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May 1, 2025

To: New Jersey Board of Public Utilities

Re: In the Matter of the 2024 New Jersey Energy Master Plan, Docket QO24020126-

The Institute for Policy Integrity at New York University School of Law (Policy Integrity)[1] respectfully submits the following comments to the New Jersey Board of Public Utilities (BPU) regarding the 2024 New Jersey Energy Master Plan (2024 EMP). Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and public policy.

In January 2020, BPU released the 2019 Energy Master Plan (2019 EMP), outlining seven strategies for achieving Governor Phil Murphy's target of 100% clean energy by 2050 and meeting the Global Warming Response Act (GWRA)[2] mandate to reduce statewide greenhouse gas emissions 80% below 2006 levels by 2050 (the 2050 limit).[3] Policy Integrity previously submitted comments on both the scoping phase[4] and the draft version of the 2019 EMP.[5]

As outlined in the presentation by BPU and Energy + Environmental Economics (E3) on March 13, 2025 (March EMP Presentation), the 2024 EMP will assess New Jersey's progress toward the 2019 goals while identifying viable pathways to reduce statewide greenhouse gas

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[1] This document does not purport to present the view, if any, of New York University School of Law.

[2] 2007 N.J. Laws ch. 112 (codified at N.J. Stat. § 26:2C-37 et seq.), as amended by 2019 N.J. Laws ch. 197. "No later than January 1, 2050, the greenhouse gas emissions in the State shall be stabilized at or below the 2050 limit and shall not exceed that level thereafter." N.J. Stat. § 26:2C-40. "2050 limit" means "the level of greenhouse gas emissions equal to 80 percent less than the 2006 level of Statewide greenhouse gas emissions." N.J. Stat. § 26:2C-39.

[3] 2019 NEW JERSEY ENERGY MASTER PLAN: PATHWAY TO 2050 (2020), https://perma.cc/P2XK-2FHU.

[4] *See* INST. FOR POL'Y INTEGRITY, *Comments on New Jersey 2019 Energy Master Plan* (Oct. 12, 2018), https://perma.cc/VK4L-8PD4.

[5] *See* INST. FOR POL'Y INTEGRITY, *Comments on New Jersey 2019 Draft Energy Master Plan* (Sept. 16, 2019), https://perma.cc/X5RR-WGM6.

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emissions to achieve the 2050 limit established in the GWRA.[6] It will also incorporate the accelerated goal of 100% clean energy by 2035, adopted under Executive Order 315.[7]

Policy Integrity respectfully submits the following recommendations to enhance New Jersey's ability to leverage the 2024 EMP's identification of cost-effective pathways to achieve its critical climate and energy objectives. The 2024 EMP should:

- Commit BPU to providing policy scenario assumptions from the 2024 EMP to PJM for inclusion in the Order 1920 long-term scenario development process, to ensure that PJM plans for the transmission infrastructure necessary to support the energy transition.
- Recommend that the legislature and regulatory agencies codify policy goals that, while presently non-binding, are necessary to achieving the 2050 limit established in the GWRA, to ensure that PJM fully accounts for transmission needs driven by those policies.
- Account for PJM's proposed procedures for evaluating and selecting transmission projects, to ensure that the EMP identifies feasible decarbonization pathways.
- Adopt natural-gas-sector-specific strategies and targets, and commit BPU to implementing them through its regulation and oversight of New Jersey's local gas distribution companies, to ensure that end-use natural gas consumption and gas-sector emissions decrease to the extent necessary to reach the 2050 limit established in the GWRA.

I. New Jersey should coordinate the 2024 EMP with PJM's Order 1920 scenario development process.

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[6] N.J. Bd. of Pub. Utils. & Energy + Env't Econ., 2024 New Jersey Energy Master Plan Executive Summary Draft 4 (2025), https://perma.cc/C8KN-GNEV [hereinafter March EMP Presentation]. During the 2019 EMP proceeding, BPU provided a comprehensive draft plan outlining specific strategies for achieving the GWRA limit. Draft 2019 New Jersey Energy Master Plan: Policy Vision to 2050 (2019), https://perma.cc/59TQ-TBSZ. Here, New Jersey has provided only a presentation containing modeling results for different pathways to achieving the GWRA target, without identifying the pathway it is likely to adopt or outlining specific policy interventions needed to carry out those pathways.

[7] N.J. Exec. Order No. 315 (2023), https://perma.cc/9LSX-JZZJ ("It is the policy of the State to advance clean energy market mechanisms and other programs in order to provide for 100 percent of the electricity sold in the State to be derived from clean sources of electricity by January 1, 2035.").

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Although the March EMP Presentation does not address transmission directly, the strategies it contemplates both depend on and drive the need for a well-planned, robust electric transmission system. The March EMP Presentation projects that rapid decarbonization of the electricity sector will be required to achieve the 2050 limit established by the GWRA. The analysis assumes New Jersey will meet 100% of retail sales with clean electricity by 2035, relying on significant additions of solar, wind, nuclear, and storage capacity while reducing reliance on gas and electricity imports.[8] Simultaneously, the March EMP Presentation incorporates projections that annual electricity consumption and peak electricity demand will increase dramatically through 2050, in part driven by electrification strategies that New Jersey proposes to adopt to meet the 2050 limit.[9]

Significant investment in long-range transmission infrastructure is necessary to decarbonize the grid and to achieve New Jersey's statutory decarbonization mandate. Expanding long-range transmission infrastructure allows new renewable resources (which are often intermittent and located far from load) to connect to the grid cost-effectively while maintaining reliability.[10] At the same time, load growth (including growth driven by electrification, data centers, and U.S.-based manufacturing) increases the need for new resources—and thus new transmission—to meet higher demand.[11]

The Federal Energy Regulatory Commission (FERC) regulates the bulk power system. PJM Interconnection (PJM) is the regional entity that operates the transmission system that

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[8] MARCH EMP PRESENTATION, *supra* note 6, at 22–23.

[9] *Id.* at 20, 50–52. Data centers and the electrification of buildings, industry, and transportation will drive increases in electricity consumption and demand. *Id.* at 20, 31.

[10] Patrick R. Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115, 116 (2021) (finding that the construction of new interstate transmission capacity, in combination with interstate and interregional capacity planning and dispatch, significantly reduces the cost of decarbonizing the grid); LAUREN AZAR ET AL., ENERGY SYS. INTEGRATION GRP., TRANSMISSION PLANNING FOR 100% CLEAN ELECTRICITY 4–5 (2021), https://perma.cc/4ULW-2PCJ (noting that lack of transmission infrastructure has prevented many wind and solar resources from accessing the grid); Paul L. Joscow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector*, 10 ECON. ENERGY & ENV'T POL'Y 57, 58–59 (2021) (stating that expanding transmission makes it possible to use wind and solar generation more efficiently and reliably).

[11] U.S. DEP'T OF ENERGY, NATIONAL TRANSMISSION NEEDS STUDY 87–89 (2023), https://perma.cc/E9BX-7Y6J.

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serves New Jersey. FERC Order 1920[12] aims to promote cost-effective electric transmission development by requiring PJM and other transmission providers to conduct long-term planning every five years.[13] During each planning cycle, PJM must develop at least three plausible and diverse long-term scenarios projecting transmission needs over a 20-year horizon.[14] Each scenario must incorporate seven categories of factors driving transmission needs. Those factors include "legally binding obligations, incentives (e.g., tax credits), and/or restrictions" in two categories: (1) those that affect resource mix and demand;[15] and (2) those concerning decarbonization and electrification.[16] They also include policy "goals" that affect long-term transmission needs but "may not have the same durability and binding impact of laws and regulations."[17]

New Jersey policies included in the 2024 EMP, and that are critical to achieving the 2050 statutory limit for greenhouse gas emissions, are also relevant to the Order 1920 transmission planning process. To ensure that PJM plans for the transmission necessary to facilitate the strategies set out in its 2024 EMP and to achieve the 2050 limit, the 2024 EMP should: (1) commit BPU to providing the modeling inputs used in developing the 2024 EMP to PJM; and (2) recommend that the legislature and regulatory agencies codify any policy goals identified in the 2024 EMP that are necessary to achieving the 2050 limit. PJM has also proposed that it may not commit to planning for transmission needs driven by certain categories of generation resources that are critical to achieving the 2050 limit. The 2024 EMP should thus account for PJM's proposed Order 1920 procedures to ensure that the pathways and strategies it adopts will be feasible.

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[12] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024) [hereinafter Order No. 1920].

[13] *See generally* INST. FOR POL'Y INTEGRITY, GUIDE TO STATE PARTICIPATION IN PJM LONG-TERM SCENARIO DEVELOPMENT UNDER FERC ORDER NO. 1920 (2024), https://policyintegrity.org/publications/detail/guide-to-state-participation-in-pjm-long-term-scenario-development-under-ferc-order-no-1920.

[14] *Id.* at 2 (scenarios are plausible versions of future grid conditions that help planners account for uncertainty).

[15] Order No. 1920 at P 433.

[16] *Id.* at P 440. This includes policies that affect long-term transmission needs "by limiting the carbon intensity of electricity generation or electrifying energy end uses and thereby significantly increasing electricity use in certain sectors of the economy, such as transportation and building heating and cooling." *Id.*

[17] *Id.* at P 483.

