Gas Regulation for a Decarbonized New York

Recommendations for Updating New York Gas Utility Regulation

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AUTHORS

Asa Hopkins, PhD
Alice Napoleon
Kenji Takahashi

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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EXECUTIVE SUMMARY

In recent years, New York has taken important steps to promote clean and efficient energy, reduce greenhouse gas emissions (GHG), and mitigate disproportionate environmental burdens. The 2019 Climate Leadership and Community Protection Act (CLCPA) calls for ambitious, economy-wide clean energy and climate targets. It requires all sectors of the state's economy to collectively achieve 40 percent emissions reductions from 1990 levels by 2030 and net zero emissions by 2050. To meet these goals, New York will need to drastically reduce fossil fuel use and shift how it regulates all energy sources—including conventional natural gas (fossil gas).

> The state's current gas planning process is not up to the task of getting the state to net zero emissions.

While the New York Public Service Commission (PSC) has been a national leader in electric utility regulation reform, on balance there has been more emphasis on transformation of the electricity sector than on reforming gas utility regulation.[1] The state's current gas planning process is not up to the task of getting the state to net zero emissions. This process lacks transparency and other elements that help ensure outcomes are broadly aligned with state policy and are in the public interest. The good news is that the Commission is posed to redress the limitations of existing gas utility regulatory processes. Responding to several recent gas utilities' claims that gas infrastructure constraints prevented them from offering new firm service, the PSC opened a new proceeding to improve the transparency and inclusiveness of the gas utilities' planning processes, supply and demand analysis, moratoria on new connections, and use of demand-reducing measures (e.g., energy efficiency, electrification, demand response, non-pipe solutions) to address supply constraints.

The CLCPA sets a high bar for the state, and meeting its targets will require having a plan to achieve them in an affordable manner. Given that gas use must decline to meet New York's climate targets, gas utilities' existing and new assets are at risk of becoming stranded. Stranding is when a change in policies, markets, economics, or other factors results in the utility being unable to recover the value it expected at the time of its investment. If gas pipelines or other assets are depreciated over their engineering lives—typically 50 to 70 years—many of them will not be fully depreciated by 2050. Assets that are not fully depreciated and cease to be used and useful will certainly prompt the question of whether and how to allow investors to recover their investment (or a portion thereof).

The confluence of the CLCPA, gas moratoria, and the Gas Planning Order presents an opportunity to redress the limitations of existing gas utility regulatory processes on planning, gas connections, retirement, cost recovery, and future business models. The time is ripe for doing so, as gas companies

[1] Throughout this white paper, the term "fossil gas" refers to conventional natural gas, while "gas" refers to conventional (fossil) gas, biomethane, and synthetic natural gas.

(and possibly their customers) will increasingly face challenges associated with balancing the need to replace aging, leaky infrastructure with the need to maintain rates that are low enough to avoid mass, unmanaged defection away from gas service and stranding vulnerable customers with unaffordable rates.

RECOMMENDATIONS FOR GAS REGULATION REFORM	
	More critically examine conventional gas investments
	Require open and integrated energy planning
	Modernize and standardize gas load forecasting
	Develop a comprehensive framework for non-pipeline alternatives
	Revisit obligation to provide gas service in light of socialized costs
	Require data reporting to inform legislation to minimize the socialized costs of new connections to the gas system
	Stakeholders should discuss and develop plans for strategic retirement of existing assets
	Provide regulatory guidance as soon as possible on how cost recovery for both new and existing stranded assets will be treated
	Require utilities and stakeholders to explore alternative business models and regulated return on investment for gas utilities

We recommend the Commission use this opportunity to explore and make reforms to address both short- and long-term challenges facing the gas utilities, their investors, regulators, and customers. Within the planning process, the Commission should more critically examine conventional gas investments, require open and integrated energy planning, modernize and standardize gas load forecasting, and develop a comprehensive framework for non-pipeline alternatives. Given that electric alternatives to gas-consuming equipment are readily available, the obligation to provide gas service should be revisited in light of gas's high costs to health, the environment, and other customers (in terms of socialized connection costs). Further, the utilities should be required to report data that will help inform legislation to minimize the socialized costs of new connections to the gas system. Stakeholders should discuss and develop plans for strategic retirement of existing assets. The Commission should provide regulatory guidance as soon as possible on how cost recovery for both new and existing stranded assets will be treated. Finally, utilities and stakeholders, including potential competitors, should explore appropriate alternative business models and regulated return on investment for gas utilities.

1. BACKGROUND

1.1. Climate and energy goals

In recent years, New York has taken important steps to promote clean and efficient energy, reduce greenhouse gas emissions (GHG), and mitigate disproportionate environmental burdens. In 2014, Governor Cuomo launched Reforming the Energy Vision (REV), a broad initiative to "reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets."[2] The 2015 State Energy Plan (SEP), which serves as a roadmap for REV, included energy-sector GHG reduction targets of 40 percent from 1990 levels by 2030 and 80 percent by 2050.[3] Surpassing the 2015 SEP goals for GHG reductions, Governor Cuomo signed into law the Climate Leadership and Community Protection Act (CLCPA) in July 2019. The CLCPA calls for ambitious, economy-wide clean energy and climate targets—requiring all sectors of the state's economy to collectively achieve 40 percent emissions reductions from 1990 levels by 2030 and 85 percent emissions reductions by 2050, as well as achieve net zero GHGs by 2050 (meaning sectors must offset any remaining emissions). The CLCPA also requires 70 percent renewable electricity by 2030 and 100 percent carbon-free electricity by 2040.[4]

CURRENT NEW YORK CLIMATE LAW

- 40% emissions reduction economy-wide by 2030
- 85% emissions reduction economy-wide by 2050
- Net zero emissions by 2050
- 70% renewable electricity by 2030
- 100% carbon-free electricity by 2040

In order to meet these goals, New York will need to drastically reduce fossil fuel usage and shift how it regulates all energy sources—including gas. The New York Public Service Commission (PSC) has been a national leader in electric utility regulation reform, yet its attention to reform of gas regulation has lagged. While the PSC has adopted aggressive targets for gas energy efficiency savings,[5] on other gas-related regulatory topics it has not shown the same progress.

[2] NY PSC 2015. Order Adopting Regulatory Policy Framework and Implementation Plan. February 26, 2015. Case 14-M-0101.

[3] The SEP also established goals that 50 percent of electricity will come from renewable energy resources and that energy efficiency savings will increase to 600 trillion Btu statewide. (https://www.nyserda.ny.gov/Researchers-and-Policymakers/New-York-State-Energy-Plan).

[4] S 6599/A 8429, available at https://www.nysenate.gov/legislation/bills/2019/s6599.

[5] The PSC's January 16, 2020 Order in Case 18-M-0084 built on earlier targets under the New Efficiency New York framework and adopted ambitious electricity and gas efficiency savings targets on par with states leading in energy efficiency achievement. As a key component in a strategy to reduce fossil fuel use in buildings, this Order establishes targets for heat pumps and adopts a novel framework to promote building electrification and set future heat pump targets.

1.2. Gas constraints and moratoria

Claiming that gas infrastructure is constrained, two New York utilities have levied moratoria on new gas connections in the past few years.

In September 2017, Con Edison filed a petition for approval of its Smart Solutions program to address its projected growing shortfall of peak day[6] pipeline capacity in Westchester county—resulting in Case 17-G-0606. The Smart Solutions program filing contained several initiatives, including an enhanced gas energy efficiency program, a gas demand response pilot, a non-pipeline alternative (NPA) portfolio,[7] and shareholder incentives. These initiatives were not, according to Con Edison, sufficient to entirely eliminate the unmet need within the timeframe of the projected shortfall.[8] The Commission approved the Company's proposal for NPAs with modifications. On March 15, 2019 the Company began a moratorium on new gas connections in Westchester County to temporarily avoid the need to build new gas infrastructure. At the time of this writing, the moratorium is still ongoing.[9]

National Grid also implemented and then lifted a moratorium on new gas hook-ups in its service areas in Brooklyn, Queens, and Long Island. Based on its identification of future needs for firm peak gas supply capacity, National Grid signed a precedent agreement for the development of a proposed pipeline project known as the Northeast Supply Enhancement (NESE) project.[10] The NESE project would have involved installing approximately 24 miles of underwater pipeline to transport gas from Pennsylvania to downstate New York.[11] When the NESE's pipeline project application was denied without prejudice by

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[6] Peak day, also known as design day, is the day of a year with the expected highest demand for gas under extreme cold weather conditions. Design day demand, which represents the utility's projection of the demand on the peak day going forward, is an input to the analysis of need for new capacity (either new gas infrastructure or new alternatives).

[7] NPAs are also called non-pipeline solutions. Discussed in more depth in Section 4.5, NPAs are collections of measures, commonly at the premises of end-use customers, that can meet the reliability need without new gas infrastructure investments. The Gas Planning Order states that "[n]on-pipeline solutions, which include temporary supply, energy efficiency, electrification, and clean demand response, can reduce or eliminate the need for gas infrastructure and investments" (Gas Planning Order, p. 7).

[8] Con Edison found that "the Enhanced Gas EE Program, the Gas DR Program, and the Gas Innovation Program may provide relief to meet approximately 3 percent of the Company's overall pipeline capacity needs by 2023. Assuming a gas supply portfolio that would include up to 10 percent of Delivered Services, the Company still anticipates a shortfall of approximately 9 percent of peak day gas needs in 2023, prior to the impact of the Non-Pipeline RFI" (Con Edison. 2017. Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, Case No. 17-G-0606 (September 29, 2017), page 26).

[9] Con Edison. About the Westchester Natural Gas Moratorium. https://www.coned.com/en/save-money/convert-to-natural-gas/westchester-natural-gas-moratorium/about-the-westchester-natural-gas-moratorium, accessed May 28, 2020.

[10] Takahashi, Kenji, et al. 2020. *Assessment of National Grid's Long-Term Capacity Report: Natural gas capacity needs and alternatives.* Synapse Energy Economics. Available at https://www.synapse-energy.com/sites/default/files/Synapse-final-report-for-EELC-%28April-15-Revision%29-20-023.pdf.

