STATE OF MAINE
PUBLIC UTILITIES COMMISSION

PUBLIC UTILITIES COMMISSION **RE: Inquiry Regarding the Future of Natural Gas** **Docket No. 2025-00145**	**COMMENTS OF ACADIA CENTER, CONSERVATION LAW FOUNDATION, AND SIERRA CLUB** **September 4, 2026**

Acadia Center, Conservation Law Foundation, and Sierra Club respectfully submit the following comments in response to the Maine Public Utilities Commission's ("Commission") August 6, 2026 Procedural Order setting forth a Staff Straw Proposal ("Straw Proposal").

I. Introduction and Description of Straw Proposal

The Straw Proposal covers two potential new requirements for gas utilities:

1. A framework outlining minimum filing requirements for gas utility applications ("Gas Proposal Framework"). At a minimum, Staff has proposed that this framework would apply to gas supply contracts. The proposed framework would require the following analyses of a utility-proposed contract or project and at least one alternative: greenhouse gas ("GHG") emissions impacts, rate impacts, reliability and operational impacts, demand forecasts (including the impact of beneficial electrification on gas demand), project economics, technical feasibility, and equity and environmental justice.

2. A requirement to file an integrated resource plan ("IRP") every five years. The IRP would need to include a 10-year demand forecast under a range of alternative scenarios, an assessment of demand-side management programs, an assessment of supply options, an assessment of the infrastructure necessary to reliably meet forecasted demand, an assessment of non-pipeline alternatives, and "actionable steps to demonstrate the plan's integration and consistency" with the state's greenhouse gas targets.

In addition to seeking comment on the straw proposal generally, the Commission invites comment on two specific questions:

1. Whether the filing requirements framework should apply to all gas cases, gas supply contract cases only, or some other set of gas cases; and
2. Whether gas utilities should be required to file IRPs every 3 years, consistent with Docket Nos. 2005-00087 and 2005-00273, or every 5 years consistent with New Hampshire's IRP requirement.

We begin by addressing the Commission's two questions, then provide constructive comment aimed toward increasing the specificity of the proposed requirements, accounting fully for emissions impacts, and enabling stakeholder engagement in the IRP process.

II. Straw Proposal Questions

1. Applicability of Framework

We recommend the Commission presume the framework apply to all gas-related cases rather than only gas supply cases. Several of the components of the framework, including alternatives analysis, GHG impacts, rate impacts, project economics, technical feasibility, and equity, are equally applicable to other types of proceedings such as requests for cost recovery of gas capital expenditures in rate cases. Moreover, the Commission's duty to advance the state toward its decarbonization targets behooves it to consider these implications wherever applicable. While not every component of the framework may apply to every proceeding, the gas utility should bear the burden of demonstrating which if any components are not applicable when it files its application.

2. Cadence of IRP Filings

We recommend that the Commission require gas utilities to file IRPs every two to three years. While a five-year cadence would align with New Hampshire requirements, we are concerned that this would not be sufficient to give the Commission meaningful forward-looking review of projects in the later part of the five-year window. Gas utility projects are often scoped fewer than five years in advance. Our experience in other jurisdictions with more frequent gas planning filings has shown that the set of planned projects can change meaningfully from filing to filing, in just two to three years. These considerations are more compelling than reducing the workload for the gas utilities, which could seek to align New Hampshire's requirements with Maine's to avoid duplicative efforts.

As a recent example, Xcel's Colorado utility included multiple projects in its 2023 Gas Infrastructure Plan for the 2027-2029 period that it subsequently removed from its 2025 Gas Infrastructure Plan.[1] Meanwhile, Xcel's 2025 Gas Infrastructure Plan added the $45 million Speer Canal starting in 2025, which was not included in the 2023 Plan.[2] A five-year filing cadence would not have captured these changes, making it more likely that projects would proceed without the opportunity for forward-looking Commission review. To ensure that project changes such as these are captured in Maine utilities' IRPs, we recommend a shorter cadence of two to three years.

[1] *See* Colorado PUC Proceeding No. 23M-0234G, Decision No. C24-0092, para. 126, discussing the Fort Lupton Compressor Station and Mead to East Longmont capacity expansion projects. See also the Interim Report filed by Public Service Company of Colorado on May 1, 2024 at page 18-20 in the same docket, which discusses that revised forecasts obviated the need for both projects.

[2] Colorado PUC Proceeding No. 25A-0220G, Hrg. Exh. 101, Attachment JJP-1 at 93.

III. General Comments on Framework/Guidelines for Evaluating Long-Term Gas Proposals

We support the Commission's adoption of a framework for evaluating gas proposals and decision-making, and appreciate and agree with several components of staff's Gas Proposal Framework. However, we recommend several amendments to strengthen the framework to ensure the Commission's gas docket analyses comport with its decarbonization directives. Foremost is an overarching observation: culmination of this process in "non-binding recommendations"[3] would provide utilities too little oversight and the Commission too little authority to fulfill its statutory roles. We urge the Commission to formally adopt filing requirements to ensure utility compliance. Below, we provide additional constructive feedback on various elements of the Gas Proposal Framework, largely aimed at providing clarity around the filing requirements for utility projects and proposals.