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a. The 2024 EMP should commit BPU to providing its 2024 EMP modeling assumptions to PJM during Order 1920 scenario development.

Much of the analysis that New Jersey has described in the March EMP Presentation is directly relevant to PJM's Order 1920 scenario development. New Jersey should thus supply PJM with its modeling assumptions, especially those concerning electrification, resource mix, and demand growth, to ensure that PJM develops plausible and diverse scenarios incorporating New Jersey's energy needs.

i. Order 1920 requires PJM to consult with states on how to incorporate state policies that drive transmission needs into its long-term scenarios.

PJM must incorporate any factor that is likely to affect long-term transmission needs into its long-term scenarios,[18] relying on the "best available data."[19] Under Order 1920, PJM can rely entirely on stakeholders to identify relevant policies driving transmission needs; thus, if states fail to report key policies, PJM may not plan for all future needs.[20] Beyond allowing states to identify policies, transmission providers "must consult with and consider the positions of the Relevant State Entities"—state entities responsible for electric utility regulation or siting of transmission facilities[21]—regarding "how to account for" those policies in the long-term scenarios.[22] This consultation includes whether a policy is likely to affect needs and "the method and data used" to model a policy.[23] States can also provide input on "how to adjust the treatment of the specific state policy across Long-Term Scenarios," including by specifying a plausible range of policy impacts on electricity demand and resource mix.[24]

ii. The March EMP Presentation describes GWRA compliance pathways that incorporate policies likely to drive transmission needs.

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[18] *Id.* at P 415.

[19] *Id.* at P 633. Best available data is "timely," developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the principles of coordination, openness, transparency, information exchange, comparability, and dispute resolution. *Id.* at PP 224, 633–34.

[20] Order No. 1920 at P 508.

[21] *Id.* at P 44.

[22] Order No. 1920-A at P 344.

[23] *Id.*

[24] *Id.* at PP 344–45.

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The March EMP Presentation describes three "mitigation" scenarios that would successfully meet the 2050 limit established in the GWRA: (1) a high electrification scenario; (2) a demand management scenario; and (3) a hybrid electrification scenario. It also identifies certain "no regret" actions that New Jersey will need to take in the near term, including building and transportation electrification, solar and battery storage deployment, and energy efficiency measures.[25]

Each scenario projects changes in energy use and generation mix driven by various state and federal policies that affect resource mix and demand or concern electrification and decarbonization.[26] For example, the March EMP Presentation identifies the Advanced Clean Trucks[27] and Advanced Clean Cars[28] Rules, the Memorandum of Understanding (MOU) concerning Accelerating the Transition to Zero-Emission Residential Buildings signed by the Northeast States for Coordinated Air Use Management (NESCAUM),[29] and N.J. Executive Orders 307,[30] 315,[31] and 316[32] as "key policies influencing the 2024 EMP Results."[33] The March EMP Presentation also identifies federal funding from the Infrastructure Investment and Jobs Act

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[25] *Id.* at 32.

[26] MARCH EMP PRESENTATION, *supra* note 6, at 13.

[27] N.J. Admin. Code §§ 7:27–31 (requiring manufacturers to sell zero-emission trucks as an increasing percentage of annual sales from 2025 to 2035).

[28] N.J. Admin. Code §§ 7:27–29A.1–29A.7 (requiring manufacturers to sell zero-emissions vehicles as an increasing percentage of light-duty vehicles, reaching 100% by 2035).

[29] The NESCAUM MOU commits the signatory states to pursue a target of having zero-emission heat pumps make up 90% of residential heating, cooling, and water heating sales by 2040. Accelerating the Transition to Zero-Emission Residential Buildings, Multistate Memorandum of Understanding (May 24, 2024), https://perma.cc/P9Y7-HYAZ.

[30] N.J. Exec. Order No. 307 (Sept. 21, 2022), https://perma.cc/P8WW-LWAM (increasing the offshore wind goal from 7,500 MW by 2035 to 11,000 MW by 2040).

[31] *See supra* note 7.

[32] N.J. Exec. Order No. 316 (Feb. 15, 2023), https://perma.cc/7H7Q-Z6KC (setting a target of installing zero-carbon emissions space heating and cooling systems in 400,000 homes and 20,000 commercial buildings by 2030, and of making 10% of low-to-moderate-income households electrification-ready by 2035).

[33] MARCH EMP PRESENTATION, *supra* note 6, at 9.

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of 2021 and the Inflation Reduction Act of 2022 as policies driving investment in clean energy and electrification.[34] All of those policies are potentially relevant inputs to Order 1920 planning.

New Jersey has estimated a range of plausible grid outcomes driven by these state and federal policies. For example, the March EMP Presentation describes estimated future stocks and sales of electric vehicles under different scenarios, with differing shares of internal combustion, battery-electric, hybrid-electric, and hydrogen fuel cell vehicles.[35] Similarly, the March EMP Presentation describes estimates of future stocks and sales for different types of space heating devices, with differing levels of adoption for fossil-fueled, electric, and hybrid heating in each scenario.[36] Those modulations in policy outcomes help to determine how electricity use will change under different future conditions—indeed, the March EMP Presentation depicts how EVs and heat pumps will contribute to annual load growth and peak load under the different scenarios.[37]

iii. The 2024 EMP should commit BPU to providing its policy scenario assumptions to PJM to ensure that the Order 1920 long-term scenarios reflect a plausible and diverse range of future grid conditions.

By December 2025, PJM plans to develop, with states and stakeholders, an "informational" baseline scenario, which it will use to inform how it will conduct future planning cycles.[38] States will also have an opportunity to contribute to the scenario development phase of the initial planning cycle beginning in June 2027.[39] To ensure that PJM conducts Order 1920-compliant scenario planning that fully accounts for New Jersey's GWRA legal mandate, the 2024 EMP should commit BPU to timely requesting that PJM include the EMP's most likely pathway to meeting the 2050 legal mandate in each of PJM's three planning scenarios, or to include the three mitigation scenarios in different long-term scenarios. New Jersey should explain how the policies incorporated in its 2024 EMP are likely to drive long-term transmission

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[34] *Id.* at 36.

[35] *Id.* at 47–48.

[36] *Id.* at 45–46.

[37] *Id.* at 20, 51.

[38] MOJGAN HEDAYATI, PJM, BASE SCENARIO DEVELOPMENT MOCKUP (ORDER NO. 1920 SCENARIO DEVELOPMENT TRACK) 2 (Apr. 10, 2025).

[39] EMMANUELE BOBBIO, ORDER 1920 UPDATED STAKEHOLDER ENGAGEMENT TIMELINE 3 (Mar. 13, 2025).

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needs. Where relevant, it should specify a plausible range of anticipated technology uptake and the resulting change in electricity demand. Similarly, it should report plausible pathways for generator additions and retirements.

New Jersey's input is critical to ensuring that PJM models with specificity the effects on New Jersey of state and federal policies, which will ultimately result in a more accurate identification of long-term transmission needs. Without New Jersey's input to the scenario development process, PJM may be unaware of relevant policies, or lack the information necessary to translate the policies into corresponding grid impacts. If it fails to participate effectively, New Jersey could squander the opportunity to ensure that PJM plans for its most likely energy future.

b. The 2024 EMP should recommend that New Jersey codify any policies that are necessary for successful implementation of the 2024 EMP.

In addition to ensuring that PJM incorporates all relevant inputs within its Order 1920 scenarios, the EMP should recommend that the legislature to codify any non-binding policies that are necessary for achieving the GWRA's 2050 statutory mandate or, where ample authority exists, commit state regulatory bodies to promulgating regulations designed to achieve its selected pathway.[40] Such actions may steer PJM away from discounting their effect when assessing future transmission needs and provide agencies with concrete actions to achieve the preferred EMP pathway towards meeting New Jersey's legal mandate.

i. If the 2024 EMP characterizes some policies as voluntary, PJM may choose not to fully account for those policies when conducting Order 1920 planning.

Order 1920 permits PJM to discount non-binding policy goals in its long-term scenarios. Discounting means that PJM can make an independent determination about whether a factor is "likely to be realized in full, in part, or exceeded."[41] PJM may not discount "legally binding obligations"; instead, it must assume that government actors and regulated entities will satisfy

[40] The Energy Master Plan statute provides: "Upon the adoption of the energy master plan, and upon each revision thereof, the committee shall cause copies thereof to be printed and shall transmit sufficient copies thereof to the Governor and the Legislature, for the use of the members thereof, and to each State department, commission, authority, council, agency, or board charged with the regulation, supervision or control of any business, industry or utility engaged in the production, processing, distribution, transmission, or storage of energy in any form." N.J. Stat. § 52:27F-14(e).

[41] Order No. 1920 at P 516.