[11] Balaraman, Kavya. November 25, 2019. "National Grid lifts gas moratorium following deal with New York." *Utility Dive*. https://www.utilitydive.com/news/national-grid-lifts-gas-moratorium-following-deal-with-new-york/568044/.

the New York Department of Environmental Conservation (DEC) for the second time in May 2019, National Grid placed a moratorium in May 2019 on all new gas service connections.[12] Pursuant to an agreement with the state in November 2019, National Grid resumed connecting gas service to downstate customers for a roughly two-year period and was assessed $15 million in penalties to compensate customers impacted by the moratorium, and/or fund energy efficiency projects for them.[13] The settlement order also requires National Grid to pay $20 million to support new conservation and clean energy technologies and companies in New York to reduce reliance on fossil fuels.[14] National Grid will implement initiatives for gas energy efficiency, heat pumps, and other NPAs going forward, to reduce or eliminate the threat of shortfalls and associated new moratoria on gas connections. As of this writing, New York regulators have not yet directed National Grid to implement a specific set of solutions for any supply shortfall that might be identified based on robust modeling of future demand.

1.3. Order Instituting Proceeding on Gas Planning Procedures

Responding to several recent gas utilities' claims that gas infrastructure constraints prevented them from offering new firm service, the PSC opened a new proceeding to consider the gas utilities' planning processes.[15] The PSC's March 19, 2020 Order Instituting Proceeding (the Gas Planning Order) called for an examination of these issues:

- Locational constraint analysis
- Transparent and comprehensive information on utility planning
- Consideration of alternatives to minimize costs, preserve reliability, and advance state policies (including carbon reduction) in gas planning
- Framework for incorporating non-pipe alternatives into the planning process
- Criteria for reliance on peaking services
- Standards governing moratoria
- Demand response and rate design
- Criteria pollutant reduction
- Tariff and rule revision

[12] Takahashi, Kenji, et al. 2020. *Assessment of National Grid's Long-Term Capacity Report: Natural gas capacity needs and alternatives*. Synapse Energy Economics. Available at https://www.synapse-energy.com/sites/default/files/Synapse-final-report-for-EELC-%28April-15-Revision%29-20-023.pdf.

[13] Office of Governor Andrew M. Cuomo. November 25, 2019. "Governor Cuomo and National Grid Announce Agreement to Lift Moratorium Immediately." Available at https://www.governor.ny.gov/news/governor-cuomo-and-national-grid-announce-agreement-lift-moratorium-immediately.

[14] State of New York Public Service Commission. Order Adopting and Approving Settlement. November 26, 2019. Case 18-G-0678.

[15] State of New York Public Service Commission. Order Instituting Proceeding, March 19, 2020. Case 20-G-0131.

The Gas Planning Order requires each gas utility to file supply and demand analysis for areas with known supply constraints by June 17, 2020 and for their entire service area by July 17, 2020.[16] Also in July, the utilities are required to present a proposal on criteria for relying on peaking services and management of moratoria.[17]

The Gas Planning Order also called for utilities to file a status report on the extent to which the utility uses or anticipates using demand reducing measures (e.g., energy efficiency, electrification, demand response, NPS) to address supply constraints, as well as proposals for so doing. The PSC Staff are charged with developing and issuing a proposal to modernize the gas system planning process.[18] Both of these filings are due in August 2020.

1.4. The opportunity

The confluence of the CLCPA, gas moratoria, and the Gas Planning Order presents an opportunity to update gas utility regulation. New York has a wealth of experience to draw on for this endeavor: in recent years, the state has made major advances in electric utility planning. REV initiated the transition from a unidirectional, centralized electric system serving inelastic demand to a more dynamic system that values and increasingly relies on distributed and demand-side resources.[19] New York has an opportunity to refresh its approach to gas utility regulation on the heels of the reforms put in place on the electric side through REV.

2. Gas Utility Planning and Business Models Must Be Aligned to Achieve State Energy and Climate Goals

The CLCPA gave the state ambitious targets that necessitate careful planning. But relying on the traditional business and planning practices currently in place is inadequate to reach net zero emissions by 2050. To get a different result, the state needs to look at planning in a new way.

[16] The Order called for the utilities to file supply and demand analyses for locations known to be vulnerable to supply constraints by June 17, 2020 and to file supply and demand analyses for each local distribution company's entire service territory by July 17. The utilities requested and were granted an extension on both of these analyses to July 17, 2020 and July 31, 2020, respectively. (State of New York Public Service Commission, Case 20-G-0131 – Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, June 17, 2020.)

[17] State of New York Public Service Commission. Order Instituting Proceeding, March 19, 2020. Case 20-G-0131.

[18] State of New York Public Service Commission. Order Instituting Proceeding, March 19, 2020. Case 20-G-0131.

[19] State of New York Public Service Commission 2016. Order Adopting Distributed System Implementation Plan Guidance. Case 14-M-0101. Issued and Effective April 20, 2016.

2.1. Gas reduction has an important role in meeting GHG goals

Consumption of fossil gas must fall substantially to meet the GHG levels required by the CLCPA. In the relatively mild winter weather of 2016, gas combustion in New York's buildings and industry was responsible for emissions equal to 19 percent of the state's 1990 GHG emissions.[20] Even if the only emissions that remain in the state in 2050 are from fossil gas, sales would have to fall more than 20 percent to meet the 85 percent reduction requirement. In reality, the percentage will likely be much higher than 20 percent, as it will probably be more difficult to reduce the emissions from other sectors to zero.

Given that gas use needs to decline to meet the climate targets, gas utilities' existing and new assets are at risk of becoming stranded. Stranding is when a change in policies, markets, economics, or other factors results in the utility being unable to recover the value it expected at the time of its investment. If New York gas pipelines or other assets are depreciated over typical 50- to 70-year lifetimes, reflecting their engineering life, many of them will not be fully depreciated by 2050. This is especially true of recent capital investments, many of which were driven by legitimate concerns about pipeline safety and leaks. Meanwhile, declining gas consumption will mean that many of these assets will be increasingly underutilized or entirely unused leading up to 2050. Stranding creates hardship both for the gas companies' investors and, potentially, for their customers.

If assets that are not fully depreciated cease to be used and useful[21]—a regulatory standard for informing which assets' costs can be passed on to customers—regulators will certainly face the question of whether and how to allow investors to recover their investments (or a portion thereof). The remaining value of assets that are no longer used and useful would either be written off as losses by the gas utility (with the potential for leading to bankruptcy if they are large enough) or recovered in some way. In the case of electric utility restructuring across the country, for example, customers paid transition charges that provided compensation to utility investors for the stranded assets that resulted from that change in policy. Climate policy could result in similar effects for the gas system. However, it may be more complex in the gas case because many of the assets would be retired rather than sold, and there may be very few if any gas utility customers to bear this transition cost.

2.2. Achieving climate targets cost-effectively requires planning

Accomplishment of the state's energy and climate goals in the most cost-effective manner will likely draw on a mix of programs, policies, and processes from all sectors—including transportation and residential, commercial, institutional, and industrial buildings and processes. At the same time, it is likely

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[20] NYSERDA. July 2019. *New York State Greenhouse Gas Inventory: 1990–2016*. https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf.

[21] The used and useful principle means that only plants currently providing or capable of providing utility service to customers should be included in rate base (Bryant PhD, Mark. 2009. Ratemaking in the U.S. July 23-24, 2009. Available at https://pubs.naruc.org/pub.cfm?id=53768A01-2354-D714-517A-DC3B4EC72920).

that sources of emissions from other sectors will be technically harder or more expensive to eliminate than those from fossil gas. Responsibility should be spread across fuels and across sectors in a way that best reflects state policies, the characteristics of each sector, and the costs and benefits of the unique measures.

While the price and limited supply of biomethane and hydrogen are prohibitive to large-scale use, other alternatives are available, cost-effective, and environmentally superior to fossil gas. Gas efficiency, electrification, clean demand response, and other alternatives can help avoid new investments in gas infrastructure that are at risk of becoming stranded in the mid-term.[22] In order to limit the risk of creating additional stranded assets, avoiding investments in unnecessary new gas delivery infrastructure will be essential if New York is to cost-effectively meet its GHG targets. Identifying and prioritizing approaches to decarbonize the state that align with the state's multiple objectives requires a robust, integrated planning framework.[23]

2.3. Substantially different gas utility role requires a new business model

In a CLCPA-compliant future with declining fossil gas consumption, gas utilities will simultaneously face two potentially competing challenges:

- Maintaining rates that are low enough to avoid accelerating defection away from gas service—which, if unmanaged, could leave remaining customers shouldering tremendous costs; and
- Aging pipes that leak or pose safety risks.

Classic utility approaches to addressing these challenges individually include maximizing sales through existing pipes to lower the per-therm cost of distribution service (such as by adopting rate designs intended to induce customers to retain gas connections or use more gas) and investing in pipe replacement programs. Using either of these strategies could put the state on a collision course with the CLCPA. Actions to increase sales of fossil gas are not going to be CLCPA-compliant, and pipeline replacement would increase revenue requirements without increasing sales—thus driving rates up and exacerbating the competitiveness challenge.

In the future, gas companies could provide biomethane, renewably produced hydrogen, and/or synthetic natural gas to customers with end-uses for which economically viable alternatives do not yet exist. In setting New York's path to net zero (rather than absolute zero) GHG emissions, policymakers chose to reflect the fact that some emissions may be very difficult to eliminate, and that some kind of

[22] NY PSC. 2019. Order Approving with Modification the Non-Pipeline Solutions Portfolio. Case 17-G-0606. Issued and effective February 7, 2019.

[23] The CLCPA calls for a climate action council (CAC) to be convened to develop a plan for attainment of the statewide greenhouse gas emissions limits. The CAC process will consider a range of policies and programs, including beneficial electrification (ECL §75-0103(11) to (13)). Nonetheless, the PSC should not wait for the CAC to provide guidance to the gas utilities, given the long-term impacts that decisions made today will have. Rather, the PSC should provide guidance that is flexible enough to accommodate the CAC's recommendations.

offsets or sequestration may be necessary. Some of the emissions that are very difficult, late, or expensive to eliminate may include fossil gas system emissions from industrial processes and combined heat and power. Gas utilities may serve a necessary purpose as the providers of pipelines to bring non-fossil gas to these customers. Due to the cost of these commodities, this future presents a much smaller opportunity than the fossil gas market of today.[24]

However, as gas utilities' traditional business of delivering fossil gas through pipelines shrinks, they will likely also consider alternative lines of business. Some may be regulated, and some may be unregulated. Some may be gradual changes from existing models, while others may involve sharp breaks. Not all gas utilities are likely to choose the same path forward—in particular the path forward for joint gas and electric utilities that serve the same customers may be different from standalone gas companies. Joint companies have the potential for greater coordination of fuel-switching actions and paired infrastructure investment and retirement (see the discussion of integrated planning, below). In each case, however, regulators and other stakeholders must be prepared to engage with a wide range of options and implications and to provide the needed regulatory structure.

