects, and development of rate design structures to support this effort.

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<sup>55</sup> E3. *BGE Integrated Decarbonization Strategy*. October 2022. Available at: [https://www.ethree.com/wp-content/uploads/2022/10/BGE-Integrated-Decarbonization-White-Paper\\_2022-11-04.pdf](https://www.ethree.com/wp-content/uploads/2022/10/BGE-Integrated-Decarbonization-White-Paper_2022-11-04.pdf).

- **Regulatory process to identify opportunities for NPAs.** This would include the assessment of technical feasibility, customer acceptance, and net-benefits and costs of NPAs.

### ***Climate Policy for Maryland’s Gas Utilities: Financial Implications (Synapse for OPC)***

The Maryland Office of People’s Counsel (OPC) sponsored a study titled *Climate Policy for Maryland’s Gas Utilities: Financial Implications* (Nov 2022), conducted by Synapse Energy Economics. This study quantifies the impacts of policy-consistent electrification on gas rates for the state’s three large gas utilities, incorporating the utilities’ current plans for capital spending on aging pipe replacement and assuming no change in depreciation rates. The analysis shows that gas rates increase by a factor of five to ten, driven by the combination of reduction in sales and the cost of alternative gaseous fuels. The modeling shows that the utilities’ rate base in 2050 is comparable to today’s rate base in inflation-adjusted dollars. The report points out that changes in capital investment and depreciation can reduce the pace of rate increases and mitigate stranded cost risks, while also improving equity outcomes.

#### 4.3.2. CASE NO. 9692

In BGE’s 2023 rate case, Case No. 9692, the utility sought to recover additional revenues in its Multi-Year Rate due primarily to storms, inflation and supply chain issues, and state policy, with the goal of improving and maintaining safety and reliability.

The Commission rejected BGE’s plan to use pipe replacement as its only strategy to comply with federal transmission safety rules (PHMSA) because the company did not show it had sufficiently considered potentially lower-cost options such as NPAs, and the expensive strategy BGE proposed was “incongruous” with and demonstrated little-to-no consideration for the long-term future of gas infrastructure in Maryland.<sup>56</sup>

The Commission similarly denied authorization for BGE’s two-phase gas meter conversion project because of its risk to ratepayers, lack of analytical support.<sup>57</sup> The Commission stated that investing in the wholesale replacement of BGE’s suite of gas meters was not in the best interest of shareholders or ratepayers, given the possibility that BGE will have fewer gas customers as Maryland nears its 2045 emissions reduction milestone.

The Commission also implemented reporting requirements for aging pipe replacement projects historically associated with BGE’s Strategic Infrastructure Development and Enhancement program (STRIDE).<sup>58</sup> Though the Commission approved continued investment through this program, the

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<sup>56</sup> Order No. 90948 on Application for a Multi-Year Rate Plan. Maryland PSC-9692, p. 119–132. December 14, 2023, page 143

<sup>57</sup> Id. at 150.

<sup>58</sup> Order No. 90948 on Application for a Multi-Year Rate Plan. Maryland PSC-9692, p. 119–132.

reporting requirements aim to ensure the projects appropriately target leak reduction and are absolutely necessary.

#### 4.3.3. CASE NO. 9707

OPC filed a petition in front of the MD PSC for near-term priority actions and comprehensive long-term planning for Maryland’s Gas Companies, due to misalignment between GHG emission reduction goals and the utilities’ spending on infrastructure. The Commission requested written comments on the OPC Petition from February, to be filed by October 10, 2023.

The PSC held a public hearing on July 25, 2024, for parties to present priorities and concerns for the future of gas and the OPC’s proposal. The OPC and other stakeholders, including a sizeable coalition of non-profits, supported the initiation of this proceeding to address the future of gas in Maryland. OPC expected a decision from PSC on granting the petition in 2024, but as of March 2025 none has been made.<sup>59</sup> In its decision on WGL’s 2023 Rate Case, the Commission stated that larger gas planning issues should be considered as part of the Future of Gas docket requested by the OPC.<sup>60</sup>

## 5. DISTRICT OF COLUMBIA

*The Clean Energy DC Act established by the Mayor’s Office and City Council, commits the District to reducing GHG emissions at least 50 percent by 2032 from 2006 levels, and achieve carbon neutrality by 2050. Utilities in Washington, D.C. are regulated by the DC Public Service Commission (DCPSC). It regulates one natural gas utility, Washington Gas & Light (WGL). In light of the Clean Energy DC Act, the DCPSC created Formal Case No. 1167, a climate policy proceeding to consider if the utilities are meeting and advancing DC’s climate goals and then to take action, where necessary, to guide the companies in the right direction.*

### 5.1. KEY REGULATORY PROCEEDINGS

- **GD2019-04-M:** Investigation into an analytical framework to approach the implementation of the 2019 Clean Energy DC Act.

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<sup>59</sup> Maryland OPC. *Gas spending update and long-term gas system planning petition*. Accessed April 22, 2025. Available at: <http://opc.maryland.gov/Consumer-Learning/Gas-and-Gas-Spending/Gas-Planning-Petition>.

<sup>60</sup> Leonard, T. 2023. “Maryland PSC Denies Large Portion of Washington Gas Light’s Rate Increase Request.” Maryland PSC. Available at: [https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request\\_12142023.pdf](https://www.psc.state.md.us/wp-content/uploads/Maryland-PSC-Denies-Large-Portion-of-WGL-Rate-Increase-Request_12142023.pdf).



- **Formal Case No. 1167:** The District’s proceeding on strategies to achieve climate goals and address the future of gas.
- **Formal Case No. 1175:** WGL’s initial application for the approval of its District Strategic Accelerated Facility Enhancement Plan (DistrictSAFE) in project PIPES 3, the utility’s current program to replace aging pipes.
  - **Order 22003:** DCPSC order rejecting WGL’s application and requiring modification.
- **Formal Case No. 1179:** Proceeding to address WGL’s revised application for the approval of its District Strategic Accelerated Facility Enhancement Plan (DistrictSAFE) in project PIPES 3.

## 5.2. ACTIONS ON KEY ISSUES

### Gas Planning

- The DCPSC required WGL to file Climate Business Plans in 2020 discussing how it intends to evolve its business model to support the District’s climate goals.

### Accelerated Pipe Replacement Programs

- The DCPSC required WGL to refile its PIPES 3 application with modifications that take into account cost-effectiveness of pipe replacement, consideration of alternatives, and alignment with climate goals.
- WGL did not propose to implement any electrification or other NPAs in its initial or revised project PIPES 3 filings; however, its proposed Customer Choice Pilot Program would give customers advanced notice of impending pipe replacements, allowing them the opportunity to opt out of gas service and potentially avoid the asset replacement.

### Alternatives to Natural Gas

- WGL included consideration of NPAs in some of its Climate Business Plan scenarios, but no notable action has been taken to implement NPAs at scale.

### Line Extension Policy

- No notable findings.

## 5.3. EXISTING ANALYSIS

### 5.3.1. FC1167

This proceeding arose out of the merger between AltaGas and Washington Gas & Light in Formal Case No. 1142. The terms of the settlement agreement required WGL to file Climate Business Plans. Formal

Case No. 1167 was opened to assess Climate Business Plans and address other issues related to achieving the District's emission reduction goals.