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those obligations, "unless and until there is a change in law."[42] But it may discount "policy goals"—that is, those that are not binding.[43]

The March EMP Presentation characterizes certain policies as voluntary and non-enforceable, opening up the possibility that PJM may treat them as non-binding policy goals. The "current policy" scenario "includes finalized state and federal policies as of 2024, but excludes voluntary targets without enforcement mechanism."[44] Policies that the March EMP Presentation excludes from the current policy scenario, and thus impliedly categorizes as voluntary targets without enforcement mechanisms, include: (1) Executive Order 307, which increased New Jersey's offshore wind target from 5,000 MW by 2030 to 11,000 MW by 2040, and (2) Executive Order 315, which accelerated the target of achieving 100% clean electricity from 2050 to 2035.[45] The March EMP Presentation indicates that the "current policy" scenario would not meet the 2050 limit established in the GWRA. Yet while indicating that current policies would put New Jersey in violation of its existing legal mandate, the Presentation fails to present legal mechanisms by which the state could achieve compliance.

The March EMP Presentation's classification of some New Jersey policies as voluntary targets without enforcement mechanism also suggests that, when conducting Order 1920 scenario development, PJM may discount their effect on long-term transmission needs. For example, PJM could assume that New Jersey will build less than 11 GW of offshore wind by 2040, because New Jersey has identified only its 5 GW target as a "finalized" policy. A scenario that assumes a lower offshore wind requirement would likely identify less need for new transmission connecting offshore wind to load. And PJM would ultimately include less transmission capacity to connect offshore wind to load in its long-term plan.

[42] *Id.* at P 512. Order No. 1920-A defines "laws and regulations" to mean "enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction." Order No. 1920-A at 324. Despite this definition, the Notice of Proposed Rulemaking for Order 1920 cited an offshore wind solicitation schedule directed by a gubernatorial executive order as an example of a binding policy. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028, at P 104 n.189 (Apr. 21, 2022).

[43] Order No. 1920 at P 516 & n.1134.

[44] MARCH EMP PRESENTATION, *supra* note 6, at 41.

[45] *Id.* at 9.

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ii. Some policies that the March EMP Presentation characterizes as voluntary and without enforcement mechanism are critical to achieving the GWRA's 2050 limit.

Many of the New Jersey policies that PJM could decide to discount as non-binding policy "goals" when conducting long-term transmission planning are critical to achieving the 2050 limit set forth in the GWRA. For example, all three "mitigation" scenarios assume that New Jersey will meet the 11 GW by 2040 offshore wind target, compared to 5 GW by 2030 under the "current policy" scenario.[46] Similarly, all three "mitigation" scenarios anticipate that New Jersey will meet its 100% clean electricity standard by 2035, while the "current policy" scenario assumes only a 50% RPS standard by 2030.[47] Only the mitigation scenarios achieve the GWRA's 2050 limit. But PJM could decide to discount the GWRA-compliant policy pathways and include only the 5 GW target and the 50% RPS standard in its long-term scenarios.

In addition to discounting the amount of future clean generation capacity, PJM might discount future load growth. All three "mitigation" scenarios assume higher adoption of zero-emission vehicles and heat pumps than the "current policy" scenario.[48] Correspondingly, the March EMP Presentation states that annual electricity consumption will grow by over 90% in each of the "mitigation scenarios," compared to only 66% in the "current policy" scenario.[49] To the extent that the increase in electricity demand stems from policies that PJM might categorize as non-binding goals, PJM could assume lower levels of future demand in its scenarios.

If PJM does not fully incorporate those policies (and others) in its Order 1920 long-term scenarios, then it is less likely to identify the transmission constraints that currently present barriers to integrating clean energy to the grid or to meeting growing demand caused in part by electrification. This makes it less likely that PJM will plan for and build transmission to relieve such constraints in a cost-effective manner. And the resulting shortfall in transmission capacity could make it infeasible for New Jersey to connect enough clean generation or electrify adequately to achieve its decarbonization obligations.

iii. New Jersey should codify its policies to ensure that PJM fully accounts for them in long-term transmission plan and to provide concrete obligations for agencies to operationalize the EMP.

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[46] MARCH EMP PRESENTATION, *supra* note 6, at 41.

[47] *Id.*

[48] *Id.*

[49] *Id*. at 20.

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Having done the significant work of modeling and mapping legally compliant pathways, the finalized 2024 EMP should identify concrete legislative and regulatory steps essential to achieve compliance, and commit the relevant state bodies to achieving those milestones by particular dates. To the extent policies that exceed the requirements in New Jersey's "current policy scenario" are necessary to achieving the 2050 limit established in the GWRA, codification will ensure that PJM cannot discount such policies in its long-term plans, and increases the likelihood that PJM will plan to meet transmission needs driven by those policies. A transmission plan that addresses needs driven by state policies in turn makes those policies more achievable and more affordable. Codification of policies to fulfill the strategies set out in the EMP also fulfills the intent of the New Jersey legislature in adopting the EMP statute "that the actions, decisions, determinations and rulings of the State Government with respect to energy shall to the maximum extent practicable and feasible conform with the energy master plan."[50]

To the extent that New Jersey does not codify its policies through legislation or regulation, the state at a minimum should explain to PJM why the instruments it is using, such as executive orders, are legally binding.[51] Absent codification, New Jersey should provide as much information as possible to PJM supporting the likelihood that it will meet its policy goals. PJM may only discount a policy to the extent that the resulting scenario remains plausible.[52] A scenario is not plausible if PJM understates the effect of a policy that New Jersey is highly likely to carry out fully. For example, PJM's scenarios would be implausible if they excluded from the future generation stack projects that have secured construction permits, and thus are likely to be completed. New Jersey can decrease the likelihood that PJM discounts its policy goals by providing any information that indicates New Jersey is likely to achieve them. By thoughtfully anticipating these needs to the extent possible, the 2024 EMP can support New Jersey's communications to PJM.

c. The 2024 EMP should account for PJM's proposed Order 1920 procedures for evaluating and selecting transmission projects when developing feasible decarbonization pathways.

Even if New Jersey provides comprehensive input on its policies to PJM, the procedures PJM adopts to evaluate and plan for future transmission projects may determine whether the pathways that New Jersey ultimately adopts in the 2024 EMP are viable. Participating actively in

[50] N.J. Stat. § 52:27F-15(b).

[51] For example, New Jersey can provide clear explanations of executive orders' relationship to the relevant statutory scheme and/or constitutional power. *See supra* note 42. Additionally, to the extent that BPU Orders establish policies, New Jersey should explain to PJM why they are legally binding.

[52] Order No. 1920 at P 518.

the Order 1920 stakeholder process will allow New Jersey to remain informed on PJM's procedures as they evolve, and to provide feedback on those procedures to ensure that they allow New Jersey to meet its decarbonization obligations.

New Jersey must ensure that the preferred pathway it adopts in the 2024 EMP account for PJM's transmission planning assumptions. As just one example, during presentations describing its proposed evaluation process for including transmission projects in its long-term plan, PJM has suggested that it will categorize projects into those satisfying "core" and "additional" needs.[53] PJM has proposed defining "core" needs are those "identified through reliability tests" and associated with load forecasts, deactivations, and generation necessary to meet resource adequacy requirements. PJM would exclude from "core" needs resource-specific targets, such as energy storage or offshore wind targets, unless such resources have obtained certain approvals that reduce uncertainty over whether developers are likely to complete the projects. Although PJM has indicated that it will commit to selecting projects that satisfy "core" needs in the long-term plan, it may in general decide not to select a project satisfying "additional" needs unless a state has agreed to pay for that project's cost.[54]

New Jersey relies on substantial offshore wind buildout to achieve the GWRA's 2050 limit.[55] Under PJM's proposed compliance approach, however, PJM may not plan for transmission projects that would allow New Jersey to meet its wind targets unless the state agrees upfront to pay for that transmission. Thus, if New Jersey is not willing to shoulder the full cost of transmission upgrades that facilitate the addition of new offshore wind capacity but that have significant grid-wide reliability benefits to other states, then under the potential process PJM is currently describing, those GWRA-compliant pathways depending on significant offshore wind may not be reflected in PJM's planning. New Jersey should participate actively in the Order 1920 stakeholder process to advocate for an approach to transmission project need identification, evaluation and selection that fully reflect its legally binding 2050 emissions limits.

II. New Jersey should commit to a pathway for decarbonizing the natural gas sector.

New Jersey should adopt natural gas sector-specific targets and/or strategies to ensure a sufficient reduction in emissions derived from end-use natural gas consumption to achieve its decarbonization commitments. Those strategies must account for the incentives that the gas utility regulatory model provides for continual expansion of the gas system, as discussed in more

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[53] EMMANUELE BOBBIO, PJM, COMPLIANCE APPROACH TO SOME PORTIONS OF ORDER 1920 LONG-TERM REGIONAL TRANSMISSION PLANNING REQUIREMENTS 14 (Mar. 13, 2025).

[54] *Id.* at 16.

[55] MARCH EMP PRESENTATION, *supra* note 6, at 23.

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detail in the attached policy brief, Misaligned Incentives: Rethinking the Gas Utility Regulatory Model for Decarbonization.[56]

a. The March EMP Presentation contemplates a reduction in natural gas consumption for end-use purposes to achieve the 2050 limit set forth in the GWRA.