1. Process for Establishing a Robust Non-Pipes Alternative (NPA) Framework

The Gas Proposal Framework refers to utility evaluation of "at least one alternative" to a traditional gas system investment in multiple instances. We strongly support the evaluation of non-pipes alternatives (NPAs) as a key mechanism for minimizing ratepayer costs by mitigating the risk of over-indexing on gas system upgrades and expansions in the face of state GHG reduction mandates that necessitate a major shift away from combustion of fossil fuels across the economy. However, utility evaluation of NPAs, without carefully developed parameters, could be an exercise in futility and significantly waste time, effort and resources. We are concerned that requiring evaluation of only one alternative per utility proposal is insufficient, and more generally, we urge the Commission to undertake a stakeholder process to establish a robust NPA framework that ensures adequate evaluation of NPAs against traditional gas system investments.

The recent example of Massachusetts, a near-neighbor to Maine that has already spent several years on its Future of Gas process, should be instructive to the Commission. The Massachusetts Department of Public Utilities ("MA DPU") determined in its Future of Gas docket that

> consideration of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation, is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented. Going forward, the Department states that as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery.[4]

However, despite this direct order from the MA DPU, the state's six gas utilities evaluated over 500 gas alternative projects for 2026 and found, incredulously, that none were

[3] Straw Proposal at 1.
[4] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 20-80-B, Order on Regulatory Principles and Framework (Dec. 6, 2023) at 2.

viable.[5] Jamie Van Nostrand, the MA DPU Chair at the time of Order 20-80-B referred to the utilities' approach to alternative analysis as "grossly inadequate."[6] This highlights the major concern, applicable across states, that if the NPA process is left fully under the control of the utilities it is likely to fail in finding viable NPAs that cost-effectively make progress towards the energy transition required to align with state climate mandates. This is hardly surprising given investment in NPAs directly interferes with utilities' growth-based business models.

The MA DPU's evaluation of the utilities' draft NPA Framework has been integrated into the 2025 Climate Compliance Plan proceedings (MA DPU 25-40 through 25-45), in which a still decision is still pending. Developing a viable NPA Framework is hard work and it takes time; Massachusetts started its NPA Working Group stakeholder process in October 2024, and the NPA Framework is still in draft form. Massachusetts' difficulties in creating an effective NPA framework highlight the urgency of the Maine PUC initiating a robust process to establish a viable NPA Framework as soon as possible that takes important lessons from Maine's neighbor and other states, and avoids duplicating mistakes and wasted time. To best serve Maine, the NPA Framework must be developed with meaningful stakeholder engagement and must not provide the utilities with unfettered rein over the drafting pen.

While a robust analysis of NPAs is essential to minimize the risk of stranded gas assets moving forward, the Straw Proposal lacks specifics on how that NPA evaluation should take place and what it would entail. Indeed, the Straw Proposal appears to allow utilities to evaluate a single alternative, handpicked by them, without additional process or parameters. If past experience in other states is any indicator, this utility-led analysis is destined to reach conclusions favorable to the utility's business: that is, a finding that the NPAs are nonviable. To avoid that outcome, we strongly urge the Commission to undertake a stakeholder process to develop a uniform approach to evaluation of NPAs. We also offer the following suggestions to enhance the NPA assessment within the confines of the Straw Proposal.

The utility should be required to present an NPA analysis for all known pipeline projects anticipated within 10 years of the IRP filing, including but not limited to all individual projects included in the company's infrastructure plan. The Commission should require utilities to present sufficient detail on their NPA evaluations to enable the Commission to verify that the option selected to meet the infrastructure need is least-cost and least-risk compared with alternatives. This information may include:

- The alternatives evaluated for each project. Common non-pipeline alternatives include electrification, efficiency, demand response, and thermal storage.
- Alternatives eliminated from consideration as technically or commercially unviable for the project, if applicable, and a justification for why those alternatives were eliminated from consideration.
- An analysis of technical and market or achievable potential for deployment of demand-side measures within the project area.

[5]https://www.governing.com/infrastructure/massachusetts-communities-went-fossil-fuel-free-utilities-kept-building-gas-lines.
[6] Id.

- A cost-benefit analysis comparing the pipeline infrastructure alternative and the non-pipeline alternative. The Commission should specify the cost test to be used, whether in its IRP rule or elsewhere.
- A justification for the company's preferred project selection.

To mitigate administrative burden, the level of detail provided for smaller NPAs may be more streamlined than the level of detail provided for larger NPAs. For example, for planned gas projects costing less than $1 million, the gas utilities may present an initial cost-benefit screen in spreadsheet format with standardized cost assumptions and perform a more detailed potential analysis and/or cost-benefit analysis for projects that pass the initial screen. This approach mirrors the approach currently required by New York, which allows projects falling below a certain dollar threshold to use an "expedited standardized" NPA review with a "streamlined economic and technical analysis."[7]

Additionally, we recommend that the utilities identify and propose "programmatic NPAs" for certain investment types in their IRPs. A programmatic NPA is a standardized service offering that can be designed in advance (similar to any other demand-side management offering) and extended to customers in lieu of a pipeline project. An example of a programmatic NPA is a service line NPA, which offers customers an enhanced electrification incentive that is less than or equal to the cost of a service line replacement. As an example, ConEd is currently piloting a service line NPA in New York that offers $10,000 in financial incentives for electric appliances for customers with pre-1972 service lines requiring replacement.[8] Other types of programmatic NPAs could target new business requests or meter replacements.