Whichever direction each utility decides to pursue, this end state should be used to inform each of the subsequent decisions and actions.

3. Existing Gas Planning Process Is Inadequate

The current gas planning process is not up to the task of getting the state to net zero emissions. Documentation of the current process is scattered and sparse. We understand that, under the current process, the Commission opens a docket to review the gas utility's supply plans each year. Although the Commission has broad discretion in these dockets,[25] the process lacks transparency and other elements that help ensure that outcomes are broadly aligned with state policy and are in the public interest.

Traditionally, claims of confidential data have allowed little insight into the gas plans and their underlying assumptions.[26] In the case of Con Edison, redacted information included the logic behind capacity expansion decisions, pending system expansions, requests for conversion to gas, consideration

[24] Borgeson, Merrian. 2020. "A Pipe Dream or Climate Solution? The Opportunities and Limits of BioGas and Synthetic Gas to Replace Fossil Gas." https://www.nrdc.org/experts/merrian-borgeson/report-renewable-gas-pipe-dream-or-climate-solution.

[25] Testimony of Gregory Lander on behalf of CLF, p. 37.

[26] Hodgson Russ LLP. 2020. "NYS Aligning Long-Term Planning for Gas Utilities with Carbon Neutrality Mandate." JDSupra: https://www.jdsupra.com/legalnews/nys-aligning-long-term-planning-for-gas-92596/.

of the impacts of electric markets on gas and vice versa, and other critical data. These pieces of information are fundamental to understanding and assessing the reasonableness of the supply plan.[27]

The plethora of redactions make stakeholder participation in the process difficult. Moreover, intervenors have historically not had discovery rights in these proceedings.[28] The process lacks formal records of technical conferences, and there are no evidentiary hearings.[29] The Commission has not made public its findings on the supply plans in these proceedings. In short, the current process lacks transparency, representation by affected interests, and accountability. Without these elements, it is unlikely that this process would put the gas sector and the state as a whole on track to meet CLCPA targets.

The current process lacks transparency, representation by affected interests, and accountability. Without these elements, it is unlikely that this process would put the gas sector and the state as a whole on track to meet CLCPA targets.

4. Recommendations for Gas Utility Planning Updates

New York needs to bring its gas interconnection, forecasting, planning, and new investment approval processes into alignment with its long-term climate change targets under the CLCPA. Below we discuss several key elements that need to be addressed in order to meet these targets as they relate to investments in new gas infrastructure. These elements include weighing the obligation to serve against other policy objectives, setting a higher threshold for approving new gas investments, requiring integrated resource planning, modernizing gas load forecasting methodology, developing a comprehensive framework for screening alternatives to gas infrastructure, and reforming gas connection rules. We discuss regulatory treatment and replacement of existing gas infrastructure in Section 6.

4.1. Weigh the obligation to serve in light of socialized costs to customers, health impacts, and policy goals

In New York, the obligation to serve dictates that customers can be asked to pay for new gas service connections only if the connection is over 100 feet long.[30] This obligation can put other customers on the hook for the risk that some portion of the costs of new main and service lines not be recovered.

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[27] Testimony of Gregory Lander on behalf of CLF, p. 34.

[28] Id., p. 37.

[29] Id., p. 37.

[30] PSL Section 31.

Conversely, the customer or utility currently has no obligation to evaluate whether gas is the right choice or whether other power sources may be preferable.

Lawmakers should reconsider the obligation to serve in light of gas's high costs to health and the environment, as well as the socialized costs to customers. As electricity is now able to serve almost all of the functions that gas does with lower emissions rates, the social and equity imperative to provide access to gas is simply no longer valid. It is time to divorce the obligation to provide electric service from the obligation to provide gas service, and to consider the cost of new gas service in terms of the other policy goals that it jeopardizes.

It is time to divorce the obligation to provide electric service from the obligation to provide gas service, and to consider the cost of new gas service in terms of the other policy goals that it jeopardizes.

4.2. Set a higher threshold for approving new gas investments

In general, the role of utility regulation is to encourage natural monopolies to act as if they were subject to competition and market forces. When policies or other external circumstances change, businesses in competitive markets can thrive, struggle, change approach, or even go bankrupt or dissolve. It was true of regulated telecommunications monopolies with the changes in policy and technology that ushered in a different paradigm. In competitive markets, imprudent business decisions result in falling market share and/or falling profit, as other firms take advantage.

State action on climate change is such an external change in circumstances, and utility management must make prudent decisions in this evolving context in order to be assured of the chance to earn its allowed return. The need for rapid change in the energy sector, including in the gas utility business, to meet the urgent imperative to reduce GHG emissions has been clear for many years. And now the CLCPA represents a definitive state climate policy mandate and should force a step change in gas utility management. As the Commission stated in the order on Con Edison's Smart Solutions proposal, "Gas utilities will need to maintain safe and reliable service, accommodate economic development, and improve affordability, all while carbon emissions are dramatically reduced, sales of fossil fuels decline over the longer term, and traditional infrastructure solutions become infeasible. These challenges will certainly occupy the Commission for years to come, as decarbonization policies move forward."[31] There is now a higher bar to clear for investment in new assets to be considered "prudent."

This Gas Planning docket is focused on gas utility planning and decisions to invest in new gas system infrastructure. This is but one aspect of utility management, and only one aspect that is clarified by the CLCPA. (Later in this white paper we will address a wider range of utility management issues and decisions that are also implicated and are closely related to utility planning.) When new assets are considered, the "book lives" used to assess the economics of new and existing gas resources should assume that the existing or new gas resources will be retired by a date consistent with meeting state

[31] NY PSC, Order Approving with Modification the Non-Pipeline Solutions Portfolio, February 7, 2019, Case 19-G-0606, p. 35.

GHG targets. The shorter book lives will result in a more accurate representation of the costs of new gas resources and will help mitigate the creation of stranded gas assets.

The state should take steps to raise the standard for conventional gas investments. As discussed below, the state should require all the gas utilities to demonstrate that they have considered non-pipeline alternatives before proposing conventional gas assets. In addition, such proposals should include quantitative analysis of the risks associated with each alternative.

Where utilities do pursue investments in conventional gas assets, they should be required to demonstrate how any proposal for such investment complies with state energy and climate goals. The PSC, with feedback from stakeholders in this proceeding, should provide guidance on conditions or circumstances under which investment in traditional gas assets might be a reasonable approach, for example to serve industrial processes that lack a viable electric alternative to gas. To demonstrate compliance with this requirement, utilities should provide analysis using standardized assumptions vetted by stakeholders in the current proceeding.

If the utility decides to move ahead with investment in new conventional gas infrastructure, this asset should be subject to accelerated depreciation. Depreciation lifetimes should reflect the time period over which an asset is expected to be used and useful given the state's energy and climate goals, rather than its engineering life. We discuss accelerated depreciation in Section 7.

4.3. Require integrated gas and electric planning

Meeting the CLCPA mandates will likely require extensive electrification of heating and transportation end uses. Other market and policy forces are also pushing for electrification of end-uses currently fueled by combustion of fossil fuel. For example, New York City's Local Law 97 (LL97) and the electric utilities' New Efficiency: New York programs call for ramping up heat pumps and other electrified loads.[32] In light of these pressures, it is critical to consider electric and gas consumption, prices, and impacts in an integrated manner.

In the REV proceedings, the state has made leaps forward in electric utility planning. REV initiated the transition from yesterday's grid—a unidirectional electric system serving inelastic demand—to a more modern grid—a dynamic system that increasingly relies on distributed resources and dynamic load management as alternatives to conventional, centralized power supply infrastructure.[33] Through Distributed System Implementation Plans (DSIP), the Commission required electric utilities to jointly identify and develop the tools, processes, and protocols to analyze, plan, and operate a grid capable of dynamically managing distribution resources and supporting retail markets.[34] The DSIP process

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[32] NY PSC. 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025.

[33] State of New York Public Service Commission 2016. Order Adopting Distributed System Implementation Plan Guidance. Case 14-M-0101. Issued and Effective April 20, 2016.

[34] Id., p. 3.

considers capacity constraints and the potential for deployment of distributed energy resources to alleviate those constraints. REV has moved the state toward more consistent, statewide electricity planning.

REV has also promoted transparency in electricity planning. In the order adopting DSIP guidance, the Commission explained how transparency is vital for innovation, private investment, and utility planning:

> In the context of the DSIP, improved information means greater transparency and visibility of electric system planning and operations. Greater transparency to market participants, both of system needs and of operational modes that can meet those needs, will encourage innovation and will support efficient private capital investments. Improved visibility is also critical on the utility-facing side of planning and operations to improve efficiency and resilience.[35]

The gas side of energy planning has historically seen less attention to transparency, representation by affected interests, and accountability in the planning process. As noted in the Gas Planning Order, claims of confidentiality impede transparency and participation in the planning process.[36] Increased transparency and inclusiveness in the gas planning process is critical to enable stakeholders to meaningfully participate and to ensure alignment of gas planning with state policy priorities.

The Gas Planning Order holds promise for making vast improvements in the planning process. It seeks to improve gas planning, operational practices, transparency, consideration of alternatives, and alignment with policy. It seeks a criteria-driven, data-based approach to demonstrating need and consistent standards for declaring and implementing moratoria.

While the Gas Planning Order seeks consistency in when and how moratoria are declared, it does not appear to contemplate more consistency in gas planning and methodology statewide. Aspects of gas regulations—for example, on peak forecasts and evaluation of NPAs—provide incomplete guidance to utilities on methodologies for planning, and as a result planning may be inconsistent across utilities. Yet there are many factors that do not vary from gas utility to gas utility. These include alignment with policy goals, as well as methodology and criteria for identifying and responding to locational supply constraints and for handling the uncertainty inherent in load forecasting. All of these call for a more coordinated, integrated framework and a decision-making process common to all of the gas utilities in the state. These integrated planning processes should provide a venue for the analysis of strategic retirement, discussed in Section 6 below.

