

**STATE OF NEW YORK
PUBLIC SERVICE COMMISSION**

**Proceeding on Motion of the)
Commission In Regard to Gas Planning)
Procedures)**

Case 20-G-0131



**COMMENTS OF
ENVIRONMENTAL DEFENSE FUND
ON
STAFF GAS SYSTEM PLANNING PROCESS PROPOSAL**

Dated: May 3, 2021

TABLE OF CONTENTS

INTRODUCTION	1
BACKGROUND	3
DISCUSSION.....	6
I. The Proposed Planning Process is an Important Step Forward in Gas Utility Planning, and Should be Improved to Increase Transparency and Accountability and Ensure Climate Policy Alignment	6
A. All-In Cost Metrics and Additional Information Needed for True Comparison of Alternatives.....	9
B. Depreciation Methodologies Must Be Updated	12
C. Proposed Changes to Annual Plan Filings and Gas Cost Reconciliation Process	15
D. Proposed Changes to Annual Look-Back (May 31) Filings.....	17
E. Proposed Changes to Annual Winter Preparedness Review	18
F. Proposed Changes to Supply and Demand Forecasts.....	20
G. Avoided Cost of Gas Working Group	22
II. The NPA Screening Process Should be Broadened to Allow for a More Systemized Approach to Compare All Alternatives.....	23
III. The Commission Should Adopt a Standard Method for Assessing the GHG Emissions Attributable to Specific Projects and Overall Gas Utility Operations .	28
IV. Affiliate Transactions Must be Subject to Greater Scrutiny	33
A. To Protect Against the Threat of Affiliate Abuse, the Commission Should Adopt a Clear and Transparent Framework to Compare Affiliate and Non-Affiliate Alternatives.....	33
B. The Commission Should Update and Clarify its Filing Requirements and Review Process for Affiliate Contracts.....	36
V. The Commission Must Revise Part 230 of its Regulations and Provide Clarity on the Parameters of the Public Service Law	41
A. The Commission Should Revise Part 230 of its Regulations	42
B. The Commission Should Clarify the Future Role of Gas Utilities As the State Achieves its CLCPA Objectives.....	45
C. The Commission Should Open a Second Phase of this Proceeding to Further Address Legal Barriers to the Gas Transition.....	48

VI. The Planning Proposal Must be Durable Enough to Accommodate the Policy Objectives of the State and New York City	49
A. Widespread Building Electrification, and a Corresponding Reduction in Gas Use, is Required to Achieve CLCPA Goals	49
B. The Gas Utility Planning Process Must Integrate Known Building Electrification Objectives	53
C. An Unmanaged Contraction of the Gas System Would be Costly, Particularly for Low-Income Ratepayers	56
D. The Commission Should Begin a Joint Gas-Electric Planning Process to Address the State’s Building Electrification Objectives.....	59
VII. The Commission Should Direct Utilities to Engage in a Stakeholder Collaborative to Develop a Process for Strategic Decommissioning Portions of the Distribution System	61
VIII. The Commission Should Direct Utilities to Deploy Super-Emitter Programs to Address Gas Leaks and Remove Barriers to Advanced Leak Detection Technology Adoption	64
IX. The Commission Should Evaluate Generator Pricing Rules in Light of New York State’s Evolving Policy and Regulatory Environment	69
A. Gas Generators Require Tailored Transportation and Balancing Services to Meet their Variable Needs	71
B. Bringing Enhanced Price Discovery and Transparency to Natural Gas Transportation and Balancing Services Will Spur Competition in the Electric Market.....	73
C. Suggested Recommendations to Improve Electric Generator Rate Design	75
CONCLUSION.....	76
APPENDIX OF ATTACHMENTS.....	78

INTRODUCTION

The New York Department of Public Service Staff (“Staff”) Gas System Planning Process Proposal (“Planning Proposal”) represents a meaningful step towards improving the current gas planning process. However, improvements to the Planning Proposal are necessary to ensure that New York gas utilities align their investments and operations with state climate law. The Planning Proposal correctly requires utilities to develop long-term plans that are reviewed annually, but those long-term plans must be tied to cost recovery to ensure accountability, and the selection process for individual infrastructure projects should be more rigorous to protect against stranded assets. The Planning Proposal identifies the need for a stringent test for new infrastructure tied to associated greenhouse gas emissions, and EDF offers a tool for calculating utility greenhouse gas (“GHG”) emissions associated with all gas supply and demand relief options. The New York Public Service Commission (“Commission”) and Staff acknowledge the need to subject affiliate transactions to greater scrutiny, but the Planning Proposal is inadequate to abate the threat of affiliate abuse and the Commission must clarify its process for reviewing transportation and precedent agreements.

The Commission must also take steps to prepare for an energy future that will look much different. As New York pursues its climate targets, infrastructure once deemed to be used and useful may no longer be needed—and that transition will accelerate over the next decade as the State and New York City deploy their stated electrification plans and programs. To prepare for this future, EDF recommends additional planning efforts that the Commission should require, including a Joint Feasibility Assessment to be conducted by both gas and electric utilities to identify the challenges, opportunities, and barriers to high electrification scenarios as well as a

stakeholder collaborative to begin to assess the costs, feasibility, GHG impacts, and barriers to decommissioning portions of the gas system.

The Climate Leadership and Community Protection Act (“CLCPA”) creates a new imperative for the Commission to update policies and regulations to support GHG emission reductions within the existing law—and to identify and root out standards that conflict with the mandates of the CLCPA, such as Part 230 of the Commission’s regulations governing the requirements for which residential applicants for natural gas service may be entitled to a certain amount of infrastructure for free. The Commission should also provide guidance and clarity regarding the future role of gas utilities and find that gas utilities are entitled to meet customers’ and prospective customers’ thermal needs through technologies that do not rely directly on the combustion of methane. Providing this clarity will serve the public interest, as it will foster the development of alternate methods of delivering energy in line with the state’s climate objectives, encourage early adoption of new technologies, and help reduce customer costs.

The Commission should address methane leakage from the existing gas system by directing utilities to deploy Super Emitter Programs to address the largest leaks on their systems and remove barriers to advanced leak detection technology adoption. Facilitating adoption of this technology and removing barriers to its implementation will allow utilities to design leak repair, replacement, and retirement programs that achieve the maximum methane emissions reductions possible.

The Commission should also evaluate its generator pricing rules in light of the future needs of New York’s electric grid. In order for gas generators to provide the required ramping capability to the electric grid, they need to be able to access gas supplies and capacity services that correspond to their daily variations in load. New balancing tariff services should be

explored to ensure that one of the most essential attributes of our future electric grid—flexibility—is accurately priced.

Considering the users of the gas system during this transition, changing energy demand and utilization patterns, and the equity of the transition itself, is critical. Incorporating EDF’s recommendations will strengthen the Planning Proposal into a comprehensive planning framework that meets today’s needs and is also durable enough to accommodate changes that will be required as the state achieves its climate objectives and the Climate Action Council provides further direction.

BACKGROUND

The CLCPA was signed into law by Governor Cuomo on July 18, 2019 and took effect January 1, 2020.¹ The CLCPA mandates that the State of New York adopt measures to reduce statewide GHG emissions by 40% by 2030 and 85 percent by 2050 (from 1990 levels), with an additional goal of achieving net zero emissions across all sectors of the economy by 2050 (the remaining 15 percent can come from carbon offsets).² The Act also requires adoption of a state energy plan to produce 70% of electricity from renewable sources by 2030, and to achieve a zero-GHG-emission electricity sector and increase energy efficiency 23% (from 2012 levels) by 2040.³ Additionally, the CLCPA recognizes the importance of addressing emissions of the

¹ New York State Climate Leadership and Community Protection Act (“CLCPA”), 2019 N.Y. Laws 106, available at <https://legislation.nysenate.gov/pdf/bills/2019/S6599>.

² CLCPA § 1(4); *id.* § 2 (N.Y. ECL § 75-0107(1)).

³ CLCPA § 1(12)(d); CLCPA § 4 (N.Y. PSL § 66-p(2)).

greenhouse gas methane, which causes 84 times as much global warming as the equivalent amount of carbon dioxide over a twenty-year horizon.⁴

New York government analyses indicate that significant reductions in natural gas use will be required to achieve the CLCPA targets. According to the New York State Energy Research and Development Authority's ("NYSERDA") New York State Greenhouse Gas Inventory released in July 2019, the state's 1990 GHG emissions totaled 236.19 million metric tons ("MMT").⁵ An 85% reduction from that total yields a 2050 GHG emissions budget of 35.42 MMT. The same Inventory also tells us that as of 2016, the combustion of natural gas was producing more than 70 MMT of GHGs.⁶ In other words, the most recent Inventory suggests that natural gas combustion *alone* yields GHG emissions that are more than double the state's 2050 economy-wide emissions budget. The New York Department of Environmental Conservation issued its rule setting a statewide emissions limit in December 2020, calculating that statewide GHG emissions in 1990 were 409.78 MMT (carbon dioxide equivalent) and setting a 2050 statewide limit of 61.47 MMT.⁷ Under either the NYSERDA or NY DEC 1990 estimate, current natural gas use is responsible for more GHG emissions than the *entire* statewide 2050 budget. And since some amount of the 2050 budget will presumably have to come from other uses, it is clear that natural gas combustion must significantly decrease.

⁴ CLCPA § 2 (N.Y. ECL § 75-0101(7)); Direct Testimony of Joseph von Fischer on behalf of EDF at 5-6, Transcript Vol. 9 at 5584-85 (Aug. 30, 2019) ("EDF von Fischer Testimony").

⁵ NYSERDA, *New York State Greenhouse Gas Inventory: 1990-2016* at Table S-2 (July 2019), <https://www.nyserd.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf>.

⁶ *Id.* at Figure S-4.

⁷ 6 NYCRR § 496.4, https://www.dec.ny.gov/docs/administration_pdf/revexpterm496.pdf.

Section 7 of the CLCPA requires that “all state agencies,” “[i]n considering and issuing . . . administrative approvals and decisions, . . . shall consider whether such decisions are inconsistent with or will interfere with the attainment of the statewide greenhouse gas emissions limits established in article 75.”⁸ If an agency concludes that its action is inconsistent with the GHG emission limits, the agency “shall provide a detailed statement of justification as to why such limits/criteria may not be met, and identify alternatives or greenhouse gas mitigation measures to be required where such project is located.”⁹ Additionally, state agencies are required to “not disproportionately burden disadvantaged communities” and “shall also prioritize reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities.”¹⁰

On March 19, 2020, the Commission issued an order instituting this proceeding, Case 20-G-0131, to consider issues related to gas utility planning procedures.¹¹ The Commission acknowledged that “conventional gas planning and operational practices adopted by natural gas utilities have not kept pace with recent developments and demands on energy systems,” as indicated by several New York utilities’ decisions to declare moratoria on new gas service over the past several years.¹² The Commission stated that planning must be conducted consistent with the CLCPA and acknowledged that the “current approach to gas system planning poses risks of incomplete alignment with [the] CLCPA.”¹³

⁸ CLCPA § 7(2).

⁹ *Id.*

¹⁰ *Id.* § 7(3).

¹¹ NYPSC Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Order Instituting Proceeding (Mar. 19, 2020).

¹² *Id.* at p2.

¹³ *Id.* at p6-7.

In its March 2020 order, the Commission established a procedural schedule under which each gas utility was required to submit a supply and demand analysis for areas vulnerable to supply constraints and subsequently for its entire service territory.¹⁴ Per the order, gas utilities then filed proposed criteria for reliance on peaking services and then filed status reports regarding current and anticipated use of demand-reducing measures.¹⁵ The Commission directed Staff to submit a proposal to modernize the gas system planning process in August 2020, but Staff requested multiple deadline extensions and the Commission Secretary granted the requested extensions.¹⁶ Staff submitted a Gas System Planning Process Proposal (“Planning Proposal”) and a Moratorium Management Proposal to the Commission on February 12, 2021.¹⁷

DISCUSSION

I. The Proposed Planning Process is an Important Step Forward in Gas Utility Planning, and Should be Improved to Increase Transparency and Accountability and Ensure Climate Policy Alignment

The Planning Proposal establishes a much-needed framework for gas utilities to plan investments and meet demand on a long-term timescale through a process that is more transparent and inclusive. The Planning Proposal correctly states that “short-term and long-term

¹⁴ *Id.* at p11-12.

¹⁵ NYPSC Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Joint LDCs, Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management (July 17, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=249491&MatterSeq=62227>.

¹⁶ *See, e.g.*, Letter from Michelle Phillips, Secretary of NY Pub. Serv. Comm’n, to Brandon Goodrich, Assistant Counsel, NY Dept. of Pub. Service, Re: Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* (Jan. 8, 2021) (granting Staff’s request for an extension and extending the deadline for the Staff proposal to Feb. 12, 2021).

¹⁷ NYPSC Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, NY DPS Staff, Staff Gas System Planning Process Proposal and Staff Moratorium Management Proposal (Feb. 12, 2021) (“Planning Proposal”).

processes are both necessary and should be consistent with each other.”¹⁸ The components of Staff’s proposal include, for each utility: a long-term plan every 3 years, an annual plan, an annual look-back filing (due May 31),¹⁹ an annual winter preparedness review, and rate cases approximately every 3 years. Each of these components are appropriate and should be incorporated into a Commission-mandated planning process for gas utilities. This framework can and must be improved, however, to ensure that near-term investments are connected to a utility’s long-term plan and to promote accountability and transparency in decision-making, consistent with the Commission’s order in this proceeding.

Staff’s recommendation that each gas utility should develop a long-term plan on a 20-year time horizon will provide an important basis for utilities, Staff, stakeholders, and members of the public to collectively ensure that a utility is appropriately planning to align its operations with New York climate targets under the CLCPA while avoiding moratoria. EDF recommends several additional items of information that utilities should provide in their long-term plans, annual reports, and annual look-back filings. EDF also recommends that the all-in cost metric be incorporated into the planning process to allow for an accurate cost comparison of alternative supply projects and non-pipes alternatives. EDF further recommends that the annual gas cost reconciliation process be directly connected to the long-term and annual plans. Table 1 summarizes the Planning Proposal and changes recommended by EDF:

¹⁸ *Id.* at p7.

¹⁹ At page 12 of the Planning Proposal, Staff recommends that by May 31 of each year, each utility should provide detailed information about the previous year’s gas throughput, actual gas load, and other items. EDF refers to this filing as the “annual look-back” because it allows regulators and stakeholders to look back at what happened during the prior year. enabling a prompt comparison of “plan” to “actual.”

Figure 1. Comparison of Current Planning Process, Staff’s Planning Proposal, and EDF’s Proposed Additions

Current Planning Process ²⁰	Staff Planning Proposal (blue text indicates Staff changes)	EDF Planning Proposal (green text indicates EDF changes)
<ul style="list-style-type: none"> • Rate Cases – Utility-initiated, approximately every 3 years • Annual Winter Preparedness Review – Staff issues data requests to gas utilities in May, responses due mid-July 	<ul style="list-style-type: none"> • Long-Term Gas System Plan, every 3 years • Annual Report on Gas System Plan, every year except when a Long-Term Plan is filed • Annual “Look-Back” Filing (due May 31) • Rate Cases – Utility-initiated, approximately every 3 years • Annual Winter Preparedness Review – Staff issues data requests to gas utilities in May, responses due mid-July 	<ul style="list-style-type: none"> • Long-Term Gas System Plan, every 3 years <ul style="list-style-type: none"> ○ Additional info should be provided • Annual Report on Gas System Plan, every year except when a Long-Term Plan is filed <ul style="list-style-type: none"> ○ Additional info should be provided • Annual “Look Back” Filing (due May 31) <ul style="list-style-type: none"> ○ Additional info should be provided • Rate Cases – Utility-initiated, approximately every 3 years • Annual Winter Preparedness Review – Staff issues data requests to gas utilities in May, responses due mid-July <ul style="list-style-type: none"> ○ Additional info should be provided • Annual Gas Cost Reconciliation, per 16 NYCRR 720-6.5(g) – this preexisting process should be tied to the Long-Term Plan.

²⁰ The Planning Proposal identifies additional existing planning-related filings required of gas utilities, such as Article VII certificates and required contract filings. *See* Planning Proposal, Appendix at p17, 19. Those filings are not included in this chart because they are not altered or affected by the planning proposals detailed herein.

A. All-In Cost Metrics and Additional Information Needed for True Comparison of Alternatives

As New York works to achieve the CLCPA targets, there is a need for a transparent demonstration of the true demands of the gas system and the all-in costs of meeting that demand with various resources, being mindful not to lock-in greenhouse gas emissions from unnecessary long-lived and possibly stranded infrastructure. To ensure that the planning process facilitates fulsome consideration of these issues, utilities should be required to calculate and report the all-in cost of different proposals (as explained below) and utilities should be required to provide additional supply and demand information beyond what is detailed in the Planning Proposal.

Existing metrics do not allow for easy comparison of the varied supply and demand options utilities might consider—such as a contract for existing pipeline capacity vs. a home weatherization program to reduce demand—and therefore a different assessment tool is needed. To address this deficiency, the Commission should require the use of the all-in cost metric to compare the true costs of different supply and demand options. This will help stakeholders compare different options and ensure that costs to ratepayers are minimized appropriately.

The all-in cost is determined by looking at the annual facilities' fixed costs plus commodity/O&M cost per unit of demand met taking into account the load factor of the annual demand to be met, or of the Design Day demand to be met. This allows for an apples-to-apples comparison of different supply-side and demand-side options based on how often they will actually be used (or based on design day). The formulas are provided below.

$$\text{All-In Cost (Design Day)} = \left(\frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected Design Day Dth of use (i.e., quantity) of project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

$$\text{All-In Cost (Estimated Use)} = \left(\frac{\text{the sum of the fixed cost per year of the project + the fixed O\&M cost (if any) of the project (i.e., total annual non-gas cost)}}{\text{the projected annual use (i.e., quantity) of/by or through the project (to arrive at modeled per Dth of use non-gas cost)}} \right) + \text{the variable commodity cost per Dth of the project} + \text{the variable O\&M cost per Dth (if any)}$$

The all-in cost metrics should be incorporated into several elements of the Planning

Proposal:

- **Non-Pipes Alternative (“NPA”) Framework** – The NPA Framework proposed by Staff would be used to compare alternative project options, including to assess opportunities for the deferral or elimination of traditional gas distribution infrastructure.²¹
 - If the Commission adopts EDF’s recommendation to expand this framework into an open RFP process, the all-in cost metrics should be required to be presented in all proposals and detailed in the utility’s selection process. See *infra* Part II.
 - If the Commission adopts Staff’s NPA Framework proposal, assuming the yet-to-be-developed NPA suitability criteria will assess project costs, utilities should be required to report both of the all-in cost metrics for each option under consideration. Recognizing that Staff has proposed that each utility will develop its own suitability criteria, the Commission should

²¹ Planning Proposal at p8.

establish guardrails for those criteria that apply to all utilities, including the use of the all-in cost metrics.

- **Long-Term Plans** – The Planning Proposal contemplates that a utility’s long-term plan must detail each identified supply need and include a “no infrastructure option.”²² Utilities should be required to calculate and report the all-in cost metric for each current or proposed source of supply, including the no infrastructure option under consideration. This is particularly valuable so that when stakeholders have the opportunity to comment on the initial long-term plan and present alternatives, they can engage in an apples-to-apples comparison of each option using the all-in cost metrics. See Attachment 1.
- **Annual Plans** – See Part I(B) below, and Attachment 1.
- **Annual Look-Back (May 31) Filing** – See Part I(C) below, and Attachment 1.

The Planning Proposal correctly states that utilities “must include the information necessary to enable stakeholders to understand the balance of supply and demand,” and utilities “must provide necessary system data that allows for timely and effective engineering, operations, and business analyses needed to support well informed decisions.”²³ Utilities should be required to provide the information detailed in the Planning Proposal in support of their planning filings, and they should be required to provide additional information that is necessary to allow for a comprehensive assessment of demand and supply options and their utilization by the utility, Commission, Staff, and stakeholders.

The graph at page 16 of the Planning Proposal, which demonstrates an example representation of a 20-year portfolio in MDth/day of supply and demand, should be also stated in MDth/hour over the same 20-year planning horizon. This same level of detail (i.e., MDth/day and MDth/hour of supply and demand information) should be provided at the geographic operational level (i.e., Westchester, Long Island, Albany, Rochester, etc.). Providing this

²² Planning Proposal at p7.