Case Study: NPA Framework in Colorado

Colorado's NPA framework was established through a 2022 gas infrastructure planning regulation, which specifies that gas utilities must evaluate NPAs for new business and capacity expansion projects above a certain threshold (currently set at $3 million for Xcel Energy, Colorado's largest utility). The regulation defines the high-level requirements for the NPA analysis, requiring the utility to specify the clean heat technologies or approaches evaluated and proposed, the projected timeline, the projected feasibility of the alternatives, and a cost-benefit analysis of the NPA against the pipeline investment.[9] A 2025 "M-docket" or informational proceeding decision provides further guidance on load forecasting and cost-benefit analysis as applied to NPAs and pipeline projects.[10]

Pursuant to the Colorado rules, Xcel has filed two Gas Infrastructure Plans ("GIP") to date, one in 2023 and one in 2025. These plans analyzed a total of eight potential NPAs across the two proceedings. Of the eight NPAs analyzed, two have been approved for implementation,

[7] New York PSC Case 20-G-0131 and 12-G-0297, Order Adopting Gas System Planning Process, May 12, 2022, at 37-38.
[8] Joe Dammel, Jack Teener, Olivia Prieto, and Mike Henchen, 2025, "Service Line NPAs: Unlocking Savings and Driving Electrification," https://rmi.org/resources/service-line-npas-unlocking-savings-and-driving-electrification/.
[9] Colorado Code of Regulations, 4 CCR 723-1, Rule 4552(c)(I)(P).
[10] Colorado PUC Proceeding No. 24M-0261G, Decision No. R25-0083

both proposed in Xcel's earlier 2023 GIP.[11] Due to the cost-benefit assumptions used in the 2025 GIP, Xcel did not find any NPAs to be cost-effective in its 2025 application.

Based on the Sierra Club's experience as an intervenor in the 2022 Colorado GIP rulemaking, the 2023 Xcel GIP proceeding, and the 2025 Xcel GIP proceeding, we have observed the following best practices, which we recommend applying to the proposed NPA process in Maine:

- **The Commission should workshop and promulgate specific guidelines on screening and cost-benefit analysis for NPA analyses.** The Colorado PUC has issued prescriptive direction to Xcel on forecasting and cost-benefit analysis across multiple proceedings. The Commission conducted an informational proceeding between Xcel's 2023 and 2025 GIP filings to solicit stakeholder input on forecasting and cost-benefit analysis for NPAs. Notably, this stakeholder process was led by the Commission rather than the utilities themselves. The PUC's 2025 decision in the informational proceeding specifies how Xcel should calculate the capital cost and rate impact of pipeline investments, calculate participant costs of NPAs, and project marginal electric system capacity required for NPAs.[12] While the Commission has since expressed frustration over Xcel's lack of adherence to these directives in the 2025 GIP,[13] the Colorado PUC's prescriptiveness has preempted the practice that we have observed from gas utilities in other jurisdictions, wherein the utilities eliminate large lists of capital projects from consideration for NPAs with little to no explanation or analysis.[14]

- **The Commission should not impose overly high or restrictive project thresholds or preemptively restrict NPA analyses to specific project categories.** The Colorado PUC's 2022 rules limited NPA analyses to new business and capacity expansion projects exceeding a threshold of $3 million for Xcel. Following the 2023 Xcel GIP, the Colorado PUC expressed its concern that these criteria were overly limiting and "would prevent the development of alternatives analysis in a way that meets future system realities," expressing an intent to expand NPAs to system safety and integrity projects, which comprised a majority of Xcel's capital plan.[15]

- **The Commission should adopt a programmatic approach to NPAs for specific project categories (e.g., service lines).** A programmatic NPA approach, as noted elsewhere, is a standardized service offering that can be designed in advance and extended to customers in lieu of a pipeline project. It is ideal for smaller, standardized types of pipeline projects where undergoing a full NPA analysis would be overly burdensome. The Commission's 2025 GIP decision directed Xcel to propose a service

[11] Colorado PUC Proceeding No. 23M-0234G, Decision No. C24-0092, p. 47.
[12] Colorado PUC Proceeding No. 24M-0261G, Decision No. R25-0083, pp. 40-53.
[13] Colorado PUC Proceeding No. 25A-0220G, Decision No. C26-0371, p. 53.
[14] For example, National Grid's most recent Gas Rate Case in Massachusetts analyzed more than 6,000 planned projects for NPA potential and eliminated all of them from consideration with little explanation or supporting evidence. See Massachusetts DPU Docket 26-50, Exh. SC-CLF-MF at 39.
[15] Colorado PUC Proceeding No. 23M-0234G, Decision No. C24-0092, p. 39.

line NPA pilot in subsequent proceedings.[16]

2. GHG Analysis

As stated above, we urge the Commission to require GHG analysis and other framework components for *all* gas utility proposals unless the utility demonstrates that components of the framework are not applicable.