It is also important that both gas and electric utilities are involved in the gas planning process, given the interrelated issues with gas and electric supply, demand, infrastructure, and emissions. Stakeholders representing a range of sectors should also be involved, including potential interveners in energy

[35] State of New York Public Service Commission 2016. Order Adopting Distributed System Implementation Plan Guidance. Case 14-M-0101. Issued and Effective April 20, 2016, p. 2.

[36] State of New York Public Service Commission. Order Instituting Proceeding, March 19, 2020. Case 20-G-0131, p. 5.

planning and rate case proceedings. Stakeholders could include representatives of consumer advocacy groups, the attorney general, the environmental community, real estate developers, housing and economic development organizations, labor organizations, energy and environment departments, affordable housing groups, low-income advocates, environmental justice organizations, and other interested groups.

New York should consider developing an independent or collaborative planning committee that would vet forecasts, screen for NPAs, and provide transparency to the infrastructure planning process. The information yielded by this group should inform the higher-level activities of the CAC. As an example of such a committee that New York could emulate, Vermont's System Planning Committee is described below.

Vermont System Planning Committee

Just as New York is now wrestling with gas planning issues that had previously not been seen as pressing, the Vermont System Planning Committee (VSPC, https://www.vermontspc.com) was created in the aftermath of the permitting of an electricity transmission line that could likely have been avoided if there had been better planning processes in place. In 2005, the Vermont legislature required VELCO, the state's electric transmission system operator, to regularly develop a long-range transmission plan, and the Vermont Public Service Board (VPSB) opened Docket 7081, an "Investigation into Least-Cost Integrated Resource Planning for Vermont Electric Power Company, Inc.'s Transmission System." The MOU that settled the issues in that docket established the VSPC, which met for the first time in 2007.

The founding purpose of the VSPC was to review VELCO's long-range transmission plan, to undertake studies necessary to be ready to seriously consider alternatives to transmission lines, and to identify opportunities for cost-effective non-transmission alternatives. As the VSPC has shown its value as a venue that convenes critical stakeholders and provides a transparent and rigorous vetting of electric utility planning issues, the VSPC's members and PUC have expanded its purview. In addition to examining potential non-wires alternatives, it now reviews distribution utility forecasts and infrastructure plans and has served as a venue for stakeholders to analyze a new kind of transmission issue for the state: a region with export constraints due to renewable generation.

This flexibility—and the trust that Vermont policymakers and stakeholders place in the group—are a result of the VSPC's structure and spirit of collaboration. The VSPC's success depends on the fact that it has been explicitly charged by the state's regulators to undertake its tasks, and its conclusions are given substantial weight by the regulators. The formal membership of the VSPC includes transmission and distribution utilities, public representatives (residential, commercial/industrial, environmental, and land-use planning), and representatives of entities that can develop supply and demand resource alternatives to utility wires investments. Policymakers attend meetings but are not formal members. By convening the same group quarterly to examine practical issues, members have developed mutual trust and understanding. Non-technical members have developed a working understanding of distribution and transmission planning, while utility representatives get a chance to address stakeholder concerns in an informal setting.

4.4. Modernize gas load forecasting methodology

One of the most critical elements of a gas planning reform is reformulating gas load forecasting to align with climate objectives.

Load forecasts serve multiple purposes. For the purpose of near-term supply planning (making sure there is enough capacity for the next few winters) utilities, regulators, and stakeholders need a different kind of forecast than the forecast used to make a long-term capital investment decision. Different horizons for forecasting should reflect different drivers and reality regarding the policies and programs. A business as usual (BAU) forecast is used for the purpose of near-term supply planning. This forecast includes the impacts of the existing policies and programs and is used to ensure there is enough capacity to meet the expected loads over the next several years and identify any capacity gaps. A long-term load forecast is used for the purpose of meeting the state's long-term policy requirements, such as GHG targets.

In order to help avoid building unnecessary gas infrastructure, the gas utilities in New York now need to develop a more credible gas load forecast based on the best available information, including the impacts of state and local decarbonization policies and market trends. A business-as-usual, historical gas consumption trend is unlikely to continue into the future due to new market trends and policies. A modernized approach to load forecasting would allow the gas utilities to accurately assess capacity constraints and the magnitude of the need for new infrastructure investments or non-pipeline alternatives. It would also ensure that gas utilities' forecasts and planning are subjected to additional scrutiny from more angles, which may not have been adequate in the past given how closed the process has been.

In order to help avoid building unnecessary gas infrastructure, the gas utilities in New York now need to develop a more credible gas load forecast based on the best available information, including the impacts of state and local decarbonization policies and market trends.

Utilities often develop their gas load forecasts for peak day and annual gas use based on econometric models which rely on long-term historical trends. This approach works fine as long as the long-term historical trends continue into the future. However, as mentioned above, the changes in markets that we are seeing now or are expecting to see are clearly different from past trends. This means that the conventional gas load forecasts need to be modified to capture these changes. Further, the state has aggressive economy-wide GHG reduction targets for 2030 and 2050, but the gas utilities are not yet prepared to meet those targets. The gas utilities need to develop long-term gas forecasts in order to find ways to meet the targets. Long-term load forecasts leading to the long-term targets will allow the gas companies to find policy and program gaps that they need to address for meeting the emission targets.

Gas load forecasting modernization requires several key updates to the utilities' gas load forecasting methodology, including:

- Use the most up-to-date assumptions on market trends for new gas connections and fuel switching

- Fully incorporate the expected impacts from existing state and local policies, especially on building electrification
- Look out far enough and in sufficient temporal and geographic detail that there is time for developing and implementing NPAs
- Develop long-term gas load forecasts that are compatible with long-term state and local climate mandates

The following subsections present in detail how the gas utilities can incorporate these updates into their load forecasts.

Use the most up-to-date assumptions on market trends and policy implementation for new gas connections and fuel switching

A business-as-usual, historical gas consumption trend is unlikely to continue into the future due to new market trends and policies. Over the past decade or more, many consumers converted to gas heating equipment from oil heating equipment because of low gas commodity prices (resulting from hydraulic fracturing—or "fracking"—and horizontal drilling) and also because gas was viewed as a cleaner fuel. This has the effect of driving up gas consumption. Now however, there are market trends pushing consumption in the other direction: efficient electric heat pumps that can reliably work in cold climates were introduced in the U.S. market several years ago and now have become a popular choice among consumers.

Econometric forecasts usually require at least a decade of past data to create a forecast. However, markets for heating fuels and technologies have changed within the last decade and will continue to change. Accounting for these changing trends in the econometric modeling will require innovation. Recent data are more representative of the future state of markets and consumer behavior than older data. Thus, utilities should put more weight on the recent data in predicting a business-as-usual trend.

For example, gas utilities often use a regression model to predict future customer counts based on a historical trend. In the future, gas utilities could use the recent conversion rates or the recent changes in customer conversion rates (from delivered fuels—mainly oil—to gas) as the basis for customer-count growth rates. Alternatively, utilities could attempt to explicitly model the changing trend and drivers (e.g., by modeling the increased customer interest in heat pumps driven by greater availability and cost-competitiveness, modulated by the relative prices of gas and electricity).

Fully incorporate the expected impacts from existing state and local policies, especially on building electrification

New policy trends have emerged in New York where the state and local governments have implemented new policies to reduce building-related GHG emissions. Such policies either set targets that specifically promote building electrification or set GHG emission targets that are strict enough to make electrification the most viable option.

For example, the NY PSC issued an order on January 16, 2020, under the New Efficiency: New York (NENY) framework set by the state, that established energy efficiency and electrification and heat pump targets for investor-owned utilities for 2020 through 2025.[37] The state's gas utilities need to fully incorporate the expected impacts from these mandates in their load forecasts.

While it is straightforward to estimate the impact from gas energy efficiency programs, it is more challenging to assess the impacts of the electric utilities' electrification programs in the gas service territories. One reasonable approach is to assess the overlaps of the electric utility programs in gas territories, based on geography, population, and/or commercial floor space. The gas utilities also need to consider whether and to what extent heat pump installations convert gas or fuel oil (or other fuels). All heat pumps that displace gas will impact gas use. On the other hand, if heat pumps displace fuel oil, utilities need to consider (a) the current saturation of oil heating customers in a given area and (b) the extent to which the oil heating customers would have had access to and considered switching to gas without the heat pump program.[38] Gas infrastructure investments are usually driven by peak winter days, so it is critical to capture whether heat pump installations will supplement gas systems that remain in place and are likely to be used, at least to some extent, on the coldest days, or if gas heating will be removed.

As another example, New York City's LL97 requires buildings larger than 25,000 square feet to meet certain carbon dioxide (CO_2) emissions limits based on building type. This regulation is relevant for Con Edison (electric, steam, and gas) and National Grid (gas) as they serve customers in New York City. The compliance period of LL97 begins in 2024, and even stricter guidelines are set for 2030. While energy efficiency measures will be vital to meet these targets and may be sufficient for the first phase of the regulation, switching to heat pump systems is likely to be a crucial and cost-effective strategy for many buildings to meet the increasingly strict 2030, 2035, and beyond thresholds. (Due to CLCPA mandates that 70 percent of electric sector generation be renewable by 2030, low grid emission rates will make electrification an even lower-carbon option in the future.) In order to estimate the expected impacts on gas use from LL97, utilities should first assess how many buildings (and how much floor area) would not meet the 2030 standards and how much emission reduction would be needed from such buildings to meet the standards, based on the current emission profiles of each building subject to LL97.[39] Secondly, utilities should determine which of the buildings would likely need to electrify their heating systems based on the estimated emission reductions required for meeting LL97.

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[37] NY PSC. 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025.

[38] An example of this analysis is found in Takahashi et al. 2020. *Assessment of National Grid's Long-Term Capacity Report*, page 27 to 29. Available at https://www.synapse-energy.com/project/assessment-national-grids-long-term-capacity-report.

[39] 2018 Energy and Water Data Disclosure, available at https://www1.nyc.gov/html/gbee/downloads/excel/nyc_benchmarking_disclosure_2017_consumption_data.xlsx.

As the state and other municipalities adopt further policies and programs that change customer behavior with respect to fuel choice and gas consumption, utilities must continue to adjust forecasts to account for their impacts.

Use a study horizon and provide sufficient temporal and geographic detail to allow NPAs to be developed and implemented

Nearly any growth-related gas pipeline investment could in theory be avoided with fuel switching, because cold climate heat pumps are now available for consumers and can technically replace all of fossil gas consumption for space and water heating for most buildings. However, it could take some time for the cumulative impacts of electrification as an NPA to be large enough to match the total amount of the expected capacity need.