²³ *Id.* at p13.

localized information should enable identification of current, as well as potential future, geographic areas needing attention.

The utilities should be required to present winter period (November-March) and non-winter (April-October) hourly as well as daily load duration curves with the resources identified as serving those load durations (i.e., the resource stacks). These load duration curves and resource stacks should cover both the historic previous 5-year periods and project the future load duration. In the long-term plan filings, the future daily and hourly load duration curves should be presented both as systemwide and by geography using the same geographic regions as those presented above to enable utilities, regulators and stakeholders to identify current as well as potential future geographic areas needing attention.

The additional information that should be required in utility planning filings is detailed in Attachment 1 to this comment.

B. Depreciation Methodologies Must Be Updated

There is a fundamental disconnect between the depreciation analysis employed by many New York gas utilities and state climate policy (as well as some of the utilities' own climate commitments). New York agencies are articulating a vision for a clean energy future that significantly reduces reliance on natural gas, but many gas utilities continue to rely on traditional assumptions that they will maintain and expand their existing gas distribution systems and depreciate assets at historic rates. These disparities must be reconciled. Addressing this problem would be consistent with the industry standard NARUC Depreciation Manual, which

acknowledges multiple factors that drive retirement of utility plant, including “requirements of public authorities,” i.e., law and policy.²⁴

EDF presented detailed testimony on the need to update depreciation analyses in a recent rate case.²⁵ The testimony demonstrates that, for one example gas utility under its currently proposed depreciation rates, the company would be recovering the costs of existing plant until 2086, and will have an undepreciated balance of \$186 million in 2050.²⁶ The testimony presents an illustrative scenario under which the remaining service lives of all mains and services on the company’s system would end by 2050, such that the plant would be fully depreciated at that time. This depreciation scenario does not assume that all mains and services *will* be retired by 2050—rather, parts of the distribution system could still be in operation but the company would have fully recovered the costs. Other stakeholders have observed that it could be more appropriate to use a shorter average depreciable life of 15 or 20 years for gas plant, to reflect the expectation that segments of the distribution system may be retired well before 2050.²⁷

²⁴ See NYPSC Case No. 20-G-0381 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of James Garren on behalf of Environmental Defense Fund at p21 (Nov. 25, 2020). <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256482&MatterSeq=63187> (citing NARUC Depreciation Manual p14-15).

²⁵ *Id.*, Direct Testimony of James Garren.

²⁶ This analysis considers the largest plant accounts: transmission and distribution mains accounts and distribution services accounts. *See id.* p24-25.

²⁷ See NYPSC Case No. 20-G-0381 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Rebuttal Testimony of Ezra Hausman, Ph.D., on behalf of Sierra Club and Natural Resources Defense Council at p13-15 (Dec. 16, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=257465&MatterSeq=63187>. Changes to accelerate the depreciation schedule to make existing infrastructure in line with climate goals is only one method; additional options are detailed in an EDF report “Managing the Transition: Proactive Solutions for Stranded Gas Assets in California,” available at www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

Several utilities are already starting to address this issue in individual proceedings,²⁸ and the Commission should provide state-wide guidance going forward. Specifically, the Commission should require each gas utility to undertake a new depreciation study that accounts for the effect of the CLCPA and climate policy on the company's service life and net salvage expectations. Such depreciation studies should not only assess the effect of climate law and policy, but should establish appropriate survivor curves for use in base rate filings. The Commission could require these depreciation studies be incorporated into each gas utility's first Long-Term Plan or into its next rate case. Additionally, the Commission and Staff should consider developing guidance for utility depreciation studies to ensure that climate policy is appropriately considered and that any new costs are allocated in the most equitable way.

While measuring the precise impact of New York climate policy will take further analysis, there is no question that both in the cost of new investments and in the accelerated retirement of old investment, the actions required of gas utilities to meet the CLCPA target of net-zero greenhouse gas emissions by 2050 will need to be carefully managed to ensure equitable outcomes. Any delay in reaching a plan for the depreciation of these assets is going to entail a significant burden on future gas consumers at the expense of current gas consumers. The Commission should particularly consider how to address mitigate bill impacts for communities

²⁸ Consolidated Edison Company of New York Inc.'s Joint Proposal, approved by the Commission, obligates the Company to file a study on "the potential depreciation impacts of climate change policies and laws on its gas, electric, steam, and common assets." *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Case 19-G-0066 Joint Proposal at 113 (Oct. 18, 2019), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=234578&MatterSeq=58902>. Corning Natural Gas Corporation in New York states that, as a consequence of New York's climate law, Corning's assets (and improvements that reduce GHG emissions) should be permitted to have "depreciable lives [that] match the expected economic lives of utility assets." *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service*, Case 20-G-0101, Direct Testimony of Firouzeh Sarhangi at FS-5 (Feb. 27, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241529&MatterSeq=62108>.

that already experience disproportionate energy burdens—such as low-income, African American, Latino, and renters who pay up to three times more than the average household on home energy costs.²⁹

C. Proposed Changes to Annual Plan Filings and Gas Cost Reconciliation Process

EDF agrees with Staff that utilities should be required to submit the information identified at pages 11-12 of the Planning Proposal in their Annual Plan filings. In addition, a utility's Annual Plan should provide a direct comparison to the projections set out in the most recent Long-Term Plan, and the Annual Plan process should be explicitly tied to the annual gas cost reconciliation process.

Currently, each gas utility engages in annual gas cost reconciliation before the Commission, in which the utility submits a reconciliation of actual gas cost recoveries with actual gas expenses each year and computes a surcharge accordingly.³⁰ The computation is to be filed with the Commission by October 15 each year, addressing the preceding 12-month period ending August 31.³¹ Based on review of the public filings in the dockets, this process appears to be a limited proceeding where utilities submit cost information for Staff review and the Staff issues a summary report.³² It does not appear that the Commission approves the individual

²⁹ Ariel Drehobl and Lauren Ross, *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities*, ACEEE (2016), <https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf>.

³⁰ 16 NYCRR 720-6.5(g).

³¹ *Id.*

³² See NYPSC Case 20-G-0395, *In the Matter of the Filing of Annual Reconciliation of Gas Expenses and Gas Cost Recoveries for 2020*, Staff Report Regarding Reconciliation of Purchased Gas Expense and Gas Recoveries (filed Dec. 17, 2020, updated Jan. 27, 2021), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=259769&MatterSeq=63269>; NYPSC Case 20-G-0395, *In the Matter of the Filing of Annual Reconciliation of Gas Expenses and Gas Cost Recoveries for 2020*, Con Edison 2020 Annual GCF Reconciliation Effective January 2021 (Oct. 15, 2020),

filings or rules directly on the Staff report. In 2020, for example, Staff stated in its report that it “has completed the review of each LDC’s annual reconciliation filing,” explained that it made recommendations to a utility to correct errors, and concluded that “all LDC’s surcharge or refund rates should be allowed by the Commission to become effective January 1, 2021.”³³

This process can be improved, and the establishment of a long-term planning framework with annual reporting provides an important opportunity to clearly connect utilities’ actual cost recovery to their long-term plans.

A joint proposal submitted by Rhode Island Staff and the utility to the Rhode Island Public Utilities Commission (“RIPUC”) employs a similar process to align the gas utility’s long-term plan with its annual gas cost recovery. Under this framework, Narragansett Electric Company (d/b/a National Grid) submits a long-range plan that is subject to approval by the RIPUC and uses the same forecasts from the long-range plan in its annual gas cost reconciliation filings, such that the gas cost reconciliation will be “a proceeding that effectively reconciles costs from known and supported commitments.”³⁴ The utility “shall prepare a comparison of volumes and costs presented in its GCR [gas cost reconciliation] filing in the same form (i.e., presentation format) as its annual LRP [long-range plan] filing from June of the same year and identify any differences,” which ensures that “[b]y the time the GCR is filed, these items found in the Company’s LRP submission will have already been fully vetted.”³⁵

<http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=254051&MatterSeq=63269>.

³³ NYPSC Case 20-G-0395, *In the Matter of the Filing of Annual Reconciliation of Gas Expenses and Gas Cost Recoveries for 2020*, Staff Report Regarding Reconciliation of Purchased Gas Expense and Gas Recoveries at p7 (filed Dec. 17, 2020, updated Jan. 27, 2021).

³⁴ Attachment 2: RIPUC Docket No. 4816, *Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27*, Joint Memorandum of the Narragansett Electric Company d/b/a National Grid and the Division of Public Utilities and Carriers at p3 (Feb. 20, 2019).

³⁵ Attachment 2, *id.* at p7.

To apply these principles in New York, each Annual Plan should present both the projection for peak and annual gas use from the last Long-Term Plan (i.e., as filed) for the coming year, alongside the updated projection (of peak and annual gas use) for the same year—presenting this updated view as a variance from the Long-Term Plan. This variance from the Long-Term Plan is an updated projection of the year ahead. Then, during the utility’s gas cost reconciliation proceeding, this updated projection can and should be used as the baseline against which the recovery of actual costs is benchmarked. This process—i.e., presentation of Long-Term Plan, followed by evolution of the plan in subsequent Annual Plan filings, finally resulting in the “actual” results of the plan in the gas cost reconciliation—would provide the Commission, Staff, and stakeholders with an explicit way to gauge the degree to which “plans” converge with “actual” as well as depict the degree to which “actuals” diverge from “plan.”³⁶

Such analysis of how past plans evolved and became actual will inform current and future planning and enable more meaningful and achievable expectation-setting associated with policy and costs. This information can in turn inform the pace, effectiveness, and limits (if any) associated with policies to achieve New York climate goals.

D. Proposed Changes to Annual Look-Back (May 31) Filings

The look-back analysis detailed in the Planning Proposal is a valuable addition to the gas utility planning framework because it allows regulators and stakeholders to compare the prior Annual Plan against the reality of the past year. In addition to the information the Planning Proposal would require utilities to file by May 31 in an annual look-back, each utility should also be required to file a review of the prior year’s actual All-In Costs (both Design Day and per

³⁶ Additional proposed changes to the information presented in the Annual Plan are detailed in Attachment 1.

Estimated Use) as a way of evaluating the prior year's Annual Plan and informing the projections for the current and subsequent years.

Unlike the gas cost reconciliation process, the May 31 look-back filing is focused on management of the long-term and annual plans, achievement of metrics identified in the planning process, and a high level view of operations in the context of plan management. The Planning Proposal explains that “[a]s each year progresses, this will allow stakeholders to see whether efficiency programs need to be adjusted, and if the utility’s efforts to control demand growth have been effective.”³⁷ This look-back filing will be useful and is distinct from the detailed accounting and associated metrics presented in the gas cost reconciliation proceedings.

The Planning Proposal correctly specifies that gas utilities “should identify and make available to clean heat developers at least the minimally necessary data to enable them to develop demand-side solutions.”³⁸ To the maximum extent possible, such data should be made completely public, but if a utility requests confidential treatment of this data, the Planning Proposal is correct that the utility should propose a pathway for entities to appropriately access the data through non-disclosure agreements or similar means. EDF looks forward to comments from other stakeholders regarding what data might be needed to support the development of demand-side solutions such as electrification of gas load.

E. Proposed Changes to Annual Winter Preparedness Review

The annual winter preparedness review has historically been a closed process between Staff and individual gas utilities with little to no accessibility for other stakeholders. For example, gas utilities often redact information from their publicly responses to Staff data

³⁷ Planning Proposal at p12.

³⁸ *Id.*

requests in this proceeding, claiming confidential business information.³⁹ As the Commission ordered and the Planning Proposal acknowledged, it is important that gas utility planning become a more transparent and inclusive process.⁴⁰ Those principles should extend to the annual winter preparedness review, such that the Commission should encourage utilities to minimize redactions, and where redaction of confidential business information is deemed necessary, the Commission should ensure a process is in place for stakeholders to gain appropriate access to data, such as by entering nondisclosure agreements.⁴¹

Furthermore, the annual winter preparedness review should be updated to ensure that it does not impose expectations and objectives on gas utilities that may be in conflict with New York climate law and policy. In 2020 data requests from Staff—issued after the CLCPA took effect—utilities were asked to detail all “natural gas distribution system expansion projects . . . being pursued in the next five years,” and if there were none, explain how this was “justified given the Commission’s stated goal of expanding the gas system in New York State,”⁴² (referring to a 2012 Commission Policy Statement⁴³). The Staff data requests also asked gas

³⁹ See, e.g., NYPSC Case No. 20-M-0189, *Report on the New York State Electric & Gas Supply Readiness for 2020-2021 Winter*, Con Edison Winter Supply Review Data Request at p6, 41-70 (July 15, 2020).

⁴⁰ See NYPSC Case No. 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Order Instituting Proceeding at p3 (Mar. 19, 2020); Planning Proposal at p10.

⁴¹ See Planning Proposal p12 n.8.

⁴² NYPSC Case No. 20-M-0189, *Report on the New York State Electric & Gas Supply Readiness for 2020-2021 Winter*, Con Edison Winter Supply Review Data Request at 33 (July 15, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=249285&MatterSeq=62435>.

⁴³ NYPSC Case No. 12-G-0297, *Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service*, Order Instituting Proceeding and Establishing Further Procedures (Nov. 30, 2012), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=83153&MatterSeq=40220>.

utilities if they “see new opportunities to expand gas services, regardless of the ever-changing cost differential between natural gas and its alternatives?”

Staff should revise its approach to the annual winter preparedness review docket to better align with the objectives of the CLCPA, and the Commission should consider revising out-of-date policies such as its 2012 policy statement (*see infra* Part V).

F. Proposed Changes to Supply and Demand Forecasts

The Planning Proposal would allow each gas utility to determine for itself how to incorporate demand management, energy efficiency programs, electrification, and “other external impacts” into its 20-year demand and supply forecasts.⁴⁴ The Proposal states that utility supply forecasts “should clearly state if the forecast maintains the status quo as of a specific date or historical period, adjusts for current Commission-approved spending levels, or assumes some other level of change or trend in outer years.”⁴⁵

While some utility discretion may be warranted due to unique service territory characteristics, the Commission should provide guidance to ensure that utilities incorporate into their forecasts both utility-run programs (efficiency, demand response, electrification, etc.) as well as external policies and programs that can be expected to influence demand and thus needed supply. National Grid’s approach to long-term demand forecasting is a positive example: “That forecast reflects current New York climate and energy policies—e.g., New Efficiency New York

⁴⁴ *See* Planning Proposal at p14-15, 17.

⁴⁵ Planning Proposal at p17.

gas energy efficiency and heat electrification. As additional policies are implemented, the Company will update its annual long-term natural gas demand forecast appropriately.”⁴⁶

As new policies are formalized by the Commission and other agencies to implement the CLCPA, the Commission or Staff should update their guidance to gas utilities regarding what information should be incorporated into demand and supply forecasts. Examples of external programs that should be considered by gas utilities in developing their demand and supply forecasts are: the forthcoming Building Electrification Roadmap and Carbon Neutral Buildings Roadmap from NYSERDA;⁴⁷ the forthcoming Scoping Plan from the Climate Action Council, which is expected by January 1, 2022;⁴⁸ and natural gas demand reduction efforts by New York City and other local governments.

A revamped forecasting framework will be needed to incorporate the demand changes related to climate goals. Improvements to demand forecasts could follow recommendations already being considered or implemented on the electric side, including incorporating weather impacts attributable to climate change, embedding state climate goals into the model, explicitly modeling non-pipeline alternatives, and requiring forecasts to be based on publicly available data and publicly available accessible models.

⁴⁶ Attachment 3: NYPSC Case Nos. 19-G-0309 & 19-G-0310, *In the Matter of The Brooklyn Union Gas Company d/b/a National Grid NY & KeySpan East Gas Corporation d/b/a National Grid*, National Grid Response to Data Request No. EDF-7 (Feb. 8, 2021).

⁴⁷ NYSERDA, *Toward a Clean Energy Future: A Strategic Outlook 2021-2024* at p48-49 (Jan. 2021), <https://www.nysERDA.ny.gov/About/Publications/Program%20Planning%20Status%20and%20Evaluation%20Reports/Strategic%20Outlook> (“NYSERDA Strategic Plan”).

⁴⁸ N.Y. E.C.L. § 75-0103(11).

G. Avoided Cost of Gas Working Group

In light of the outstanding questions and issues detailed in the Planning Proposal, EDF supports the creation of an Avoided Cost of Gas Working Group. Although the utilities, by necessity, may be the source of much of the data that this Working Group will need to develop accurate metrics, it is important that regulators and other stakeholders have a voice in the development of such metrics.

The Planning Proposal identifies a need for estimates of avoidable upstream fixed and variable costs on the wholesale capacity markets.⁴⁹ One possible estimation would be to use a basket of previous projects' costs plus any known or estimable factors which would increase those previous projects' costs, to establish working metrics for avoidable wholesale market costs. The Planning Proposal identifies a need to include avoided distribution costs in BCAs for energy efficiency programs, and to develop a more accurate Marginal Cost of Service ("MCOS") tool to determine these avoided costs. These are important metrics that should be part of a BCA framework. It is essential to accurately determine the costs that can be saved by avoiding an expansion of the distribution system, or by a managed contraction of the distribution system.

The Planning Proposal identifies a need for standards to be applied to "nontraditional methane" in order for it to qualify as "renewable gas."⁵⁰ Any such standards must incorporate analysis of the greenhouse gas emissions attributable to such nontraditional methane compared to traditional natural gas. In order for gas utilities to "claim" any achieved GHG emission reductions from nontraditional methane, the utility would have to procure any renewable energy credits associated with the fuel. If credits are available and can be purchased by another entity,

⁴⁹ Planning Proposal at p23.

⁵⁰ *Id.* at p24.

then the utility is not actually claiming the benefit of the GHG emission reductions unless it purchases those credits.

II. The NPA Screening Process Should be Broadened to Allow for a More Systemized Approach to Compare All Alternatives

In the Planning Proposal, Staff proposes that the utility’s long-term plan should identify any infrastructure constraints and then should identify traditional supply-side solutions, demand management programs, and a no-infrastructure alternative requiring “consideration of other approaches to reduce gas demand.”⁵¹ The Proposal recommends that larger capital projects would trigger a requirement for a full-scale solicitation of NPA alternatives. Rather than engaging in a solicitation of NPA alternatives as a side effort that may not be prioritized if a utility already has a preferred supply-side option lined up, the Commission should consider employing a more systemized approach to comparing alternatives that could either provide natural gas supply or demand relief.

EDF proposes a framework that builds on Con Edison’s December 21, 2017 Request for Proposals submitted in the Smart Solutions proceeding (Case No. 19-G-0606) and borrows from other state processes used to discipline affiliate transactions.⁵² In brief, the retail gas utility

⁵¹ *Id.* at p18.

⁵² See *Application of Pacific Gas and Electric Company for Authorization to Enter into Long-Term Natural Gas Transportation Arrangements with Ruby Pipeline, for Cost Recovery in PG&E's Gas and Electric Rates and Nonbypassable Surcharges, and for Approval of Affiliate Transaction*, California Public Utilities Commission (“CPUC”), Decision 08-11-032, November 6, 2008 Order at 85-93, 118-122 (citing CPUC D.04-09-022; CPUC D.06-12-029, Appendix A-3, Rule III.B.1; CPUC D.04-12-048) (explaining that the CPUC’s rules require utilities to use an open and transparent solicitation process when involving affiliates and have a neutral independent evaluator review solicitations that involve affiliates); Direct Testimony of Greg Lander, Missouri Public Service Commission Case No. GR-2017-0215, GR-2017-0216 at Schedule EDF-06 (September 8, 2017) (proposing modifications to the gas supply and transportation standards of conduct).

would issue a Request for Proposals (“RFP”), seeking a broad array of innovative solutions that could either provide natural gas supply or demand relief.

This competitive-type process would not only protect against affiliate abuse—see discussion in Part IV below—but would also incentivize Capacity Service Providers⁵³ to develop solutions that are narrowly tailored (in terms of size and cost) to the ultimate need⁵⁴ while minimizing costs, GHG emissions, and adverse impacts on communities and the environment.⁵⁵ To ensure genuine comparison of costs and climate impacts, the process should include consideration of the All-In Cost metrics (*see supra* Part I(A)) and New York DEC Value of Carbon and Methane Guidance.⁵⁶ As a result of this robust and competitive process, the retail gas

⁵³ A Capacity Service Provider is an entity that provides, for a price, one or more Capacity Service(s). Capacity Service is defined as one or more asset(s), service(s), product(s) or any combination of same that enables the ultimate need (as defined below) to be met. Examples of Capacity Service Providers would include: (1) a pipeline that provides firm transportation service to the Retail Gas Utility or end market served by the Retail Gas Utility; (2) an entity that sells CNG, RNG and/or LNG delivered into the Retail Gas Utility and/or into a pipeline able to effectuate firm incremental delivery to the Retail Gas Utility or end market served by the Retail Gas Utility; (3) an entity that provides a firm, bundled capacity and commodity service to the Retail Gas Utility or end market served by the Retail Gas Utility; (4) demand response providers whose demand response reduces demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days; and (5) Energy Efficiency providers whose energy efficiency measures reduce demand of specified end use customers during hours of peak demand – typically early morning and evening periods on peak demand days .