The March EMP Presentation specifies that distributed natural gas consumption will decline by over 70% between 2025 and 2050 in all three "mitigation" scenarios.[57] In the "current policy" scenario, it declines by only 22%. Only the mitigation scenarios achieve the 2050 limit established in the GWRA. But the March EMP Presentation provides no clear pathway for achieving the required natural gas emissions reductions. Instead, it leaves for "next steps" the development of "new strategies to guide the evolution of the natural gas distribution system towards clean energy attainment, consistent with EO317."[58] And while the March EMP Presentation identifies the adoption of heat pumps as a key component of reducing emissions, focusing on decarbonizing heating systems in buildings alone, without attention to the gas distribution system, does not ensure gas utilities will make the changes to their system planning and operation that would be necessary to ensure the gas-system-related costs of building decarbonization are not higher than necessary.

There is no avoiding requiring gas distribution utilities (also known as local distribution companies, or LDCs) to actually plan and prepare for the energy transition, because economy-wide goals alone, even coupled with policies that reduce end use customers' consumption of natural gas, are unlikely to result in gas utility infrastructure decisions aligning with necessary natural gas reductions.

b. The gas utility regulatory model provides incentives for continual expansion of the natural gas distribution system, and decarbonization policies that focus on decarbonizing electricity while ignoring natural gas use exacerbate the consequences.

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[56] INST. FOR POL'Y INTEGRITY, MISALIGNED INCENTIVES: RETHINKING THE GAS UTILITY REGULATORY MODEL FOR DECARBONIZATION (2025), https://policyintegrity.org/publications/detail/misaligned-incentives.

[57] MARCH EMP PRESENTATION, *supra* note 6, at 19.

[58] *Id.* at 32.

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Under cost-of-service regulation, an investor-owned utility earns a rate of return on its capital investments.[59] This kind of regulation creates a strong incentive to continue building or replacing main or service lines, because the more a utility builds, the more its shareholders profit. Because gas distribution utilities pass through the cost of natural gas directly to consumers,[60] policies that affect the price of natural gas have no effect on their bottom line. Furthermore, New Jersey case law has interpreted N.J. Stat. § 48:2-27 to impose a *mandatory* obligation on utilities to extend utility service to new customers, despite the legislature's use of the word "may,"[61] and despite language in a separate provision authorizing BPU to require public utilities to furnish "safe, adequate, and proper service . . . in a manner that tends to conserve and preserve the quality of the environment."[62]

Continual, unmitigated expansion of the distribution gas system is an unsustainable and costly approach in light of the 2050 limit established in the GWRA. New distribution pipelines often have an expected useful life of over 50 years. Public utility commissions have historically amortized the cost of the capital investment evenly over that period, making the investment appear relatively inexpensive.[63] But if New Jersey is serious about achieving the GWRA's 2050 limit, BPU may need to seek accelerated depreciation of its assets.[64] Similarly, prudently

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[59] JOEL B. EISEN, EMILY HAMMOND, JIM ROSSI, DAVID B. SPENCE, & HANNAH J. WISEMAN, ENERGY, ECONOMICS, AND THE ENVIRONMENT: CASES AND MATERIALS 480–81 (5th ed. 2020).

[60] *See, e.g.*, Pub. Serv. Elec. & Gas Co., Tariff for Gas Service, Sheet No. 54 (2024).

[61] N.J. Stat. § 48:2-27 states: "The board *may* . . . require any public utility to establish, construct, maintain and operate any reasonable extension of its existing facilities where, in the judgment of the board, the extension is *reasonable and practicable* and will furnish sufficient business to justify the construction and maintenance of the same and when the financial condition of the public utility reasonably warrants the original expenditure required in making and operating the extension." (emphases added).

[62] N.J. Stat. § 48:2-23. In *In re Centex Homes, LLC*, the Appellate Division of the New Jersey Superior Court invalidated BPU regulations barring utilities from providing service extensions free of charge outside of areas designated for growth by the State Planning Commission. 985 A.2d 649, 658–59 (N.J. Super. Ct. App. Div. 2009).

[63] *See* NAT'L ASS'N OF REGUL. UTIL. COMM'NS (NARUC), DEPRECIATION EXPENSE: A PRIMER FOR UTILITY REGULATORS 24–27 (2021), https://perma.cc/8HGP-VS2S.

[64] For example, at least one New York gas utility has recommended a decrease in service life for certain long-lived gas investments, and a corresponding increase in depreciation rates, to account for New York's economy-wide decarbonization target. *See, e.g.*, Dir. Test. of Depreciation Panel, N.Y. Pub. Serv. Comm'n, Case No. 25-00242, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules*

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incurred distribution pipelines may become no longer used and useful before the planned end of their useful life, forcing ratepayers and shareholders to shoulder the unrecovered cost.[65]

Unlike electric utilities (which can substitute renewables for gas-fired generation), or combination utilities (which can switch gas customers to electric service), gas-only utilities face unique challenges in transitioning to a less carbon-intensive business model. Although some utilities have proposed substituting renewable natural gas or hydrogen for methane gas, the emissions reduction potential of these fuels is limited.[66] Relying on "renewable" fuels in its hybrid electrification scenario in the 2024 EMP, as the March EMP Presentation contemplates,[67] cannot reliably yield emissions reductions of sufficient magnitude—but it can delay serious realignment of gas utility planning and operation. While gas distribution utilities have reason to prefer this outcome based on their inherent incentives, such a delay would come at high cost to New Jersey and its ratepayers, in the form of additional stranded utility costs as well avoidable customer investments in emitting equipment that may need to be retired before the end of its useful life. The delay would also jeopardize New Jersey's achievement of the GWRA's 2050 limit.

These features of the regulatory model explain why, without targeted policy intervention, gas utilities will continuously expand their capital investments, at unnecessarily high cost,

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and Regulations of Consolidated Edison Company of New York, Inc. for Electric and Gas Service 13–14 (Jan. 31, 2025).

[65] SCOTT HEMPLING, REGULATING PUBLIC UTILITY PERFORMANCE: THE LAW OF MARKET STRUCTURE, PRICING AND JURISDICTION 3.C.3, 6.D.1 (2d ed. 2021).

[66] Blending hydrogen with natural gas has the potential to reduce greenhouse gas emissions if the hydrogen comes from low-carbon sources, but potential adverse effects on appliances limit the maximum blend, and the distribution pipeline system often requires retrofitting to prevent embrittlement and leakage. *See* M. W. MELAINA, O. ANTONIA & M. PENEV, NAT'L RENEWABLE ENERGY LAB'Y, BLENDING HYDROGEN INTO NATURAL GAS PIPELINE NETWORKS: A REVIEW OF KEY ISSUES v–x (2013). The availability of waste methane that has been diverted from the atmosphere is insufficient to support a full-scale transition to RNG; intentionally producing methane for RNG purposes is likely to increase emissions due to leakage. *See* Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates*, 15 ENV'T RSCH. LETTERS 1, 7 (2020).

[67] MARCH EMP PRESENTATION, *supra* note 6, at 41.

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putting New Jersey's statutory climate goal at risk.[68] Moreover, while this absence of gas-focused policy intervention persists, electricity-focused policies like New Jersey's Renewable Portfolio Standard[69] and the Regional Greenhouse Gas Initiative[70] exacerbate the innate incentives for ever more gas by raising the cost of electricity, making gas comparatively more affordable and entrenching it further.

c. The 2024 EMP should adopt clear policy requirements that directly target the gas sector, and should recommend codifying those targets.

The faster New Jersey can halt the unmanaged expansion of the gas distribution system, the less costly the transition will be. But it must adopt gas-specific policies that take into account the incentives arising from the utility regulatory model.

Near-term strategies for transforming gas utilities' cooperation in planning and building for a low-emissions future that New Jersey might consider include: (1) adopting performance incentives or standards that require utilities to facilitate end-use customers' adoption of emissions-free heating equipment at a scale that is aligned with economy-wide decarbonization;[71] (2) exploring new business models that give New Jersey gas utilities a stake in the migration to new technologies for providing emissions-free thermal service;[72] and (3)

[68] *See Growth in Natural Gas Mains by Material*, AM. GAS ASS'N, https://perma.cc/D844-CQ23 (last visited Apr. 6, 2025) (explaining that total mileage for natural gas distribution lines grew 56% between 1990 and 2023 for main lines, and 65% for service lines).

[69] Clean Energy Act, 2018 N.J. Laws ch. 17 (establishing New Jersey's Renewable Portfolio Standard, requiring 35% of electricity sold in the state to be supplied by renewable resources by 2025, and 50% by 2030).

[70] N.J. Exec. Order No. 7 (2018) (authorizing New Jersey to rejoin the Regional Greenhouse Gas Initiative).

[71] *See, e.g.*, Order, Mass. Dep't of Pub. Utils., Case Nos. 23-80 & 23-81, *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan* 2, 28–58, 78–92 (June 28, 2024) (adopting performance-based ratemaking plan that seeks to align incentives of gas utilities with state greenhouse gas reduction targets); ; MARION SANTINI ET AL., REGUL. ASSISTANCE PROJECT, CLEAN HEAT STANDARDS HANDBOOK 36–38 (2024), https://perma.cc/Z54A-5BMQ.

[72] *See, e.g.*, ILL. COMMERCE COMM'N, THERMAL ENERGY NETWORK REPORT 6–25 (2024), https://perma.cc/J7PR-3QK7.