Thus, it is critical for gas utilities to develop long-term gas load forecasts and identify where load might be projected to grow and when capacity thresholds of existing infrastructure might be reached. We recommend that the gas utilities develop at least a 20-year demand forecast, but ideally through 2050, and couple that forecast with the known limits of the existing gas system.[40]

Load forecasts need to be location-specific so that they can match to the location for any expected capacity gaps and needs. National Grid recently developed a load forecast specific to its Downstate New York territory consisting of its service territories in Brooklyn (KEDNY) and Long Island (KEDLI), where it presented and analyzed its expected gas supply gap for serving this area in the long term.[41] Gas utilities should develop forecasts focused on more specific locations than this when capacity constraints are a result not of the supply capacity, but of the gas distribution infrastructure. Such location-specific forecasts will allow the gas utilities to identify NPAs that can target specific locations to relieve constraints at the distribution level.

Examine the gap between long-term gas load forecasts that are compatible with climate mandates and current load trajectories

Prudent utility planning requires (a) developing a long-term gas demand forecast that reflects the full impacts of the new policies and market trends and (b) developing a long-term forecast that is consistent with recent trends (which may or may not be consistent with the future gas consumption necessary to meet state and local GHG reduction mandates). The difference between these forecasts can inform policymakers regarding the gap yet to be filled with policy or market actions. While state and local mandates do not yet specifically require the gas utilities to take further actions to reduce gas use and GHG emissions from their customer base to the level compatible with the long-term state and local GHG

[40] At least one utility in the state currently uses a 20-year period for its gas plan. See, Con Edison 2019. Gas Long-range Plan: 2019-2038. Available at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf.

[41] National Grid, February 2020, *Natural Gas Long-Term Capacity Report;* and National Grid, May 2020, *Natural Gas Long-Term Capacity Supplemental Report*. Available at https://ngridlongtermsolutions.com.

targets, it is reasonable to assume that the gas utilities need to take their equal share to meet the long-term GHG reduction targets (i.e., 40 percent by 2030 and 85 percent by 2050 under CLCPA). Thus, it is a prudent business practice to develop such a forecast so that the gas utilities can understand the magnitude of the changes that are expected to meet the long-term targets. More importantly, this practice will enable the gas utilities to prepare to develop and implement further actions (in the market, and in their own business models) in case the state and local governments implement new regulations that require the gas utilities to further reduce gas use and the associated GHG emissions.

4.5. Develop a comprehensive NPA screening framework

While gas infrastructure is in service, customers count on it to operate reliably. When reliability concerns arise, such as due to local demand growth, a traditional response is to build new infrastructure. However, avoiding making these investments where possible will reduce the risk of stranded costs and could reduce total customer costs. The underlying reliability concern that would have driven the need for the investment must nonetheless be cost-effectively addressed.

Energy efficiency, demand response, and heating electrification (e.g., using heat pumps instead of gas furnaces, boilers, or water heaters) are generally clean energy resources[42] that can work as effective NPAs to help meet gas supply and infrastructure capacity needs.[43] Building envelope improvements and heating electrification also save energy and emissions throughout the year. However, NPA analysis and design should have a higher threshold for supporting long-lived investments in gas-consuming equipment, even if the investment increases gas efficiency. For example, upgrading from a traditional gas heating system to an efficient gas furnace may reduce gas, but at the same time it prolongs reliance on gas and may represent the only opportunity to replace this equipment between now and 2050. Thus, the NPA screening process should carefully evaluate whether gas efficiency NPA measures are the only viable measure or whether other clean NPA measures that do not rely on gas equipment are available to defer gas infrastructure investments.

Other NPA measures include local biogas and local gas storage such as compressed gas. However, any new small-scale fossil gas system that could defer large gas investments should be viewed as a temporary solution as it is not compatible with CLCPA. Any biogas measure should be carefully assessed for its emission impacts as it is not correct to simply assume that biogas is emission-free on a lifecycle basis. For example, if agricultural methane emissions would be mitigated by other policies (such as requiring flaring), processing biogas to pipeline quality and using it in buildings may not reduce

[42] Some traditional gas demand response measure such as using a back-up oil boiler can result in an increase in air emissions. However, other types of demand response that shift loads, such as a storage water heater or a pre-heating a building, are clean demand response options.

[43] Con Edison proposed a portfolio of NPAs on September 28, 2018 which included targeted gas energy efficiency programs for low-income customers and government buildings and residential geothermal heat pumps and air-source heat pumps for multifamily buildings. This application was approved by the Commission's February 7, 2019 order in Case 17-G-0606.

emissions.[44] Further, processes that consider these alternative gases should explicitly and transparently account for their indoor air quality impacts (similar to fossil gas) and the potential for methane leaks.[45]

The Gas Planning Order calls for transparent and comprehensive gas utility planning that incorporates "a full range of practical alternatives so that it can serve to minimize total lifetime costs, while ensuring reliable solutions for consumers, and also while advancing state policies."[46] This order also calls for NPAs to be "integrated into gas utilities' planning processes, both in the context of specific avoidable projects in a particular area of distribution system, and system-wide to reduce overall demand and the need for infrastructure investment."[47] Further, the Gas Planning Order requires the use of the following criteria in this NPA integration process: "reliability, practicality, environmental impact, avoided need for infrastructure investments, cost allocations over the appropriate time frame, emissions, and local community impacts."[48]

The Gas Planning Order set these high-level directions but did not provide details on how exactly NPA measures should be incorporated into the gas planning process. To meet this need, this section provides a broad NPA screening framework that the gas utilities can adopt so that they can appropriately engage in an NPA screening and integration process.

This NPA framework includes the following:

- Include all available NPA measures and evaluate their cost-effectiveness at the portfolio level;
- Evaluate cost-effectiveness from the societal perspective;
- Account for lifetime impacts from NPA and demand-side measures over their measure lives;
- Consider including option value—value of flexibility; and
- Annually update the assessment of the capacity shortfalls and evaluate the status and performance of each NPA.

Gas utilities can approach the evaluation of NPA measures in two different ways. The first approach is the approach National Grid used in its recent Long-Term Capacity Report where it estimated net costs of multiple options to address the expected capacity shortfalls—including NPA, hybrid, and large infrastructure build-out options—relative to a base case (or "no action" case).[49] This approach, when conducted well, estimates net costs of the proposed options by incorporating the expected benefits

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[44] Grubert, Emily. 2020. "At scale, renewable natural gas systems could be climate intensive: The influence of methane feedstock and leakage rates." *Environ. Res. Lett.* in press. DOI 1748-9326. https://doi.org/10.1088/1748-9326/ab9335.

[45] Borgeson, Merrian. 2020. "A Pipe Dream or Climate Solution? The Opportunities and Limits of BioGas and Synthetic Gas to Replace Fossil Gas." https://www.nrdc.org/experts/merrian-borgeson/report-renewable-gas-pipe-dream-or-climate-solution.

[46] NY PSC. 2020. Page 5.

[47] Ibid.

[48] Ibid.

[49] National Grid. 2020. *Long-Term Capacity Report*.

from each option (e.g., avoided costs of gas, emissions, and avoided health impacts) and determines which option is most preferable. There is no avoided cost of any gas infrastructure option in this approach, because the gas infrastructure options are among the options being compared.

The second approach is a more traditional benefit-cost analysis used to evaluate energy efficiency and other distributed energy resources. The PSC's January 21, 2016 Order established the Benefit Cost Analysis Framework (BCA Framework) for evaluating cost-effectiveness of distributed energy resources. In this approach, NPA measures or a portfolio of NPA measures are evaluated for their cost-effectiveness (typically based on benefit-cost ratios and net benefits) against a single gas infrastructure build-out option. As required in the BCA Framework, this approach should include all benefits and costs associated with NPA measures, including the avoided costs of the gas commodity and the gas infrastructure option. In addition, NPAs should be credited with avoided emissions, avoided gas leaks, and avoided negative health impacts as benefits. The process to develop a solution to one reliability concern could use both approaches—for example by using the all-option approach to narrow the evaluation down to two options (one the traditional infrastructure solution, one the NPA), then using the BCA Framework to compare the options in detail. The BCA approach may be better suited to ongoing tracking and adjusting once an NPA is being implemented because it stays focused on the performance of the set of NPA measures relative to the base case.

Regardless of the approach taken, the above-mentioned principles for the NPA framework need to be incorporated in gas utilities' NPA evaluation process.

Include all available NPA measures and evaluate their cost-effectiveness at the portfolio level

NPA portfolios make sense when they provide net benefits relative to the pipeline or other infrastructure investment.

Given the time-sensitive and geographically limited nature of NPAs, generic program designs may not be sufficient, and programmatic innovation may be required to build cost-effective portfolios. Some measures may not be cost-effective on their own, but such measures could still be included if the overall NPA portfolio is cost-effective and those measures are essential to meet the NPA goals. Under the BCA Framework, the cost-effectiveness analysis of distributed energy resources should "assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).[50] Ultimately, an NPA portfolio that is less expensive than a proposed gas infrastructure investment saves customers money and helps meet the state and local clean energy targets. That said, investments in long-lived gas-consuming equipment should be

Investments in long-lived gas-consuming equipment should be required to pass a higher threshold, even if the investment increases gas efficiency, to avoid prolonging reliance on gas.

[50] NY PSC. 2016. Order Establishing the Benefit Cost Analysis Framework. CASE 14-M-0101. January 21, 2016, page 2.

required to pass a higher threshold, even if the investment increases gas efficiency, to avoid prolonging reliance on gas.

Evaluate cost-effectiveness from the societal perspective

The BCA Framework set the societal cost test (SCT) as the primary test for assessing the cost-effectiveness of distributed energy resources. As a primary reason for this decision, the PSC states that "New York's clean energy goals are set in recognition of the effects of pollutants and climate change on society as a whole, and only the SCT would both properly reflect those policies and create a framework for meeting those goals."[51]

Based on this perspective, the utilities in New York must include costs and benefits for society when evaluating cost-effectiveness of NPA measures. NPA costs under the societal perspective typically include the full incremental costs of NPA measures (net costs beyond the cost of standard equipment) and the cost of implementing and administering the NPA program. Key benefits from the societal perspective include avoided costs of carbon and GHG emissions, including from methane leaks from gas systems, and health damage costs. We discuss each of these benefits below.