⁵⁴ The ultimate need must be defined clearly and substantiated by the Retail Gas Utility.

⁵⁵ For instance, an interstate pipeline could distinguish its proposal by incorporating additional features that would provide environmental benefit such as enhanced methane reduction measures. *See, e.g.*, Iroquois Spring 2020 Report, https://www.iroquois.com/site/assets/files/1057/spring_2020_safety_issue_web.pdf (“As part of the ExC Project, Iroquois plans to reduce methane and overall emissions at project sites through the installation of low Nitrous Oxide (NOx) turbine units that will reduce NOx emissions by 40% over standard turbine units, as well as adding oxidation catalysts on the newly installed turbines, thereby reducing Carbon Monoxide (CO) emissions by approximately 90%. In addition, Iroquois is proposing to install methane recovery systems at each project site to capture released natural gas from station operations.”).

⁵⁶ *See* NY DEC, *Establishing a Value of Carbon: Guidelines for Use by State Agencies* (Dec. 2020), <https://www.dec.ny.gov/regulations/56552.html>.

utility would have several options to choose from and its selection process would be transparent and apparent to the Commission and interested stakeholders.

1. [Retail Gas Utility] will use a competitive bidding process in which requests for proposals (RFPs) are submitted by [Retail Gas Utility] to Capacity Service Providers to provide either natural gas-supply or natural gas-demand relief. For any exceptions to the competitive bid and award process, [Retail Gas Utility] will have a documented process for the approval and award process, including (a) justification requirements, (b) authorization process, (c) contemporaneous documentation requirements (for internal Company information and external communications), and (d) effective monitoring and controls. [Retail Gas Utility] will maintain internal controls such that no information regarding the content or subject of communications by and between non-affiliate potential bidders and [Retail Gas Utility] personnel with access to such information shall be communicated or made accessible to personnel of [Retail Gas Utility] affiliate(s).
2. The RFP process shall be open to all Capacity Service Providers who wish to bid and shall be publicly posted on the [Retail Gas Utility's] website and filed with the Commission. The intent is to gain the broadest practical participation by eligible Capacity Service Providers in submitting competitive bids. Once such a process is reasonably developed, appropriately implemented and effectively monitored and controlled, the results of that process are intended to establish the most innovative solutions to provide natural gas-supply or natural gas-demand relief, considering the all-in cost metrics, GHG emissions, as well as impacts on communities and the environment. [Retail Gas Utility] shall require that proposals quantify the GHG emissions associated with their offer, using an agreed-upon methodology such as the Gas Company Climate Planning Tool presented in Part III of this comment.⁵⁷ [Retail Gas Utility] shall provide the Commission with a report, including an explanation of any credit, performance or other criteria that [Retail Gas Utility] takes into consideration in developing the RFP. This report should include a comparison of all bids received based on the New York DEC Value of Carbon and Methane Guidance, as well as any BCA adopted by the Commission.
3. No affiliate of [Retail Gas Utility] shall be awarded a capacity service contract where such contract would result from an exception to the competitive bid and award process. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] as a result of the RFP or other competitive bidding process, the affiliate shall be held to the same performance requirements as non-affiliated Capacity Service Providers.
4. In the event a capacity service contract is awarded, [Retail Gas Utility] shall maintain the following contemporaneous documentation: (a) any diversity, credit, or reliability-related capacity limitations placed on the maximum capacity [Retail Gas Utility] will purchase from an individual Capacity Service Provider (if applicable); (b) an explanation of the diversity, credit and/or reliability-related reasons for imposing such limitations (if applicable); (c) a description of the process used to evaluate bids, and negotiate final prices

⁵⁷ M.J. Bradley & Associates, New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

and terms; (d) a complete summary of all bids received and all prices accepted, together with copies of all underlying documents, contracts and communications; (f) a summary and explanation of Capacity Service Providers disqualified for credit, performance or other criteria, and (g) a copy of the policy or procedure employed by [Retail Gas Utility] for awarding contracts in instances where an affiliate and an unaffiliated Capacity Service Provider have offered identical pricing terms. For phone calls or texts, [Retail Gas Utility] shall maintain contemporaneous logs documenting the discussions and decisions.

5. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility], the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the affiliate's bid price was equal to or lower than the bids received from non-affiliates.
6. In the event a capacity service contract is proposed to be awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which no other bids were received, [Retail Gas Utility] shall re-issue an RFP to the broadest practical set of eligible Capacity Service Providers in order to obtain competitive capacity service bids for the capacity service contract proposed to be awarded to an affiliate of [Retail Gas Utility].
7. In the event a capacity service contract is awarded to an affiliate of [Retail Gas Utility] for a capacity path between a supply receipt area and a delivery area along or through which [Retail Gas Utility] also received bids for and/or awarded capacity service contract(s) to non-affiliated Capacity Service Providers, the [Retail Gas Utility] shall maintain contemporaneous documentation showing that the price established under the contract awarded the affiliate was within or lower than the range of prices established under contracts awarded to entities other than the affiliate.
8. If the affiliate's bid price or contract price does not meet the criteria in paragraphs 5, 6 or 7, [Retail Gas Utility] may not award the capacity service contract to the affiliate, unless the [Retail Gas Utility] can demonstrate and contemporaneously document that a more favorable bid was rejected for legitimate reasons relating to the rejected bidder or bidders' creditworthiness, performance history (or lack thereof), or other consideration bearing on the fitness and reliability of the bidder to provide the requested service.
9. In the interests of optimizing the competitive benefits of the RFP process, the RFP will explicitly inform potential bidders that [Retail Gas Utility] permits Capacity Service Providers to propose alternative ways of satisfying the ultimate need, including but not limited to basic quantity, reliability, receipt, delivery and pricing terms of the RFP in addition to those specifically contemplated by the RFP. The RFP may also utilize ranges for such quantity, reliability, receipt, delivery, pricing and/or other terms.

This type of proposed framework has numerous benefits. It will bring enhanced clarity and transparency to available supply and demand alternatives, spur innovative solutions to facilitate the objectives of the CLCPA, and assist the Commission, Staff, utilities, and interested

stakeholders in making informed decisions in shaping the future energy system. As noted above, other jurisdictions employ a similar framework, and this type of before-the-fact review of any interstate capacity contracts would also assist the Federal Energy Regulatory Commission in its decision-making at the federal level.⁵⁸ And as discussed in Part IV of these comments, such a framework is necessary to achieve Staff’s objective of applying heightened scrutiny to affiliate transactions.

The proposed RFP framework could also help alleviate concerns that gas utilities might promote supply projects as urgent in order to avoid considering NPAs. The Planning Proposal provides that “projects addressing conditions that pose an immediate threat to system reliability and/or public safety, or where construction is imminent, i.e., within 12 months, such as immediate work related to gas leaks or high priority leak-prone pipe segments, would be exempted from consideration for a NPA.”⁵⁹ But under the RFP framework, NPA providers would have the opportunity to respond to an RFP like any other capacity service provider. There may be some emergency situations where a utility must bypass the RFP process, but the Commission could also approve a shortened-timeline RFP process for use when near-term projects are absolutely necessary. It is important, however, to guard against the possibility that utilities could (1) present projects as immediate or urgent to avoid comparing alternatives, or (2)

⁵⁸ See Preliminary Determination on Non-Environmental Issues, *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224 at P 37 (Sept. 4, 2009) (finding the proposed Ruby pipeline and transportation contract “consistent with Commission policy” in part because the California Public Utilities Commission “directed PG&E to replace expiring contracts on GTN in order to diversify PG&E’s gas supply, and, after evaluating several options, the CPUC approved PG&E’s acquisition of capacity on Ruby’s proposed pipeline”).

⁵⁹ Planning Proposal at p18-19.

break large projects up into smaller chunks for approval, in order to qualify for the expedited track described in the Planning Proposal.⁶⁰

Under Staff’s proposed NPA Screening Process or EDF’s proposed RFP process, the perspectives of interested stakeholders and community members are relevant to the review process. The utility should be required to identify and describe the responses it receives to an RFP, and stakeholders should be able to submit requests for information to the utility. The utility’s long-term report and annual reports should contain lists of (1) RFPs issued over the last two years where a proposal has been selected, detailing the selected proposal; (2) pending RFPs where a proposal has not yet been selected; and (3) anticipated upcoming RFPs.

III. The Commission Should Adopt a Standard Method for Assessing the GHG Emissions Attributable to Specific Projects and Overall Gas Utility Operations

In initiating this planning proceeding, the Commission stated that it “seeks to establish planning and operational practices that best support customer needs *and [GHG] emissions objectives* while minimizing infrastructure investment and ensuring the continuation of reliable, safe, and adequate service to existing customers.”⁶¹ The Commission further stated that “incomplete or insufficiently transparent planning can lead to adverse consequences,” including increases in GHG emissions.⁶² Carrying forward this important focus, Staff stated in the Planning Proposal that “calculating and reporting the emissions of greenhouse gas associated with all solutions, both supply-side and demand-side, is necessary for transparency when

⁶⁰ See *id.* at p19 (“Smaller projects would utilize an expedited standardized review approach (Expedited Track), including a streamlined economic and technical analysis. The purpose of this is to determine the potential economic and technical feasibility of an NPA that may or may not include a full-scale solicitation for NPA options.”).

⁶¹ Order Instituting Planning Proceeding at p4 (emphasis added).

⁶² *Id.* at p3.

considering choices among alternative solutions.”⁶³ The Planning Proposal also puts forward the concept of a “stringent test for new infrastructure” due to the reality that new gas infrastructure “may not help the State achieve its greenhouse gas reduction goals.”⁶⁴

The Commission and Staff are correct to emphasize the importance of calculating and reporting GHG emissions associated with supply/demand solutions, because plans to expand and fortify natural gas infrastructure could lock in greenhouse gas emissions and costs for decades. It is essential that chosen solutions drive continued reductions in statewide GHG emissions, consistent with the CLCPA. EDF has emphasized before the Commission the importance of requiring gas utilities to report on their GHG emissions in a meaningful and consistent way, so that progress can be tracked over time and so that individual solutions can be compared against each other.⁶⁵

The Commission has an obligation under the CLCPA to consider whether its approvals and decisions are “inconsistent with or will interfere with the attainment of the statewide greenhouse gas emissions limits established in article 75.”⁶⁶ The Commission is also required to “prioritize reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities.”⁶⁷ To ensure that it makes informed decisions and can assess the GHG emissions

⁶³ Planning Proposal at p26.

⁶⁴ *Id.*

⁶⁵ See NYPSC Case No. 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of Joseph von Fischer on behalf of EDF at p28, (Nov. 25, 2020); NYPSC Case Nos. 19-G-0309 & 19-G-0310, *In the Matter of The Brooklyn Union Gas Company d/b/a National Grid NY & KeySpan East Gas Corporation d/b/a National Grid*, Post-Hearing Brief of Environmental Defense Fund at p5-7 (Apr. 6, 2020); NYPSC Case Nos. 19-G-0309 & 19-G-0310, *In the Matter of The Brooklyn Union Gas Company d/b/a National Grid NY & KeySpan East Gas Corporation d/b/a National Grid*, Direct Testimony of James Fine on behalf of EDF (Feb. 6, 2020).

⁶⁶ CLCPA § 7(2).

⁶⁷ CLCPA § 7(3).

impact of a given course of action, the Commission should build into the planning process requirements that gas utilities must use a common methodology to calculate the GHG emissions associated with a proposed project, and to project their overall GHG emissions out to 2050.

To this end, EDF commissioned M.J. Bradley & Associates to develop a framework—the Gas Company Climate Planning Tool—to enable regulators, gas utilities, and the public to understand and assess the lifecycle GHG emissions of gas utilities.⁶⁸ The tool and accompanying framework report are appended to this comment as Attachment 2. M.J. Bradley summarizes the framework as follows:

The Gas Planning GHG Framework is comprehensive and flexible, so it can be used in several ways. It can be used to evaluate different portfolios of gas supply options against each other, to compare specific discrete options against each other, or to evaluate the effect of a proposed portfolio on state-wide GHG reduction goals.

The Gas Planning GHG Framework consists of a life cycle approach that accounts for GHGs emitted throughout the entire value chain of natural gas and other fuels, from production all the way through end use. For convenience, the framework follows the convention of dividing the fuel life cycle into three segments that are consistent with the data sources recommended for use in calculating emissions at each stage: 1) upstream, 2) LDC operations, and 3) end-use.⁶⁹

The Gas Planning GHG Framework is based on the following six core principles:

1. Account for all combustion-related GHG emissions and fugitive methane emissions.
2. Account for both supply- and demand-side options to manage and meet gas demand.
3. Use the most recent, publicly available data.
4. Identify and incorporate significant uncertainties.
5. Align the analysis with economy-wide GHG emission reduction targets under the CLCPA.
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.⁷⁰

⁶⁸ Attachment 4: M.J. Bradley & Associates, New York Gas Company Climate Planning Tool and New York Gas Planning Greenhouse Gas Framework (May 2021), https://mjbradley.com/mjb_form/Gas-tools.

⁶⁹ M.J. Bradley & Associates, New York Gas Planning Greenhouse Gas Framework at p4 (May 2021).

⁷⁰ *Id.*

The tool and accompanying framework report incorporate a methodology consistent with the CLCPA—for example, the framework applies a lifecycle GHG analysis, which is consistent with the CLCPA directive to consider upstream GHG emissions attributable to end-use in New York. Additionally, the framework applies a Global Warming Potential of 20, as directed by the CLCPA; and incorporates the recent Value of Carbon Guidance issued by the New York Department of Environmental Conservation⁷¹ to calculate the social cost of GHG emissions savings compared to a business-as-usual scenario. Figure 1 demonstrates a sample results table generated by the tool:

Figure 2. Sample Results Table from Gas Company Climate Planning Tool



⁷¹ NY DEC, *Establishing a Value of Carbon: Guidelines for Use by State Agencies* (Dec. 2020), <https://www.dec.ny.gov/regulations/56552.html>.

As Staff recommended in the Planning Proposal, the Commission should require transparent reporting of GHG emissions by utilities, including that utilities must provide a GHG emissions assessment for any proposed capital project. If the Commission were to adopt the RFP framework detailed in Part II above, then bidders should be expected to present GHG emissions projections as part of their bid, and if the utility selects a proposal that does not have the lowest associated GHG emissions then the utility must justify why the selected proposal is aligned with achieving the CLCPA goals. Additionally, the Planning Proposal should be updated to require that gas utility Long-Term Plans should include a GHG emissions projection out to 2050, to demonstrate how the utility is contributing to CLCPA targets. The Annual Plan should be updated with any adjustments to the GHG emissions projection. Any “variance” in the Annual Plan reflecting an adjustment from the Long-Term Plan should be accompanied by a corresponding projection of the impact on the utility’s GHG emissions.⁷²

All stakeholders and members of the public should be able to have a voice in gas utility planning, as the Commission and Staff have recognized. The Gas Company Climate Tool furthers that objective by allowing anyone to conduct a GHG emissions analysis for a given gas utility. This is important because it allows stakeholders to compare supply and demand options on their own terms, and not just be tied to the information provided by the utility. EDF and M.J. Bradley & Associates will continue to update the tool as methodologies for calculating GHG emissions improve over time.

Every dollar of gas utility investment either brings New York closer to or further from the state’s climate targets. EDF submits this framework to puts decision makers on the right path to select investments that make economic sense, protect the environment, and are equitable. The

⁷² See Attachment 1.

Commission, Staff, and gas utilities should apply this tool to comprehensively assess life cycle GHG emissions associated with each utility. Utilities, regulators, and stakeholders in New York and across the country can begin using this tool today.

IV. Affiliate Transactions Must be Subject to Greater Scrutiny

Building on previous advocacy, EDF presents recommendations to strengthen the Planning Proposal and current Commission practice with regard to affiliate transactions.

A. To Protect Against the Threat of Affiliate Abuse, the Commission Should Adopt a Clear and Transparent Framework to Compare Affiliate and Non-Affiliate Alternatives

In the Order Instituting Proceeding, the Commission directed Staff to review affiliate relationships to examine incentives that are not aligned with state policies.⁷³ While the Order stated that Staff should examine the practice of procuring pipeline supply from affiliate companies, Staff has extended that directive to also apply to the practice of procuring pipeline capacity from affiliates.⁷⁴ The Planning Proposal states that going forward, “such arrangements should receive more scrutiny given New York’s desire to reduce the construction of unnecessary infrastructure and the possible creation of stranded assets that would accompany those assets.”⁷⁵ The Commission should adopt Staff’s recommendation, as it is consistent with New York precedent finding that the “PSC’s broad authority to determine just and reasonable rates includes not only the right but the duty to scrutinize transactions between a utility and its affiliates”⁷⁶

⁷³ NYPSC Case 20-G-0131, Order Instituting Proceeding at p7 (Mar. 19, 2020) (“the practice of procuring pipeline supply from affiliated companies should also be examined for incentives that are not aligned with state policies.”).

⁷⁴ Planning Proposal at p31, n.14.

⁷⁵ *Id.* at p32.

⁷⁶ *Rochester Tel. Corp. v. Pub. Serv. Comm’n*, 201 A.D.2d 31, 35-36 (3d Dep’t 1995).

In addition, other state commissions,⁷⁷ FERC,⁷⁸ and appellate courts⁷⁹ have recognized the importance of applying heightened scrutiny to affiliate transactions because of the threats they pose. Adopting Staff’s recommendation to apply heightened scrutiny to affiliate transactions will protect customers from unnecessary infrastructure that locks in excessive costs and GHG emissions.

To fulfill its objective of applying heightened scrutiny to affiliate transactions, Staff proposes that LDCs should present alternatives to all infrastructure projects, including those sponsored by interstate pipelines, whether they are affiliated with the LDC or not.⁸⁰ The presentation of alternatives is an important part of utility planning but additional safeguards are needed to ensure that the LDC does not simply choose its affiliate project after putting forth other options. EDF recommends that the Commission adopt the framework, detailed in Part II above, by which a gas utility could evaluate both affiliate and non-affiliate alternatives. Most critically, the framework provides that, in the event a contract is awarded to an affiliate, the gas utility must maintain contemporaneous documentation showing that the affiliate’s bid price was

⁷⁷ Michigan Public Service Commission December 9, 2016 Order in Case No. U-17999 at pages 14-15 (“The Commission will determine whether NEXUS-related investments should be included in plant in service in a future rate case after a full review of all contractual arrangements between DTE Gas and its affiliates. Accordingly, it should come as no surprise to DTE Gas that the Commission will require copies of the agreements with DTE Pipeline Company and NEXUS Gas Transmission Company (and any other affiliates). Such information is necessary for the Commission to make an informed decision on the reasonableness and prudence of DTE Gas’s investment in NEXUS-related capital upgrades and whether the arrangements with affiliates comply with affiliate and code of conduct rules. In the next rate case, DTE Gas shall provide a complete revenue requirement calculation for the NEXUS project, including evidence on the project’s costs and revenues for DTE Gas. If revenues are not as they have been represented, the Commission will take action to protect ratepayers.”).

<http://efile.mpsc.state.mi.us/efile/docs/17999/0133.pdf>

⁷⁸ *Transcontinental Gas Pipe Line Corp.*, 60 FERC ¶ 62,153 at p. 63,378 (1992) (“Transactions between affiliates create special concerns due to the fact that these are not arms-length transactions.”).

⁷⁹ *Brooklyn Union Gas Co. v. FERC*, 190 F.3d 369, 374 (5th Cir. 1999) (explaining that an affiliate relationship is “a circumstance that ought to trigger a hard look”).

⁸⁰ Planning Proposal at p32.

equal to or lower than the bids received from non-affiliated suppliers. This provision will ensure that customers will be protected against any unnecessary costs resulting from an affiliate-backed transaction.