### ***Climate Business Plan***

The Climate Business Plan (CBP) was developed as part of the settlement in FC1142. It is a business plan for how Washington Gas can evolve its business model to support and serve the District's 2050 climate goals. It was delivered on March 2020.<sup>61</sup> Supplementary materials were also made available, including the ICF Technical Report and Supplemental Technical Information.<sup>62</sup>

**Scenarios.** The analysis included the creation of four scenarios—Business As Usual, Partial Decarbonization, Policy Driven Electrification, and Fuel Neutral Decarbonization—to assess the effectiveness, costs, potential trade-offs, and equity implications associated with these scenarios. AltaGas proposed the Fuel Neutral Scenario as the preferred option that would meet the District's climate goals at 59 percent of the cost of full electrification while maintaining energy reliability and customer choice.

**Unrecovered Cost of Service.** The CBP also estimated the unrecovered cost of service on the gas system that would not be covered based on existing rates. This was estimated at \$4.6 billion for the Policy Driven Electrification case and \$3.6 billion for the preferred Fuel Neutral Decarbonization case. This assumed that sales volume decreases to 8 percent of 2018 levels by 2050.

**Stranded Cost Estimates.** The Policy Driven Electrification Case assumed that gas service in the District would be almost or completely terminated. In this case, the report estimates stranded rate base in 2050 to be \$1.5 billion to \$2.1 billion. This assumes current depreciation policies along with incremental capex for maintenance and reliability. The study did not provide backup for these estimates.

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<sup>61</sup> Washington Gas and AltaGas. March 2020. *Natural Gas and its Contribution to a Low Carbon Future: Climate Business Plan for Washington, D.C.* Available at: <https://washingtongasdclimatebusinessplan.com/wp-content/uploads/2020/04/Climate-Business-Plan-March-16-2020-FOR-WEB.pdf>.

<sup>62</sup> Available for download at <https://washingtongasdclimatebusinessplan.com/>.

**Table 1. Comparison of additional cumulative 2020–2050 cost elements beyond those evaluated in scenarios (\$2018 millions)**

Impact	Policy Driven Electrification Case	Fuel Neutral Decarbonization Case	Additional Costs in Policy Driven Electrification Case
<b>Cumulative Incremental Costs in Study Results (Million\$)</b>	6,532	3,843	+2,690
<b>High Level Estimation of Transmission and Distribution Costs to Accommodate Peak Demand Growth – Using SEU Approach</b>	\$2,800 +/-	0	+\$2,800 +/-
<b>Unrecovered Cost of Service 2020-2050 (at Current Rates)</b>	\$4,600 +/-	\$3,600 +/-	+\$1,100 +/-
<b>Stranded Rate Base in 2050</b>	1,500 to \$2,100 or more	0	+\$1,500 to \$2,100 or more
<b>Final Customer Transition Costs</b>	\$800 +/-	0	+ \$800 +/-
<b>System Decommissioning Costs</b>	+ Unknown	0	+ Unknown
<b>Reliability and Resiliency Costs</b>	+ Unknown	0	+ Unknown
<b>BAU Costs of 100% RPS – Not Included in incremental Power Generation Production Costs</b>	+ Unknown	+ Unknown	Negligible

Source: ICF International. April 2020. *Opportunities for Evolving the Natural Gas Distribution Business to Support the District of Columbia’s Climate Goals*. Prepared for Washington Gas and AltaGas. Page 62. Available at: <https://washingtongasdcclimatebusinessplan.com/wp-content/uploads/2020/04/Technical-Study-Report-Opportunities-for-Evolving-the-Natural-Gas-Distribution-Business-to-Support-DCs-Climate-Goals-April-2.pdf>

**Policy Recommendations.** The CBP notes that policy changes are required to ensure recovery of the full cost of service and to address stranded assets and system transition costs associated with certain scenarios. Two regulatory proposals were highlighted:

- Decoupling rates from volumetric throughput: Decoupling of throughput from cost recovery or restructuring of rates to reduce cost recovery related to throughput.
- Cost sharing: A recovery mechanism to socialize cost and benefits of gas use to all energy users. The intent is to equitably distribute fixed costs of the natural gas system and maintain reasonable rates for customers.

### 5.3.2. FC1179

WGL filed its initial application for approval of the District Strategic Accelerated Facility Enhancement Plan (DistrictSAFE) in December 2022. This was the third iteration of WGL’s Accelerated Pipe Replacement Plan (called project PIPES) – PIPES 1 was approved in 2014 and PIPES 2 was approved in

2020.<sup>63</sup> WGL's application requested \$670 million for pipe replacement projects over five years, double the cost of the first ten years of the program. The DCPSC rejected WGL's initial PIPES 3 application, noting concerns about the cost-effectiveness of WGL's risk reduction approach and lack of consideration of alternatives and climate targets.<sup>64</sup> The DSPSC required WGL to refile its plan with a) an approach that considers stranded asset risk, b) a plan that targets the highest risk segments of pipe, c) a change in focus of the program to address the District's climate policies and promote electrification, and more.<sup>65</sup> WGL filed a revised plan in September 2024, and awaits Commission review.

## 6. MINNESOTA

*In 2007 Minnesota passed the Next Generation Energy Act, which required the state to reduce GHG emissions by 80 percent between 2005 and 2050 while maintaining reliable and affordable energy. In 2023, the Minnesota legislature updated these goals to reduce GHG emissions 50 percent by 2030 from a 2005 baseline and achieve net-zero emissions by 2050.<sup>66</sup> The State has also developed a Climate Action Framework, which it planned to continue to update through 2025. The Climate Action Framework outlines immediate actions that can avoid the worst impacts of climate change and demonstrates a strategy to reduce GHG emissions by improving efficiency and accelerating the clean energy transition.<sup>67</sup>*

*The Natural Gas Innovation Act (NGIA) was signed into law on June 26, 2021, directing the commission to initiate a proceeding to evaluate changes to natural gas utility regulatory and policy structures to meet Minnesota's state GHG emission reduction goals. In response, the Minnesota Public Utilities Commission (MN PUC) created docket G999-CI-21-565.*

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<sup>63</sup> MN PSC Order 22003, June 12, 2024, available at: <https://edocket.dcpssc.org/apis/api/Filing/download?attachId=206883&guidFileName=8abcb06b-def7-4421-b43b-39393ead96d7.pdf>.

<sup>64</sup> MN PSC Order 22003.

<sup>65</sup> MN PSC Order 22003.

<sup>66</sup> State of Minnesota. *Greenhouse Gas Emissions*. Accessed February 24, 2025. Available at: <https://mn.gov/mmb/one-mn-plan/measurable-goals/ghg-emissions.jsp>.

<sup>67</sup> State of Minnesota. *Climate Action Framework*. Accessed April 22, 2025. Available at: <https://climate.state.mn.us/minnesotas-climate-action-framework>.

## 6.1. KEY REGULATORY PROCEEDINGS

- **MN PUC Docket G-999/CI-21-566:** Opened January 27, 2022, this docket serves to establish the analytical frameworks that the gas utilities can use to develop Innovative Resource Plans.<sup>68</sup>
- **MN PUC Docket G-999/CI-21-565:** Broader proceeding to look at the future of gas, which has largely been on pause, pending efforts on establishing gas integrated resource plan (IRP) processes in Docket 23-117.<sup>69</sup> The MN PUC published a scope and timeline update in January 2025.<sup>70</sup>
- **MN PUC Docket 23-117:** Gas Integrated Resource Planning (IRP) docket requiring gas utilities to submit forward-looking plans with 10-year projections of demand for gas in their service territories and new customers.<sup>71</sup>

## 6.2. ACTIONS ON KEY ISSUES

### Gas Planning

- LDCs are encouraged to file Innovation Plans discussing utilities' resource plans, including GHG emissions accounting and benefit-cost analysis for each resource option, and pilot programs to explore innovative resources.

### Accelerated Pipe Replacement Programs

- No notable findings.