Avoided costs of carbon. The BCA Framework requires the utilities to use the social cost of carbon developed by U.S. Environmental Protection Agency. This framework supports the aggressive CLCPA goals by appropriately valuing resources for their expected or estimated reductions in GHG.

The methodology for assessing cost-effectiveness of NPA measures should be consistent with the BCA Framework and use the same avoided cost of carbon. Both Con Edison and National Grid appropriately include the cost of carbon in their benefit-cost analysis handbooks (BCA Handbook).[52] When Con Edison filed an application for approval of its non-pipeline solutions portfolio in 2019, it included the benefit of avoided carbon values using a $50 per ton carbon value according to its BCA Handbook.[53] However, when National Grid recently evaluated demand-side investments as NPAs along with various gas infrastructure options, it initially failed to consider and quantify this benefit from the NPAs.[54] In its

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[51] NY PSC. 2016.

[52] Con Edison. 2018a. *Interim Benefit Cost Analysis Handbook for Non-Pipeline Solutions*. Case 17-G-0606. September 28, 2018. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7C3D0CD-E2B3-4B42-807C-82B553AE63F9}. National Grid. 2018. National Grid *Version 2.0 Benefit-Cost Analysis Handbook*, Case 14-M-0101, Case 16-M-0411.July 31, 2018, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B95DCC733-8863-4A52-9DE5-CF5238F40BC3%7D.

[53] Con Edison. 2018a; Con Edison. 2018b. *Request for Approval of Non-Pipeline Solutions Portfolio in The Smart Solutions for Natural Gas Customers Program*. Case 17-G-0606. September 28, 2018, available at, http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=17-G-0606&submit=SearchCon.

[54] National Grid. February 2020.

Supplemental Report, National Grid calculated the avoided societal carbon cost, although it provided the results as a supplemental (rather than core) result.[55]

Avoided cost of methane emissions. Numerous studies have revealed that the gas production and delivery process results in substantial methane leakage. Methane has a much higher global warming potential than CO_2, so even small leak rate assumptions can be substantial in the overall GHG balance between options. A 2018 study published in the journal *Science* found that the current emission leak rate from the U.S. oil and gas system is 2.3 percent, or 60 percent higher than the current leak rate of 1.4 percent used by U.S. EPA.[56] A more recent study published in April 2020 evaluated methane leaks from the Permian Basin located in New Mexico and Texas and found that 3.7 percent of gas produced in this basin is leaked into the atmosphere.[57]

Because methane leaks occur throughout the gas production and delivery process, from the extraction to the burner tips, gas use reductions through gas energy efficiency measures and other NPAs could help reduce methane leaks. Thus, a cost-effectiveness analysis of NPA measures should account for the benefits of reducing methane leaks. Utilities and the PSC should develop and use a standardized approach to methane leak rates (such as a common value for avoiding upstream emissions paired with utility-specific values for avoided distribution system leaks). This approach should be based on the latest scientific evidence and monetize the avoided methane value based on the cost of methane emission established by the Interagency Working Group (IWG) on Social Cost of Greenhouse Gases and the U.S. EPA under the Obama administration.[58] As a reference, the cost of methane is estimated to be $1,200 per ton ($2007) for 2020 at a 3 percent discount rate, according to the IWG.

Avoided cost of health damage. Gas appliances emit pollutants, in particular nitrogen dioxide (NO_2), when gas is burned in buildings. Numerous studies found links between indoor NO_2, such as NO_2 emitted from indoor gas appliances, and serious health problems such as increased respiratory symptoms, asthma attacks, and hospital admissions in people with asthma.[59] The Gas Planning Order requires the gas utilities to account for environmental and local community impacts in the NPA evaluation. (Thus, the avoidance of the potential health damages should be accounted for as a critical

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[55] National Grid. May 2020.

[56] Alvarez et al. 2018. "Assessment of methane emissions from the U.S. oil and gas supply chain," *Science.* 13 Jul 2018. Vol. 361, Issue 6398, pp. 186-188 https://science.sciencemag.org/content/361/6398/186.

[57] Storrow, Benjamin. 2020. "Methane Leaks Erase Some of the Climate Benefits of Natural Gas" E&E News on May 5, 2020. Available at https://www.scientificamerican.com/article/methane-leaks-erase-some-of-the-climate-benefits-of-natural-gas/.

[58] A website of the U.S. EPA. under Obama Administration, "Social Costs of Carbon" https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html; Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. 2016. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866. Table 1. Available at https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.

[59] Seals, Brady, and Andee Krasner. 2020. *Health Effects from Gas Stove Pollution*, Rocky Mountain Institute, Physicians for Social Responsibility, Mothers Out Front, and Sierra Club. https://rmi.org/insight/gasstoves-pollution-health.

benefit of clean NPA measures.) Utilities and the PSC should establish methodologies to quantify and monetize avoided costs of health damage from gas use reductions with help from key stakeholders in the state.

Account for lifetime impacts from NPA measures over their measure lives

The BCA Framework requires that a cost-effectiveness analysis "address the full lifetime of the investment."[60] NPA measures such as building energy efficiency, electrification, and demand response generally provide energy and peak load demand savings benefits for many years over the course of their measure lives, while the program costs and incentives for such measures are often paid upfront. Analyses of NPA measures or demand-side measures sometimes erroneously or inadvertently truncate their analysis period in a future year even though some of the measures assumed to be implemented would still operate and save more energy beyond the future year. A careful and comprehensive NPA analysis avoids such an oversight and fully accounts for the benefits and costs of NPAs over the life of the measures.

Consider including option value—value of flexibility

An option value is generated when postponing a decision on something large and expensive by implementing a small-scale and less expensive measure buys time to gain more certainty into the future and help make a better decision. An NPA can provide such option value. More specifically, cost-effective NPA measures that are individually or in combination large enough to meet near-term capacity shortfalls could allow decisions on building costly large gas infrastructure to be deferred. This would allow the state and utilities to examine how the actual gas loads develop and how long-term load forecasts change. This would then allow the state and utilities to make a better decision on infrastructure investments.

For example, a new, revised load forecast may turn out to be significantly lower than previously estimated and the need to build expensive gas infrastructure may shrink or disappear. This situation may allow the utility to cancel the construction plan entirely and save a substantial amount of customer money. However, if instead a utility built large-scale infrastructure at the beginning without examining NPA measures and later found out the infrastructure is not needed (because the expected load increase did not show up), the facility cannot be unbuilt. This would lead to a stranded asset.

NPA measures could help avoid this situation by buying time to see more accurate information on capacity shortfalls. Thus, it is important to incorporate the value of optionality when evaluating the benefits of NPA measures. Because there has not been an industry standard on the quantification of option value for NPA measures, we recommend the PSC, stakeholders, and gas utilities together investigate and develop a standardized methodology to quantify and monetize the option value to be

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[60] NY PSC. 2016, page 2.

attributed to NPA portfolios. Utilities in the region have historically used option value when analyzing resource planning decisions and parties could develop a similar approach for NPAs.[61]

Annually update the assessment of the capacity shortfalls and evaluate the status and performance of NPA measures

Load forecasts change every year as new data on gas usage and other key economic and demographic factors become available. Thus, it is important to update load forecasts every year and reevaluate capacity shortfalls. This will enable gas utilities to reassess the magnitude of the capacity need for NPA measures each year. Further, as utilities implement NPA measures, new data about the performance of NPA measures become available. For example, certain NPA measures (or a combined portfolio) may perform better or worse than expected, or new NPA measures may become available. A periodic evaluation of load forecasts and the performance of NPA measures will allow the utilities to adjust their current NPA implementation plan and implement a new NPA procurement plan that reflects the latest information on the capacity shortfalls and existing and potential NPA measures.

5. Recommendations on Gas Connection Rules

New gas services should be subject to similar rigorous review and analysis as other kinds of new gas infrastructure. Typically, customers seek connection to the gas system for newly constructed or gut renovated buildings, or to switch from other fuels such as oil or propane. In all of these cases, while the buildings already have or will have connections to the electric system, gas services are additional and optional. Today, electric heating and appliances—and all-electric homes—are very accessible and highly cost-effective. They draw on an electric grid that is increasingly powered by renewable energy and offer a cleaner indoor environment because they do not combust fuel.

In New York, state law dictates that customers can be asked to pay for new gas services only if the connection is over 100 feet long.[62] For lines that are 100 feet or less, the costs are socialized—i.e., are paid for by utility customers collectively. If customers requesting services buy gas in sufficient quantities and over a long enough period of time, the utility can recover these costs through their bills. Given the timeframe of the CLCPA and the need to decarbonize the building stock, it is likely that many of the socialized costs incurred today will not be recovered from customers before the end of the systems' useful lives, and for some classes of customers it is not clear that the costs are ever fully recovered.

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[61] Lowell, Jonathan B., 1994. "Applying Financial Option Theory to Utility Resource Planning." *Proceedings of the ACEEE Summer Study.* New England Electric. Available at https://www.aceee.org/files/proceedings/1994/data/papers/SS94_Panel7_Paper12.pdf.

[62] PSL Section 31.

The 100-foot rule effectively shifts gas costs and risks away from new customers and onto existing customers. This works against state clean energy goals, creates a barrier to electrification, and misaligns costs and benefits to customers, utilities, and society.

State lawmakers and regulators should consider several reforms to gas interconnection laws and regulations, including:

- Requiring standard definitions of and consistent reporting on drivers of interconnections across all utilities statewide;
- Disclosing the costs of gas connections to new customers;
- Minimizing socialized costs of new gas connections; and
- Reconsidering obligation to serve in light of socialized costs to customers, health impacts, and policy goals.

Require statewide, standard definitions and consistent reporting on interconnections

Gas connections costs are not transparent. Further, methodologies for calculating them are not consistent across the different utilities.[63] The incomplete and inconsistent data result in widely varying estimates of the cost of the 100-foot rule. New York Geothermal Energy Organization (NY-GEO) found that reported costs range from a low of $3,500 per customer in Niagara Mohawk's service area, to an order of magnitude higher cost of $37,000 in Orange & Rockland's territory.[64]

The lack of such information makes it difficult for policymakers to weigh and balance the state's competing goals (e.g., reduction in GHG emissions and environmental hazards, improved energy affordability, and accessibility). The state should require standard definitions of, and consistent reporting on, interconnections across all utilities statewide. Such data collection would allow reconsideration of how the many line extensions are socialized and at what cost.