Such a framework is particularly necessary to achieve the Planning Proposal's objective of applying heightened scrutiny to affiliate transactions because there are no such protections in place at the federal level that govern newly formed affiliate pipeline developers. The Planning Proposal asserts that FERC has rules in place that address the potential for affiliate abuse by transmission providers and affiliates, citing to FERC Order 717.⁸¹ The standards of conduct adopted in FERC Order 717 apply to existing interstate natural gas pipelines.⁸² A newly formed affiliate pipeline developer becomes a natural gas company, as defined by section 2(6) of the Natural Gas Act and subject to FERC jurisdiction, "[u]pon the receipt of its requested certificate authorizations and commencement of pipeline operations."⁸³ However, during the pivotal period of the open season process and contract negotiation, there are no rules in place governing the interactions between a newly formed pipeline developer and its affiliate gas utility. In practice, this means there is no meaningful separation between the pipeline development personnel and gas supply and operations personnel and that major new infrastructure projects are proposed and designed as the result of "negotiations" within the same corporate family and primarily for the benefit of that same corporate family's shareholders.

FERC's requirement that pipeline applicants conduct an open season process similarly does not cure this regulatory gap, as newly formed pipeline developers routinely offer precedent

⁸¹ Planning Proposal at p32.

⁸² 18 C.F.R. § 358.1.

⁸³ *Spire STL Pipeline LLC*, 164 FERC ¶ 61,085 at P 3 (2018); *see id.* at P 104 (summarizing Spire's argument that it is not yet a "transmission service provider" and therefore not subject to the Commission's Order No. 717, *Standards of Conduct for Transmission Providers*).

agreements with their affiliate gas utilities that were not connected to, or a result of, the open season process.⁸⁴ For example, in the Mountain Valley Pipeline proceeding, FERC acknowledged that Consolidated Edison became an affiliate of Mountain Valley Pipeline and a shipper of the project three months after the initial certificate application was filed.⁸⁵ FERC reiterated that its open season policy “only requires that a pipeline applicant conduct a fair and transparent open season, prior to filing its application, for potential shippers to seek and obtain firm capacity rights.”⁸⁶ FERC’s primary concern regarding affiliates in certificate proceedings is whether there may have been undue discrimination against a non-affiliate shipper.⁸⁷ This concern completely ignores the threat of affiliate abuse posed when a newly formed pipeline developer enters into a negotiation with its affiliate gas utility and uses that precedent agreement to justify need for a major infrastructure project. To correct this regulatory gap, the Commission should apply heightened scrutiny to affiliate transactions by adopting the clear and transparent framework described in Part II above.

B. The Commission Should Update and Clarify its Filing Requirements and Review Process for Affiliate Contracts

The Planning Proposal states that all gas capacity and gas supply contracts entered into by LDCs must be filed with the Secretary, which allows for a prudence review of the contract.⁸⁸ The current process is deficient for three reasons. First, as EDF has observed in the past, utilities

⁸⁴ *Spire STL Pipeline LLC*, 164 FERC ¶ 61,085 at P 77 (2018) (noting that “the precedent agreement was not the direct result of the open season, but stemmed from prior discussions between Spire, Spire Missouri, and their corporate parents...”).

⁸⁵ *Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043 at P 49 (2017).

⁸⁶ *Id.* at P 54.

⁸⁷ *Id.* at P 45.

⁸⁸ Planning Proposal at p32.

have filed such contracts without disclosing the underlying affiliate relationship between the relevant contracting parties.⁸⁹ The filing of such contracts, without revealing the nature of the affiliate relationship between the contracting parties, does little to achieve the goal of increased transparency. Second, it appears that all gas utilities file their contracts in a legacy docket from 1993, Case 93-G-0932. The burden then falls on the interested stakeholder to sift through all of the contracts filed in this docket and conduct research as to the relationship of the contracting parties to fully understand whether a contract poses a threat of affiliate abuse. Third, the Planning Proposal states that “[i]f an issue is discovered, a proceeding may be initiated to address it,”⁹⁰ but this has not been the case.

Since 2017, EDF has been seeking clarity regarding the process by which to challenge the prudence of Consolidated Edison’s Mountain Valley Pipeline contract.⁹¹ EDF has submitted repeated letters requesting clarity, as well an analysis demonstrating the risk and cost-shifting concerns regarding the Mountain Valley Pipeline contract.⁹² EDF has stated to the Commission that “[u]nless and until Con Ed can demonstrate that its affiliate transaction and precedent agreement complies with the statutory public interest standard, costs associated with the MVP pipeline project should not be included in rates and/or imposed on retail ratepayers.”⁹³ Despite

⁸⁹ EDF Letter, Case 93-G-0932 at page 1, n.1 (June 19, 2017) (noting that Con Edison filed its Mountain Valley Pipeline precedent agreement in Case 93-G-0932 on February 28, 2016 but did not disclose its affiliate relationship with Mountain Valley Pipeline).

⁹⁰ Planning Proposal at p32.

⁹¹ EDF Letter, Case 17-G-0610 (June 9, 2020) (detailing the petition for declaratory ruling EDF submitted on October 2, 2017 and renewing the request that the Commission rule on the petition in order to clarify the forum for review of the Mountain Valley Pipeline transaction).

⁹² Applied Economics Clinic, Ratepayer Impacts of ConEd’s 20-Year Shipping Agreement on the Mountain Valley Pipeline (Sept. 2017), https://static1.squarespace.com/static/5936d98f6a4963bcd1ed94d3/t/59d7e57329f187b71a721378/1507321204234/Final+Report+EDF+MVP_20170922.pdf.

⁹³ Letter from EDF Requesting Heightened Scrutiny of Precedent Agreements Supported by Affiliates, Case 93-G-0932 at page 2 (June 19, 2017).

multiple attempts requesting a process to review this contract, there remains a lack of clarity as to whether, and if so when, a proceeding will be opened to address the prudence of this contract. Good government demands better.

To address these deficiencies, the Commission should adopt an improved filing process for all gas contracts and clarify the review process for affiliate contracts. At minimum, the Commission should require the gas utility to disclose whether it has an affiliated relationship with the contracting party as part of its filing. A separate docket could then be opened for each gas utility so that all contracts associated with that particular gas utility could be housed within one location and easily accessible to interested stakeholders. Most importantly, the Commission should provide clarity as to the appropriate timing and forum to review the prudence of affiliate transactions.

Guidance is particularly needed for affiliate transportation contracts, as gas utilities enter into precedent agreements years in advance before the ultimate transportation costs are passed through the gas cost factor in utility tariffs. Commission precedent makes clear that “[p]ursuant to PSL §§ 66(12) and 72, prudence review may be undertaken in rate cases, in proceedings to investigate utility recoveries through the fuel adjustment clause (FAC), or proceedings devoted to review of a particular utility decision.”⁹⁴ Because prudence can be challenged in various types of proceedings, there remains a lack of clarity as to the appropriate timing and process for review. This issue arose regarding Consolidated Edison’s request to recover the costs of firm electric transmission associated with a new PJM Interconnection L.L.C. (“PJM”) transmission

⁹⁴ Consolidated Edison Company of New York, Inc., Long Island Lighting Company, and Orange and Rockland Utilities, Inc., Joint Petition For Approval of Long-Term Hydro Quebec Firm Power Purchase Contracts, Case 90-E-0775 (Dec. 10, 1990).

service. Con Edison filed a rate case in May 2009, and the Commission issued an order approving a three-year rate plan ending March 1, 2013. The new PJM service went into effect on May 1, 2012 and Con Edison began passing through the PJM charges on June 12, 2012. In a 2013 order, the Commission ultimately denied recovery of the charges through the Monthly Adjustment Clause (“MAC”):

We specifically determined in the February 2000 Order what cost components were to be collected by the Company through the MAC. Con Edison should have had, therefore, no expectation that it could simply recover these substantial PJM OATT costs through the MAC without our review and approval of the prudence of the decision to take the PJM OATT service and a determination on the allocation of the costs among customers. This review could have been performed in the Company’s last rate case which began in May 2009 and concluded with an Order approving a three-year rate plan for the period ending March 31, 2013. In addressing the Company’s rates in that case, the Company could and should have apprised Staff and the parties of the need, timing and magnitude of the anticipated PJM OATT charges, and rates could have been set accordingly. In particular, since carrying charges of \$34 million per year would cover a significant capital investment by the Company in transmission, Con Edison should have provided evidence showing that its business decision was reasonable, comparing the PJM OATT service to building transmission or any other alternative means to address its reliability concerns. Since the Company decided not to bring this issue into that proceeding, its inability to get the rate treatment it now proposes should come as no surprise.⁹⁵

Regarding the concerns EDF has raised with Con Edison’s Mountain Valley Pipeline contract, the Commission has yet to rule on the need, timing, and magnitude of transportation charges associated with this contract, or a comparison of the decision to take service on Mountain Valley Pipeline versus alternatives that would address its gas supply needs. This review is sorely needed given the significant change in circumstances that have arisen since Consolidated Edison

⁹⁵ *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Denying Petition for Recovery of Charges, Case 09-E-0428 (February 14, 2013).*

first entered into this contract in 2014 and have transpired since Con Edison’s 2019 rate case.⁹⁶ As New York precedent makes clear, in assessing prudence, the Commission may also consider information and circumstances that arose after contract execution.⁹⁷ If Staff seeks to “reduce the construction of unnecessary infrastructure and the possible creation of stranded assets,”⁹⁸ then it must review and analyze the costs and risks associated with this agreement.

Many state commissions have clear processes as to whether and when the prudence of affiliate contracts may be challenged. For instance, the Missouri Public Service Commission (“Missouri Commission”) allows for prudence challenges as part of its Annual Cost Adjustment proceedings.⁹⁹ After EDF and others challenged Spire Missouri’s purchased gas adjustment filing, the Missouri Commission detailed the process by which the affiliate contract would be reviewed in the case, which included the opportunity for all parties to conduct discovery in the case.¹⁰⁰ The Commission should similarly issue guidance regarding the prudence review for Con Edison’s Mountain Valley Pipeline contract, as well as all affiliate precedent and transportation contracts going forward. Clarifying the procedures for review will provide regulatory certainty

⁹⁶ See EDF Letter, Case 93-G-0932 at page 1, n.1 (June 19, 2017) (detailing the significant legal challenges the project has faced, the investigation of potential criminal and/or civil violations of the Clean Water Act and other federal statutes, and ballooning cost estimate of \$5.5 billion).

⁹⁷ *Rochester Gas & Elec. Corp. v. Pub. Serv. Com.*, 449 N.Y.S.2d 77, 79 (N.Y. App. Div. 1982) (“[T]he Commission may not rely on a reckoning when actual experience is available and establishes that the predictions have been substantially incorrect. Likewise here, the commission ought not be bound by the projections of the early 1970’s, and is permitted to take into account post-acquisition events and circumstances in a current rate proceeding.”).

⁹⁸ Planning Proposal at p32.

⁹⁹ *In the Matter of the Laclede Gas Company’s Request to Increase Its Revenues for Gas Service, et al.*, File No. GR-2017-0215, *et al.*, Amended Report and Order at page 56 (March 7, 2018) (“If Spire Missouri ultimately makes a business decision to enter into a transportation agreement with a new interstate natural gas pipeline, the Commission will have an opportunity to review the prudence of that decision in a future ACA case.”).

¹⁰⁰ *In the Matter of Spire Missouri, Inc. d/b/a Spire (Easter) Purchased Gas Adjustment (PGA) Tariff Filing*, File No. GR-2021-0127, Order Denying Motion to Establish Procedural Schedule (January 6, 2021).

to gas utilities and eliminate the burden on interested stakeholders to continually submit pleadings to the Commission seeking guidance as to where and when prudency issues will be assessed.

V. The Commission Must Revise Part 230 of its Regulations and Provide Clarity on the Parameters of the Public Service Law

Achieving New York’s greenhouse gas reduction goals will necessitate profound changes in the provision of natural gas service available in the state of New York, with significant ramifications for the State’s gas utilities.¹⁰¹ Yet until now, including in this docket, the governing assumption is that demand always goes up, and never down. The assumption that gas utilities must always be growing the gas system – and that their existence as viable commercial entities is inextricably linked to such growth – is based on provisions of the Public Service Law enacted decades before the CLCPA went into effect. The passage of the CLCPA creates a new imperative for the Commission to assess steps it can take to update policies, regulations, and standards to support GHG emission reductions within the existing law—and to identify and root out those which conflict with the mandates of the CLCPA.¹⁰²

In the Order Instituting Proceeding, the Commission acknowledges that “resolution of some issues in this proceeding may require revision of gas utility tariffs, the adoption of new tariffs, or revision of the Commission’s rules found at 16 NYCRR Part 230.”¹⁰³ Below, EDF offers suggestions the Commission could take in revising this section of the regulations to align

¹⁰¹ See *infra* Part VI.

¹⁰² See generally Justin Gundlach & Elizabeth Stein, *Harmonizing States’ Energy Utility Regulation Frameworks and Climate Laws: A Case Study of New York*, *Energy Law Journal* Vol 41:211 (Nov. 15, 2020), <https://policyintegrity.org/publications/detail/harmonizing-states-energy-utility-regulation-frameworks-and-climate-laws>.

¹⁰³ Order Instituting Proceeding at page 10.

its oversight of gas utilities with the objectives of the CLCPA. EDF also requests that the Commission provide guidance and clarity regarding the future role of gas utilities and find that gas utilities are entitled to meet customers' and prospective customers' thermal needs through technologies that do not rely directly on the combustion of methane. Providing this much-needed clarity will serve the public interest, as it will foster the development of alternate methods of delivering energy in line with the state's climate objectives, encourage early adoption of new technologies, and help reduce customer costs.

A. The Commission Should Revise Part 230 of its Regulations

Natural gas consumption will need to drastically reduce GHG emissions from current levels to achieve the GHG emissions reduction targets mandated in the CLCPA.¹⁰⁴ The Commission order opening this proceeding and Staff's Planning Proposal acknowledge that new natural gas infrastructure is likely to increase GHG emissions, rendering such expansions inconsistent with the objectives of the CLCPA.¹⁰⁵ While some distribution system additions may be reasonably necessary to serve the comparatively small range of natural gas use cases that survive into the mid-21st century, customary additions that serve the same types of customers who have received gas service in the past, without considering the longevity of these new customers' reliance on natural gas, are manifestly a step in the wrong direction.

One driver of unsustainable expansion of natural gas infrastructure is New York's so-called "100-foot rule," pursuant to which residential applicants for natural gas service may be entitled to a certain amount of infrastructure for free. Although the 100-foot rule is often

¹⁰⁴ See E3, Presentation: New York State Decarbonization Pathways Analysis, Summary of Draft Findings at Slide 11 (June 24, 2020), <https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-CAC-Presentation.pdf>.

¹⁰⁵ Planning Proposal at p26; Commission Order at p3.

described as “statutory,”¹⁰⁶ the contours of the 100-foot rule as we know it are detailed in implementing regulations: Part 230 of 16 NYCRR, which governs extension of gas mains and service lines and can be modified by the Commission, as acknowledged in the Order Instituting Proceeding.

Although New York’s legislature has not expressly repealed or modified Section 31 of the Public Service Law (which concerns a variety of utility services, not only natural gas), the goals of the CLCPA cast a dark cloud over the idea that as-of-right free gas line extensions are necessarily in the public interest. As such, the Commission should reverse its 1986 determination that if some as-of-right free gas line extensions are good, more would be even better.¹⁰⁷ In the New York State Register Notice of Adoption of Part 230, the Commission announced that it had decided to expand the scope of the gas infrastructure entitlement in at least two significant ways: it expanded both the range of customers who would be eligible for free as-of-right extensions of natural gas infrastructure (from merely those who were already located near existing mains to all customers)¹⁰⁸ and the extent of the natural gas infrastructure to which each eligible customer would be entitled (from 100 feet of total facilities to 100 feet of main and 100 feet of service line).¹⁰⁹

¹⁰⁶ See, e.g., NYPSC Case No. 18-E-0067, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service et al.*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, Attachment A: November 9, 2018 Joint Proposal at p48 (Mar. 14, 2019) (“Statutory requirements under Part 230 of the Commission’s Rules and Regulations are excluded [from the BCA].”).

¹⁰⁷ New York State Register at 16 (July 2, 1986).

¹⁰⁸ “[T]he Commission concluded that Section 31(4) grants to residential applicants whose buildings are located within 100 feet of gas mains the right to have the facilities necessary for receipt of gas service provided, without charge. The Commission also found that good public policy of equitable treatment among customers would require the provision, without charge, of a comparable amount of facilities for residential applicants located more than 100 feet away....” New York State Register at 16 (July 2, 1986).

¹⁰⁹ “With applicants for non-residential heating services granted the right to up to 100 feet of total main and service line without charge, the Commission decided that the additional revenue derived from

The basis for these vast expansions by the Commission—particularly the finding that such expansions may be economically justified due to increased utility revenue—cannot be sustained in the face of the CLCPA’s climate goals, the questionable long-term viability of new gas infrastructure, and the likelihood that *all* such new gas infrastructure may be stranded before the end of its useful life. To the extent the 1986 determination aimed to facilitate equitable energy access, revisions to align Commission policy with climate goals should continue to pursue the objective of equitable energy access in the context of the clean energy transition, as required by the CLCPA and the public interest.

Another area where the Commission has an opportunity to cabin the 100-foot rule’s relentless expansionary drive arises from Part 230 itself, as currently promulgated. Part 230 requires that any applicant for a gas line extension begin by “assuring the corporation that he/she will be a reasonably permanent customer.”¹¹⁰ Given that it is no longer reasonable to expect any particular instance of fossil gas usage will be “permanent” in New York, or even long-lived, one possibility is that the Commission could put gas utilities on notice that they alone will bear the risk of any stranded assets resulting from any such expansions, and encourage the utilities to set very high bars for prospective natural gas customers to “assure” them that they will be “reasonably permanent.”

Alternatively, the Commission could formally recognize the impermanence of new natural gas infrastructure by amending the rule to replace “reasonably permanent customers” with “customers until 2040,” or a similarly clear and specific threshold based on a date certain.

residential heating customers justifies the free installation of more than 100 feet. The rules will require the provision of up to 100 feet of main and up to 100 feet of service line for such customers.” New York State Register at 17 (July 2, 1986).

¹¹⁰ 16 NYCRR § 230.2.

In addition to eliminating the outdated concept of natural gas residential customer permanence from the regulation, a cutoff date would also highlight the misalignment of new residential fossil gas consumption with the decarbonization targets established by the CLCPA. Ideally, as the cutoff date draws closer, the extent of the subsidization of the fossil fuel infrastructure would gradually decline, such that applicants in later years would increasingly bear the cost and risk (including the risk that early retirement would render the expenditure uneconomic) associated with their line extension requests.

The Commission should also revisit and reconsider its outdated 2012 order establishing proceedings to “Examine Policies Regarding the Expansion of Natural Gas Service,” which sought to “foster [natural gas] use through expansion of the natural gas delivery system or otherwise.”¹¹¹

If the Commission does not revise these outdated standards, it will continue the business-as-usual regulatory paradigm applied to gas utilities and exacerbate the tension with the reductions in climate pollution needed to achieve the goals of the CLCPA.

B. The Commission Should Clarify the Future Role of Gas Utilities As the State Achieves its CLCPA Objectives

Given that the CLCPA makes dramatic reductions in New Yorkers’ natural gas consumption essentially a certainty, gas utilities need to begin preparing for a future with greatly reduced demand. Given the risks associated with a haphazard transition, the need to get utilities, especially standalone gas utilities, to mindfully plan and prepare for a future in which their role in meeting their customers’ energy needs may be greatly reduced, although still critically

¹¹¹ NYPSC Case No. 12-G-0297, *Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service*, Order Instituting Proceeding and Establishing Further Procedures (Nov. 30, 2012), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=83153&MatterSeq=40220>.

important¹¹²—and to actively engage in the retirement of assets that had previously been the basis for their earnings—is critical to address. The ability of gas utilities to participate robustly in New York’s future low-emissions energy system will determine the types of planning that they need to be engaged in, as well as how difficult it will likely be to engage them productively in such planning.

New York will be able to more effectively achieve its climate objectives if gas utilities have an opportunity to share in the upside associated with the energy transition – for example, by providing, owning, and maintaining infrastructure and equipment that continues to meet their customers’ thermal needs, albeit not by providing natural gas to combust. Leadership and guidance is needed from the Commission to set the state up for success in this transition.