### Alternatives to Natural Gas

- LDCs are required to consider alternatives for two or three gas expansion projects within their gas IRPs in Docket 23-117.

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<sup>68</sup> Minnesota Public Utilities Commission. Order Establishing Preliminary Procedures for Implementing Minnesota's Natural Gas Innovation Act. CI-21-566. January 27, 2022.

<sup>69</sup> State of Minnesota. Gas Resource Planning. Accessed April 22, 2025, available at: <https://mn.gov/puc/activities/economic-analysis/planning/gas-irp/>.

<sup>70</sup> Minnesota Public Utilities Commission. *Notice of Current Scope of Docket and Timeline*. Docket No. G999/CI-21-565. January 17, 2025.

<sup>71</sup> Minnesota Public Utilities Commission. *In the Matter of a Commission Investigation into Gas Utility Resource Planning*. Docket No. CI 23-117. March 27, 2024, page 5.



## Line Extension Policy

- No notable action has been taken. However, the issue of line extensions is slated to be addressed in Docket G-999/CI-21-565, starting with a Notice of Comment Period planned to start March 2025.<sup>72</sup>

## 6.3. EXISTING ANALYSIS

### 6.3.1. FUTURE OF GAS STUDIES

#### ***Minnesota Building Decarbonization Analysis: Equitable and Cost-Effective Pathways toward Net-Zero emissions for homes and businesses (Synapse, June 2024)***

For Clean Heat Minnesota, Synapse Energy Economics performed a study to help identify the most feasible, equitable, and cost-effective pathways for reducing emissions from Minnesota’s natural gas distribution sector at a pace and magnitude consistent with Minnesota’s GHG emission reduction goals.

Synapse focused on residential and commercial energy end uses and the impacts that their decarbonization would have on the gas and electric systems, on costs to customers, and on health and environmental issues. The resulting report describes analysis of two “book-end” scenarios to illustrate potential pathways to decarbonization: one to maximize building electrification and one to maximize the feasible use of alternative fuels.

#### ***Decarbonizing Minnesota’s Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations***

This report, published by the Great Plains Institute in 2021, summarizes the recommendations of a stakeholder group regarding the decarbonization of Minnesota’s natural gas end uses.<sup>73</sup> The stakeholder group includes members from utilities, regulators, state agencies, consumer and environmental advocates, and others. The results were presented to the Minnesota PUC in August 2021. The report notes specifically that NGIA “establishes a regulatory framework for natural gas and dual-fuel utilities to implement and recover their costs for programs that reduce or avoid GHG emissions from customers’ use of natural gas.”<sup>74</sup>

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<sup>72</sup> Minnesota Public Utilities Commission. *Notice of Current Scope of Docket and Timeline*. Docket No. G999/CI-21-565. January 17, 2025.

<sup>73</sup> Great Plains Institute and Center for Energy and Environment. July 2021. *Decarbonizing Minnesota’s Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations*. Available at: <https://e21initiative.org/wp-content/uploads/2021/07/Decarbonizing-NG-End-Uses-Stakeholder-Process-Summary.pdf>.

<sup>74</sup> Id.



**Scenarios.** The stakeholders hired Energy and Environmental Economics Inc. (E3) to model high-level scenarios for decarbonizing natural gas end uses by 2050. The results are intended to support further discussions. The four scenarios were: (a) a reference case, (b) high electrification in which almost all buildings switch to all-electric and industry is electrified where possible, (c) high electrification with gas backup where buildings keep their gas connection for backup heating, and (d) high decarbonized gas where gas is replaced by biomethane, synthetic natural gas, and hydrogen for building heating.

**Residential delivery cost of gas.** The scenario analysis included a projection of the impact to the residential delivery cost of gas. It looked, in particular, at the impact to residential bills where electrification and increasing gas commodity costs to customers lead to lower gas demand and exodus of customers, thus leaving the remaining customers with a higher share of the system cost. Assuming no gas system cost reductions, and no changes to rate structure or design, in the high decarbonized gas scenario, residential delivery costs of gas will increase from \$385/year in 2020 to \$902/year in 2050. Under a high electrification scenario, it will go up to \$28,685/year. A scenario where electrification is mitigated by a gas backup scenario (where all existing customers remain connected to the system for backup heat), reduces this to \$920/year.

**District System.** A district system sensitivity analysis was performed, looking at impact on electric peak load if a percentage of load was served by the district. It found that installing district systems in new construction would result in electric system cost savings of about \$1.2 billion in 2050.

**Policy Recommendation – Rate Design and Utility Financing.** The scenario analysis concluded with the recommendation to implement a stakeholder process to consider potential changes to rate design (for gas and electricity) and utility financing mechanisms to support transition to a decarbonized energy system. E3 presented the following for consideration:<sup>75</sup>

- *Natural gas customers switching to electricity could pay all or some portion of any stranded costs given the infrastructure was built to serve their original energy needs.*
- *It may be appropriate for electric utilities to pay for some natural gas system costs if the additional electricity sales from electrification are sufficiently beneficial to justify that payment.*
- *It may be appropriate for electric utilities to pay natural gas utilities for the capacity and demand benefits of backup heating provided by gaseous fuels.*
- *Securitization or other utility system financial tools to address transition costs.*

### 6.3.2. DOCKET G-999/CI-21-566

Docket G-999/CI-21-566 serves to address the provisions of Minnesota’s NGIA. The NGIA encourages natural gas utilities to file “Innovation Plans” showing how they can contribute to meeting the state’s climate goals. Innovation Plans must present the GHG emission intensity of utilities’ resource plans

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<sup>75</sup> Decarbonizing Minnesota’s Natural Gas End Uses, page 82.



including a benefit-cost analysis comparing different resource options, identify pilot programs for innovative resources, and estimate the total emissions from natural gas use by utility customers.<sup>76</sup>

As part of the docket, the Commission adopted frameworks for GHG emissions accounting and benefit-cost analysis. Utilities that choose to file Innovation Plans must adopt the Commission's frameworks in their filings. The gas utilities were able to present their "innovative" resources to achieve decarbonization at the MN PUC beginning in June 2021, including the deployment of strategic electrification using cold-climate air-source heat pumps, carbon-free ground-source district energy systems, and energy efficiency measures that go beyond the existing programming.<sup>77</sup> Alongside their Innovative Plans, the companies are required to submit utility system reports and forecasts detailing infrastructure characteristics, projected capital and fuel investments, carbon emissions, and incentive programs with respect to fossil gas.<sup>78</sup>

CenterPoint Energy filed its Innovation Plan as Docket No. 23-215, which was approved by the Commission in July 2024.<sup>79</sup> Xcel Energy filed its Innovation Plan as Docket No. 23-518, which was approved by the MN PUC in February 2025.<sup>80</sup>

### 6.3.3. DOCKET G-999/CI-21-565

Established concurrently with Docket G-999/CI-21-566, the G-999/CI-21-565 proceeding is intended to look more broadly at the future of gas, looking at policy and regulatory changes necessary to meet state climate goals. It had largely been on pause, as the MN PUC spent efforts on establishing gas IRP processes in Docket 23-117.<sup>81</sup> After approval of the gas IRP framework in October 2024, progress in Docket G-999/CI-21-566 is continuing in 2025. The MN PUC published an updated scope and timeline in January 2025, which included issues related to line extension policy and rate design.<sup>82</sup>

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<sup>76</sup> Minnesota Public Utilities Commission. Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act. CI-21-566. June 1, 2022.

<sup>77</sup> Minnesota Public Utilities Commission. Order Establishing Frameworks for Implementing Minnesota's Natural Gas Innovation Act. CI-21-566. June 1, 2022.