The Commission should require an analysis of all Scope 1, 2, and 3 emissions resulting from the proposal *and its alternatives.* From the perspective of a utility, scope 3 emissions entail all emissions associated with gas customer combustion of natural gas, and thus, represent the vast majority of emissions associated with the gas distribution system in Maine. The Legislature imposed on the Commission an obligation to align with Maine's GHG mandates, requiring it to "facilitate [the mandates'] achievement" while "executing its duties, powers and regulatory functions . . . [and] while ensuring system reliability and resource adequacy."[17] To further ensure the Commission treated this new duty on par with its historic obligations, the Legislature amended the Commission's very purpose, requiring it to "reduce greenhouse gas emissions to meet the greenhouse gas emissions reduction levels" while regulating public utilities.[18] Thus, the Commission's assessment of GHG emissions must not be undertaken in isolation, but rather, in view of compliance with the state's overarching GHG mandates and strategy for achieving them, including by decarbonizing buildings by electrification. Given these legal directives, it is essential that the Commission consider scope 3 emissions associated with combustion of gas by customers when reviewing the prudency of utility proposals. The gas utilities must be required to track and report on Scope 3 emissions resulting from their distribution systems so that such emissions can be considered by the Commission.

Maine's policymakers have prioritized electrification as the state's building decarbonization pathway in planning documents, regional agreements, and allocation of funding. This choice must inform the Commission's analysis of the future of gas use in Maine. Maine's Climate Plan,[19] most recently updated in November 2024, is the state's foremost climate planning document.[20] To combat the building sector's significant GHG contributions, the Climate Plan sets aggressive building electrification targets, including a target of 481,000 homes in Maine being fully electrified with heat pump heating systems by 2050 to comply with Maine's Climate Law.[21] Understanding how Maine will achieve those levels of electrification entails a closer look at Evolved Energy Research's analysis of "future pathways to meet Maine's gross

[16] Colorado PUC Proceeding No. 25A-0220G, Decision No. C26-0371, p. 72.
[17] 35-A M.R.S. § 103-A.
[18] *Id.* § 101.
[19] Maine Climate Council, *Maine Won't Wait, A Four-Year Plan for Climate Action* (Nov. 2024) ("Climate Plan").
[20] 38 M.R.S. § 577(1) ("By December 1, 2020, and every 4 years thereafter, the Maine Climate Council, as established in section 577-A and referred to in this section as "the council," with input from stakeholders, shall update the state climate action plan under this section and shall include in the plan strategies to meet the greenhouse gas emissions reduction levels specified in section 576-A."); *see also* Climate Plan at 11 ("this updated report to the Governor, Legislature, and people of Maine will now serve as a roadmap to advance Maine toward its climate goals for the next four years.").
[21] Climate Plan at 57, 172.

greenhouse gas emissions targets," conducted to support the 2024 Climate Plan.[22] The state's consultant's assumptions underlying the 2030 and 2050 heat pump deployment numbers foretell a trajectory away from fossil fuels for heating and toward 100% electrification in the residential and commercial spaces, and specifically call out that all heating system sales, both for residential and commercial space heating, are 100% heat pumps by 2035.[23]

A separate Maine report produced simultaneously to the 2024 Climate Plan doubles down on widespread building electrification. The Governor's Energy Office retained The Brattle Group and Evolved Energy Research to conduct modeling and technical analysis to "inform an updated State Energy Plan that will ensure affordable, reliable, and clean energy that supports the growth of Maine's economy while meeting greenhouse gas (GHG) emissions reduction requirements and supporting communities across Maine."[24] The culminating "Pathways Report" acknowledges that "over the coming decades most furnaces and boilers will need to be replaced over time with efficient electric heat pumps."[25] In the "Core Pathway" modeled, "electrification greatly reduces the consumption of fuels such as gasoline, diesel, heating oil, propane, and pipeline natural gas. . . . Pipeline natural gas demand decreases from about 19 trillion BTU in 2023 to 7 trillion BTU in 2040 and 2 trillion BTU in 2050."[26] **In other words, the Core Pathway envisions the volume of pipeline gas delivered to buildings in Maine decreasing approximately 90% by 2050.**

In the context of the Straw Proposal, there is a fundamental difference between projects that marginally reduce building sector emissions and projects that are aligned with decreasing building sector emissions at the pace and scale required to meet the state's GHG emission mandates. For example, a gas system expansion project that enables the conversion of a number of homes from oil heating to natural gas heating marginally reduces building sector emissions but is misaligned with both the State's heating electrification goals, as described above, and therefore GHG reduction mandates.

As suggested in our June 2025 comments, the Commission should conduct a decarbonization pathways analysis for Maine premised on the Climate Plan and Pathways Report building electrification targets as well as the underlying assumptions showing 100% electric heat pump sales for heating and water heating in the residential and commercial sectors by 2035 (space heating) or 2040 (water heating), and the modeling informing the Pathways Report. From there, the Commission should develop a trajectory for limiting growth of (and phasing out, as necessary) gas systems to comport with the electrification needs. Once the Commission has identified such a trajectory, it can evaluate future natural gas decisions for consistency with that trajectory and therefore the state's GHG emission reduction mandates.