To date, to the extent the Commission has made existing utilities responsible for heat pump adoption, it has given that responsibility to electric utilities.¹¹³ Although heat pumps run on electricity, the relevant equipment does not appear to meet the definition of “electric plant”¹¹⁴; not only does electrification not “*facilitate* the generation, transmission, distribution, sale or

¹¹² Even operating at a much smaller scale to meet a comparatively narrow range of niche applications, elements of the gas system may remain critically important to society as a whole. For example, natural gas-fired electric generation resources, potentially using carbon capture and sequestration, may continue to play a critical role in a future electric system that runs primarily on intermittent renewables, with ramifications for electric reliability and affordability for all electric customers.

¹¹³ See NYPSC Case No. 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Order Adopting Accelerated Energy Efficiency Targets at p60 (Dec. 13, 2018) (describing heat pump targets in the context of electric utility portfolios, with no discussion of gas utilities); NYPSC Case No. 20-E-0380 & 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of Staff Efficiency and Sustainability Panel at p59 (explaining that Staff views “utility ownership of geothermal loop fields and/or heat pumps as a last resort in the event that the private market is unwilling or has failed to provide a cost-effective solution”).

¹¹⁴ “The term ‘electric plant,’ when used in this chapter, includes all real estate, fixtures and personal property operated, owned, used or to be used for or in connection with or to facilitate the generation, transmission, distribution, sale or furnishing of electricity for light, heat or power; and any conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission of electricity for light, heat or power.” Public Service Law Section 2(12).

furnishing of electricity for light, heat or power,” (emphasis added) but, arguably it does the opposite, because more electrification at scale places increasing demands on the tasks of generation, transmission, distribution, sale, and furnishing of electricity. By contrast, providing such equipment to meet the thermal needs of some customers or prospective customers meets the definition of “gas plant”¹¹⁵ in that it can “facilitate” gas utilities’ conveying, transportation, distribution, sale or furnishing of gas to their remaining customers without violating their portion of the greenhouse gas emissions limits established in the CLCPA. As such, clarifying that gas utilities are entitled to meet customers’ and prospective customers’ thermal needs through technologies that do not rely directly on the combustion of methane would be one pathway that the Commission could take to facilitate engaging gas utilities in the rightsizing of their methane distribution systems that New York’s climate goals demand.

Clarifying a role for gas utilities could help accelerate adoption of clean technologies, particularly if the utility owns or subsidizes the decarbonization investment.¹¹⁶ Electrification of heating will require capital-intensive infrastructure deployment over long planning horizons. Early adoption of technology would improve climate outcomes and help reduce customer costs. Such interpretation would be consistent with how other state commissions have addressed this issue, including the Massachusetts Department of Public Utilities (“DPU”). The Massachusetts

¹¹⁵ “The term ‘gas plant,’ when used in this chapter, includes all real estate, fixtures and personal property operated, owned, used or to be used for or in connection with or to facilitate the manufacture, conveying, transportation, distribution, sale or furnishing of gas (natural or manufactured or mixture of both) for light, heat or power, but does not include property used solely for or in connection with the business of selling, distributing or furnishing of gas in enclosed containers.” Public Service Law Section 2(10).

¹¹⁶ See, e.g., NYPSC Case No. 20-G-0381 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of Future of Heat Panel at p11-64 (July 31, 2020) (“Being able to invest in geothermal projects would encourage gas utilities to consider this for NPAs, reducing the net gas capital investments to meet customer needs, avoiding gas demand growth and limiting the need for incremental investment in delivery infrastructure.”).

DPU approved NSTAR Gas Company’s proposal to own and operate a geothermal network in D.P.U. 19-120, finding that the intent of the Company’s proposal is consistent with the Global Warming Solutions Act and the Commonwealth’s energy climate policies, including the statewide emissions limit for 2050.¹¹⁷ Noting that large upfront capital costs and infrastructure maintenance outside an individual or entity’s premises are significant barriers to widespread adoption of geothermal networks, the DPU found that the experience of developing and maintaining a company-owned geothermal network could inform the potential regulatory policies related to broad scale geothermal deployment and the role of LDCs in the future.¹¹⁸

Alternatively, if the Commission concludes that under current law, gas corporations simply cannot have a role in meeting customers’ thermal needs, the State will need to prepare for the profound economic, labor, and equity ramifications that will flow from such a finding.

C. The Commission Should Open a Second Phase of this Proceeding to Further Address Legal Barriers to the Gas Transition

There is a pressing need for clarity regarding the legal and regulatory barriers, and potential opportunities, regarding the role of gas utilities in a clean energy future. Above, EDF has identified two examples ripe for resolution yet others still remain. The Commission should open a second phase of this proceeding to assess additional barriers that will need to be resolved as part of the energy transition. These include:

1. What rate design changes are needed to ensure that low income customers are not subject to increasing distribution rates as the gas utility’s revenue requirement is spread over a diminishing customer sales base?
2. Low income customers and environmental justice communities may not be able to cost-effectively electrify their home heating without additional policy measures. What

¹¹⁷ *Petition of NSTAR Gas Company doing business as Eversource Energy for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism*, D.P.U. 19-120 at page 139 (October 30, 2020).

¹¹⁸ *Id.* at page 140.

incentives or additional policy measures are necessary to assist in the electrification of their homes?

3. In approving plans to address leak prone pipe replacement plans, should the Commission require gas utilities to compare leak prone pipe replacement with other alternatives, such as abandoning leak-prone pipes for targeted electrification initiatives and or geo-thermal projects?
4. Beyond any actions underway by the Commission to revise Section 230, what other policies and standards require revisiting to ensure alignment with the CLCPA?

VI. The Planning Proposal Must be Durable Enough to Accommodate the Policy Objectives of the State and New York City

The Planning Proposal represents a meaningful step forward to align gas utility planning with state climate policy while seeking to avoid moratoria that present hardship to utilities and customers alike. Staff’s action establishes a framework that could be a strong foundation to ensure that gas utilities plan for the clean energy transition, but more is needed to achieve the Commission’s stated objective of aligning gas planning with the CLCPA. A gas utility’s long-term plan, for example, is unlikely to be an effective tool for tracking climate progress unless the Commission provides clearer guidance as to what the utility should be planning *for*.

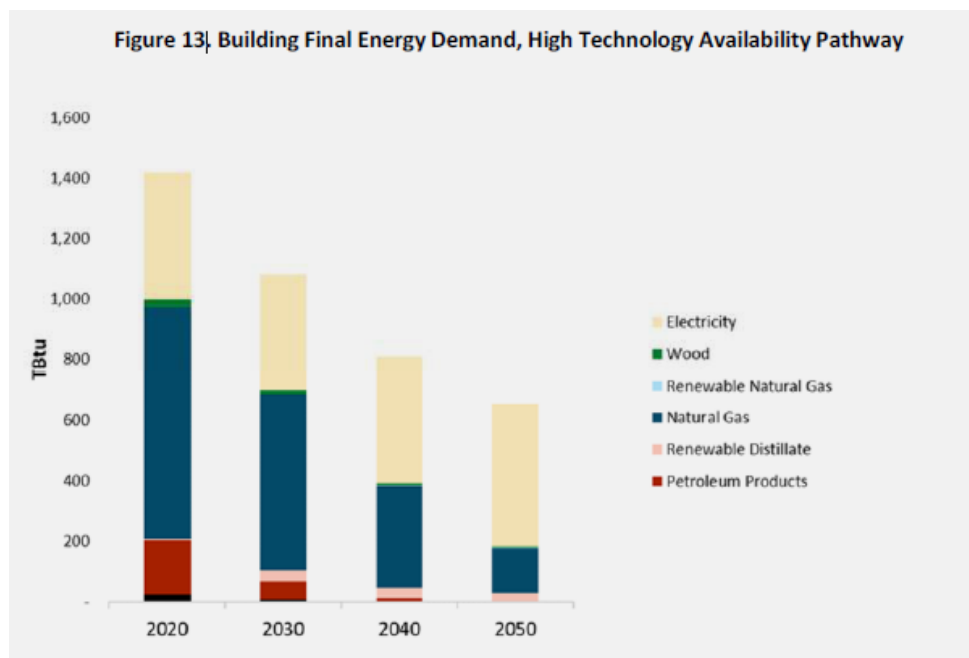
The Commission and Staff must adopt a forward-looking proposal that can accommodate and facilitate the changes that are and will be required to reduce statewide greenhouse gas emissions 40% by 2030 and 85% by 2050. The planning process should incorporate the actions and programs of other New York agencies to implement the CLCPA.

A. Widespread Building Electrification, and a Corresponding Reduction in Gas Use, is Required to Achieve CLCPA Goals

There is no question that building electrification is a major element of New York’s efforts to reduce GHG emissions from buildings and achieve the CLCPA goals. More than 25% of New York GHG emissions are from fossil fuels—predominantly natural gas—burned for building

heating and appliances.¹¹⁹ According to an analysis by Energy + Environmental Economics (“E3”) conducted for NYSERDA, GHG emissions from buildings must be reduced 31-39% by 2030 and 85-93% by 2050 in order to achieve the CLCPA goals, requiring a significant reduction in natural gas use in buildings.¹²⁰ According to a more recent analysis of building decarbonization policies conducted by RMI, E3, et al., the building sector may even need to achieve GHG emission reductions *greater than* 40% by 2030 and 85% by 2050 to make up for harder-to-abate sectors and achieve the CLCPA goals.¹²¹

Figure 3. New York Building Final Energy Demand Under a Decarbonization Scenario¹²²



¹¹⁹ NY CAC EE&H Panel, Feb. 4 Presentation, Slide 7.

¹²⁰ Energy + Environmental Economics, Presentation: New York State Decarbonization Pathways Analysis, Summary of Draft Findings at Slide 11 (June 24, 2020), <https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-CAC-Presentation.pdf>.

¹²¹ RMI, E3, et al., Presentation: *Building Decarbonization Policies Preliminary Findings on Impacts and Costs* (Feb. 10, 2021), found at Slide 29, Note 1, of Climate Action Council, Energy Efficiency and Housing Advisory Panel meeting presentation (Feb. 10, 2021), <https://climate.ny.gov/-/media/CLCPA/Files/2021-02-10-Energy-Efficiency-and-Housing-Advisory-Panel-Presentation.pdf>.

¹²² E3, Pathways to Deep Decarbonization in New York State at p25 (June 24, 2020), <https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf>.

In its 2021-24 strategic plan, NYSERDA states: “In order to realize its goals of a carbon neutral economy by mid-century, New York State needs to move away from its dependence on the combustion of natural gas (fossil fuel-derived methane) to heat homes and businesses and power industrial processes.”¹²³ The agency is “launch[ing] a comprehensive building electrification initiative with consumer incentives and market support to move New York toward all-electric homes and buildings and accelerate transition away from natural gas and fossil fuel.”¹²⁴ NYSERDA acknowledges, however, that “this transition away from natural gas to lower-carbon energy sources may be one of the most challenging pieces of our decarbonization agenda.”¹²⁵ The agency is expected to issue a Carbon Neutral Buildings Roadmap and a Building Electrification Roadmap that will detail an approach to accelerate building electrification, and a recent \$13 million NYSERDA award in the Buildings of Excellence competition explained that 100% of the projects are “carbon neutral, meaning they are highly efficient, all-electric with no use of fossil fuel combustion on site for daily operations.”¹²⁶

The Climate Action Council is similarly emphasizing building electrification and a corresponding decrease in reliance on natural gas for building heating and appliances. The Energy Efficiency and Housing Advisory Panel to the Climate Action Council issued Draft Recommendations in January 2021 that include a series of proposed building codes and other

¹²³ NYSERDA, *Toward a Clean Energy Future: A Strategic Outlook 2021-2024* at p48 (Jan. 2021), <https://www.nyserdera.ny.gov/About/Publications/Program%20Planning%20Status%20and%20Evaluation%20Reports/Strategic%20Outlook> (“NYSERDA Strategic Plan”).

¹²⁴ *Id.* at p26.

¹²⁵ *Id.* at p49.

¹²⁶ NYSERDA, Press Release: Governor Cuomo Announces \$13 Million in Award Winning Projects in Second Round of Buildings of Excellence Competition (Mar. 11, 2021), <https://www.nyserdera.ny.gov/About/Newsroom/2021-Announcements/2021-03-11-Governor-Cuomo-Announces-13-Million-in-Award-Winning-Projects-in-Second-Round-of-Buildings-of-Excellence-Competition>.

regulations “to phase out fossil fuel use in buildings” and recommendations for the “policy transition from gas to clean energy.”¹²⁷ A cross-panel discussion of the Climate Action Council advisory panels—including a panel lead by then-Public Service Commission Chairman Rhodes—identified the need for comprehensive planning for the gas transition, particularly “to converge utility long-term planning with building codes.”¹²⁸ New York State’s government is on the record, in various forums, expressing that CLCPA implementation will require significant reductions in natural gas usage in buildings.

Local governments are also promoting policies to address climate change that will affect natural gas demand and use cases. New York City enacted Local Law 97 in 2019, which requires a minimum 40% reduction in citywide GHG emissions by 2030, and an 80% reduction by 2050, relative to 2005 levels.¹²⁹ Local Law 97 places increasingly stringent carbon caps on most buildings larger than 25,000 square feet starting in 2024, spurring investment in building energy efficiency and electrification. In the recent Pathways report developed in consultation with Con Edison and National Grid, the City of New York projects that total natural gas demand across all sectors will fall more than 60% by 2050, even under a “low carbon fuels” pathway.¹³⁰

¹²⁷ New York Climate Action Council, Presentation: Energy Efficiency and Housing: Public Engagement Session at Slides 13, 18 (Feb. 4, 2021), <https://climate.ny.gov/-/media/CLCPA/Files/2021-02-04-EEH-Public-Engagement-Session.pdf> (“EE&H Draft Recommendations Presentation”).

¹²⁸ Climate Action Council, Presentation: Energy Efficiency and Housing Advisory Panel meeting at Slide 15 (Feb. 10, 2021), <https://climate.ny.gov/-/media/CLCPA/Files/2021-02-10-Energy-Efficiency-and-Housing-Advisory-Panel-Presentation.pdf>.

¹²⁹ 2019 N.Y.C. Local Law No. 97 § 3, codified at N.Y.C. Admin. Code §§ 24-803.

¹³⁰ City of New York Mayor’s Office of Sustainability, Con Edison, & National Grid, *Pathways to Carbon-Neutral NYC: Modernize, Reimagine, Reach* at p75 (Apr. 2021), <https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf> (“NYC Pathways Study”).

B. The Gas Utility Planning Process Must Integrate Known Building Electrification Objectives

Achievement of the CLCPA climate goals will require a significant amount of building electrification. This will in turn require a managed contraction of the natural gas distribution system, diminished natural gas usage, and a reduction in the existing natural gas customer base as many homes, apartments, and commercial buildings transition to heat pumps and other non-fossil heating options.¹³¹ The Planning Proposal does not explicitly address this need.

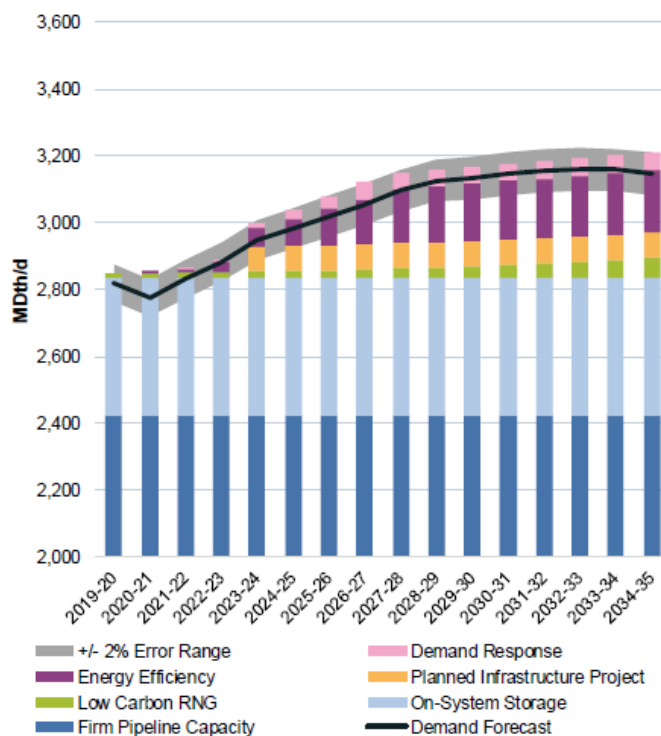
The Planning Proposal relies on proposals from the gas utilities regarding building electrification and gas pipe retirement, in that the utilities would be required to submit a 20-year demand forecast that includes “the source(s) of anticipated demand growth” and adjustments for “energy efficiency, electrification, demand response,” and non-pipeline alternatives.¹³² The Planning Proposal contains no discussion of Staff or the Commission setting building electrification targets or projections, or gas demand reduction targets.¹³³ For example, consider Figure 2 below, the sample supply forecast that is presented in the Planning Proposal to show how gas utilities should be demonstrating their supply forecast through 2035. This is presented as an illustrative example, but it is telling that the sample forecast projects year-over-year growth to 2033-2034, including decades of continued new planned infrastructure projects.

¹³¹ *See, e.g.*, NYC Pathways Report at p75.

¹³² Planning Proposal at p14-15.

¹³³ *See id.* at p13.

Figure 4. Example Gas Supply Forecast from DPS Staff Planning Proposal¹³⁴



In prior proceedings, Staff have explicitly stated an intent to defer to the Climate Action Council to determine recommended actions to achieve the CLCPA targets. This approach is exemplified in rate case testimony recommending that “the programs which result from this proceeding should be consistent with both Commission policy and the requirements of the CLCPA, but should not pre-judge the recommendations of the Climate Action Council nor make an end-run around the process required by the CLCPA.”¹³⁵ While coordination with the Climate Action Council is important, it should not supplant the Commission and Staff’s obligation in this proceeding to design a robust and thorough gas planning process that is aligned with the

¹³⁴ *Id.* at p16.

¹³⁵ *In the Matter of The Brooklyn Union Gas Company d/b/a National Grid NY & KeySpan East Gas Corporation d/b/a National Grid*, Cases 19-G-0309 & 19-G-0310, Rebuttal Testimony of Staff Efficiency and Sustainability Panel at p8 (Sept. 2019).

objectives of the CLCPA and is durable enough to accommodate the electrification plans articulated by the State and New York City.

The Planning Proposal does contain multiple provisions that suggest an implicit acknowledgment by Staff that the gas system may contract. For example, the Proposal suggests that opportunities to merge the retirement of leak-prone pipe with a non-pipeline alternative (“NPA”) should be explored, such that “an alternative energy approach can supplant renewing the natural gas assets.”¹³⁶ But the Proposal does not *require* any gas utility to pursue programs to retire leak-prone pipe, which could be an excellent pathway to pursue building electrification that maximizes near-term reductions in methane emissions from the leakiest pipe segments. In another example, the Proposal states that the sensitivity analysis employed in the Benefit Cost Analysis (“BCA”) Handbook could be improved by comparing NPA projects against traditional gas infrastructure solutions with a scenario assuming that the full value of any new gas assets will be depreciated by 2050.¹³⁷ And the Proposal recommends that the gas utilities provide an alternative bill impact analysis and an additional Net Present Value of costs analysis that assumes the full value of any new gas assets is depreciated by 2050.¹³⁸ But these recommendations fail to address whether depreciation rates should be adjusted to reflect the realistic useful life of gas plant in light of New York’s bold climate goals.

The Joint Utilities’ submission indicates that New York gas utilities are seeking regulatory clarity regarding their approach to projecting gas demand. The Joint Utilities emphasize the “importance of establishing planning practices that incorporate state policy objectives” and acknowledge that “much has changed over the past few years” in energy policy,

¹³⁶ Planning Proposal at p19.

¹³⁷ *Id.* at p22-23.

¹³⁸ *Id.* at p25, 26.

including enactment of the CLCPA.¹³⁹ The submission also states that the planning process should “guide the [gas utilities] in the development of” long-term plans and reflect the latest information regarding “policy goals” as well as “anticipated demand, the expected contribution of existing and potential supply-side and demand-side resources, [and] market conditions.”¹⁴⁰ New York government has made clear its objective to significantly reduce natural gas use in buildings via large-scale building electrification programs.