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requiring consideration of non-pipeline alternatives[73] and coordinating gas and electric long-term planning.[74] New Jersey might also consider adopting legislation overruling case law interpreting N.J. Stat. § 48:2-27 to impose a mandatory service extension obligation,[75] and clarifying that BPU may deem a natural gas line extension to be not "reasonable and practicable"[76] where it impedes New Jersey from achieving its statutory decarbonization obligations and thus does not "conserve and preserve the quality of the environment."[77]

Ideally, the 2024 EMP would expressly identify specific measures that agencies should take to ensure that New Jersey takes coordinated actions to achieve its decarbonization targets. Although the BPU opened a proceeding in 2023 requiring the development of natural gas utility plans to reduce emissions from the natural gas sector to levels consistent with the GWRA mandate,[78] beginning with a two-day technical conference in August 2023,[79] the agency and its staff appear to have made no public-facing progress in that docket since parties filed post-technical-conference comments in October 2023. As time passes, New Jersey gas utilities continue to engage in business-as-usual practices that may be increasing the cost for New Jersey ultimately to achieve its climate mandate. The 2024 EMP should clearly commit BPU to refocusing on its obligation, pursuant to Governor Murphy's Order 317, to develop recommendations for how the natural gas industry can best meet climate goals.[80]

Because a decrease in end-use natural gas consumption implies an increase in electricity consumption, New Jersey should also report its natural gas policies to PJM for inclusion in Order

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[73] *See, e.g.*, Notice Seeking Further Comments, N.Y. Pub. Serv. Comm'n, Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* (July 3, 2024) (requesting proposals for screening criteria, cost recovery, and incentive mechanisms for non-pipeline alternatives).

[74] *See* MARK LEBEL ET AL., ENERGY MKTS. & POLICY, BERKELEY LAB, OPPORTUNITIES FOR INTEGRATING ELECTRIC AND GAS PLANNING 11 (2025), https://perma.cc/6RGF-QQPW.

[75] *In re Centex Homes, LLC*, 985 A.2d 649, 655 (N.J. Super. Ct. App. Div. 2009).

[76] N.J. Stat. § 48:2-27.

[77] N.J. Stat. § 48:2-23.

[78] Order Initiating Proceeding, N.J. Bd. of Pub. Utils., Case No. GO23020099, *In the Matter of the Implementation of Executive Order 317 Requiring the Development of Natural Gas Utility Plans* (Mar. 6, 2023), https://perma.cc/DG5C-KS82.

[79] *See* Notice of Technical Conference, N.J. Bd. of Pub. Utils., Case No. GO23020099, *In the Matter of the Implementation of Executive Order 317 Requiring the Development of Natural Gas Utility Plans I* (July 28, 2023), https://perma.cc/9NZR-HWEQ.

[80] N.J. Exec. Order No. 317, https://perma.cc/J4LN-VUK5.

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1920 long-term scenario development. And to ensure that PJM fully accounts for (and does not discount) those targets in Order 1920 long-term transmission planning, it should consider adopting legislation or regulations codifying its targets for the natural gas sector.

Respectfully submitted,

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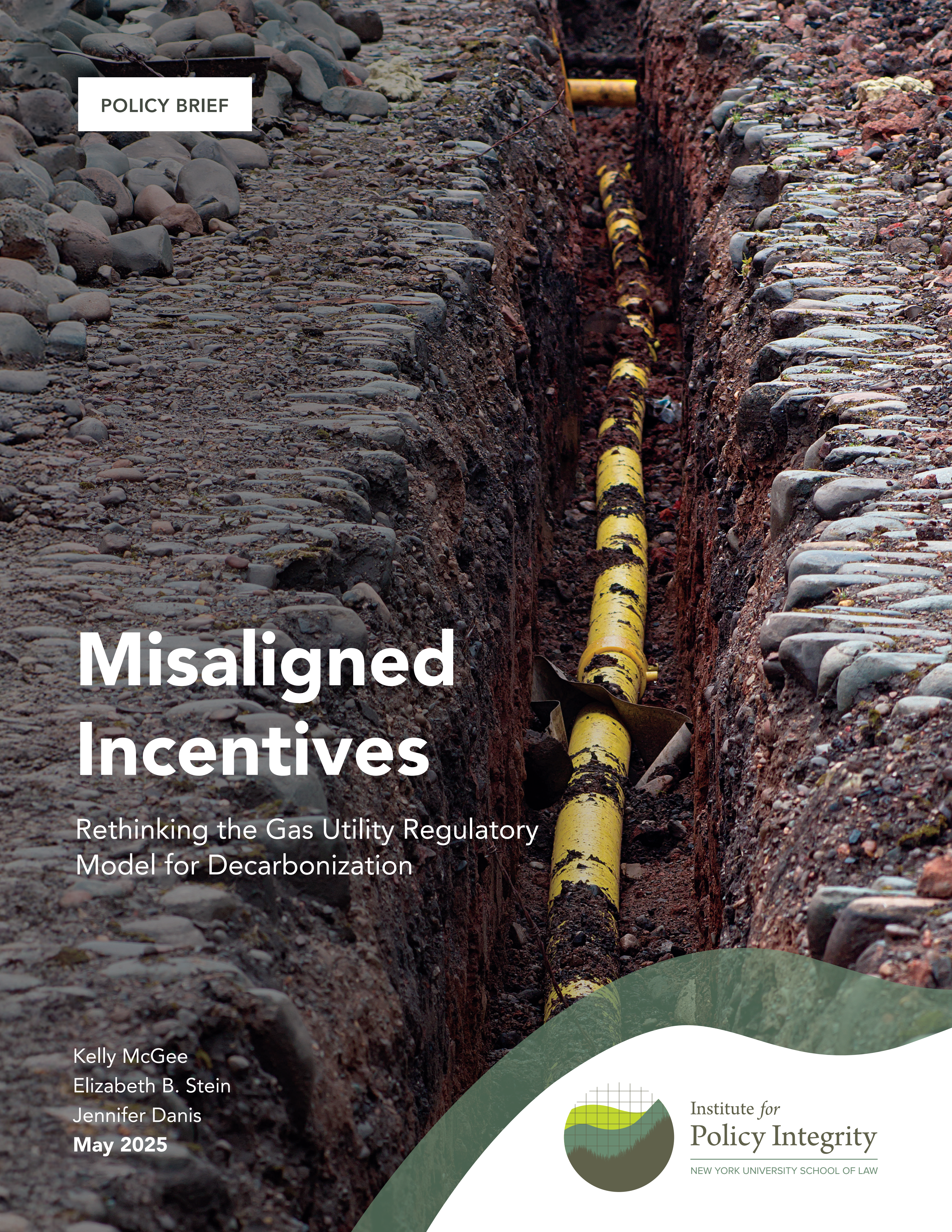
Attachment: Kelly McGee, Elizabeth B. Stein, & Jennifer Danis, Inst. For Pol’y Integrity, Misaligned Incentives: Rethinking the Gas Utility Regulatory Model for Decarbonization (2025)



POLICY BRIEF

Misaligned Incentives

Rethinking the Gas Utility Regulatory Model for Decarbonization

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May 2025

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I. Introduction

Reducing emissions from end-use natural gas consumption is a crucial yet often overlooked step in achieving decarbonization. In 2022, direct emissions from the commercial and residential sectors—those generated from buildings themselves rather than off-site electricity generation—accounted for 13% of total U.S. greenhouse gas emissions.[1] And 78% of the direct carbon dioxide emissions from the residential and commercial sectors came from using natural gas.[2]

Many states with decarbonization goals[3] set clear targets for the electricity sector,[4] but fail to establish similar objectives for the natural gas sector or define a long-term role for gas utilities.[5] Without clear direction, meaningful action by natural gas utilities is unlikely. The traditional regulatory model for local gas distribution utilities ties profits primarily to investments in gas-delivery infrastructure. This regulatory model creates a strong incentive for utilities to invest in a gas distribution system that, if states are to achieve their decarbonization targets, will not be fully utilized and may need to be scaled back. Customers and potentially investors will be forced to pay the costs of those investments.

To be effective, state-level decarbonization strategy must confront these structural incentives. This issue brief provides a short overview of the regulation of investor-owned gas distribution utilities. It identifies three key features of that model that create obstacles to reducing reliance on natural gas: (1) utilities' incentive to expand and use gas infrastructure; (2) utilities' insensitivity to gas prices; and (3) utilities' duty to extend and maintain gas service to gas customers. The brief then identifies five strategies to better align the gas utility regulatory model with state decarbonization targets, including: (1) setting gas-sector-specific emissions targets, (2) modernizing service obligations; (3) creating emissions accountability and performance incentives; (4) supporting new business models; and (5) reforming gas planning.