If the Commission does not have the funding and/or staff bandwidth to commit to this type of modeling effort, it should instead rely on the most recent modeling conducted as part of

[22] Climate Plan at 175.
[23] Evolved Energy Research, Prepared for Maine Governor's Office of Policy Innovation and the Future, Maine Climate Council Emissions Modeling Results and Assumptions (Nov. 13, 2024) at 8.
[24] The Brattle Group, Evolved Energy Research, prepared for Maine Governor's Energy Office, Maine Pathways to 2040: Analysis and Insights (Jan. 2025), at vi.
[25] *Id.*
[26] *Id.* at 26.

Maine's Climate Plan and the Pathways Report, both discussed above, that, respectively, show 84% of homes in the state fully electrified by 2050, 100% heat pump sales in the commercial building sector by 2035, and a 90% decrease in the volume of pipeline gas delivered to buildings in Maine by 2050. In other words, utility proposals should not be evaluated on the basis of whether a marginal emissions reduction will be achieved, but rather if the proposal is aligned with the most cost-effective trajectory to achieving the state's GHG emission mandates and Maine's most recent economy-wide modeling articulating the overarching building decarbonization vision.

To that end, as emphasized above, focusing on scope 1 or 2 emissions is far too narrow an inquiry. Without considering scope 3 emissions (like the Mass DPU requires of gas utility Climate Compliance Plans[27]), the Commission will be unable to fulfill its role in ensuring the gas utilities under its jurisdiction are advancing their businesses to comport with the state's GHG reduction mandates. Furthermore, we disagree with Staff's assessment that "a capacity or supply project is unlikely to cause changes to consumer behavior or usage."[28] Supply and capacity projects are likely to facilitate higher Scope 3 emissions than demand-side alternatives, particularly when those projects are associated with expansion of the gas distribution system. Non-pipeline alternatives like beneficial electrification and energy efficiency, on the other hand, can reduce Scope 3 emissions relative to the pipeline infrastructure option. A sole focus on Scope 1 and 2 emissions for capacity and supply projects would overlook the Scope 3 emissions benefit of potential alternatives, which are likely to be greater in magnitude than the Scope 1 and 2 emissions impacts.

3. Demand Forecasts

We appreciate Staff's recommendation that the utility must provide a demand forecast under multiple alternative scenarios, including at least one that considers beneficial electrification. We recommend that the utility be required to file, at a minimum, a High, Medium, and Low demand scenario. We also recommend adding additional detail on how the utilities must consider electrification, including:

- The Base or Reference case scenario should incorporate the effects of current laws, policies, and programs that require or incentivize beneficial electrification. These policies include, at a minimum, building codes; building performance standards; appliance standards; and federal, state, local, and utility program incentives for beneficial electrification.

- The modeled scenarios should be consistent with Maine's long-term greenhouse gas mandates requiring a 45% reduction in gross GHG emissions by 2030, an 80% reduction in gross GHG emissions by 2050, and net-zero emissions by 2045, including Maine's most recent Climate Plan and Pathways Report. As discussed above, absent additional decarbonization pathways modeling conducted by the Commission, a demonstration of consistency with these overarching state emissions mandates should be aligned with the

[27] The Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 20-80-B, Order on Regulatory Principles and Framework (Dec. 6, 2023) at 134.
[28] Staff Straw Proposal at 2.

Climate Plan-modeled finding of 84% of homes in the state fully electrified by 2050 and the Pathways Report modeled finding of a 90% decrease in the volume of pipeline gas delivered to buildings in Maine over the next ~25 years. This will ensure that the gas distribution system, and the broader building sector, is doing its fair share in contributing to overarching state emissions reduction mandates.

- Forecasts should be geographically disaggregated where applicable, in order to incorporate the impacts of local policies that may apply to a portion of a utility's service territory.

Additionally, we agree with Staff's recommendation that for proposals associated with gas system expansion, the utility must assess options for demand-side alternatives. We further recommend that this requirement explicitly apply to *all* elements of the framework; in other words, for all system expansion projects, the utility must incorporate at least one feasible demand-side alternative into its GHG Analysis, Rate Impact Analysis, Reliability Analysis, Project Economics Analysis, Technical Feasibility Analysis, and Equity and Environmental Justice Analysis. If there are no feasible demand-side alternatives, the utility should explain why not. The specifics of this process should be fleshed out in significantly more detail through a robust, stakeholder-driven NPA Framework development process as discussed above in our comments.

4. Project Economics

We agree with Staff's recommendations in this section of the Straw Proposal. We further recommend that for this element of the framework, the utility should apply a cost-benefit test to compare the selected project against alternatives. As mentioned in the NPA section above, we recommend the Commission specify the cost-benefit test the utility must run. The inputs and results of the cost test should be provided in executable format with the utility's application. In addition to the components that Staff has identified, we recommend that the cost analysis include:

- A comparison of the annual and total revenue requirement that must be collected to recover the project as compared with alternatives under at least two depreciation scenarios: the current depreciation scenario and a scenario that depreciates all pipeline assets by 2050.

- Consideration of the net salvage that must be collected to decommission the project, compared with alternatives.