The Planning Proposal must be refined to acknowledge this objective and to prepare for the significant actions this objective will require. Demand and supply forecasting should be updated to reflect electrification policies, *see supra* Part I(E). Depreciation paradigms must be modernized to reflect the realistic useful life of new and existing gas plant, as detailed by EDF in recently filed rate case testimony.¹⁴¹ Thoughtful, deliberate planning will be required to ensure a managed transition consistent with the CLCPA.

C. An Unmanaged Contraction of the Gas System Would be Costly, Particularly for Low-Income Ratepayers

Reducing gas use in buildings can be expected to lead to a reduction in the gas customer base, a diminished need for existing gas distribution infrastructure, and may accelerate the time horizon for decommissioning of gas assets.¹⁴² These pathways pose potentially significant risks

¹³⁹ Joint New York Gas Utilities, Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management at p6, 7, Case 20-G-0131 (July 17, 2020).

¹⁴⁰ *Id.* at p9.

¹⁴¹ NYPSC Case No. 20-G-0381 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of James Garren on behalf of EDF (Nov. 25, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256482&MatterSeq=63187>.

¹⁴² *See* EDF, *Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California* (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

for gas utilities and ratepayers without proactive management. For example, if successful building electrification efforts obviate the need for delivered gas in certain areas, this could render existing gas plant no longer “used and useful” prior to the conclusion of its originally anticipated useful life, resulting in stranded assets. Increasing rates resulting from stranded assets creates the potential of a utility death-spiral effect, where higher rates lead customers to electrify more quickly and raise the rates for remaining customers even more.¹⁴³ This places the greatest impact on low-income ratepayers, who are least able to make the up-front investments required to electrify but who are the most affected by higher utility bills.¹⁴⁴ The CLCPA requires that state agencies not take actions that “disproportionately burden disadvantaged communities” and “shall also prioritize reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities.”¹⁴⁵ Thus, it must be a priority of this Commission to consider and mitigate harmful impacts to low-income ratepayers in the face of a changing gas system.

The New York ISO Climate Change Impact Study (“CCIS”) puts into context the magnitude of change that will be required to reduce gas use in buildings. That study assumes that 60% of current residential natural gas consumption electrifies in the utility service territory via heat pumps by 2040.¹⁴⁶ This new electrified heating load would require over 4 million heat pumps by 2040, assuming a 75%/25% split as between air source and ground source heat pumps added. Customer capital costs would amount to over \$80B for the state of New York, at current average heat pump prices. According to a preliminary analysis by The Brattle Group for EDF of

¹⁴³ EDF, *Aligning Gas Regulation and Climate Goals: A Road Map for State Regulators*, at p4 (Jan. 2021), <http://blogs.edf.org/energyexchange/files/2021/01/Aligning-Gas-Regulation-and-Climate-Goals.pdf>.

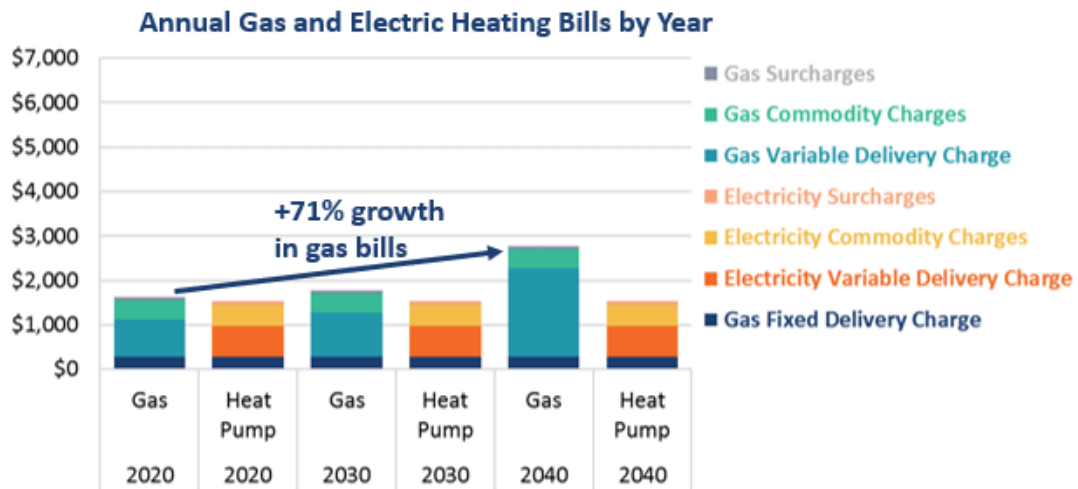
¹⁴⁴ *Id.*

¹⁴⁵ CLCPA § 7(3).

¹⁴⁶ The 60% figure is an estimate derived from the NYISO study’s 2040 electric heating demand and then converted to gas usage.

a generic gas utility in New York, under a “business as usual” or do nothing scenario, assuming the rate of heat pump adoption specified in the NYISO CCIS forecast, rates to non-participating gas customers will increase by about 71% across a twenty-year time frame, holding constant other variables:

Figure 5. Comparison of 2020, 2030, and 2040 Annual gas and Electric Heating Bills by Year



*Rate impact for an air source heat pump customer.

This “death spiral” impact requires that the interests of low income customers be put front and center in policy decisions. Given that low income customers may not be able to cost-effectively electrify their home heating without additional policy measures, the Commission must give thought to incentives or additional policy changes that are necessary to assist in their electrification of their homes. As an initial step, as discussed in Part V, New York will be able to more effectively achieve its climate objectives if gas utilities have an opportunity to share in the upside associated with the energy transition – for example, by providing, owning, and maintaining infrastructure and equipment that continues to meet their customers’ thermal needs, albeit not by providing natural gas to combust. In addition, the Commission should consider rate

design changes that ensure that low income customers are not subject to increasing distribution rates as the gas utility's revenue requirement is spread over a diminishing customer sales base

D. The Commission Should Begin a Joint Gas-Electric Planning Process to Address the State's Building Electrification Objectives

A successful long-term planning process for New York gas utilities must incorporate an assessment of the impacts of the state's aggressive building electrification objectives. Credible analyses of the pathways to achieve the GHG emission reduction targets set by the CLCPA require large-scale building electrification efforts, and although the Climate Action Council has not finalized a scoping plan, the Commission should adopt a plan that is durable enough to accommodate the electrification policies detailed above. There is no question that natural gas demand must decline significantly by 2030 and 2050 to achieve the CLCPA goals.¹⁴⁷

To address this need, as a starting place, the Commission should require that all utilities in the state submit a Joint Feasibility Assessment to address the challenges, opportunities, and regulatory barriers in achieving a high electrification scenario, such as those presented in the NYSERDA E3 study and forthcoming Building Electrification Roadmap. Other states are conducting similar types of analyses to inform how gas utility operations will need to evolve in light of rigorous climate goals. For example, in Massachusetts, the gas utilities are evaluating both high electrification and low electrification scenarios. The high electrification scenario assumes a significant reduction in LDC sales and requires the LDC to conduct a feasibility and impact assessment:

Building on the 2030 CECP Examination, perform a detailed examination of the feasibility and impact on customers and the LDCs' gas distribution operations through 2050, assuming a pace of building services electrification and required emissions

¹⁴⁷ See NYC Pathways Study at Executive Summary xvii.

reductions as described in the 2050 Roadmap All Options scenario resulting in an approximately 90% volumetric reduction in total LDC sales.¹⁴⁸

The Joint Feasibility Assessment should consider hard-to-electrify buildings and industrial applications that are the most likely to continue relying on gas molecules instead of electrification, and conversely should consider the low-hanging fruit areas for electrification. Most critically, the analysis should be conducted in coordination with the corresponding electric utility (or utilities) operating in the gas utility's service territory. For combined gas and electric utilities, this coordination would occur more naturally. Gas-only utilities may need to institute more formal channels of communication between the gas utility and electric utility counterpart to coordinate respective capabilities and plans.

This type of thoughtful and deliberate planning can help save costs for both utilities and ratepayers, for example through strategic targeting of electrification efforts. “[I]f electrification occurs on a house-by-house basis, both gas pipelines and electricity lines in a neighborhood will be maintained and benefits from electrification could take longer to manifest. The state could therefore miss critical opportunities for market and grid transformation. There may be better bang for the buck to push to electrify entire blocks or subdivisions, both from a marketing perspective and from deployment of grid infrastructure.”¹⁴⁹ By requiring a Joint Feasibility Assessment early in the energy transition, the Commission can provide greater regulatory certainty to both gas and electric utilities, accelerate the adoption of clean energy technologies, and reduce costs to customers associated with an unmanaged transition.

¹⁴⁸ Massachusetts Dept. of Pub. Utilities, Request for Proposal: The Role of Gas Distribution Companies in Achieving the Commonwealth's 2050 Climate Goals at p7 (Feb. 5, 2021), <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13209897>.

¹⁴⁹ EDF, Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California at p25 (2019), https://www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

VII. The Commission Should Direct Utilities to Engage in a Stakeholder Collaborative to Develop a Process for Strategic Decommissioning Portions of the Distribution System

The Planning Proposal states that “[o]pportunities to merge the retirement of leak-prone pipe with an NPA should be explored. Thus, utilities should assess whether a segment of main and associated services can be retired, and an alternative energy approach can supplant renewing the natural gas assets. A process to search for such opportunities should be developed and implemented.”¹⁵⁰ Staff’s proposal of linking leak prone pipe retirement with non-pipeline alternatives is an excellent recommendation that builds upon steps utilities are already considering,¹⁵¹ but would benefit from additional detail, structure, and accountability. Retirement of leak-prone pipe provides the greatest near-term climate benefit because of the potential for reduced fugitive methane emissions, and Staff is correct to emphasize this as a starting place, but planning for strategic retirement of distribution infrastructure should not be limited to leak-prone pipe.

California is in the midst of engaging in a similar analytical exercise and is conducting cost benefit analyses for possible electrification and decommissioning of portions of the gas

¹⁵⁰ Planning Proposal at p19.

¹⁵¹ See NYPSC Case Nos. 17-E-0459 and 17-G-0460, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service*, Central Hudson Gas & Electric Corporation’s Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives at p1 (June 21, 2019) (“The Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire non-essential sections of [leak prone pipe] ... [which] requires the conversion [of] existing natural gas users to alternate forms of energy sources, such as electric, so that the LPP asset is no longer in use.”), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=228704&MatterSeq=54152>; Case No. 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of the Future of Heat Panel at p30 (July 31, 2020) (proposing a geothermal shared loop pilot project divert new and existing customers off of gas service, including a focus on evaluating existing customers served by leak-prone pipe in order to “avoid replacement of the leak-prone pipe and instead remove that segment from service”).

system, assessing how to avoid future stranded assets, and ensuring energy equity for disadvantaged and low-income communities.¹⁵² Borrowing from this study effort, EDF provides below suggestions to ensure that Staff’s suggested process is both equitable and transparent and considers the appropriate scope of issues to inform important decisions regarding the future of the gas system.

This process should not be left solely within the utility’s discretion but rather should be designed around joint decision-making and facilitate stakeholder input, including from any electric utility operating in the gas utility’s service territory. The decision to transition the gas system to an alternative energy approach such as electrification will require a thorough assessment of costs, customer acceptance, needs of low-income and disproportionately impacted communities, GHG emission reductions, site feasibility, gas infrastructure topology, among others. These decisions must be made in a transparent and equitable way using quality data.

To facilitate a robust process, the Commission should direct all gas utilities in the state to engage in a stakeholder collaborative to study this issue in each gas service territory. The purpose of the collaborative would be to develop a framework to guide decision-making, culminating in the selection of a pilot project site to explore the decommissioning of select portions of the gas system. Below, EDF offers a suggested plan for the stakeholder collaborative. The collaborative would first develop a set of issues to be studied, which would

¹⁵² As the California Energy Commission explain, “[t]he result of the research would be a set of guidelines and criteria that enable decision makers to easily identify potential project sites for natural gas system decommissioning, quantify the avoided natural gas infrastructure costs associated with all-electric service, assess costs of electric system upgrades and building electrification, and evaluate expected cost savings and customer acceptance. The awardees from this solicitation will propose at least three pilot projects where the approaches can be implemented and verified in the near-term or within five years.” California Energy Commission, Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Natural Gas Infrastructure (Dec. 7, 2020), <https://www.energy.ca.gov/solicitations/2020-12/gfo-20-503-strategic-pathways-and-analytics-tactical-decommissioning-portions>.

be memorialized into a framework for decision-making, and then ultimately tested on a pilot basis. A preliminary list of issues to be studied could include:

1. Cost Assessment. The high replacement cost associated with aging natural gas infrastructure must be a threshold issue of evaluation, given the significant amount of leak prone pipe in New York, as noted in the chart below:¹⁵³

Figure 6.

State	Bare Steel		Cast Iron	
	Main Miles	Service Count	Main Miles	Service Count
Connecticut	139	37,182	1,221	17
Massachusetts	1,288	147,075	2,925	1,373
Maine	1	98	36	24
New Hampshire	7	5,255	81	14
New Jersey	588	184,769	3,911	0
New York	5,152	213,570	3,175	3,847
Pennsylvania	6,415	238,492	2,532	73
Rhode Island	199	33,726	700	127

The costs of replacing aging pipes is expensive and can range from \$1M to \$5M per mile.¹⁵⁴ Costs of replacement would need to be compared with the direct costs of decommissioning, costs to the rest of the system, and the costs of electrification.

2. Site Feasibility. An assessment of potential site locations would be driven by engineering considerations, including gas infrastructure topology, pressure analyses, geographic limitations and other issues.
3. Community Outreach and Acceptance. The decommissioning of the gas system cannot occur without meaningful input from impacted communities. Utilities should be prioritizing the needs of low income customers as part of the energy transition at multiple stages of the process—in the development of criteria to be included in the decision framework, in the analysis of potential sites, and in the construction and operation of the pilot project itself. Utilities must engage in outreach and education to inform customers,

¹⁵³ National Association of Regulatory Utility Commissioners, Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs at page 19 (January 2020), <https://pubs.naruc.org/pub/45E90C1E-155D-0A36-31FE-A68E6BF430EE>

¹⁵⁴ American Gas Association, AGA Guidelines for Reducing Natural Gas Emissions from Distribution Systems (May 2014), https://www.aga.org/sites/default/files/aga_guidelines_for_natural_gas_emission_reduction_bd_approved_may_17_2014.pdf.

particularly low-income customers and disadvantaged communities, about the opportunities and choices associated with strategic decommissioning and to understand their priorities and needs.

4. GHG Reduction Potential. A central purpose of any decommissioning proposal should be to reduce a utility's GHG emissions. As part of the working group, the utility should be required to provide an estimate of the GHG emissions reductions to be achieved at each site location.
5. Financing Strategies/Ratemaking Changes. The working group should evaluate financing strategies and incentive programs that can support customer electrification, with a focus on reducing transition costs. The working group should also evaluate ratemaking changes that will be needed to effectively decommission portions of the gas system.

Once an assessment of the issues to be studied is complete, the working group should then memorialize the findings in a decision-making framework to guide site selection. Each gas utility would then develop a pilot project at a site selected using the decision-making framework. To ensure timely execution of this effort, the Commission should adopt a schedule to guide the stakeholder collaborative, with specific milestones and timelines, including the timeline for stakeholder meetings, the filing of a decision-making framework, and the deadline for implementing a deployment plan. The Commission should require gas utilities to include a description of the decommissioning assessment in their long-term and annual planning reports, particularly with regard to the progress of each utility's decommissioning pilot project.

VIII. The Commission Should Direct Utilities to Deploy Super-Emitter Programs to Address Gas Leaks and Remove Barriers to Advanced Leak Detection Technology Adoption

The Planning Proposal primarily addresses the issue of gas leaks within the context of leak prone pipe retirement.¹⁵⁵ As discussed above, this is a critical piece of the energy transition and should be built out in further detail. The Commission should also, however, pursue near-term measures to quickly and effectively reduce methane emissions from a utility's system.

¹⁵⁵ See, e.g., Planning Proposal at p19.

Methane, the principal component of natural gas, is a potent greenhouse gas that traps 84 times more heat than carbon dioxide over the first 20 years it is released.¹⁵⁶ New research confirms that because methane is relatively short-lived as compared to carbon dioxide, reducing methane emissions can immediately slow global warming.¹⁵⁷

Incorporation of advanced leak detection technology and data analytics (“ALD+”) into utility leak management practices can more cost-effectively and rapidly reduce methane emissions while improving safety and reliability. ALD+ uses highly sensitive sensors that can detect methane emissions on the level of parts per billion, and the emissions data are then analyzed using algorithms to draw out key information, identifying leaks and assessing leak size with much greater accuracy and precision than traditional leak survey methods.¹⁵⁸ Utilities can use ALD+ to improve leak management practices, to prioritize leak-prone pipeline replacement as well as retirements, and to track their system-wide methane emissions.¹⁵⁹ These applications benefit public safety, ratepayers, and the environment.

Peer-reviewed research has demonstrated that utility crews using traditional survey methods locate only 35% of leaks on the gas distribution system compared to the leaks identified

¹⁵⁶ Myhre, G.; Shindell, D.; Bréon, F.-M.; Collins, W.; Fuglestedt, J.; Huang, J.; Koch, D.; Lamarque, J.-F.; Lee, D.; Mendoza, B.; Nakajima, T.; Robock, A.; G. Stephens, T. T.; Zhang, H. In *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*; Stocker, T., Qin, D., Plattner, G., Tignor, M., Allen, S., Boschung, J., Nauels, A., Xia, Y., Bex, B., Midgley, B., Eds.; Cambridge University Press, 2013.

¹⁵⁷ Ilissa Ocko et al., *Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming*, 2021 *Envtl. Research Letters* in press, <https://doi.org/10.1088/1748-9326/abf9c8>.

¹⁵⁸ Weller, Z. D., Yang, D. K., & von Fischer, J. C. (2019), An open source algorithm to detect natural gas leaks from mobile methane survey data. *Plos One*, 14(2), e0212287, doi.org/10.1371/journal.pone.0212287.

¹⁵⁹ See Palacios, Virginia et al. “Integrating Leak Quantification into Natural Gas Utility Operations,” *Public Utilities Fortnightly* (May 2017), www.fortnightly.com/sites/default/files/whitepapers/2017_Palacios%20et%20al_Integrating%20Leak%20Quantification%20into%20Natural%20Gas%20Utility%20Operations.pdf

using ALD+.¹⁶⁰ Such research has also demonstrated that observed methane emissions from cities are about twice that reported in the U.S. EPA GHG inventory.¹⁶¹ More recently, researchers using data collected with ALD+ estimated that nationwide methane emissions from gas distribution pipes are about *five times* greater than projected by the U.S. EPA GHG inventory.¹⁶² In order to make informed decisions about future changes to the system, the Commission, utilities, and interested stakeholders must have an accurate count of leaks on the system, and ALD+ can facilitate this outcome and allow for data-driven decision-making.

Importantly, a few “super-emitter” leaks are responsible for a significant proportion of the leakage from gas distribution systems, making it essential for utilities to identify and address these leaks to reduce methane emissions.¹⁶³ A report by the Downstream Natural Gas Initiative notes the success of Pacific Gas and Electric Company’s (“PG&E”) program:

[A]ccelerating leak detection and repair efforts for large leaks (defined as greater than or equal to 10 scfh) in a gas distribution system has the potential to substantially reduce methane emissions. PG&E’s Grade 3 leak abatement program does just that. Through this program, DSI member PG&E uses mobile leak detection technology (Picarro) to conduct annual surveys specifically

¹⁶⁰ Weller, Zachary *et al.*, Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty, *Envtl. Sci. & Tech.*, 52, 11922-11930 (2018), <https://pubs.acs.org/doi/10.1021/acs.est.8b03135>.

¹⁶¹ G. Plant *et al.*, Large Fugitive Methane Emissions from Urban Centers Along the U.S. East Coast, *Geophysical Research Letters* V. 46, I. 14 (July 2019), agupubs.onlinelibrary.wiley.com/doi/abs/10.1029/2019GL082635.

¹⁶² Weller *et al.*, A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems, *Envtl. Sci. & Tech.*, 54, 8958-8967 (June 2020), pubs.acs.org/doi/10.1021/acs.est.0c00437.