II. Regulation of Investor-Owned Gas Distribution Utilities

Investor-owned natural gas distribution utilities operate as regulated monopolies.[6] Public utility commissions (PUCs), the state entities that regulate these monopolies, grant these utilities exclusive rights to serve customers within defined geographic territories, shielding them from direct competition. The utilities must provide nondiscriminatory service to all customers within their territory.[7] The utility "duty to serve" entails two responsibilities:

1. Extending service to new customers by constructing new distribution mains or service lines,[8] often at no cost or at subsidized cost to the customer;[9] and

2. Maintaining reliable service for existing customers.[10]

To prevent monopoly pricing, PUCs regulate the prices these utilities can charge, ensuring that they are "just and reasonable" and fairly balance customer and investor interests.[11] One common framework for setting these rates is cost-of-service regulation, a process that begins by establishing a utility's revenue requirement: the total annual amount a utility must collect to remain financially viable while meeting its customers' needs. The revenue requirement consists of: (1) the rate base; (2) the rate of return (applied to the rate base); and (3) operating and maintenance (O&M) expenses.[12] As discussed below, the revenue requirement does not include the commodity cost of natural gas.

$$\begin{aligned}&\textit{Revenue Requirement}\\&\qquad = (\textit{Rate Base} \ * \ \textit{Rate of Return})\\&\qquad + \textit{Operating and Maintenance Expenses}\end{aligned}$$

Utilities, with regulatory oversight, design rates to recover their infrastructure costs (including a rate of return) and O&M expenses by spreading a given revenue requirement across their expected sales. Each component of the revenue requirement is discussed in further detail below.

1. The Rate Base

The rate base reflects the utility's net book value—the cost of capital investments minus the accumulated depreciation.[13] The capital investments include the gas distribution network.[14]

As infrastructure ages, its value declines through depreciation, reducing the rate base and, correspondingly, the return on outstanding investment that customers must pay.[15] Gas distribution lines routinely depreciate at a constant rate over 50+ years, which allows utilities to recover costs gradually.[16] Anticipating this long, slow recovery process prospectively makes large capital investments look relatively affordable on a year-to-year basis.

Utilities generally may recover only prudently incurred costs[17] and "used and useful" investments.[18] If a prudently incurred asset becomes no longer used and useful before the planned end of its useful life, its unrecovered value may become stranded.[19]

Recovery of potentially stranded costs is a contentious issue.[20] If the PUC allows full recovery (including a return), customers bear the cost of infrastructure that no longer provides them with service. If recovery is disallowed, then shareholders absorb the loss and do not see the benefit of their investment—even if the utility has not acted imprudently. In the long run, this may deter future investment or raise the cost of capital, ultimately impacting customers. Stranded costs, therefore, present a major challenge to affordability and future investments.

2. Rate of Return

Investor-owned utilities generally finance capital expenditures through a mix of debt and equity.[21] The rate of return represents the weighted cost of raising capital—covering both interest payments to lenders and expected returns to shareholders, applied to the relative amount of capital supplied by each.[22]

To attract shareholders who might otherwise invest elsewhere, the return on equity must be similar to the return on investments with similar risk.[23] The cost of debt financing is equivalent to the historical or anticipated cost of servicing debt, and is typically lower than the returns expected by equity holders.[24]

3. Operating and Maintenance Expenses

Operating and maintenance expenses cover the non-capital expenses necessary to keep the business running, such as employee salaries, taxes, rent, and legal fees.

This category also includes depreciation expenses. Each year, as an asset is used, the utility commission subtracts a portion of value from the rate base (preventing future return on that portion of the investment), and adds an equal amount as an operating expense (allowing for the recovery of the asset over time).[25]

Utilities do not earn a rate of return on operating and maintenance expenses.[26]

4. Cost of Natural Gas

Crucially, although utility rates for gas delivery service are generally denominated based on the quantity of gas consumed over a billing period (that is, service may be priced at cents-per-therm), the cost of natural gas itself is not included in the revenue requirement. Because distribution utilities generally do not own upstream gas wells, processing plants, or interstate pipelines, they generally procure gas for their customers from suppliers, although some large customers arrange for their own supply.[27] To the extent utilities procure on behalf of their customers, they then pass the cost on to consumers through a mechanism such as a standalone supply charge or rate adjustment.[28]

* * *

After determining the revenue requirement, PUCs set rates by spreading the revenue requirement—including both its capital expenditures, on which it earns a rate of return, and its operating costs—across the anticipated consumption of gas by all customers. The price of the gas itself is passed through directly to consumers.

III. Barriers to Reducing Natural Gas Dependence in the Gas Utility Regulatory Model

Several features of the gas utility regulatory model pose significant obstacles to reducing reliance on natural gas.

1. Incentives to Expand Infrastructure and Use Existing Infrastructure

First, gas utilities earn a rate of return on the book value of their infrastructure investments, creating a strong incentive to continue building or replacing distribution pipelines. Those distribution pipelines often have a useful life of over 50 years—well beyond many state's decarbonization timelines—but this traditional useful life expectation, coupled with the expectation that utilities will be able to pay for the investments slowly over their entire useful life, makes such investments look inexpensive before-the-fact. The more therms the utility expects to sell in a given year, the lower the per-therm rate it can set in that year. But if customers leave the gas system or decrease their usage (as they must if states are to achieve their decarbonization targets), the utility will need to spread the same capital costs across fewer therms, resulting in higher rates and potentially driving additional customer defections from natural gas. If utilization of undepreciated assets falls low enough, rates could become unsustainably high, and/or the utility's regulator could bar further recovery, in which case the remaining cost would be stranded.

2. Insensitivity to Gas Prices

Second, because gas utilities generally pass the cost of gas directly to consumers without markup, their profits are largely unrelated to the price of natural gas.[29] Therefore, policy tools that attempt to internalize the environmental costs of gas consumption by raising its price—such as emissions trading programs[30] or carbon taxes[31] that embed a compliance price in fuel—are unlikely to influence gas utilities' behavior directly.

While price-based policies would not directly affect gas utility profits or investment decisions, they may affect individual customers' choices. Depending on other energy system and market factors, a higher price for natural gas resulting from such a policy might incentivize customers to choose electric equipment over gas equipment. Although such voluntary customer decisions would reduce system utilization—potentially to the point where some existing infrastructure becomes no longer used and useful, and potentially raising the risk that future utility investments predicated on expected consumption growth could be deemed imprudent—they would not directly negate the gas company's incentives to prefer more, and more heavily used, infrastructure. Nor would they relieve the utility of its duty to serve remaining customers, as described in the next subsection.

In practice, consumers in most of the U.S. do not experience any emissions-related surcharge when they purchase natural gas, whereas in many states they do experience charges in connection with electricity.[32] Policies that increase the price of electricity can make natural gas seem comparatively cheaper, further entrenching its use.

3. The Duty to Serve

Third, the duty to serve requires a gas utility to extend distribution main or service lines to any prospective new customer located within the utility's regulatorily-defined service territory requesting natural gas service. Often, depending on the customer's proximity to the utility's existing gas distribution infrastructure, the customer pays no direct cost to connect, meaning that the utility then spreads the cost of new lines across all ratepayers.[33] Despite the tension between expanding natural gas infrastructure and achieving state emissions goals, PUCs in states with such goals generally allow cost recovery for investments made to satisfy this duty.[34] Once gas service is established, the utility cannot unilaterally withdraw it.[35] Even if a significant share of households in a neighborhood transition to electric service, the utility must continue to supply gas to the remaining customers (unless policymakers have modified this duty).

These features of the regulatory model explain why, without targeted policy intervention signaling a need to change course, gas utilities have continuously expanded their capital investments, including after the establishment of economy-wide climate goals in recent years. Between 1990 and 2023, the total mileage of natural gas distribution lines in the U.S. grew significantly (net of replaced lines): main lines by 56% and service lines by 65%.[36] That includes 37,926 net miles added between 2020 and 2023.[37] Driven mostly by distribution-related investments, annual capital expenditures have surged over the past decade, including a 44% increase between 2022 and 2023—the largest one-year increase since the 1990s.[38] The replacement of aging or leaking distribution pipelines also drives much of this spending, and utilities will recover those costs through rates far into the future.[39]

Especially when combined with state and local efforts to promote building electrification, which could drive defections from the gas system in a manner that is not geographically coordinated, a growing rate base threatens to saddle the remaining gas customers with inefficiently high costs. Because a PUC sets rates by dividing the revenue requirement across all anticipated sales, when customers leave the gas system, the remaining customers each pay a greater share of the remaining revenue requirement.[40] Heat pump adoption is lower in communities of color and areas with a higher proportion of renters, meaning that households in those areas are more likely to bear the burden of rising gas rates.[41] In an effort to meet decarbonization targets, utilities and PUCs may seek accelerated depreciation to recover the costs of their assets sooner.[42] Although expecting a shorter asset life mitigates the tendency for new gas investments to appear deceptively affordable upfront, faster depreciation increases the financial pressure on customers.

In sum, the current regulatory model drives utilities to invest in infrastructure that, if states are to achieve their decarbonization goals, is likely to be underutilized and therefore not a cost-effective investment. To mitigate the cost of transitioning to a lower-emitting energy system, state policymakers need to act promptly to align utility investment decisions with the state's preferred energy transition pathway. The earlier states act to discourage investments that are likely to become stranded, the lower the cost of transition will be.

IV. Aligning Gas Utility Regulation with State Decarbonization Goals

To meet economy-wide emissions reduction targets, states must consider the unique business and regulatory landscape of the natural gas sector.