<sup>78</sup> 2024 Minnesota Statutes 216B.2427.11 Natural Gas Utility Innovation Plans.

<sup>79</sup> Minnesota Public Utilities Commission. Natural Gas Innovation Act. Accessed April 22, 2025. Available at: <https://mn.gov/puc/activities/economic-analysis/ngia/#:~:text=CenterPoint%20Energy%20and%20Xcel%20Energy,Commission%20in%20February%20of%202025>

<sup>80</sup> Minnesota Public Utilities Commission. February 7, 2025. Minnesota Public Utilities Commission approves Xcel Energy's first-ever Natural Gas Innovation Plan. Accessed April 22, 2025. Available at: <https://content.govdelivery.com/accounts/MNPUBUC/bulletins/3d1234a#:~:text=The%20Natural%20Gas%20Innovation%20Plan,and%20investing%20in%20emerging%20technologies>

<sup>81</sup> State of Minnesota. Gas Resource Planning. Accessed April 22, 2025. Available at: <https://mn.gov/puc/activities/economic-analysis/planning/gas-irp/>.

<sup>82</sup> Minnesota Public Utilities Commission. *Notice of Current Scope of Docket and Timeline*. Docket No. G999/CI-21-565. January 17, 2025.



#### 6.3.4. DOCKET 23-117

Docket 23-117 establishes requirements for gas IRP to better address state climate goals and the impacts of severe weather on the gas distribution system.<sup>83</sup> As part of the 10-year plans submitted as part of the gas IRP process, each utility must select two or three gas system expansion projects and conduct an Expansion Alternative Analysis evaluating the potential to use alternative resources such as electrification, efficiency measures, thermal energy networks, or NPAs.<sup>84</sup> These assessments must factor the emissions reductions including the social cost of carbon, and air quality for the alternatives. Utilities are also broadly required to consider Minnesota’s GHG reduction goals and report their plans’ emissions from both their upstream and gas distribution systems to ensure that the state has important data to identify potential further emissions reduction opportunities.<sup>85</sup>

## 7. ILLINOIS

*Illinois joined a group of states in the U.S. Climate Alliance in 2019, committing the state to the Paris Agreement’s emissions reduction goals and aligning Illinois with the decarbonization pathways the country aimed to follow more broadly, which require building electrification. Through the Paris Agreement, members of the U.S. Climate Alliance commit to reducing gas emissions by at least 26–28 percent below 2005 levels by 2025.<sup>86</sup> Illinois has also passed the Climate and Equitable Jobs Act (CEJA), which requires the electricity industry to achieve zero-emissions by 2045 and allows an electric utility to “offer and promote measures that electrify space heating, water heating, cooling, drying, cooking, industrial processes, and other building and industrial end uses that would otherwise be served by combustion of fossil fuel at the premises provided that [it] reduce[s] total energy consumption at the premises.”<sup>87</sup> The Illinois Commerce Commission (ICC) also demonstrated its commitment to ensuring that*

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<sup>83</sup> Minnesota Public Utilities Commission. Order Requiring Actions to Mitigate Impacts from Future Natural Gas Price Spikes, Setting Filing Requirements, and Initiating a Proceeding to Establish Gas Resource Planning Requirements. Docket No. G-999/CI-21-135. February 17, 2023.

<sup>84</sup> Minnesota Public Utilities Commission. In the Matter of a Commission Investigation into Gas Utility Resource Planning. Docket No. CI 23-117. March 27, 2024, pages 11-12.

<sup>85</sup> Minnesota Public Utilities Commission. In the Matter of a Commission Investigation into Gas Utility Resource Planning. Docket No. CI 23-117. March 27, 2024, pages 11-12.

<sup>86</sup> Illinois Environmental Protection Agency, “U.S. Climate Alliance.” Accessed April 22, 2025. Available at: [https://epa.illinois.gov/topics/climate/climate-alliance.html#:~:text=%E2%80%8B%E2%80%8BOn%20January%202023,Paris%20Agreement%20\(the%20Agreement](https://epa.illinois.gov/topics/climate/climate-alliance.html#:~:text=%E2%80%8B%E2%80%8BOn%20January%202023,Paris%20Agreement%20(the%20Agreement)

<sup>87</sup> Illinois General Assembly, Public Act 102-0662.



*gas companies plan for the transition of the gas system in its recent decision in the People's Gas Light and Coke Company rate case, Case 23-0069.<sup>88</sup>*

## 7.1. KEY REGULATORY PROCEEDINGS

- **IL Commerce Commission (ICC) Case 23-0069**, November 16, 2023. The Commission assessed and ultimately rejected People's Gas's request for approval of \$265 million for its Safety Modernization Program (SMP) to replace aging pipe because the Company did not justify its proposed spending level for the SMP.<sup>89</sup>
- **ICC Docket 24-0158**, March 7, 2024- a Future of Gas proceeding to explore the future of the gas system as the state transitions toward a cleaner energy future. The proceeding is split into two phases. Phase One consisted of several working group meetings to determine the scope and topics that would be covered in Phase Two.

## 7.2. ACTIONS ON KEY ISSUES

### Gas Planning

- Gas utilities are required to file a Long-Term Gas Infrastructure Plan every two years starting in 2025 with comprehensive infrastructure and investment plans over a five year outlook.

### Accelerated Pipe Replacement Programs

- The Commission ordered People's Gas Light & Coke Company to pause its aging pipe replacement program (the Safety Modernization Program) until there is further investigation into prudent risk reduction methods.

### Alternatives to Natural Gas

- No notable findings.

### Line Extension Policy

- No notable findings.

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<sup>88</sup> Final Order, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders, and terms and conditions of service. ICC 23-0069. November 16, 2023.

<sup>89</sup> Final Order, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders, and terms and conditions of service. ICC 23-0069. November 16, 2023 at 28-29.



## 7.3. EXISTING ANALYSIS

### 7.3.1. CASE 23-0069

As part of ICC Case 23-0069, the Commission raised the Safety Modernization Program (SMP)'s high level of new pipe installation and magnitude of investments as concerns, as well as the slow pace of both replacements and retirements of pipe on the system. Over the previous five years, People's Gas had installed 75 percent more pipe than it retired in the SMP, but also only replaced 59 miles of high-risk pipe for years between 2018 and 2022; this put the utility on pace to take until 2049 to replace all of its existing high-risk pipe.<sup>90</sup>

The Commission ordered a new investigation into the program due to failure to prioritize high-risk neighborhoods and to consider alternatives to pipe installation.<sup>91</sup> It then ordered that the SMP be paused until the determination of a method for replacing certain high-risk pipe and a prudent investment level in a separate proceeding.<sup>92</sup>

### 7.3.2. DOCKET 24-0158

As part of the Future of Gas proceeding process, the ICC has directed each gas utility to file a Long-Term Gas Infrastructure Plan every two years starting in 2025. These plans must include comprehensive detail of their proposed investments and infrastructure needs to assist the Commission in conducting a more "informed" view of future rate requests by Illinois's gas companies.<sup>93</sup>

For ICC Docket 24-0158, phase two of the future of gas proceeding will investigate the feasibility and economic impact of different decarbonization pathways and explore regulatory next steps.<sup>94</sup> The topics for discussion in this proceeding include strategies for decarbonizing the gas system such as NPAs, solutions for hard-to-electrify customers, integrated gas and electric planning, mitigating stranded assets, protecting ratepayers from bearing disproportionate costs, line extension policies, and more. As these proceedings continue, the State will gain a better picture of how the gas system will evolve and how utilities should plan to transition customers and territories to electricity.<sup>95</sup>

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<sup>90</sup> Id. at 28.