¹⁶³ A. R. Brandt *et al.*, “Methane Leaks from North American Natural Gas Systems, *Science*, Vol. 343 (Feb. 14, 2011), www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf; Weller, Z. D., Yang, D. K., & von Fischer, J. C., An open source algorithm to detect natural gas leaks from mobile methane survey data, *Plos One*, 14(2), e0212287 (2019) doi.org/10.1371/journal.pone.0212287; *see also* Picarro Emissions Quantification Results Final Report in Support of the Methane Leak Surveying Report for PSE&G’s Gas System Modernization Program (“GSMP”) II Program.

targeting these larger leaks (by comparison, PG&E conducts a three-year survey cycle for all leaks). Once large leaks are identified, they can be repaired.¹⁶⁴

In its pending rate cases before the Commission, National Grid has proposed an Enhanced High Emitter Methane Program to deploy ALD+ in “monitoring, mapping, and helping the Companies to quickly and cost-effectively evaluate leak size and volume.”¹⁶⁵ Using that information, the Companies state that they can then “prioritize repair and replacement activities in areas that can achieve the greatest methane emission reductions.”¹⁶⁶ These examples highlight the benefits ALD+ could provide for all gas utilities in the state in contributing to the GHG emission reductions required by the CLCPA.

Governor Cuomo’s May 2017 Methane Reduction Plan directs state agencies, including the Department of Public Service, to develop policies to inventory methane emissions and identify strategies to reduce leaks. The Methane Reduction Plan directs the Commission to “evaluate and identify best technology and methods to identify leaks in each portion of the system,”¹⁶⁷ and further directs the Commission to “refine current methodology and ranking system for repair of non-health and safety-related leaks and determine if incentives are required in rate cases to ensure higher volume leaks are addressed by utilities, regardless of

¹⁶⁴ MJ Bradley & Associates, *The Role of Gas Networks in a Low-Carbon Future* at page 18 (Dec. 2020), https://mjbradley.com/sites/default/files/MJBA_Long-term-Vision-of-Gas%20Networks-in-a-Low-Carbon-Future_December2020.pdf.

¹⁶⁵ NYPSC Case No. 19-G-0309 & 19-G-0310, *Proceeding on Motion of the Commission as to the Rates, Charges, Rule and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY and Keyspan Gas East Corp. d/b/a National Grid*, Direct Testimony of the Future of Heat Panel at p19, lines 12-13 (April 2019); *see also* NYPSC Case No. 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of the Future of Heat Panel at p36-37 (July 31, 2020).

¹⁶⁶ *Id.* at p19, lines 14-16.

¹⁶⁷ New York State Agencies, *Methane Reduction Plan* at 5, 6 (May 2017), https://www.dec.ny.gov/docs/administration_pdf/mrpfinal.pdf.

classification.”¹⁶⁸ In its recent strategic plan, NYSERDA states that New York should pursue “novel leak-prone pipe detection and prevention methods,” particularly in hard-to-electrify use-cases.¹⁶⁹

In addition, a recent federal law detailing new requirements for the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) will impact gas utilities’ management and design of leak repair and replacement programs. Specifically, the PIPES Act of 2020 mandates that PHMSA set standards requiring use of advanced leak detection technologies—designed to address both safety and environmental considerations—as part of a gas utility’s leak repair and replacement programs.¹⁷⁰ To prepare for these anticipated PHMSA regulations, the Commission should ensure its current regulatory paradigm facilitates adoption of ALD+.

As one example, the Commission will need to revisit incentive programs that reward utilities solely for reducing the number of leaks in their backlog. ALD+ can find many more leaks than traditional survey methods on a gas utility’s distribution system, which would add to a utility’s existing leak backlog. Many New York gas utilities may be reluctant to adopt such technology because they are currently rewarded for reducing their leak backlog or penalized if the backlog increases. Instead, utilities should be incentivized to find more leaks (as measured by volume of methane) and to reduce those leaks. The incentive mechanism should be structured around reduced fugitive methane emissions (*i.e.*, leak flow volume) and could be designed via a leak distribution curve, as detailed in the testimony of Colorado State University Professor Joseph von Fischer:

¹⁶⁸ *Id.* at 7.

¹⁶⁹ NYSERDA Strategic Plan at p49.

¹⁷⁰ Consolidated Appropriations Act, 2021, Pub. L. No. 116-260, Division R – PIPES Act of 2020 Section 113 (enacted Dec. 27, 2020).

Using the information gathered from [a system-wide ALD+] survey, the Company could establish a system-wide baseline leak flow rate. Next, a volumetric leak reduction target could be established within the current leak abatement incentive. In order to receive its annual maximum positive incentive, the Company would be required to achieve a 50% reduction over three to five years which, according to our data, would require abatement of approximately the largest 20% of leaks in its non-hazardous leak inventory. This could be achieved through a combination of Type 3 leak repairs and leak-prone pipe replacement, allowing the utility to optimize its approach to leak mitigation through pipeline replacements when necessary.¹⁷¹

In order to drive near-term GHG emission reductions, the Commission should require all gas utilities to design and implement Enhanced High Emitter Methane Programs to use ALD+ on their systems, and track and monitor methane emissions reductions associated with these programs on an annual basis. In addition, the Commission should provide guidance on the design of leak incentive metrics to facilitate the use of best available technologies in addressing leaks on the system. By providing guidance and leadership on these issues on a state-wide basis, the Commission will better facilitate the goals of the CLCPA, which emphasizes the importance of ensuring a complete and accurate accounting of GHG emissions using the best available scientific, technological, and economic information, and will better prepare gas utilities for impending PHMSA regulations that require use of advanced leak detection technologies.

IX. The Commission Should Evaluate Generator Pricing Rules in Light of New York State's Evolving Policy and Regulatory Environment

Staff states that “LDCs should propose portfolios of demand response programs that not only include tried and true solutions, but also novel approaches, such as rate design changes. For

¹⁷¹ NYPSC Case No. 20-G-0381, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service*, Direct Testimony of Joseph von Fischer at p37, (Nov. 25, 2020), <http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256482&MatterSeq=63187>.

example, seasonal rates or premium pricing on peak day may be effective at shaping demand.”¹⁷²

One opportunity for rate design improvements includes LDC gas tariff provisions applicable to services provided to electric generators. In a separate pending docket before the Commission in Case 17-G-0011, Staff acknowledges that the changing dynamics of the gas system make it an opportune time to review the LDC gas tariff provisions for service to electric generators.¹⁷³ The changing dynamics of the electric system should also inform the Commission’s action on this issue, given the interplay between the gas and electric systems.

The implementation of the CLCPA will have dramatic implications for the future of New York’s electric grid and the role of gas generators in that future energy system.¹⁷⁴ Under the CLCPA, only 30 percent of New York State’s electric generation can originate from fossil fuel plants in 2030. By 2040, the CLCPA requires a zero-GHG-emission electricity sector.¹⁷⁵ The CLCPA also provides for aggressive storage and solar targets.¹⁷⁶ In addition, the New York Department of Environmental Conservation recently developed standards to reduce emissions of nitrogen oxides from peaking power plants by 2023-2025, which have both cost and use implications for these facilities.¹⁷⁷

¹⁷² Planning Proposal at p17.

¹⁷³ Staff Proposal, Case 17-G-0011 at 3 (March 30, 2020) (noting that the Commission’s Non-Pipeline Solutions Order approved alternatives, both supply and demand driven, to address gas system constraints on peak usage days).

¹⁷⁴ The CLCPA mandates that the State of New York adopt measures to reduce statewide GHG emissions by 40% by 2030 and 85% by 2050 (from 1990 levels), with an additional goal of achieving net zero emissions across all sectors of the economy by 2050 (the remaining 15 percent can come from carbon offsets). CLCPA § 1(4); *id.* § 2 (N.Y. ECL § 75-0107(1)).

¹⁷⁵ CLCPA § 1(12)(d); CLCPA § 4 (N.Y. PSL § 66-p(2)).

¹⁷⁶ CLCPA § 4.

¹⁷⁷ 6 NYCRR Subpart 227-3, “Ozone Season Oxides of Nitrogen (NO_x) Emission Limits for Simple Cycle and Regenerative Combustion Turbines,” <http://www.dec.ny.gov/regulations/116185.html>.

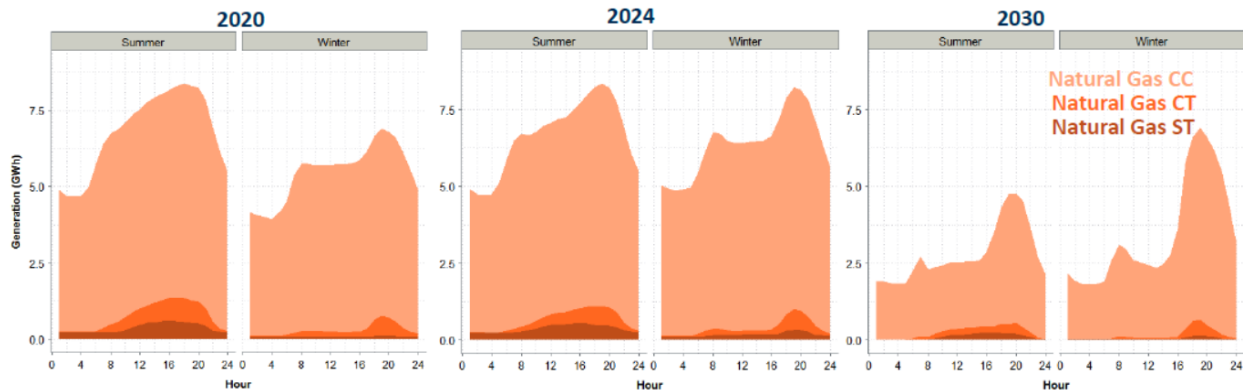
Against the backdrop of these laws, New York must consider what market design constructs will most effectively support a future electricity system with high penetrations of renewables and other zero/low carbon resources. The role of gas generators in this future system will evolve and the services supporting these generators will need to reflect this new reality. Numerous data points and projections suggest that as renewable penetration increases, output from natural gas-fired power plants, particularly baseload, combined-cycle, plants, will fall.¹⁷⁸ Gas-fired generation will serve the purpose of load-following as well as backstopping intermittent renewable resource generation.¹⁷⁹ The Commission should evaluate its generator pricing policies in light of these contemporaneous and evolving market conditions.

A. Gas Generators Require Tailored Transportation and Balancing Services to Meet their Variable Needs

In an increasingly dynamic system with more renewable penetration, the services provided by gas utilities to generators must evolve. Modeling by the Brattle Group indicates that natural gas generation declines significantly between 2024 and 2030 and becomes peakier. In 2020, statewide natural gas accounts for over 35% of total 158 TWh generation, and gas generation declines to 17% of total generation in 2030:

¹⁷⁸ See, e.g., 2018 California Gas Report, prepared by the California Gas and Electric Utilities at page 4, https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf (“overall gas demand for electric generation is expected to decline at 1.4 percent per year for the next 17 years due to more efficient power plants, statewide efforts to minimize greenhouse gas (GHG) emissions through aggressive programs pursuing demand-side reductions, and the acquisition of preferred power generation resources that produce little or no carbon emissions.”); Prepared Testimony of Mark Dyson on behalf of Environmental Defense Fund, FERC Docket No. PL18-1 at page 9 (July 25, 2018) (“The experienced and forecast price declines in emerging technologies, in particular wind and solar photovoltaic electricity generation projects as well as battery energy storage systems, suggest that natural gas-fired generation market share may diminish as these technologies achieve more widespread adoption.”).

¹⁷⁹ 2018 California Gas Report at page 4.



As the grid becomes more dynamic, the role of natural gas as a grid reliability service provider will become all the more important.¹⁸⁰ In order for combined cycle and simple cycle plants to provide the required fast-start capability, they need to be able to access natural gas supplies that correspond to their daily variations in load.¹⁸¹ The suite of transportation and balancing services should complement and facilitate the variable needs of generators, and the value of this flexibility should be reflected in the electric market. For several years now, agencies,¹⁸²

¹⁸⁰ Diversity of Reliability Attributes – A Key Component of the Modern Grid, Prepared for American Petroleum Institute by The Brattle Group at page 21, table 1 (May 17, 2017), <http://www.api.org/~media/Files/Policy/Natural-Gas-Solutions/20170517-API-Diversity-of-Attributes.pdf> (summarizing the relative advantages that different technologies have in providing the attributes needed for system reliability).

¹⁸¹ Quadrennial Energy Review Task Force, Transforming U.S. Energy Infrastructures in a Time of Rapid Change, Appendix B – Natural Gas Infrastructure at 10 (April 21, 2015) (“Many gas-fired power plants use large amounts of natural gas over short periods of time throughout the day. These swings can be very large—at full output, one 700MW natural gas power plant consumes as much natural gas on an hourly basis as the entire heating demand of a small city”).

¹⁸² Final Report of the Interagency Task Force on Natural Gas Storage Safety, Ensuring Safe and Reliable Underground Natural Gas Storage at 80 (October 20, 2016), <https://www.energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage> (The gas and electric industries “should work together to develop flexible pipeline services to accommodate the changing needs of the electricity industry.”).

RTOs,¹⁸³ and market participants¹⁸⁴ have identified a need to define and foster price formation for more flexible pipeline services. Gas utilities can take a leadership role in crafting these services, which will further promote innovation of these services from other service providers in the wholesale gas market.

B. Bringing Enhanced Price Discovery and Transparency to Natural Gas Transportation and Balancing Services Will Spur Competition in the Electric Market

Bringing transparency and price discovery to natural gas transportation service for generators has implications for the competitiveness of the electric grid and those resources which can compete with natural gas to provide flexibility services. Various types of resources can provide flexibility services.¹⁸⁵ But because the gas market does not delineate and price the flexibility that natural gas provides (*i.e.*, sub-day non-ratable flows), the markets do not effectively spur competition, innovation, or investment. In effect, the “unpriced” flexibility from the natural gas supply chain (embedded within the price for long-term transportation capacity), muddles the market for participation by more dynamic, data-driven resources like batteries and demand response. Enhanced price transparency and discovery in the gas market—if ultimately

¹⁸³ Comments and Responses of PJM Interconnection, L.L.C., Docket No. AD18-7 at 7 (Mar. 9, 2018) (asking FERC “to encourage the development of additional pipeline services tailored to the flexibility needs of natural gas-fired generation so as to encourage appropriate tailoring and pricing of services beyond today’s traditional firm/interruptible paradigm.”).

¹⁸⁴ Black & Veatch Management Consulting, LLC for the INGAA Foundation, Inc., *The Role of Natural Gas in the Transition to a Lower-Carbon Economy* at page 56 (May 2019) (“The need for fast ramping electric generation resources will continue to grow with the transition to a lower-carbon economy. Developing no-notice or short-notice transportation rates that reflect the time of use element of the delivered gas volumes will be an important step to allocate the appropriate level of costs to each shipper on the system.”).

¹⁸⁵ Electric Power Research Institute, *Contributions of Supply and Demand Resources to Required Power System Reliability Services* at 21 (May 2015), <https://www.epri.com/#/pages/product/3002006400/>; see also Alison Silverstein *et al.*, *A Customer-focused Framework for Electric System Resilience* at Appendix B, GRID STRATEGIES, LLC (May 2018), <https://gridprogress.files.wordpress.com/2018/05/customer-focused-resilience-final-050118.pdf> (detailing reliability services capabilities for major energy sources).

flowed through to the electric market—will better incentivize flexible resources during periods of tight fuel supply¹⁸⁶ and will ensure that the products and services in both the electric and gas markets will generate effective price signals in and across the two markets so that appropriate right-sized investments will be made.

This is a particularly important task in New York given the transformation envisioned by the CLCPA, as detailed above. As the New York Independent System Operator (“NYISO”) recently explained:

To the extent that the CLCPA leads to the elimination of all fossil fuel-based resources supplying the grid, the carbon-free resources supplying the grid will need to offer comparable dispatchable capabilities to meet electricity demand currently provided by the fossil fuel resources. Fossil fuel plants can typically be dispatched to a rated output level for extended periods while also offering a level of flexibility to ramp up or down as needed to continuously balance load and supply...The elimination of fossil fuel resources will necessarily require replacement with a portfolio of zero-emitting resources and energy storage resources that can match, individually or collectively, the capabilities of fossil fuels.¹⁸⁷

Moving forward, NYISO has recommended several market design and system planning enhancements to better integrate renewable resources, including pursuing energy and ancillary service pricing enhancements and integrating energy storage resources.¹⁸⁸ The Commission

¹⁸⁶ See CAISO, Commitment Cost and Default Energy Bid Enhancements Second Revised Draft Final Proposal at 13 (Mar. 2, 2018) (“By increasing the accuracy of its reference level calculations, the California ISO can better: support integration of renewable resources through improving its valuation of resources under uncompetitive conditions in a manner that will incentivize flexible resources participation during tight fuel supply; account for costs of flexible resources (gas and non-gas) to reduce risk of insufficient cost recovery; and encourage participation of non-resource adequacy and Energy Imbalance Market resources.”).

¹⁸⁷ NYISO Annual Grid and Markets Report, The Vision for a Greener Grid at p26 (2020), <https://www.nyiso.com/documents/20142/2223020/2020-Power-Trends-Report.pdf/dd91ce25-11fe-a14f-52c8-f1a9bd9085c2>.

¹⁸⁸ *Id.* at p31.

should consider the role gas utilities can play in facilitating this transition by evaluating electric generator rate design against this backdrop of change.

C. Suggested Recommendations to Improve Electric Generator Rate Design

On March 30, 2020, Staff filed a proposal on electric generator rate design in Case 17-G-0011 (In the Matter of a Review of Tariff Provisions Regarding Natural Gas Service to Electric Generators). Staff's Proposal suggested that "utilities should create provisions for optional, enhanced balancing services where and when possible."¹⁸⁹ While EDF intends to submit comments in that proceeding once a comment date is established, we highlight below the connections between Case 17-G-0011 and the instant proceeding. As part of a managed contraction of the gas system, the Commission will need to determine who will be using the system long-term, and how rate design and cost allocation will need to be revised to reflect actual future use.

As utilities evaluate optional enhanced balancing services going forward, they should consider a balancing service that is based on hourly usage instead of daily usage. For example, Consolidated Edison's current balancing charge specifies that if daily usage is +/-2% of the nominated amount, imbalances are aggregated and cashed out at the end of the month. If daily usage is greater than +/-2% of the nominated amount, imbalances are cashed out daily, using the following schedule:

¹⁸⁹ Staff Proposal, Case 17-G-0011 at p4 (Mar. 30, 2020).

CECONY - Daily Balancing Charges

	2-5%	6-10%	>10%	Index
Overburn	110%	120%	130%	TGPL Z6-NY, TETCO M3, Iroq. Z2
Underburn	90%	80%	70%	TGPL Z6-NY, TETCO M3, Iroq. Z2

Designing a tariff service based on hourly imbalances could provide several benefits to the integrated energy system, including: (1) recognizing the value of the service LDCs provide to gas generators; (2) providing intraday gas supply price signals that could improve the value of demand response programs; and (3) encouraging competition in the provision of services by interstate pipelines and competing electricity assets. In sum, gas generators will need flexibility to balance renewables and the rate charges should reflect that flexibility.

CONCLUSION

In opening this proceeding, the Commission issued a call for “Policy-Aligned Gas Planning,” observing that “[r]ecent developments have challenged conventional approaches to gas system planning,” including “the CLCPA’s establishment of state policy directions” and “the emergence of viable, less-traditional and increasingly cleaner alternative solutions for demand and supply.”¹⁹⁰ The Staff Planning Proposal responds to this call and represents a meaningful step towards improving the current gas planning process. However, improvements to the Planning Proposal are necessary to ensure that New York gas utilities align their investments and operations with state climate law.

¹⁹⁰ NYPSC Case No. 20-G-0131, Commission Order Instituting Proceeding at p6.

EDF has set forth recommendations in this comment to immediately improve the Planning Proposal, as well as recommendations for additional processes and analyses that will be required to align gas utility planning and operations with New York climate law and policy. Incorporating these recommendations will strengthen the Planning Proposal into a comprehensive planning framework that meets today's needs and is durable enough to accommodate forthcoming state climate policy direction from the Climate Action Council and other agencies. EDF looks forward to continuing to engage with the Commission, Staff, utilities, and stakeholders to ensure that gas utility planning is aligned with climate policy.