Remove incentives to gas connections by minimizing socialized costs of new connections

As noted above, the statute governing new connections, the 100-foot rule (PSL Section 31.4, part 230 of 16 NYCRR), distorts incentives to customers. Reform of this rule is critical if the state is to achieve the CLCPA targets. Recommendations for revising this rule include:

- Remove or reduce the allowance of "free" line extension costs to new customers;
- Consider shifting the risk of under-collection of line costs from the customers as a whole to the new customer; and

[63] New York GEO 2020. NY-GEO Request of the Commission in Proceeding 20-G-0131.

[64] New York GEO 2020. NY-GEO Request of the Commission in Proceeding 20-G-0131.

- Weigh the obligation to serve in light of socialized costs to customers, health impacts, environmental impacts, and policy goals.

Remove or reduce the allowance of "free" line extension costs to new customers. This would require the customer who wants to extend the gas system to pay some/a greater share or the entire cost. If policymakers wish to keep some portion of the line extension free to new customers, the decision about how much to support should be informed by an analysis of societal costs and benefits, and the costs and benefits of available alternatives, over a timeline consistent with the phase-out of gas as required by the CPCLA targets.[65] This analysis should incorporate a social cost of net lifetime GHG emissions, including both combustion CO_2 and methane leakage (upstream and on-site).

When assessing how much of the extension costs to socialize, depreciation times should be consistent with state GHG mitigation targets. Moreover, the assumed expected lifetime consumption should be reduced to reflect the potential for early retirement or less use than historically expected. Both of these will also reduce the risk of stranded costs down the road.

Consider shifting the risk of under-collection of the line costs from customers as a whole to the new customer. The utility could require these customers to pay the entire cost of the extension up front and credit the customer bill over time for any socialized portion of costs. Doing so reduces risk to both the utility and to existing customers that the new customer exits gas service before the line costs are recovered in rates.

Weigh the obligation to serve in light of socialized costs to customers, health impacts, and policy goals. One implication of the obligation to serve—as codified in the 100-foot rule—is that new customers can burden other customers with the risk that some portion of the costs of new main and service lines will not be recovered. Conversely, the customer or utility currently has no obligation to evaluate whether gas is the right choice or whether other power sources may be preferable. Lawmakers should reconsider the obligation to serve in light of socialized costs to customers, health impacts, and policy goals.

6. Recommendations for Updating Gas Utility Regulations for Existing Assets

While New York's current proceeding on gas planning is focused on planning for new investments, as discussed above, building a path forward for the state's gas utilities and service in the context of the

[65] The assumption for useful life is important in this analysis. If the pipe lifetime included in the calculation of "economic" line extensions is longer or the usage is lower than the actual lifetime or usage, then some portion of the costs has been mis-assigned, and there is a risk of stranded costs.

CLCPA also requires addressing the utilities' existing assets (that is, the results of past investments). We believe that the New York PSC and stakeholders should engage with these existing asset issues as necessary context and next steps for resolving the immediate questions of planning for new gas assets that the PSC has raised in this proceeding.

Gas utilities' existing assets are at risk of becoming stranded, which would create hardship for the gas companies' investors and, potentially, for their customers. To the extent that assets that are not fully depreciated cease to be used and useful, the question will arise of whether and how to allow investors to recover their investment (or a portion thereof). Before New York allows the situation to get to that point, however, it is reasonable to allow a prudently managed utility the opportunity and time to change its approach to asset retirement and depreciation.

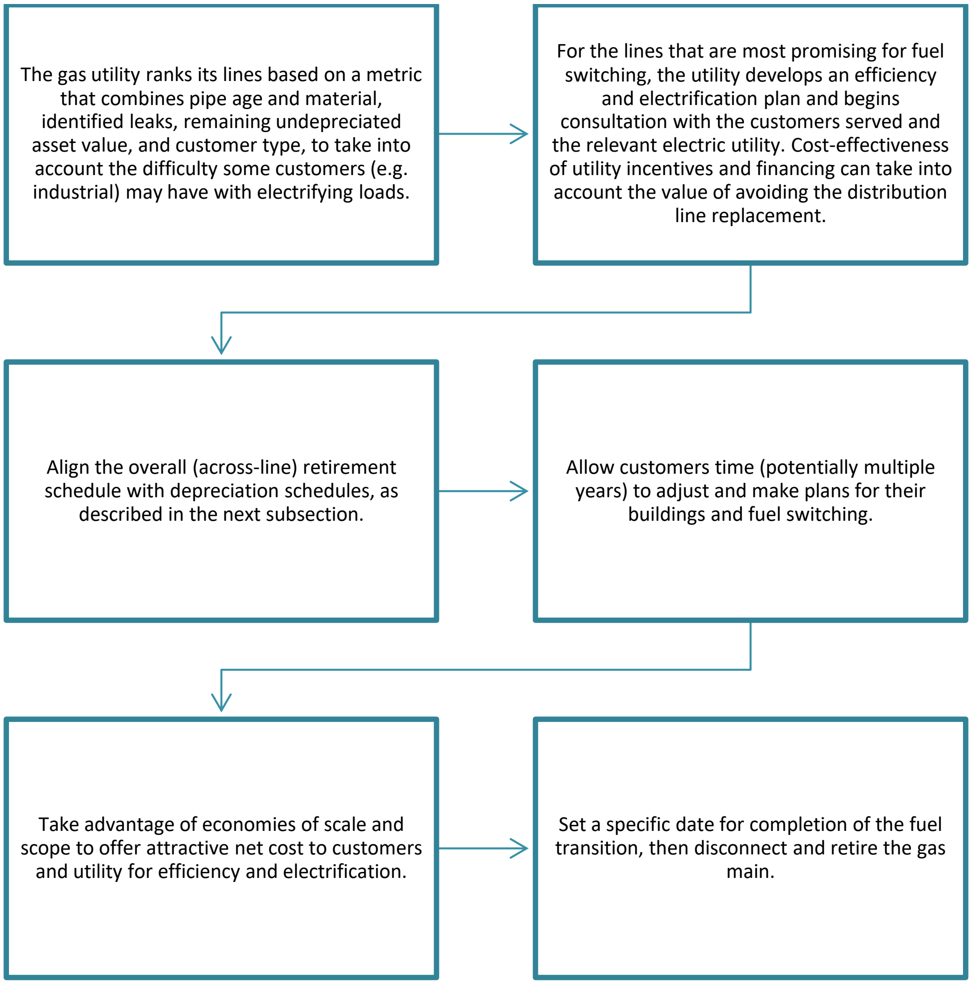
Shareholders and bondholders should have a reasonable opportunity to recover their investments, provided that their utility acts prudently and responsibly in managing the new policy context. This section identifies challenges which New York should begin to address and describes potential approaches to resolving them.

6.1. Strategic asset retirement

In a CLCPA-compliant future with declining fossil gas consumption, gas companies (and possibly their customers) will increasingly face challenges associated with balancing the need to replace aging, leaky infrastructure with the need to maintain rates that are low enough to avoid mass, unmanaged defection away from gas service—likely stranding vulnerable customers with unaffordable rates. As discussed in Section 2, classic utility approaches to addressing these challenges individually are no longer viable because they would increase sales, emissions, and revenue requirements. An alternate approach would entail strategic and planned retirement of portions of the gas distribution system. In this approach, rather than losing sales gradually on average across the service territory—and thus needing to maintain the network to serve each street—the utility would take a geotargeted approach to electrification and switch customers served by a particular distribution line, then retire that line. This approach should be particularly favorable where the gas lines in question are aging, leaking, or otherwise due to be replaced. This reduces net emissions, minimizes the asset value to be recovered through special means (see the next subsection), addresses actual leaks or the risk of leaks (reducing methane emissions and increasing safety), and opens opportunities for new business models including those built around new kinds of shared heating infrastructure (see Section 7).

Clustering electrification should also allow the electric utility to better match and pace any necessary investments in the electric system to serve new loads in the area. Rather than investing to raise the distribution capacity on an ad hoc basis driven by scattered electrification (which risks needing to rebuild as further electrification occurs) the utility could adjust the distribution network for a known new long-term load in a given area, then move to the next.

Here is an example of how this process could work:



This process could draw inspiration from that used in abandonment proceedings when a utility makes an economic case for retiring a portion of its system.[66] There are many unresolved questions about this approach, and utilities, stakeholders, and the PSC should prepare to wrestle with them. A few critical questions include:

- What is the appropriate metric to rank lines for potential retirement?
- How does planned pipe retirement relate to the utilities' obligation to serve?
- Does the obligation to serve require service in the fuel (e.g. gas) and via the mechanisms (e.g. pipeline) of the customer's choice? Or could it be generalized to oblige a utility to enable services (such as space heat and hot water)?

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[66] See, for example, Pennsylvania PUC Docket A-2011-2239521, in which NRG Energy Center Harrisburg proposed to abandon steam service to specific portions of its service territory, and the NRG Energy Center Harrisburg "Transition Service" tariff (pages 20a-20b), available at https://www.nrg.com/assets/documents/legal/overview/energy-center-rules-and-regulations/12112017-nrgh-complete-current-tariff.pdf.

- What is a fair contribution to expect from customers who are forced to switch fuels and receive new heating equipment, appliances, etc.?
- Can the gas or electric utility balance sheet be effectively used to finance the investments in each building?
- How is this process different if the customer's gas and electric utility are the same vs. different companies?
- Is it reasonable to leave unused gas mains and service lines in situ indefinitely, and save the cost of removal?

There are surely other approaches to the asset-retirement challenge, each with advantages and disadvantages. We look forward to proposals and additional discussion from utilities and other stakeholders.

7. RECOMMENDATIONS ON COST RECOVERY

Even the best planned strategic retirement plan would not be able to retire a gas utility's plant in service without leaving some stranded assets.[67] While assets may not officially become stranded (e.g., no longer used and useful) for many years, the Commission should provide regulatory guidance on how stranded assets will be treated as soon as possible, i.e., in this docket.[68] This will allow utilities to take steps immediately to address this long-term issue. Clear and early guidance from the Commission is important for three reasons:

- Better decisions regarding existing and new gas investments. Utilities will be able to make the most economic gas investment decisions as soon as possible once they are given the appropriate regulatory guidance on how stranded costs will be treated.