<sup>91</sup> Id. at 29.

<sup>92</sup> Id.

<sup>93</sup> Final Order, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders, and terms and conditions of service. ICC 23-0069. November 16, 2023, at 119.

<sup>94</sup> Illinois Commerce Commission, Initiation of Proceeding to Examine the Future of Natural Gas and Issues Associates with Decarbonization of the Gas Distribution System. Docket No. 24-0158. March 7, 2024.

<sup>95</sup> Illinois Commerce Commission. Future of Gas Phase 1 Workshops Facilitator Report to the Commission. July 29, 2024. Docket No. 24-0158.

## 8. COLORADO

*In 2019, Colorado enacted a statute that set economy-wide emissions reduction targets of at least 26 percent by 2025, 50 percent by 2030, and 90 percent by 2050 from 2005 levels. It then updated these targets in 2023 to 65 percent reductions by 2035, 75 percent by 2040, and net-zero GHG emissions by 2050.<sup>96</sup>*

*On June 24, 2021, the Colorado state legislature passed SB21-264, requiring each gas utility to file a clean heat plan with the Public Utilities Commission (PUC). This plan must demonstrate how the utility will use clean heat resources to meet the clean heat targets of a 4 percent reduction below 2015 GHG emission levels by 2025 and 22 percent below 2015 GHG emission levels by 2030. In response, the Colorado PUC opened proceeding 21R-0449G in October 2021.*

### 8.1. KEY REGULATORY PROCEEDINGS

- **Docket 21R-0449G:** In the Matter of the Proposed Amendments to the Commission’s Rules Regulating Gas Utilities, 4 Code of Colorado Regulations 723-4, Relating to Gas Utility Planning and Implementing SB 21-264 Regarding Clean Heat Plans and HB 21-1238 Regarding Demand Side Management
  - o **Decision C22-0760** – Rulemaking. Dec 1, 2022.

### 8.2. ACTIONS ON KEY ISSUES

#### Gas Planning

- Each LDC is required to file a Gas Infrastructure Plan every two years that presents its planned investments, incorporating consideration of the long-term demand for gas and the use of alternatives to natural gas where applicable.
- LDCs are required to file Clean Heat Plans outlining a proposed portfolio of measures aimed at reducing GHG emissions.

#### Accelerated Pipe Replacement Programs

- No notable findings.

#### Alternatives to Natural Gas

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<sup>96</sup> HB 19-1261, 2019 Reg. Session (CO. 2019). <https://leg.colorado.gov/bills/hb19-1261>; SB 23-016, 2023 Reg. Session (CO. 2023). <https://leg.colorado.gov/bills/sb23-016>.

- LDCs are required to consider alternatives to at least five new business or capacity expansion projects within their Gas Infrastructure Plans.
- The Mountain Energy Project is a county-wide NPA proposed by Public Service Colorado to reduce natural gas load through a mixture of electrification, energy efficiency, and LNG imports to avoid the construction of additional transmission capacity.

#### **Line Extension Policy**

- Senate Bill 23-291 prevents gas utilities from offering any incentives for gas connection, including line extension allowances.

### **8.3. EXISTING ANALYSIS**

#### **8.3.1. DOCKET 21-R-0449G**

##### ***Clean Heat Plans***

To show they are meeting their clean heat targets, gas utilities are ordered to file Clean Heat Plans to the PUC starting in 2023, as per SB 21-264. The Clean Heat Plans will include a mix of supply-side and demand-side resources, including energy efficiency programs, recovered methane, green hydrogen, and beneficial electrification. The plans also include the following elements:

- **Rate Adjustment.** Under the clean heat plans, the Commission allows a utility to propose a rate adjustment clause that provides for recovery of the utility's clean heat plan costs or any costs prudently incurred to meet additional emission reduction requirements.
- **Depreciation.** The Commission requires a utility to identify potential changes to depreciation schedules or other actions to align the utility's cost recovery with statewide policy goals.
- **Cost Recovery.** The Commission notes there could be value in assessing cost recovery mechanisms for gas infrastructure planning and Clean Heat Plans, aligning the goals of the Clean Heat Plan and the utilities.

Assessment of the Clean Heat Plans will be based on emission reductions/achievement of clean heat targets, probability of whether it can be implemented with the lowest reasonable cost and rate impact, and qualitative factors including benefits to air quality, the environment and health, and environmental justice impacts.

Three gas distribution utilities in Colorado: Public Service Company of Colorado (Xcel Energy), Atmos Energy Corporation, and Black Hills Colorado Gas have filed Clean Heat Plans, with final decisions from the Commission in July 2024, November 2024, and February 2025, respectively.<sup>97</sup>

### **Gas Infrastructure Plans**

SB 21-264 required gas utilities to file biannual Gas Infrastructure Plans (GIP) to ensure that gas system investments are aligned with Colorado’s long-term affordability and decarbonization goals. Among other things, LDCs with over 500,000 customers are required to demonstrate consideration of alternatives for at least five new business or capacity expansion projects, including a full benefit-cost analysis and job impact assessment.<sup>98</sup> If the utility determines that an NPA is not feasible, it must justify this decision and apply for a certificate of public convenience and necessity to proceed with the gas infrastructure project.<sup>99</sup>

In April 2024, the PUC issued a decision on Xcel Energy’s GIP, the first to be filed in the state, which demonstrated the Commission’s commitment to achieving an affordable and decarbonized future and its expectation that the future involves less gas. The Commission directed Xcel Energy to account for local building electrification and other policies in its gas forecasting to ensure that the company was not over-projecting gas needs and out of alignment with climate targets and market trends.<sup>100</sup> The PUC made it clear that “legacy planning processes” would “no longer [be] acceptable nor in the best interest of the ratepayers.” It went on to say that should Xcel Energy push forward with investments in the gas system without GIP or other through review, “it is likely doing so at its own risk.”<sup>101</sup>

### **8.3.2. LINE EXTENSION POLICY**

Line extension policies were first addressed in Docket 21-R-0449G, where the Commission added language to the Colorado Gas Rules requiring that line extensions “be based on the principle that the connecting customer pays its share of the estimated full incremental cost of growth, including any costs associated with increases in design day peak demand.”<sup>102</sup> Then, Senate Bill 23-291 required gas utilities

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<sup>97</sup> See CO PUC, *What is a Clean Heat Plan*. Accessed April 22, 2025. Available at: <https://puc.colorado.gov/cleanheatplans>

<sup>98</sup> CO PUC Gas Rules 4552(b)(I).

<sup>99</sup> CO PUC Gas Rules 4553(c)(I)(Q).

<sup>100</sup> Commission Decision Granting, in Part, and Denying, in Part, Application for Rehearing, Reargument, or Reconsideration of Commission Decision No. C24-0092. April 3, 2024. Page 19-20.

<sup>101</sup> *Id.* at 33.

<sup>102</sup> CO PUC, Decision No. C22-0760 Attachment 1, Docket 21-R-0449G, page 15 of 58.



to completely eliminate incentives for gas line extensions, including line extension allowances by the end of 2024.<sup>103</sup>

### 8.3.3. XCEL MOUNTAIN ENERGY PROJECT

Xcel Energy filed its Mountain Energy Plan with the PUC in January 2025, which includes \$47 million in funding for NPAs. The Mountain Energy Plan is a portfolio of NPAs combined with LNG imports that together meet the capacity needs in Breckenridge, Colorado and surrounding areas, which would otherwise require the installation of a new transmission pipeline. This is the company's largest NPA project to date; the company has said that the project will help Colorado meet its energy targets, deliver carbon-free energy to customers, and enhance reliability.<sup>104,105</sup>

## 9. OREGON

*In 2021, Oregon's Environmental Quality Commission adopted rules establishing the state's Climate Protection Program (CPP). The CPP limits emissions from the state's fossil fuel suppliers, including natural gas utilities, to 50 percent of 2017-2019 emissions by 2035 and 10 percent by 2050.<sup>106</sup>*

### 9.1. KEY REGULATORY PROCEEDINGS

- **Docket No. UM 2178G-999/CI-21-566** – Proceeding investigating different decarbonization pathways, called Natural Gas Fact Finding.