Finally, we recommend clarifying that the stranded cost analysis should analyze the undepreciated balance of the proposed asset and alternatives after 2050 under the current depreciation scenario. To satisfy this requirement, it is not sufficient for the gas utility to simply say that it does not anticipate customer exits during the proposed asset's lifetime. Rather, the stranded cost analysis should assess risk across the range of possible futures, including at least one scenario where customer exits occur in line with Maine's climate mandates, Climate Action Plan, and supportive modeling and planning showing the states beneficial electrification

trajectory (i.e., a 90% decrease in the volume of pipeline gas delivered to buildings in Maine over the next ~25 years).

IV. General Comments on Long-term Planning and Reporting Requirement

We support Staff's recommendation for an Integrated Resource Plan ("IRP") requirement. Although not explicitly stated in Staff's proposal, we would recommend that this IRP be fully litigated for all gas utilities, rather than informational as Northern Utilities' IRP currently is. As noted above, we recommend that the filing cadence occur every 2-3 years. Below, we provide recommendations that largely expand on the elements of Staff's proposal.

1. Alternate scenarios

We recommend specifying that at least one of the "range of alternative scenarios" modeled should include demand reductions consistent with Maine's long-term GHG targets of net-zero emissions by 2045 and an 80% reduction in gross emissions by 2050. Currently, Staff's proposed language simply requires the utilities to "consider" the statutory requirements. At a minimum, the utility should model a "High," "Medium," and "Low" demand scenario. As also noted in the Framework section, all demand scenarios should incorporate the effects of current laws, policies, and programs that require or incentivize beneficial electrification, including building codes; building performance standards; appliance standards; and federal, state, local, and utility program incentives for beneficial electrification.

We also would recommend that the demand forecast cover a projection period longer than 10 years. A projection period of 20 years would enable the gas utility to fully incorporate Maine's statutory requirement to achieve carbon neutrality by 2045 and reduce gross GHG emissions 80% by 2050 from 1990 levels. Declines in throughput or customer count due to climate policies will likely become more pronounced closer to the 2045 and 2050 target dates, and as such a 20-year projection period would allow the Commission more robust visibility into the potential impacts of these policies.

2. Assessment of demand-side energy management programs

We recommend further specifying how the IRP should maximize the cost-effective benefits of demand-side programs. Other jurisdictions such as Minnesota require LDCs to model demand-side resource portfolios on a consistent and comparable basis alongside supply and capacity options for meeting consumer demand.[29] We suggest incorporating such a requirement into the Maine IRP regulations. Although deployment of demand-side resources would need to be coordinated through Efficiency Maine, resource portfolio modeling can inform the targets and measures adopted through triennial plans.

[29] Minnesota PUC, Docket Nos. Docket Nos. G008, G002, G011/CI-23-117; G999/CI-21-565, October 28, 2024, Comprehensive Gas IRP Requirements at page 2.

3. Assessment of supply options

The utility should assess the cost, risks, and availability of firm and interruptible pipeline capacity, storage, peaking contracts, and spot purchases. Each resource should be described in terms of cost, contract length, flexibility provisions, and risk of underutilization. Again, all supply and demand resource portfolios should be modeled on a consistent and comparable basis.

Importantly, the Commission should not entertain proposals by the utilities to direct ratepayer resources to fuels such as renewable natural gas ("RNG") and hydrogen. In light of these fuels' higher costs combined with uncertainty regarding carbon emissions potential, availability, and safety, the Commission should adopt a policy of disallowing cost recovery for RNG and hydrogen blending.

As the Governor's Energy Office found in its Pathways Report, RNG is unable to compete with electrification as a primary decarbonization pathway due to its scarcity and high cost.[30] The Pathways Report concluded that RNG should instead be used for hard-to-decarbonize end uses.[31] Any analysis of RNG should not assume GHG emissions reductions will result, and must account for GHG emissions resulting from methane leakage throughout the supply chain. Methane is a potent GHG gas regardless of the source,[32] and even small leaks can result in significant emissions.[33] Indeed, claims of very low or even negative life-cycle greenhouse gas emissions from RNG are often premised on faulty assumptions.[34]

Hydrogen is also inappropriate for injection into the gas distribution system for several reasons. Even if made with renewable electricity, hydrogen is too volatile a fuel to pipe throughout our streets and into our homes. Hydrogen is highly combustible, even in low concentrations, raising concerns about the safety of its increased use in homes.[35] Hydrogen is highly leakable[36] and is an indirect greenhouse gas with a 100-year global warming potential 5.8 times greater than carbon dioxide.[37] Further, hydrogen embrittles steel and cast iron pipelines, and would necessitate a costly replacement of existing pipeline infrastructure to accommodate hydrogen.[38] End-use appliances are also not able to combust hydrogen and costly appliance