Unlike electric utilities, which can substitute renewable and zero-emissions electricity for gas-fired generation (and often are required to do so under renewable or clean energy portfolio standards), gas-only utilities, which are legally constrained from engaging in businesses other than gas delivery, lack a straightforward path to decarbonization. Although many gas utilities propose substituting renewable natural gas or hydrogen for natural gas from geologic sources, the emissions reduction opportunity from these fuels is at best limited.[43] And overreliance on these solutions in the near term can delay the prompt course-changes that are essential to avoiding excessive transition costs. Combined gas-electric utilities are better positioned, as they can switch gas customers to electric service. Because it would be difficult for PUCs to require all gas utilities to merge with electric utilities, policies that effectively reshape the investment decisions of gas-only utilities are critical.

1. Setting Gas-specific Targets

At a minimum, state legislatures and regulators should establish gas-sector-specific, and potentially gas-utility-specific, emissions targets within broader decarbonization frameworks.[44]

Because various sectors' contributions to overall emissions vary and change over time—for example, the electric sector used to be the most-emitting sector, but as electric power has decarbonized, it has now been surpassed by transportation[45]—the existence of an economy-wide target does not, by itself, tell a gas utility regulator how much emissions reductions gas utilities should achieve. And unless the state's target is to eliminate *all* emissions from *all* sectors, economy-wide targets that are not specifically allocated to gas utilities leave room for individual utilities, or the sector as a whole, to argue that they can reduce their emissions more modestly than the economy-wide benchmark. The underperformance of one sector or utility need not interfere with attainment of the statewide goal, the argument goes, because other sectors (or other utilities) can make up the difference by overperforming relative to that benchmark.

While emissions-abatement costs vary by sector and can even vary by utility depending on a variety of factors—and relying on the lowest-cost abatement opportunities is efficient and maximizes net benefits—in the absence of an economy-wide market mechanism for finding the lowest-cost abatement opportunities, policymakers must identify preferred decarbonization pathways across the economy. The long planning horizon and expected useful life of utility infrastructure adds urgency to this need. And a utility regulator, whose expertise and knowledge does not reach all sectors of the economy, may not be the entity with the greatest capacity to evaluate the relative challenge of decarbonizing in all sectors economywide. Even if present natural-gas-related emissions alone were to exceed the economywide emissions budget for some future date, such that the need for some level of natural-gas-related emissions abatement would be self-evident,[46] policymakers with an economywide perspective would need to set expectations for the magnitude of gas-related emissions reductions.

Gas-sector-specific and utility-specific targets are thus necessary to achieve statewide targets, and can reinforce and justify policy measures aimed at reducing gas consumption and system size.[47]

2. Modernizing Service Obligations

States can remove one barrier to gas system transition by modifying the legal obligation for utilities to continually extend service to new customers. Legislatures can revise the statutory duty to serve to be fuel- and technology-neutral, allowing utilities to meet their obligations through electric service as an alternative to gas,[48] or through utility thermal energy networks that offer a credible pathway for reducing emissions. Legislatures can also eliminate statutorily-prescribed line-extension allowances that currently subsidize new gas connections, making electrification more cost-competitive for new customers. To the extent aspects of the duty-to-serve, or the subsidization of line extensions, are a creature of regulation, PUCs can take the lead in mitigating these barriers to gas transition.

3. Creating Emissions Accountability and Performance Incentives

Other policies might require utilities to account for the emissions impacts of their fuel supply. For example, clean heat standards can obligate gas utilities to achieve specific emissions reductions—through energy efficiency measures, electrification, or lower-carbon fuel—and impose penalties for non-compliance.[49] Performance-based regulation provides additional tools. Performance incentive mechanisms reward or penalize utilities based on target outcomes that align with customer or policy priorities, like meeting emissions-reduction goals or reducing gas demand.[50] Such policies can help nudge gas utilities in the direction of reducing total gas sales, providing some counterweight to features of their business model that incentivize them in the opposite direction.

4. Supporting New Business Models

States might authorize or direct gas utilities to engage in new lines of business that support the achievement of state decarbonization goals and provide revenue opportunities that do not depend on the expansion of gas infrastructure. Thermal energy networks that circulate water through underground pipes to heat and cool a network of buildings are a potential example of a business model that some states have considered. [51] If policymakers find that developing such networks would operate in a manner that aligns with decarbonization goals, allowing natural gas utilities to play a role in developing and operating them may allow gas utilities to retrain and transition utility workers and use their existing access to capital and experience administering networked infrastructure to support neighborhood-scale decarbonization.[52]

5. Reforming Gas Planning

Finally, states can revise the decisionmaking processes around energy system planning. PUCs can require gas utilities to assume before-the-fact that new gas assets will depreciate on an accelerated schedule, and to assess the cost-effectiveness of non-pipeline alternatives before committing to investments in new gas distribution infrastructure (including upgrades, such as those associated with remediating leak-prone distribution pipelines).[53] They can also require coordination with electric utilities during long-term planning to ensure efficient investment across sectors.[54]

* * *

Which of these strategies will prove most successful remains to be seen. One thing is clear: states where gas utilities currently contribute significantly to economy-wide greenhouse gas emissions are unlikely to successfully decarbonize through economy-wide or electric-sector goals alone. Targeted policies that address the structural incentives and regulatory barriers specific to the natural gas sector, including utilities subject to state regulation, are essential for meaningful progress.

V. Conclusion

States must develop focused expectations for the future of the natural gas sector and the monopoly utilities that serve local distribution needs if they hope to achieve their emissions reductions targets. Left to operate under the current regulatory framework, gas utilities have little reason to proactively phase out existing distribution pipelines or transition customers away from gas service. Their innate financial incentives point in the opposite direction, encouraging utilities to expand and maintain gas infrastructure, even as decarbonization timelines shorten the likely in-service timeline. Price-based mechanisms targeting the cost of fuel are unlikely to shift utility behavior, as they do not affect the utility's own bottom line. Uncoordinated electrification decisions driven by building owners can exacerbate the cost and equity challenges of decarbonizing the natural gas sector. Effective and efficient decarbonization of the gas sector will require targeted policies that directly address the incentives embedded in utility regulation and realign them with climate goals.

Endnotes

[1] *Commercial and Residential Sector Emissions*, Env't Prot. Agency (last updated Mar. 31, 2025), https://perma.cc/JAS4-9VXK.

[2] *Id.*

[3] *State Climate Policy Maps*, Ctr. for Climate & Energy Sols., https://www.c2es.org/content/state-climate-policy/ (last visited Apr. 24, 2025).

[4] *Clean Electricity Standards: Tracking Clean Energy in U.S. States*, Clean Air Task Force, https://www.catf.us/us/state-policy/clean-electricity-standards/ (last visited Apr. 24, 2025).

[5] Dan Aas, Energy + Environmental Economics, Future of Gas Proceedings: Motivations, Process, Accomplishments and Barriers 4 (2024), https://perma.cc/KP5N-XUKG (identifying states with economy-wide targets but no gas-sector-specific targets).

[6] Jim Lazar et al., Regul. Assistance Project (RAP), Electricity Regulation in the US: A Guide 3 (2d ed. 2016), https://perma.cc/329A-NT7M [hereinafter RAP Report] (discussing principles of utility regulation that apply to electric and natural gas utilities). This issue brief focuses on the incentives specific to investor-owned utilities, and thus does not discuss municipally or cooperatively owned utilities.

[7] Joel B. Eisen et al., Energy, Economics and the Environment: Cases and Materials 83–84 (5th ed. 2020).

[8] Distribution mains are the pipelines that carry natural gas under or next to the streets, while service lines are the pipelines that carry gas from the main to the end user's gas meter. *See Where do lines run?*, Peoples Gas, https://perma.cc/N6J2-97NJ (last visited Apr. 24, 2025).

[9] *See, e.g.*, Justin Gundlach & Elizabeth B. Stein, *Harmonizing States' Energy Utility Regulation Frameworks and Climate Laws: A Case Study of New York*, 41 Energy L. J. 211, 226–27 (2020). For example, New York law requires utilities to extend gas lines to new customers, and specifies that the Commission may, but need not, require customers to pay for the portion of the line exceeding 100 feet. N.Y. Pub. Serv. Law § 31(4). The utility spreads any portion of the cost not paid for by the new customer across the utility's ratepayers in aggregate. Gundlach & Stein, *supra*, at 227.

[10] *See* Jim Rossi, *Universal Service in Competitive Retail Electric Power Markets: Whither the Duty to Serve?*, 21 Energy L. J. 27, 29 (2000).

[11] Gundlach & Stein, *supra* note 9, at 216.

[12] Eisen et al., *supra* note 7, at 480–81.

[13] *See id.* at 481; N.Y. State Dep't of Pub. Serv., Analysis of Rate Elements in Regulatory Price Review 17 (2011), https://perma.cc/9SUG-VNCP.

[14] *See* Russell Ernst, *Rate Base: Understanding A Frequently Misunderstood Concept*, S&P Global (Mar. 3, 2017), https://www.spglobal.com/market-intelligence/en/news-insights/research/rate-base-understanding-a-frequently-misunderstood-concept. Natural gas distribution utilities generally do not own upstream gas wells, processing plants, or interstate pipelines. RAP Report, *supra* note 6, at 23.