### 9.2. ACTIONS ON KEY ISSUES

#### Gas Planning

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<sup>103</sup> CO Senate Bill 23-291, Section 5, 40-3.2-104.3, available at: [https://leg.colorado.gov/sites/default/files/2023a\\_291\\_signed.pdf](https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf).

<sup>105</sup> Xcel Energy, "Xcel Energy unveils first of its kind plan to provide safe, clean, reliable and affordable energy service in targeted mountain communities." January 16, 2025. Available at: <https://corporate.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-unveils-first-of-its-kind-plan-to-provide-safe-clean-reliable-and-af-MC476LD6J74VGYNG7EINQSDBOPOE>.

<sup>106</sup> Oregon Department of Environmental Quality. December 22, 2021. *Climate Protection Program Brief*. Available at: <https://www.oregon.gov/deq/ghgp/Documents/CPP-Overview.pdf>.



- The Oregon PUC rejected all three gas utilities' long-term plans due to their overly optimistic assumptions about future gas demand and failure to align with state policies.

#### **Accelerated Pipe Replacement Programs**

- No notable findings.

#### **Alternatives to Natural Gas**

- No notable findings.

#### **Line Extension Policy**

- The Oregon PUC ordered Avista and NW Natural to gradually eliminate residential line extension allowances by 2027.

### **9.3. EXISTING ANALYSIS**

#### **9.3.1. DOCKET NO. UM 2178G-999/CI-21-566**

In response to the CPP, the Oregon Public Utility Commission conducted a Natural Gas Fact Finding process.<sup>107</sup> The PUC described the purpose of this process as twofold: “The first was to conduct an initial analysis of the potential ratepayer bill impacts from the limiting of natural gas utilities’ GHG emissions under the [Department of Environmental Quality’s] CPP. The second was to identify appropriate regulatory tools to mitigate potential customer impacts and accommodate utility action.”

In the Fact Finding process, each of Oregon’s three gas utilities presented modeling results showing different pathways to decarbonization with different rate and utility impacts. Scenarios included cases with restricted access to RNG, declining customer counts, technological innovation, and no access to low-cost, state-level carbon credits. The PUC staff identified that rigorously vetted assumptions on a wide range of topics would be required for future integrated planning aimed at least cost and least risk pathways.

The PUC used the Fact Finding to identify a host of regulatory tools to use in managing energy transition for gas utilities. These tools include planning, programs, and ratemaking. For example, in the near term, the PUC staff recommended the development of maps with infrastructure age and depreciation information, analysis of demand-side and non-pipe options provided by IRPs, targeted energy efficiency programs to low-income and energy justice communities, and coordination of electrification assumptions between electric utility distribution planning and gas utility resource planning.

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<sup>107</sup> Oregon Public Utility Commission. “Utility Regulation: Natural Gas Fact Finding.” Available at: <https://www.oregon.gov/puc/utilities/Pages/EO-20-04-UP-FactFinding.aspx>.

### 9.3.2. FUTURE ANALYSIS

Oregon's three largest gas utilities – Northwest Natural (NWN),<sup>108</sup> Cascade,<sup>109</sup> and Avista<sup>110</sup> – filed integrated resource plans (IRPs) in 2023. The NWN IRP was developed during the time of the Fact Finding, and it does not reflect the full integrated analysis that the Fact Finding identified as a key component of the utility and regulatory response to decarbonization. However, Cascade and Avista's IRPs were developed after the release of the Natural Gas Findings of Fact report. The PUC rejected all three IRPs due to overly optimistic assumptions about future gas demand and failure to align with state policies.<sup>111</sup> In general, the proposed IRPs focused heavily on alternative fuels and less so on electrification.

### 9.3.3. LINE EXTENSION POLICY

The Oregon PUC has been addressing the issue of line extensions in the context of individual utility rate cases. In Order 24-359, the PUC ruled for NW Natural to gradually decrease the line extension allowance offered to residential customers and phase out line extension allowances entirely by 2027.<sup>112</sup> The PUC issued a similar order for Avista in 2023.<sup>113</sup> No order has been issued yet for Cascade.

## 10. CALIFORNIA

*California has set an economy-wide target for net-zero emissions by 2045. As part of this achievement, it would lower GHG emission by 85 percent below 1990 levels. The state's 2022 Scoping Plan for Achieving Carbon Neutrality<sup>114</sup> lays out a pathway for all-electric new construction beginning in 2026 (residential) and 2029 (commercial). All residential appliance sales would be electric by 2035 and by 2045 in*

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<sup>108</sup> In the Matter of Northwest Natural Gas Company d/b/a NW Natural 2022 Integrated Resource Plan, LC 79, September 23, 2022, available at: <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23476>.

<sup>109</sup> In the Matter of CASCADE NATURAL GAS CORPORATION'S, 2023 Integrated Resource Plan, LC 83, June 2, 2023, available at: <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23650>.

<sup>110</sup> In the Matter of Avista 2023 Natural Gas Integrated Resource Plan, LC 81, March 31, 2023, available at: <https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23640>.

<sup>111</sup> Alex Baumhardt, Oregon Capital Chronicle, "All gas utilities in Oregon fail to gain approval for plans on meeting state's climate goals," March 15, 2024, available at: <https://www.ijpr.org/environment-energy-and-transportation/2024-03-15/all-gas-utilities-in-oregon-fail-to-gain-approval-for-plans-on-meeting-states-climate-goals>.

<sup>112</sup> In the Matter of Northwest Natural Gas Company d/b/a NW Natural Request for a General Rate Revision, Order 24-359, October 25, 2024, available at: <https://apps.puc.state.or.us/orders/2024ords/24-359.pdf>.

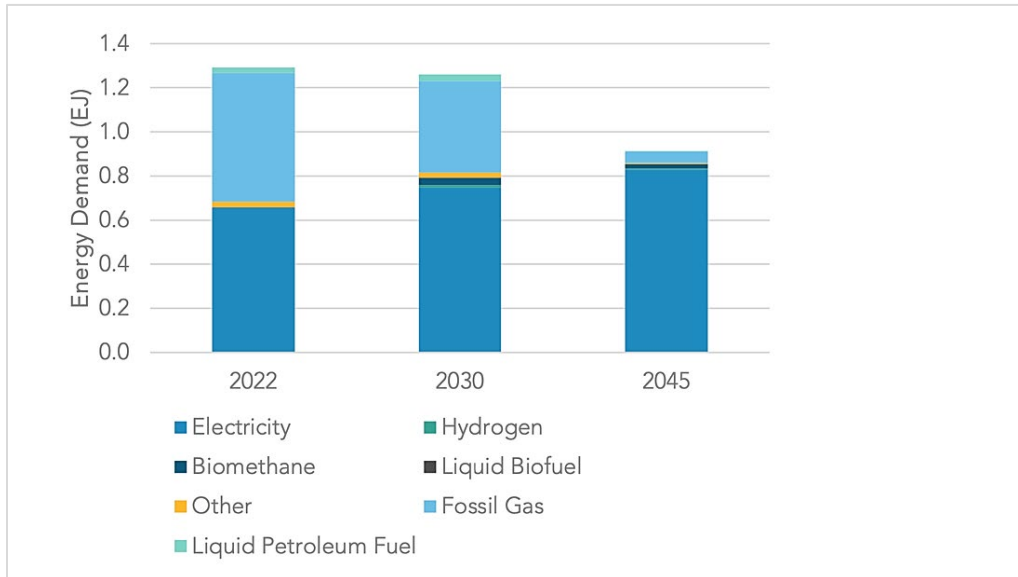
<sup>113</sup> In the Matter of Avista Corporation d/b/a Avista Utilities Request for a General Rate Revision, Order 23-384, October 26, 2023, available at: <https://apps.puc.state.or.us/orders/2023ords/23-384.pdf>.