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[30] Pathways Report at 19 (internal references omitted).
[31] *Id.*
[32] U.S. Env't Prot. Agency, *Overview of Greenhouse Gases* (May 16, 2022).
[33] Sargent, et al., *Majority of US Urban Natural Gas Emissions Unaccounted for in Inventories*, (Oct. 2021).
[34] *See, e.g.,* Conservation Law Foundation, *Limited and Careful Use: The Role of Bioenergy in New England's Clean Energy Future*, (Oct. 30, 2023) at 34-35.
[35] A study by the UK government estimated that explosions in homes would increase more than fourfold if hydrogen were to replace gas in homes. Collins, Leigh, 'Hydrogen in the home would be four times more dangerous than natural gas': government report, (RechargeNews.com, last updated August 2, 2021), available at https://www.rechargenews.com/energy-transition/hydrogen-in-the-home-would-be-four-times-more-dangerous-than-natural-gas-government-report/2-1-1047218.
[36] Fotis Rigas & Paul Amyotte, Myths and Facts about Hydrogen Hazards, 31 Chem. Eng'r Transactions 913, 914 (2013), available at https://www.aidic.it/cet/13/31/153.pdf.
[37] Derwent, R., Simmonds, P., O'Doherty, S., Manning, A., Collins, W. and Stevenson, D. 2006. "Global Environmental Impacts of the Hydrogen Economy." Int. J. of Nuclear Hydrogen Production and Applications. 1(1): 57-67. Available at: http://agage.mit.edu/publications/global-environmental-impacts-hydrogen-economy.
[38] Zahreddine Hafsi et al., Hydrogen embrittlement of steel pipelines during transients, Procedia Structural Integrity 13 (2018), 210-217, available at

replacement would be required to accommodate substantial hydrogen blends.[39] Lastly, hydrogen has a substantially lower energy density than methane, which means that far greater quantities must be combusted to generate the same energy or heat.[40] Consequently, despite the expense and complexity, blending hydrogen into methane gas streams at low concentrations would do very little to improve total greenhouse gas emissions. Similar to RNG, green hydrogen is not appropriate for distribution via the gas system and should be reserved for processes that are not easily electrified.

4. Assessment of infrastructure

In this section, and for each demand scenario, the LDC should provide a 20-year forecast of capital spending by investment category (e.g., Capacity Expansion, New Business Extension, System Safety and Integrity, Leak-Prone Pipe Replacement, MAOP, etc.) The purpose of this forecast is to provide the Commission and intervenors with visibility into upcoming investments, underlying drivers, and potential rate impacts. The 20-year planning horizon aligns with the 20-year demand forecast and shows how capital spending may respond to various policy and market factors that impact demand.

We understand that the utilities are unlikely to have developed defined budgets or scoped individual projects in the out-years of this planning horizon. For these out-years, the LDCs may rely on general assumptions about the relationship between demand and capital spending. The LDC should clearly indicate which years of the capital forecast are based on knowledge of individual projects or defined budgets and which years of the capital forecast are based on generalized assumptions.

Additionally, the utility should provide a list of all known planned projects within the next 10 years above a threshold of $1 million. The following details should be provided for all discrete projects:

- Project category (e.g., Capacity Expansion, New Business Extension, System Safety and Integrity, Leak-Prone Pipe Replacement, MAOP, etc.)
- Scope of work
- Engineering life
- Construction start date
- In-service date
- Cost estimate
- Pipeline length and diameter
- Pipeline material
- Maximum allowable operating pressure
- Impact on revenue requirement and rates

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https://www.sciencedirect.com/science/article/pii/S2452321618302683#:~:text=The%20transient%20regime%20is%20created,diffusion%20through%20the%20pipeline%20wall.

[39] Energy Innovation, Assessing the Viability of Hydrogen Proposals (Mar. 2022), available at https://energyinnovation.org/wp-content/uploads/2022/03/Assessing-the-Viability-of-Hydrogen-Proposals.pdf

[40] Ulf Bossel & Baldur Eliasson, Energy and the Hydrogen Econony, at 5, https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf ("at any pressure, the volumetric energy density of methane gas exceeds that of hydrogen gas by a factor of 3.2 (neglecting non-ideal gas effects)").

- Project location
- Number of impacted or served customers.
- Permitting requirements
- Environmental requirements
- Change in projected GHGs due to the project
- Geographic Information System (GIS) mapping of the location of the project
- For projects driven by capacity expansion, hydraulic modeling results demonstrating the forecasted capacity shortfall the project is intended to address and the date this shortfall is expected to occur
- For system safety and integrity projects, the project risk ranking, the utility risk ranking methodology, and any applicable risk thresholds the utility uses for selecting pipe segments for replacement.[41]

5. Other Issues

We recommend adding two additional elements to the IRP that are not already discussed in the Staff proposal: system mapping and a stakeholder engagement requirement, described below.

System Mapping: We would recommend adding a requirement to include system mapping in the IRPs. System maps enable the Commission and intervenors to better understand the areas of the LDCs' systems that will face upcoming capacity constraints or require replacement, facilitating geotargeting of electrification and efficiency incentives and encouraging collaboration with municipal officials on neighborhood-scale NPA projects. For example, third-party experts have used Pacific Gas and Electric's Gas Asset Analysis mapping tool to identify and evaluate potential zonal NPA projects.[42]

We would recommend that the utilities include GIS shapefiles that display locations, material, age, pressure, leak history, JANA risk scores, and other characteristics of pipe at 1:24,000 scale, alongside layers showing the street-level locations of planned projects, electrification trends, participation in efficiency and electrification programs, and environmental justice communities. While GIS shapefiles may be filed under highly confidential seal, the public version of the IRPs should include at least one high-level system map in PDF format.