[15] RAP Report, *supra* note 6, at 58.

[16] *See, e.g.*, Exhibit DP-5, N.Y. Pub. Serv. Comm'n, Case No. 25-00242, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric and Gas Service* (Jan. 31, 2025); Nat'l Ass'n of Regul. Util. Comm'ns (NARUC), Depreciation Expense: A Primer for Utility Regulators 25–26 (2021), https://perma.cc/8HGP-VS2S [hereinafter NARUC Depreciation Primer] (describing "straight-line" depreciation).

[17] During a prudence review, if applicable, the PUC will determine whether a project "has been constructed or implemented as proposed, according to sound management practices, and at a reasonable cost and with reasonable care." RAP Report, *supra* note 6, at 31; *see also* Scott Hempling, Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction 6.C.1 (2d ed. 2021).

[18] "Used" means that the facility is actually providing service, while "useful" means that the facility is reducing costs or improving quality of service. RAP Report, *supra* note 6, at 50.

[19] *See* Hempling, *supra* note 17, at 3.C.3, 6.D.1.

[20] *Id.* at 6.D.2; *see also* Andy Bilich et al., Env't Def. Fund, Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California 23 (2019), https://perma.cc/P9F5-SW4N.

[21] Debt is money borrowed from lenders that utilities repay with interest. Equity is capital that becomes available to a company through the sale of an ownership interest in that company; the entities that own that ownership interest, shareholders, receive returns on that capital through periodic dividends and/or increases in share prices. *See* James Tong & Jon Wellinghoff, *A basic primer on capital investment financing for regulated investor owned utilities*, Util. Dive (Mar. 25, 2015), https://perma.cc/N2DF-6Z6Z.

[22] Karl Dunkle Werner & Stephen Jarvis, Energy Inst. at Haas, Rate of Return Regulation Revisited 6–10 (2024).

[23] Hempling, *supra* note 17, at 6.A n.3 (quoting *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001)); *see also Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.").

[24] *See* Werner & Jarvis, *supra* note 22, at 8; RAP Report, *supra* note 6, at 53.

[25] RAP Report, *supra* note 6, at 58.

[26] Hempling, *supra* note 17, at 6.A (defining the revenue requirement as operating and maintenance expenses plus the cost of capital, which in turn is defined as the rate of return multiplied by the rate base).

[27] RAP Report, *supra* note 6, at 23–24.

[28] *See, e.g.*, Consol. Edison Co. of N.Y, Schedule for Gas Service, Leaf Nos. 155–166.3 (2022); Pub. Serv. Elec. & Gas Co., Tariff for Gas Service, Sheet No. 54 (2024).

[29] As mentioned *supra* Part II.4, gas distribution utilities generally do not own the gas production, processing, or interstate transportation infrastructure. Instead, they purchase gas from competitive suppliers.

[30] *Greenhouse Gas Cap-and-Trade Program*, Cal. Pub. Utils. Comm'n, https://perma.cc/7NNH-QJLC (last visited Apr. 24, 2025); N.Y. Dep't of Conservation & N.Y. State Energy Rsh. & Dev. Auth., Cap-and-Invest: Pre-Proposal Stakeholder Outreach New York Cap-and-Invest Natural Gas-Focused Webinar (2023), https://perma.cc/6VNM-6UCK.

[31] Some states have proposed a carbon tax, but none have so far adopted such a measure. *See, e.g.*, Off. of Program Rsch., State of Wa. House of Reps., Summary of Initiative 1631 (2018), https://perma.cc/MB2X-DB74.

[32] *See U.S. State Carbon Pricing Policies*, Ctr. for Climate & Energy Sols. (last updated Jan. 2025), https://www.c2es.org/document/us-state-carbon-pricing-policies/.

[33] Gundlach & Stein, *supra* note 9, at 237.

[34] *Id.* at 233.

[35] Rossi, *supra* note 10, at 29.

[36] *Growth in Natural Gas Mains by Material*, Am. Gas Ass'n, https://perma.cc/D844-CQ23 (last visited Apr. 6, 2025).

[37] *Id.*

[38] *Gas Utility Construction Capital Expenditure*, Am. Gas Ass'n, https://perma.cc/Z82F-982W (last visited Apr. 18, 2025).

[39] *See* Ryan C. Kelley, *Infrastructure Spending Drives Earnings Growth*, Hennessy Funds (Mar. 2021), https://perma.cc/5VAP-AK2B. State policy, such as Maryland's Strategic Infrastructure Development and Enhancement (STRIDE) law, has encouraged the replacement of aging distribution pipelines. Gas utilities spent more than $1.56 billion on new gas infrastructure under STRIDE between 2014 and 2022, and are expected to spend another $4.76 billion between 2022 and 2043. Md. Off. of People's Counsel, Maryland Gas Utility Spending: Projections and Analysis 2 (2022), https://perma.cc/7S6T-8P6A.

[40] Lucas W. Davis & Catherine Hausman, *Who Will Pay for Legacy Utility Costs?*, 9 J. Ass'n Env't & Res. Econ. 1047, 1049 (2022) (finding that utility revenues excluding the cost of gas decrease by only 5% with a 10% decline in residential customers, because the remaining customers make up part of the shortfall by paying higher prices).

[41] Morgan R. Edwards et al., *Assessing inequities in electrification via heat pumps across the US*, 8 Joule 3290, 3293–94 (2024).

[42] *See, e.g.*, Dir. Test. of Depreciation Panel, N.Y. Pub. Serv. Comm'n, Case No. 25-00242, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric and Gas Service* 13–14 (Jan. 31, 2025) (recommending a decrease in service life for certain long-lived gas investments, and a corresponding increase in depreciation rates, to account for New York's economy-wide decarbonization target). For more information on accelerated depreciation, *see* NARUC Depreciation Primer, *supra* note 16, at 26.

[43] Blending hydrogen with natural gas has the potential to reduce greenhouse gas emissions if the hydrogen comes from low-carbon sources, but potential adverse effects on appliances limit the maximum blend, and the distribution pipeline system often requires retrofitting to prevent embrittlement and leakage. *See* M. W. Melaina, O. Antonia & M. Penev, Nat'l Renewable Energy Lab'y, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues v–x (2013). The availability of waste methane diverted from the atmosphere is insufficient to support a full-scale transition to RNG; intentionally producing methane for RNG purposes is likely to increase emissions due to leakage. Emily Grubert, *At Scale, Renewable Natural Gas Systems Could be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates*, 15 Env't Rsch. Letters 1, 7 (2020).

[44] For example, Colorado's "clean heat law" requires gas distribution utilities to reduce GHG emissions 22% below 2015 levels by 2030. Colo. Rev. Stat. § 40-3.2-108(3)(b)(II).

[45] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990–2022 at ES-21 (2024), https://perma.cc/9YFY-WA2F.

[46] *See* Gundlach & Stein, *supra* note 9, at 219.

[47] For example, the Colorado Public Service Commission found that it was in the public interest to approve a portfolio of clean heat resources that would exceed the state's cap on cost increases, because such a cost increase was necessary to achieving the state's statutory target for natural gas distribution emissions reductions. Commission Decision Granting Application with Modifications, Requiring Filings, and Issuing Certain Directives to Guide Next Clean Heat Plan Filing, Co. Pub. Util. Comm'n, No. 23A-0392EG, *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2024-2028 Clean Heat Plan* 30–32 (May 2024), https://perma.cc/7XKJ-LA4Z.

[48] *See* Gundlach & Stein, *supra* note 9, at 246–47.

[49] Marion Santini et al., Regul. Assistance Project, Clean Heat Standards Handbook 36–38 (2024), https://perma.cc/Z54A-5BMQ (describing examples from Colorado, Vermont, and Massachusetts). Clean heat standards may allow for banking or borrowing of compliance credits. *Id.* at 41.

[50] *See, e.g.*, Order, Mass. Dep't of Pub. Utils., Case Nos. 23-80 & 23-81, *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan 2*, 28–58, 78–92 (June 28, 2024) (adopting performance-based ratemaking plan that seeks to align incentives of gas utilities with state greenhouse gas reduction targets); *see also* Daniel Shea, Nat'l Conf. of State Legislatures, Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy 7–8 (2023), https://perma.cc/9AAH-2K7Q.

[51] *See, e.g.*, Ill. Com. Comm'n, Thermal Energy Network Report 6–23 (2024), https://perma.cc/J7PR-3QK7.

[52] *See, e.g.*, Order on Developing Thermal Energy Networks Pursuant to the Utility Thermal Energy Network and Jobs Act, N.Y. Pub. Serv. Comm'n, Case No. 22-M-0429, *Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act* 5–6 (Sept. 15, 2022).

[53] *See, e.g.*, Notice Seeking Further Comments, N.Y. Pub. Serv. Comm'n, Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* (July 3, 2024) (requesting proposals for screening criteria, cost recovery, and incentive mechanisms for non-pipeline alternatives).

[54] Mark LeBel et al., Energy Mkts. & Policy, Berkeley Lab, Opportunities for Integrating Electric and Gas Planning 11 (2025), https://perma.cc/6RGF-QQPW.

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