<sup>114</sup> California Air Resources Board. Nov. 16, 2022. *2022 Scoping Plan for Achieving Carbon Neutrality*. Available at: <https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp.pdf>.



commercial buildings. Industrial demand would be partially electrified and partially use carbon capture and sequestration.

Figure 1. Final energy demand in buildings in 2022, 2030, and 2045 in Scoping Plan Scenario



Source: Reproduction of building sector energy demand results from California’s 2022 Scoping Plan for Achieving Carbon Neutrality.

## 10.1. KEY REGULATORY PROCEEDINGS

- **R.19-01-011:** Proceeding to address building decarbonization following the passage of Senate Bill 1477.
- **R.20-01-007:** Proceeding to establish policies, processes, and rules to ensure safe and reliable gas systems in California and to perform long-term gas system planning
  - a. Track 1: reliability standards and coordination between gas utilities and gas-fired electric generation
  - b. Track 2: long-term gas policy and planning
    - Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals (Dec 21, 2022)
- **R.24-09-012:** Rulemaking to address unresolved issues from R.20-01-007 and make decisions on long-term gas planning.
  - a. Track 1: Interim actions
  - b. Track 2: long-term gas transition planning
  - c. Track 3: SB 1221 Implementation

## 10.2. ACTIONS ON KEY ISSUES

### Gas Planning

- R.20-01-007 and R.24-09-012 address near-term and long-term considerations for gas planning such as future gas demand, alternative investments, data collection and reporting requirements, and integrated energy planning.

### Accelerated Pipe Replacement Programs

- Senate Bill No. 1221 requires each gas utility to annually file a map showing its planned gas distribution replacement projects and locations of disadvantaged communities within its service territory, beginning July 2025.

### Alternatives to Natural Gas

- PG&E has successfully converted 105 customers and disconnected them from the gas system, resulting in the decommissioning of 22 miles of transmission pipe.<sup>115</sup>
- PG&E's Zonal Equity Electrification pilot program identifies low-income neighborhoods well-suited for electrification using a geospatial mapping tool.

### Line Extension Policy

- California eliminated line extension allowances for all customers, effective July 2023.
- California eliminated subsidies for combined gas and electric hookups, effective May 2024.

## 10.3. EXISTING ANALYSIS

### 10.3.1. THE CHALLENGE OF RETAIL GAS STUDY

The California Energy Commission (the state's energy policy agency) commissioned a study entitled *The Challenge of Retail Gas in California's Low Carbon Future*, prepared by E3 and published in April 2020.<sup>116</sup> This report describes the technology options available for decarbonizing the end uses served by fossil natural gas today, including biomethane, hydrogen and synthetic methane, and electrification. The

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<sup>115</sup> Rocky Mountain Institute, "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization," May 2024, page 11, available at: [https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI\\_NG-May-2024.pdf](https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf).

<sup>116</sup> Aas, Dan, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, and Snuller Price. 2020. *The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use*. California Energy Commission. Publication Number: CEC-500-2019-055-F. Available at: <https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf>.

study was scoped prior to California’s net-zero 2045 target, so it examines pathways to 80 percent reductions in GHGs by 2050. Nonetheless, the general implications of its results carry over to the contemporary policy context.

The E3 report identifies challenges for the retail natural gas system driven by the high costs associated with either of the two prominent pathway approaches. Pathways that depend on non-fossil gases have high retail gas rates because of the cost of the fuels. Pathways that depend on electrification have high retail gas rates because reductions in throughput increase the per-unit cost to deliver gas to customers. E3 concludes that “the no building electrification scenario is unlikely to represent a stable, internally consistent future” because non-fossil gas blending “will lead to steady improvements in the economics of building electrification.”<sup>117</sup> The report then takes an important next step and examines the regulatory and policy options to mitigate the challenges associated with moving to a largely electrified building stock.

The E3 report describes the underlying dynamic of the feedback loop between gas throughput reductions and higher gas rates and highlights that: “maintaining reasonable gas rates becomes imperative because of the substantial equity concerns that could follow from a world in which the wealthy are more likely to be able to electrify, or to afford paying higher gas costs if they do not, but low- and middle- income households are less able to do so.”<sup>118</sup> E3 identifies that the financial viability of gas utilities is essential in order to meet both equity and safety objectives. The report describes the components of a strategy to maintain gas utility viability and advance equity in the face of energy transition:

- Reduce barriers to electrification
- Avoid gas system expansion
- Reduce costs of the existing gas system, such as through geographically targeted electrification and retirement of the gas system
- Accelerate depreciation
- Change cost allocation
- Recover gas system costs on the bills of electric ratepayers or other additional funds from outside the gas system
- Shut down uneconomic gas infrastructure built to serve building loads

The report includes quantitative analysis of how combinations of these components could allow the gas system to transition without creating undesirable safety or equity outcomes. For example, Figure 2 shows analysis of a combination of cost reductions and accelerated depreciation (red wedge) and

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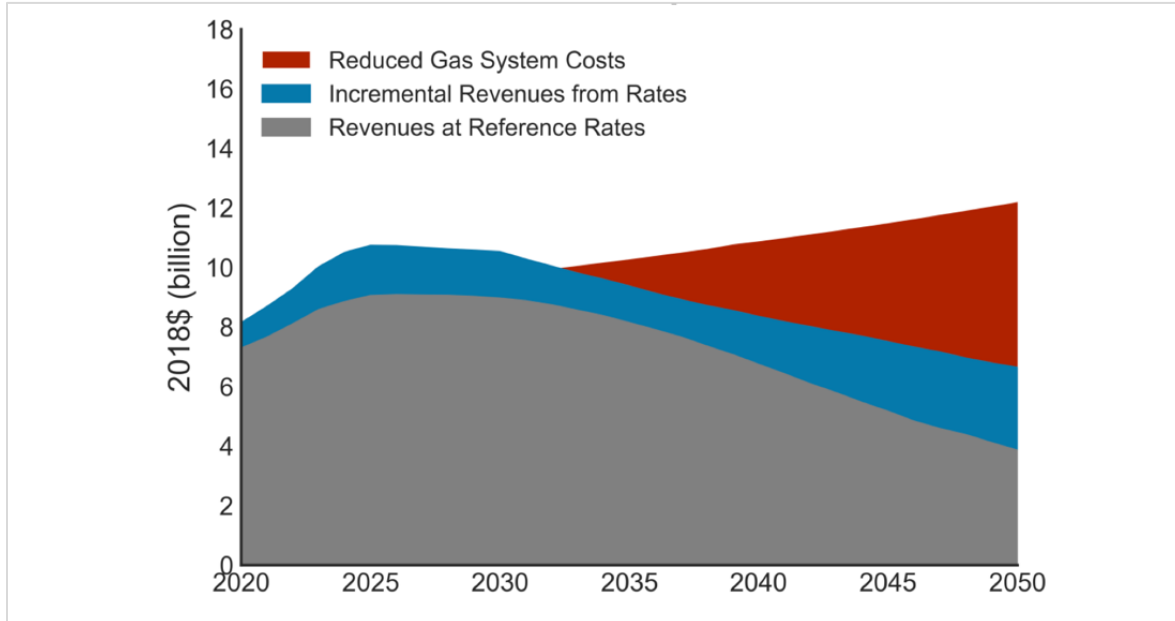
<sup>117</sup> Id., p. 56.