Stakeholder engagement: As noted above, we recommend that IRPs be fully litigated. However, at the time a litigated plan is filed in a docket, it is likely to be fully baked with few avenues for further iteration. We recommend that the Commission require a stakeholder process prior to the plan filing to allow stakeholders to review and provide feedback on the utility's plans and its application of the NPA framework. To start this process, and no later than a year before the plan filing, the utilities should file a work plan that identifies planned workshops, dates, and

[41] This list of requirements is modeled on the Gas Infrastructure Plan requirements in place in Colorado. See Colorado PUC Proceeding No. 21R-0449G, Decision No. C22-0760, Attachment A—Adopted Rules in Legislative Format, pages 25-26, subparagraph 4553(c).
[42] Halbrook, Claire. "Selecting Gas Decommissioning Pilot Locations." Gridworks, March 4, 2023. https://gridworks.org/2022/08/selecting-gas-decommissioning-pilot-locations/.

the subject of each workshop. We recommend that each LDC hold four to six workshops in total prior to filing the plan and solicit written comments from stakeholders after each workshop.

Additionally, the utilities should present a draft plan for stakeholder comment at least 90 days in advance of the plan filing. Stakeholders should be given at least 20 business days to provide comments on the draft plan to the LDC. The LDC should provide a detailed summary of feedback received on the workshops and the draft plan in an appendix to its final IRP, including the company's response and a justification for any recommendations it did not adopt.

V. Line Extension Allowances ("LEAs")

Maine's statutory climate commitments establish legally binding economy-wide greenhouse gas emissions reduction targets, including a net-zero deadline by 2045. LEAs are not consistent with these emissions reduction targets, as they promote fossil fuel expansion by lowering the upfront costs of new gas connections and locking in increased investments in the fossil fuel system that risk becoming stranded. LEAs distort the price signal for gas interconnection, actively incentivizing gas system expansion at precisely the moment when Maine's climate commitments demand a halt to growth in reliance on gas.

By reducing or eliminating the cost to a new customer of connecting to the gas system, LEAs lock in gas infrastructure investment that extends beyond Maine's net-zero deadline. While Maine's climate law requires net-zero emissions by 2045, new customer service lines generally have a depreciation life exceeding 30 years—well past the state's net-zero deadline. Each new allowance-funded connection thus adds capital investment to the rate base that must be recovered from ratepayers over decades during which Maine's climate laws require a simultaneous reduction in emissions. Existing investments are already at risk of becoming stranded as customers move away from the gas system. New allowances only serve to unnecessarily inflate the risk of unrecovered rate base, increasing risk to ratepayers for no gain.

Further, LEAs create a price distortion that promotes gas system expansion against state policy. LEAs were initially designed when gas system expansion was considered to be aligned with public policy goals such as affordability and environmental objectives. As policy has evolved, for instance to consider decarbonization, this alignment has faded, but LEAs have persisted. That persistence encourages avoidable additional gas system development specifically in opposition to the policy of the state. LEAs create a distortion in the market for heat by reducing or eliminating the upfront cost of connecting to gas, while competing technologies, such as heat pumps, require customers to pay full upfront costs. Thus, allowing LEAs produces a price signal that systematically favors gas over electric alternatives, in direct contradiction of state decarbonization policies that require a reduction in fossil fuel use. Correcting this price distortion ensures that ratepayer funds are not actively used to work against the state's emissions reduction goals.

Several other states have recognized the incompatibility of LEAs with the energy transition and have taken steps to eliminate them. California, Colorado, Maryland, Massachusetts, Minnesota, New York, Oregon, Rhode Island, and Washington have all taken action to reform or eliminate gas line extension allowances in recent years, reflecting growing

recognition that these policies are inconsistent with climate mandates and impose unacceptable risks on existing ratepayers.[43] Indeed, two of Maine's fellow New England states have moved to eliminate LEAs. The Rhode Island PUC has proposed a phase-out of LEAs beginning in April 2027 with full elimination by April 2029.[44] The Massachusetts Department of Public Utilities, following its own Future of Gas investigation and review of stakeholder input, has also proposed to eliminate LEAs.[45] Maine should join these other states in phasing out LEAs to reduce stranded asset cost risk to ratepayers and facilitate compliance with our climate mandates.

The Commission should at a minimum require the gas utilities to annually report on the impact of LEAs on ratepayers, including (1) the total cost spent on LEAs and (2) the amount of revenue collected from new customers receiving LEAs.

VI. Conclusion

We thank the Commission for undertaking this important proceeding, and for considering these comments. We look forward to continuing to engage in this process and to helping the Commission plot a path for Maine's gas utilities and gas systems that is consistent with law and best serves ratepayers.

Respectfully submitted,

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[43] *See* Rhode Island Public Utilities Commission, Docket No. 25-45-GE, Pre-filed Direct Testimony of Michael J. Walsh, at 21.
[44] RIPUC Docket No. 25-45-GE, Draft Minutes from August 21, 2026 Meeting, at 8-9.
[45] Massachusetts Department of Public Utilities, Docket No. 20-80, Order 20-80-E, August 8, 2025, at 16-17.