- Smaller and smoother rate impacts.[69] Smaller rate impacts are particularly important for managing the impact of competition between electric and gas heating, and for avoiding runaway fuel switching that leaves stranded costs with no or few customers to pay them.

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[67] For example, areas which have already been replaced with plastic piping will generally not be ready for strategic retirement before 2050.

[68] The 2019 Environmental Defense Fund publication *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California* (https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf) addresses similar issues to this section, in the California context.

[69] "Any delay in commencing accelerated recovery of depreciation expense would only mean that the same dollars would have to be collected over a shorter period with a greater impact on rates. Accordingly, it would be prudent to start recovery as soon as possible." – Testimony of Firouzeh Sarhangi, February 27, 2020, 20-G-0101, pages FS-7 and FS-8.

- Improved distributional equity. There is a high risk that customers least able to switch away from the gas system will be the customers left to pay for the stranded system. Fairness for low-income households and renters demands a solution that equitably distributes the cost of the gas system over all of its users, which means a system that distributes that cost over the appropriate period of time.

- Better inter-temporal equity. Early actions from the utility will allow for costs to start being borne in the short term to reflect the fact that today's policies and decisions are driving the costs.

The most straightforward approach to mitigating stranded cost risk is to accelerate depreciation of the assets that are likely to become stranded. Depreciation lifetimes should reflect the time period over which an asset is expected to be used and useful, rather than its engineering life. Accelerating depreciation lowers the dollar value of total shareholder returns on their investments (because their funds are not earning a return for as long). However, the investors also get the return of their capital faster, which allows them to invest those funds on other investments and earn an appropriate return. In this way, accelerating depreciation is fair to shareholders, while reducing the stranded asset risk.

New York utilities have begun to make this shift in their practice, as is prudent in light of the CLCPA. In Case 20-G-0101, Corning Natural Gas proposed to depreciate any asset classes with average remaining life that extends 2050 over a 30-year period (2020 to 2050). As Corning Gas Chief Financial Officer Firouzeh Sarhangi testified:

> Over time, this legislation [the CLCPA] will reduce gas use, revenue and access to external capital. It is critical that new mandated capital expenditures be financed with internally generated funds (principally depreciation) and that depreciable lives match the expected economic lives of utility assets. The Company believes that either systematic replacement capital expenditures have to be curtailed or the depreciable lives of assets have to be reduced. It is imperative that depreciable lives are reconciled with the expectations of the CLCPA in this case, rather than delaying such action…
>
> The new law effectively shortens the effective life of the Company's existing and future investment in infrastructure. As a consequence of these impacts of the CLCPA, we are proposing that the service lives of the Company's fixed assets be reduced to 30 years for purposes of calculating depreciation expense.[70]

Notably, Con Edison is conducting a depreciation study now that will consider these issues.

A depreciation schedule is shaped by three features: the remaining lifetime over which the asset is depreciated, the amount to be recovered, and the shape of the depreciation curve. Regarding the lifetime, once a plan is in place for the retirement of each asset, the remaining lifetime can be adjusted to ensure recovery. For new investment assets, addressing stranded asset risk means setting an

[70] Testimony of Firouzeh Sarhangi, February 27, 2020, 20-G-0101, p. FS-5 – FS-6.

appropriate depreciation lifetime when the new resource is assessed for cost-effectiveness, consistent with the results of the planning processes described earlier in this white paper. For existing assets, changing to a new depreciation schedule is possible but must be done carefully.

Typical utility practice recovers not just the initial investment in the asset, but also the end of life disposal or salvage value. (An asset that would serve some purpose for a few years and then have substantial resale value, for example, is depreciated only to the level of its resale value. The investor gets the rest of their investment back when they sell the asset.) Gas utilities may need to adjust the disposal or salvage value of their pipes depending on what the fate of these assets will be. For example, if current depreciation schedules recover some of the cost of digging up pipes to replace them at end of life, but the state decides it is suitable for gas pipes to be abandoned in place, the end of life costs may be reduced. Each utility's depreciation experts should make clear how these costs are currently calculated, and then make appropriate adjustments, subject to regulatory approval.

Utility assets are typically depreciated on a straight-line basis (e.g. for an asset with a 20-year lifetime, 5 percent of the net investment is recovered each year). However, this approach presumes that an asset will be equally used and useful for each year throughout its life. In the context of strategic recovery of the gas system, however, a faster-than-linear depreciation may be fairer. For example, if sales are projected to fall over time as customers switch to other fuels, the depreciation in each year could be proportional to the expected sales in that year.[71] This is fair because the recovery of the asset is divided over its useful service provided. Front-loading recovery to align with the time when customers are still connected could avoid leaving a small number of customers to pay the full depreciation cost late in an asset's lifetime, while creating a more stable rate trajectory.

In addition to or instead of accelerated depreciation recovered through standard rates, other options that New York stakeholders, utilities, and regulators could consider include securitization and the use of exit fees. Securitization is a process in which the utility or regulator would issue a bond and use the proceeds to pay the shareholders for the value of their current investment. Customers would then pay only the cost of the bond (and save money due to its lower cost of capital), while shareholders would receive the return of their funds and be able to make other investments. Securitization theoretically offers additional flexibility because the bond could be paid off by sources of capital other than gas rates (e.g. it could in theory be repaid through electric rates or tax revenues, after what would surely be extensive stakeholder and political process), and over a different period of time than the asset lifetime. Securitization has been used as part of the retirement of coal power plants,[72] where there is a large stranded asset whose finances can be separated from the rest of the utility. This approach is untested

[71] The projected sales trajectory could be established by the NY PSC and should be consistent with the Climate Action Council Scoping Plan.

[72] See, for example, Trabish, H. May 28, 2019. "Securitization fever: Renewables advocates seize Wall Street's innovative way to end coal." *Utility Dive*. https://www.utilitydive.com/news/securitization-fever-renewables-advocates-seize-wall-streets-innovative-w/555089/.

for the slow accumulation of early-retired assets that would accrue over the strategic retirement of the bulk of a gas utility's ratebase.

Another way to recover funds from customers leaving the gas system (and avoid leaving the last customers with the full costs of the system) would be to charge customers an exit fee as they disconnect from the gas system. We do not favor this approach for several reasons: it is gameable (customers could retain a single gas appliance to avoid paying the cost, unless a rising monthly fixed charge drives them to abandon the system); it would work directly counter to the strategic geotargeted retirement approach we described above; and more fundamentally, it would create a substantial financial barrier for customers to take actions consistent with the CLCPA.

8. Recommendations for Business Model Transition for Gas Utilities

8.1. New business models

Utilities are structured to make long-term capital investments in natural-monopoly contexts. The natural monopoly for gas delivery, which gave gas companies a corner on the space heating market, is eroded both by the increasing cost-competitiveness of electric heat pump options and policies that remove the long-term certainty as part of addressing climate change. The utilities, as businesses, may have advantages that allow them to either shift into new regulated services or compete well in unregulated spheres. For example, New York's gas utilities are already exploring providing shared ground-source heat pump infrastructure.[73] Decarbonized district heat presents another related option. Although its steam-based system could be challenging to decarbonize, Con Edison is already a district heat utility and it may be able to transition in this direction more easily than other gas companies. Shared infrastructure to provide heating service presents a potential for natural monopolies if it can result in significant cost reductions to customers due to economies of scale (albeit in the form of islands of service, rather than contiguous service territories). As such, these systems would require some form of regulatory oversight. Incumbent gas utilities and the Commission should recognize that there may be competitors to own and operate such systems, however.

[73] New York State Energy Research and Development Authority (NYSERDA). October 19, 2017. "National Grid and NYSERDA Announce Clean Heating and Cooling Demonstration Projects for Long Island Residents." https://www.nyserda.ny.gov/About/Newsroom/2017-Announcements/2017-10-19-National-Grid-and-NYSERDA-Announce-Clean-Heating-and-Cooling-Demo-Projects.

Further from today's model is "comfort as a service," where a company could own heating, cooling, and hot water infrastructure within a customer's home and collect payments for the comfort provided.[74] This would align the provider's incentives with increased efficiency of both equipment and building shells, but would require a fundamental reworking of the business model and is likely not a natural monopoly.

8.2. Consideration of competition issues

Inherent in consideration of new business models is the question of direct competition between regulated utilities selling different fuels (gas and electricity) that can provide the same service (comfort, cooking, etc.). One of the purposes of regulation is to play the role of the competition that a regulated monopoly does not naturally face.

However, the competition between two regulated utilities is not enough competition that regulators could consider some kind of deregulation (akin to telecommunications). In addition, the competition is one in which policy is very much favoring one of the market actors, so it would not be a fair contest.

> Regulators should begin to grapple with how to manage the competition between fuels in a way that advances the public interest, rather than what is necessarily in the interest of either utility.

Therefore, regulators should begin to grapple with how to manage the competition between fuels in a way that advances the public interest, rather than what is necessarily in the interest of either utility. In the case where the electric and gas companies are part of the same parent company, and shifts in staff, investment, and management attention could, in theory, execute a planned transition, regulators must remain vigilant to ensure that utilities will not take advantage of customers during the transition. Where the electric and gas utilities have different owners, regulators' role will be different and likely to be more focused on harnessing competition while overseeing business model transitions.

8.3. Return on equity

The risks to the existing gas utility business model from the policy-driven changes and the urgent need to address climate change are only going to grow. New business models are likely to be risky as well, if only due to their novelty. In a typical utility regulatory construct, investors have the opportunity to earn a return commensurate with the risk of their investment. This would imply that the allowed return on equity (ROE) for gas utilities might need to be higher. Higher allowed ROE generally corresponds to higher rates, but in the competitive context it is not clear that higher rates are sustainable.

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[74] Two United Kingdom utilities are piloting this approach. See "Industry's first: UK utilities pilot selling heat-as-a-service." February 26, 2020. Smart Energy International. https://www.smart-energy.com/industry-sectors/new-technology/industrys-first-uk-utilities-pilot-selling-heat-as-a-service/.

Changes in capital structure or value of equity may be required to address this, and it may make raising new capital challenging. It may be that a planned and managed transition for the gas company lowers risk and allows the company to maintain reasonable access to capital markets for the limited investments it needs to make as the ratebase is strategically retired. We recommend that the Commission address this important issue in depth, with diligence, innovation, and flexibility—and with input from utilities, state policymakers, and other stakeholders.