<sup>118</sup> Id., p. 57.



modest rate increases (blue area) to enable a successful transition. E3 modeled scenarios with and without these mitigating strategies and showed the moderating impact on rates.

**Figure 2. Revenue requirement with intensive reductions and accelerated depreciation**



Source: Reproduction of figure from E3, *The Challenge of Retail Gas in California’s Low Carbon Future*, showing combination of utility strategies to manage energy transition. E3 Notes: “The red wedge shows the cost savings associated with gas system cost reductions and accelerated depreciation. The blue wedge shows incremental revenue collected through gas rates. The blue wedge increases revenues substantially in the near term, but doing so enables deeper cost savings in the future than can be achieved by reduced reinvestment alone.”

### 10.3.2. CPUC RULEMAKING R.20-01-007 AND BEYOND

Track 2 of California Public Utilities Commission (CPUC) Rulemaking R.20-01-007 is intended to address “Gas Infrastructure; Safety; Data; Process; Gas Revenues and Rate Design; and Workforce Issues” through the development of a long-term planning strategy. This rulemaking process included workshops on gas infrastructure planning and equity. The summary reports on these workshops provide a snapshot of the proceeding in action. The gas infrastructure workshops covered topics essential to infrastructure decision-making: when to repair, replace, or retire transmission and distribution lines; the importance of meeting the needs of hard-to-electrify customers; the role of storage; and the obligation to serve.<sup>119</sup> The equity workshop addressed: landlord-renter issues, issues specific to disadvantaged homeowners,

<sup>119</sup> CPUC. *R.20-01-007 Track 2 – Gas Infrastructure: Final Workshop Report*. July 7, 2022. Available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/final-track-2-january-workshop-report---20220707.pdf>.

and the importance of limiting gas rate increases during the transition.<sup>120</sup> This final panel explicitly discussed accelerated depreciation and units-of-production based depreciation as a way to recover more costs while more customers remain on the gas system.

Following the workshops, the CPUC took action related to the issues raised in these processes. First, it established a new process for the review of large gas system investments that is more closely aligned with the system it uses to review investment on the electric system. Second, CPUC staff put out for discussion a proposed distribution infrastructure decommissioning framework. Staff proposed dividing California's gas-served areas into five tranches to guide the order of system decommissioning:

- 1) high-benefits early adoption (areas with the most air quality challenges and greatest opportunity for ratepayer savings)
- 2) market transition (areas prioritized by high burdens, high pipeline risk, high ratepayer savings, and feasibility)
- 3) medium-term electrification (continuing the trend from tranche 2 with medium levels of key criteria)
- 4) market rate electrification (areas with lower-than-average need and benefits from decommissioning; aim for customers to electrify at market rates or with standardized approaches)
- 5) difficult-to-electrify customers and long-term electrification (the remainder, including large hard-to-electrify customers and areas with high potential for biomethane)

The CPUC received numerous comments on staff's proposal in February and March 2023.

### ***NPA Assessment***

The PUC's Decision Adopting Gas Infrastructure General Order in December 2022 established requirements for utilities to consider NPAs for projects greater than \$50 million. Projects of this size require utilities to submit a certificate of public convenience and necessity (CPCN) application, which must now include an analysis of NPAs considered for the project. An NPA analysis must include information about the type of customers to be served by the proposed project, an estimate of the environmental and health impacts of the project, and as well as the direct costs of the project.<sup>121</sup> This information should be used to determine whether the alternative measure(s) could be accomplished at a lower cost and/or with lesser environmental impact than the proposed project.

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<sup>120</sup> CPUC. *R.20-01-007 Track 2 – Gas Infrastructure Workshop 3: Equity Workshop Final Workshop Report*. July 7, 2022. Available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/final-equity-workshop-report---20220707.pdf>.

<sup>121</sup> CPUC, Decision Adopting Gas Infrastructure General Order, Decision 22-12-021, R.20-01-007, December 1, 2022.



### **R.24-09-012**

Many issues remain unresolved in Rulemaking 20-01-007. In September 2024, the Commission proposed a new Order Instituting Rulemaking that would close R20-01-007 and take up unresolved issues and new issues related to the future of gas in a new rulemaking, R.24-09-012.<sup>122</sup> The proposed scope of R.24-09-012 includes three phases. The first phase identifies interim actions to support the energy transition including considerations about how to implement NPAs. The second phase is focused on long-term planning and is broken down into two tracks: track one addresses foundational data and analytical needs; track two addresses utility planning processes and scenario development. The third phase is focused on implementation with two separate tracks: track one addresses system mapping requirements; track two addresses prioritizing neighborhood decarbonization.

### 10.3.3. R.19-01-011 LINE EXTENSION POLICY

In California's Rulemaking 19-01-011, the PUC ruled to eliminate gas line extension allowances for all customer classes and refunds and discounts that further incentivize line extensions.<sup>123</sup> The following year, the PUC eliminated subsidies for mixed-fuel (electric and gas) hookups for new construction. This Decision removes incentives for new gas connections and encourages new all-electric buildings.

### 10.3.1. SENATE BILL NO. 1221

Approved by Governor Newsom in September 2024, Senate Bill 1221 (SB 1221) requires gas utilities to file a map annually that shows all planned gas distribution replacement projects and the locations of disadvantaged communities within their service territories.<sup>124</sup> The bill also enables utilities to launch up to 30 zonal decarbonization pilot projects, and authorizes utilities to cease the obligation to serve after the implementation of these pilot projects if the Commission finds that an adequate gas substitute is available to meet the needs of all affected customers.<sup>125</sup> Pacific Gas & Electric created a gas asset mapping tool at the granularity of individual pipe segments and meters used to identify areas where targeted electrification and pipe decommissioning is most feasible.<sup>126</sup>

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<sup>122</sup> CPUC, *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking 24-09-012, January 31, 2025, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M555/K960/555960635.PDF>.

<sup>123</sup> CA PUC, Decision 22-06-026, R.19-01-011, September 15, 2022.

<sup>124</sup> California Senate Bill No. 1221, September 25, 2024, available at: [https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill\\_id=202320240SB1221](https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB1221).

<sup>125</sup> California Senate Bill No. 1221, September 25, 2024, available at: [https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill\\_id=202320240SB1221](https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB1221).

<sup>126</sup> Energy and Environmental Economics, *Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California*, Interim Report, June 2023, available at: <https://gridworks.org/wp-content/uploads/2023/06/Evaluation-Framework-for-Strategic-Gas-Decommissioning-in-Northern-California-Interim-Report-for-CEC-PIR-20-009.pdf>.

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of  
**CONSUMERS ENERGY COMPANY** for  
authority to increase its rates for the  
distribution of natural gas and for other relief.

U-21806

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**PROOF OF SERVICE**

On the date below, an electronic copy of **Direct Testimony and Exhibits of Dr. Sol deLeon on behalf of Michigan Environmental Council and Sierra Club (Exhibit MEC-14 through MEC-15)** was served on the following:

<b>Name/Party</b>	<b>E-mail Address</b>
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The statements above are true to the best of my knowledge, information and belief.

TROPOSPHERE LEGAL, PLC  
 Counsel for MEC & SC

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