Dated: May 3, 2021

/s/ Erin Murphy

Erin Murphy
Senior Attorney, Energy Markets & Utility Regulation
Environmental Defense Fund
1875 Connecticut Avenue NW, Suite 600
Washington, DC 20009
emurphy@edf.org
202-572-3525

Natalie Karas
Senior Director and Lead Counsel, Energy
Environmental Defense Fund
1875 Connecticut Avenue NW, Suite 600
Washington, DC 20009
nkaras@edf.org

Elizabeth Stein
Lead Counsel, Energy Transition Strategy
Environmental Defense Fund
257 Park Avenue South
New York, NY 10010
estein@edf.org

APPENDIX OF ATTACHMENTS

Attachment 1

Proposed Reporting Requirements for Gas Utilities

Submitted by Environmental Defense Fund

May 3, 2021

NYPSC Case 20-G-0131

Attachment 1
Proposed Reporting Requirements for Gas Utilities
Case 20-G-0131

This attachment catalogs the utility reporting requirements proposed by Environmental Defense Fund for the long-term gas utility planning process. EDF supports the reporting requirements proposed by NY Department of Public Service Staff in its Planning Proposal, detailed immediately below in Part A, and proposes the additional reporting requirements detailed subsequently in Part B.

A. Reporting Requirements in Staff Planning Proposal

EDF has attempted to summarize in list form the reporting requirements detailed in the Staff Planning Proposal,

- Long-Term Plan, Demand Forecast
 - 20-year horizon, including peak day, peak hour, and annual load. p14.
 - Sources of anticipated demand growth.
 - Possible sources: “increased demand from existing customers, increased demand from new customers (residential customers, new commercial/industrial customers), and demand growth from conversions by customers (residential, multi-family, and commercial).” p14.
 - For conversions, “specifically identify growth related to conversions from other fuels to natural gas, especially for residential heating, and how they address such growth or applicable environmental regulations that they believe influence conversion activity.” p14.
 - Weather-adjusted back cast using actual weather conditions. p14.
 - Geographical analysis with enough granularity to clearly identify locations of anticipated localized demand growth to allow for adequate planning. p15.
 - The analysis will include a reasonable range of possible error. p14.
 - Variables:
 - Analysis should “cover scenarios (e.g., different sales forecasts based on variance in economic indicators) in the expected adoption and impact of non-traditional alternatives including demand management programs.” p14.
 - “Forecasts of future load should be consistent with short term weather and forecasted usage determination techniques and include adjustments for energy efficiency, electrification, demand response, NPAs, and other external impacts (e.g., COVID-19).” p14-15.
 - “Utilities should explicitly state what demand management and energy efficiency programs are included in the baseline demand forecast. This includes, but is not limited to, stating if the forecast maintains the status quo as of a specific date or historical period, adjusts for current

Commission-approved spending levels, or assumes some other level of change or trend in outer years.” p15.

- Long-Term Plan, Supply Forecast
 - Must align with demand forecast. Include a 20-year horizon and contain planned composition of the supply portfolio. p15.
 - Components to include: “firm pipeline contracts, gas storage, peaking supplies, demand response, energy efficiency, electrification, and contingency supplies such as trucked compressed or liquefied natural gas.” p15.
 - For all planned infrastructure projects, the utilities’ analyses need to include whether they are base load, peaking, or contingency solutions. p16-17.
 - Geographical analysis with enough granularity to identify geographical locations of anticipated, localized, supply availability to allow for adequate transparent planning. p16.
 - A margin of error around forecasting would encompass changes in load growth or availability of supply. This discrepancy can be met with contingency supply to avoid possible curtailments of firm customers or the need to declare moratoria. p16.
 - Utilities should also identify critical upstream supply issues, including vulnerabilities due to critical points of existing supply, as well as consequences of delay or cancellation of planned new supply. p17.
 - Variables:
 - Scenarios that cover a reasonable range of future market development, including any specific, identified, developments that are significant enough to reasonably warrant a scenario.
 - “[U]tilities should explicitly state what levels of demand response, electrification and energy efficiency are reflected in the baseline supply forecast. Utilities should clearly state if the forecast maintains the status quo as of a specific date or historical period, adjusts for current Commission-approved spending levels, or assumes some other level of change or trend in outer years.” p17.
- Annual Plan
 - An explanation of the LDC’s progress on its most recent long-term gas system plan;
 - Detail the LDC’s plans for implementing all necessary processes, policies, resources, and changes in standards impacting gas operations and supply;
 - Identify and describe all the information that can be used by stakeholders to help them understand the gas system needs and potential solutions to constraints, an updated gas demand forecast, including any changed circumstances that materially impact gas system planning; and,
 - Describe how the LDC’s planning and implementation efforts are organized and managed. p11-12.

- Annual Look-Back, due by May 31 of each year
 - Each utility must submit information about actual supply/demand for the previous year: “actual natural gas throughput for the preceding twelve-month period ended March 31 of that year; actual natural gas load for both firm and interruptible customers, including electric generators’ load separately reported, for the period encompassing November 1 through March 31 of the previous winter period; and peak day load for the one day of highest system throughput reported separately for residential, commercial, industrial and electric generation.” p12.
 - LDCs should make available to clean heat developers the needed data to enable them to develop demand side solutions. p12.
 - Should include “specific areas where leak-prone pipe segments exist that could be targeted for abandonment and electrification of customer gas load or where infrastructure projects may be needed in the near future to maintain system pressures.” p12.

B. Additional Reporting Requirements Proposed by EDF

All-In Cost formulas, referenced in the table below:

$$\begin{array}{l}
 \text{All-In} \\
 \text{Cost} \\
 \text{(Design} \\
 \text{Day)}
 \end{array}
 = \left(\frac{\begin{array}{l} \text{the sum of the fixed cost per year of} \\ \text{the project + the fixed O\&M cost (if} \\ \text{any) of the project} \\ \text{(i.e., total annual non-gas cost)} \end{array}}{\begin{array}{l} \text{the projected Design Day Dth of use} \\ \text{(i.e., quantity) of project (to arrive at} \\ \text{modeled per Dth of use non-gas cost)} \end{array}} \right) + \begin{array}{l} \text{the variable} \\ \text{commodity cost} \\ \text{per Dth of the} \\ \text{project} \end{array} + \begin{array}{l} \text{the variable} \\ \text{O\&M cost} \\ \text{per Dth} \\ \text{(if any)} \end{array}$$

$$\begin{array}{l}
 \text{All-In} \\
 \text{Cost} \\
 \text{(Estimated} \\
 \text{Use)}
 \end{array}
 = \left(\frac{\begin{array}{l} \text{the sum of the fixed cost per year of} \\ \text{the project + the fixed O\&M cost (if} \\ \text{any) of the project} \\ \text{(i.e., total annual non-gas cost)} \end{array}}{\begin{array}{l} \text{the projected annual use (i.e.,} \\ \text{quantity) of/by or through the} \\ \text{project (to arrive at modeled per Dth} \\ \text{of use non-gas cost)} \end{array}} \right) + \begin{array}{l} \text{the variable} \\ \text{commodity cost} \\ \text{per Dth of the} \\ \text{project} \end{array} + \begin{array}{l} \text{the variable} \\ \text{O\&M cost} \\ \text{per Dth} \\ \text{(if any)} \end{array}$$

Note: Throughout the table below, all referenced “resource stacks” should include resources available but not utilized.

Long-Term Plan Filing	Annual Plan Filing	Look-Back (May 31) Filing
All-in Cost (Design Day) of each existing contract, for the next 5 years	All-in Cost (Design Day) for coming year of each existing contract, presented as “Variance to Plan” from same year in Long-Term Plan	All-in Cost (Design Day) for the past year of each existing contract, presented as “Variance to Plan” from prior Annual Plan projection
All-in Cost (Estimated Use) of each existing contract, for the next 5 years	All-in Cost (Estimated Use), for coming year of each existing contract, presented as “Variance to Plan” from same year in Long-Term Plan	All-in Cost (Estimated Use) for the past year of each existing contract, presented as “Variance to Plan” from prior Annual Plan projection
Systemwide Daily Load Duration Curves (Winter and Non-Winter) for past 5 years with resource stack.	N/A	Actual Systemwide Daily Load Duration Curves (Winter and Non-Winter) for past year with resource stack; presented as “Variance to Plan” against prior Annual Plan projection
Systemwide Hourly Load Duration Curves (Winter and Non-Winter) for past 5 years with resource stack	N/A	Actual Systemwide Hourly Load Duration Curves (Winter and Non-Winter) for past year with resource stack as well as presented as “Variance to Plan”
Geographically Specific Daily Load Duration Curves (Winter and Non-Winter) for past 5 years with resource stack	N/A	Actual Geographically Specific Daily Load Duration Curves (Winter and Non-Winter) for past year with resource stack as well as presented as “Variance to Plan”
Geographically Specific Hourly Daily Load Duration Curves (Winter and Non-Winter) for past 5 years with resource stack	N/A	Actual Geographically Specific Hourly Load Duration Curves (Winter and Non-Winter) for past year with resource stack as well as presented as “Variance to Plan”

Long-Term Plan Filing	Annual Plan Filing	Look-Back (May 31) Filing
System-wide Daily Load Duration Curves (Winter and Non-Winter) for next 5 years with resource stack by contract	Projected System-wide Daily Load Duration Curves (Winter and Non-Winter) for next year with resource stack by contract, presented as a “Variance to Plan” for against the same year from the Long-Term Plan	
System-wide Hourly Load Duration Curves (Winter and Non-Winter) for next 5 years with resource stack by contract	Projected System-wide Hourly Load Duration Curves (Winter and Non-Winter) for next year with resource stack by contract, and presented as “Variance to Plan” against the same year from the Long-Term Plan	
Geographically Specific Daily Load Duration Curves (Winter and Non-Winter) for next 5 years with resource stack by contract	Projected Geographically Specific Daily Load Duration Curves (Winter and Non-Winter) for next year with resource stack by contract, and presented as “Variance to Plan” against the same year from the Long-Term Plan	
Geographically Specific Hourly Daily Load Duration Curves (Winter and Non-Winter) for next 5 years with resource stack by contract	Projected Geographically Specific Hourly Load Duration Curves (Winter and Non-Winter) for next Year with resource stack by contract and present as "Variance to Plan" for same year from the Long-Term Plan	
All-in Cost (Design Day) by Pipeline, NPA, EE measure, and Demand Response ¹ for Years 6-20	N/A	

¹ The quantity used in the EE and Demand response calculations would be the Dths saved/not used; and the “cost per Dth” would be the Avoided Cost i.e. the cost of the displaced Dth.

Long-Term Plan Filing	Annual Plan Filing	Look-Back (May 31) Filing
All-in Cost per Unit Used by Pipeline, NPA, EE measure, and Demand Response for Years 6-20	N/A	
System-wide Daily Load Duration Curves (Winter and Non-Winter) for next 6-20 Years with resource stack by pipeline, NPA, EE measure, and Demand Response	N/A	
System-wide Hourly Load Duration Curves (Winter and Non-Winter) for next 6-20 Years with resource stack by pipeline, NPA, EE measure, and Demand Response	N/A	
Geographically Specific Daily Load Duration Curves (Winter and Non-Winter) for next 6-20 Years with resource stack by pipeline, NPA, EE measure, and Demand Response	N/A	
Geographically Specific Hourly Daily Load Duration Curves (Winter and Non-Winter) for next 6-20 Years with resource stack by pipeline, NPA, EE measure, and Demand Response	N/A	
		LDCs should provide 3-day coincident peak day (and hourly) takes by take station from: a) pipelines, b) NPAs and c) on-system LNG/propane supply sources; plus estimated impacts (i.e., demand reductions) from EE and DR measures

Long-Term Plan Filing	Annual Plan Filing	Look-Back (May 31) Filing
<p>Systemwide GHG emissions calculation for each year from present to 2050; GHG emissions calculation for individual proposed capital projects</p>	<p>Systemwide GHG emissions calculation for each year from present to 2050, including side-by-side comparison if changed from prior Long-Term Plan; GHG emissions calculation for individual proposed capital projects, including side-by-side comparison if changed from prior Long-Term Plan</p>	
<p>Requests for Proposal (per Part II of EDF comment): (1) RFPs issued over the last two years where a proposal has been selected, detailing the selected proposal; (2) pending RFPs where a proposal has not yet been selected; (3) anticipated upcoming RFPs.</p>	<p>Requests for Proposal (per Part II of EDF comment): (1) RFPs issued over the last year where a proposal has been selected, detailing the selected proposal; (2) pending RFPs where a proposal has not yet been selected; (3) anticipated upcoming RFPs.</p>	
<p>First Long-Term Plan: Decommissioning Assessment and decommissioning pilot proposal. Subsequent Long-Term Plans: Updates or changes to Decommissioning Assessment and pilot. (per Part VII of EDF Comment)</p>	<p>Updates or changes to Decommissioning Assessment and pilot. (per Part VII of EDF Comment)</p>	

Attachment 2

RIPUC Docket No. 4816, *Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27*, Joint Memorandum of the Narragansett Electric Company d/b/a National Grid and the Division of Public Utilities and Carriers at p3 (Feb. 20, 2019)

Submitted by Environmental Defense Fund
May 3, 2021
NYPSC Case 20-G-0131

**JOINT MEMORANDUM OF
THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
AND THE DIVISION OF PUBLIC UTILITIES AND CARRIERS**

Introduction

On October 30, 2018 in The Narragansett Electric Company d/b/a National Grid's (National Grid or the Company) 2018 Gas Cost Recovery (GCR) proceeding, Docket No. 4872, the Public Utilities Commission (PUC) ordered that National Grid and the Division of Public Utilities and Carriers (Division) (collectively, the Parties and, individually, a Party) submit a joint memorandum in Docket No. 4816 outlining each of their recommendations for improving the Long Range Gas Supply Plan (LRP) as it relates to the annual GCR filing. The Parties submit this Joint Memorandum in compliance with the PUC's October 30, 2018 ruling in Docket No. 4872.

In addition to the outline of joint recommendations below, the Parties also believe it is helpful to provide a "problem statement" and summarize the underlying causes of the problem.

Problem Statement

How can the current regulatory review processes be revised to:

- (i) provide the Company assurance that it has the support of its regulators before it makes substantial financial commitments that place the Company at prudency risk from after-the-fact regulatory challenges; and**
- (ii) provide regulators assurance that an unreasonable financial risk is not being placed on customers to bear the financial responsibility for long-term commitments that may turn out to be too conservative or unnecessary, when other reasonable alternatives at lower cost may have been available?**

Two competing interests drive the problem statement. On the one hand, the Company seeks to obtain the Division's support for commitment decisions in advance of the commitments being made. It is completely understandable to the Division why regulatory support is important, when the net present value of the commitments involve tens of millions of dollars and could put the Company at prudency risk if the Division later disagrees with the commitment decision after it is too late for the Company to shift course. On the other hand, the Division desires to have insight into the rationale and justification for these commitments, to assure that customers are not being over-committed, and stranded contract costs are not being created for the future. But the current processes do not provide enough time for the Division to adequately review the decisions in advance and the Division has not been comfortable with the level of detail provided by the Company to support the decisions in advance.

Causes of the Problem

The markets in New England have changed significantly because of capacity issues that impact the reliability and cost of gas supply. This is a very different market than what was in existence over the past two decades. In the past, the key procurement decisions have revolved around gas supply purchases that rarely gave rise to pipeline constraint issues. As a result, the types of decisions that needed to be made by the Company annually tended to relate to supply contracts and the question of whether the Company should be making short- or medium-term supply commitments, given the prevailing market conditions at the time.

However, the rising demand for natural gas has resulted in winter capacity constraints that have changed the Company's procurement decisions. As can be seen from the recent GCR dockets, as well as the Company's efforts to find a longer-term solution to substitute for the loss of the liquefied natural gas (LNG) tank in Cumberland, the Company has been faced with procurement decisions that contemplate long-term contractual commitments that will result in significant costs to customers.

In the past, the LRP filings were not controversial and tended to raise few complicated issues. But now, the Company needs to plan in a way that assures adequate capacity and delivery security under supply contracts, the magnitude and implications of which have grown substantially. As a result, the current framework and template for the Company's long-range planning is no longer sufficient for an appropriate regulatory review. Further, the short time allowed for review in the GCR docket is not conducive to a complete and reasonable review. Left in its current state of regulatory processes, the GCR could become an annual contentious process with the Division compelled to oppose Company cost-recovery on the grounds that the Company has not adequately supported its decisions. Such an annual contentious process is not in the best interest of customers or the Company.

Additionally, there are two more specific items directly affecting the Company that stem from the regional capacity constraints. First, the Company's Capacity Exempt Transportation-only customers who rely on gas suppliers to deliver firm gas supply on interstate pipeline capacity that is held by third parties now assume more risk because their gas suppliers do not have access to interstate pipeline capacity due to regional constraints. Third-party suppliers are typically unwilling to make long-term (20-year) commitments to interstate pipeline companies that are necessary to build new pipeline projects. Second, due to on-system limitations, gas growth on the Company's system has resulted in the need to deliver gas to specific take stations fed by either Tennessee Pipeline Company or Algonquin Gas Transmission. This poses challenges that need to be addressed, such as limitations for gas supply options to meet gas growth.

Outline of Potential Solution

The Parties provide the following outline to address the LRP requirements and review and the annual GCR docket:

- (1) The LRP filing should take place after the winter period, using the same forecasts that will be used for the GCR docket in that year;
- (2) The LRP should no longer be limited to a foundation for planning that shows how the Company plans, but should also include concrete information about how the Company is planning to address supply and capacity needs over the five-year period;
- (3) The LRP should be subject to approval by the PUC;
- (4) If there is a material change to the LRP after approval, the Company should be required to make a supplemental filing with the PUC with notice to the Division;
- (5) A new requirement should be established through which the Company is required to seek advance approval through a filing and proceeding at the PUC for long-term commitments that meet certain triggering criteria relating to the net present value of the cost and term of commitment; and
- (6) To the extent that the larger-impact commitments are addressed through the new pre-approval process and the official approval of the LRP, this should reduce the number of litigated issues that occur in the GCR. In other words, the GCR should become a proceeding that effectively reconciles costs from known and supported commitments, rather than first-impression review of decisions that create an “all-or-nothing” financial risk for either the Company or customers.

Specific elements of this proposed solution are described in more detail below.

Long-Term Commitments:

The Parties strongly believe that item No. 5 above is a critical step in providing resolution to the long-term planning issue. The Parties believe that adoption of a “Review and Approval” mechanism in connection with long-term gas supply and/or gas transportation commitments would be beneficial. Such a mechanism would:

- Allow the Company to provide the PUC and Division with a detailed description of the proposed transaction, what gives rise to the propose transaction, what alternatives have or have not been studied and why, prior to commitment;

-
- Provide for formal discovery so that the PUC and Division have an opportunity to fully understand the proposed transaction;
 - Provide for approval by the PUC and consent from the Division (to the extent deemed to be prudent and in the best interests of the Company's customers); and
 - Upon receipt of such approval, provide the Company with assurance of recovery of the proposed costs and price structure associated with such transaction.

In furtherance of the development of such a mechanism, the Parties propose the following process:

Criteria Applicable to Commitments Greater than One Year in Duration – The Parties propose that the Review and Approval mechanism would be applicable to any gas supply and/or gas transportation commitment that will have a duration in excess of one year.

Filing – Prior to committing to any such transaction, the Company shall submit a filing to the PUC, seeking approval, and to the Division, seeking consent, to any such transaction. Such filing shall include (1) a detailed description of such transaction (including term and estimated cost); (2) a description of the customer need that such transaction is intended to address; (3) a description of the range of viable alternatives that could address the customer need; (4) a description of the alternative transactions that the Company evaluated with the results of the evaluations; and (5) such other information as may be useful to the PUC and Division in connection with their evaluation of the proposed transaction.

Discovery – Following submission of the filing, the Company shall respond to discovery requests from the PUC and Division.

Timing – The Company shall make its filing at least six months prior to the date by which it seeks approval of any transaction. Discovery shall occur, at the discretion of the PUC and Division, any time following the date of such filing until the date that is one month prior to the requested approval date. The Company shall provide written responses to the discovery requests on a rolling basis as soon as possible, and no later than 14 business days of receipt of any such request. The Division shall decide on the Company's request for consent by the requested date. The PUC shall rule on the Company's request for approval by the requested date.

Short-Term Commitments:

Notification of Short Term Commitments – Any gas supply or gas transportation commitments that have a duration of one year or less and have a reservation charge or demand charge that is \$1 million or greater will be submitted to the Division, accompanied by a brief description of the context for the commitment, within 15 business days of the commitment being made, to give the Division time to commence its review prior to the annual GCR filing.

Comprehensive LRP:

The Company's bi-annual LRP filing submitted in March 2018 (Docket No. 4816) needs to be fully reviewed and approved to be able to move forward with certainty on long-term planning. For example, design planning standards and related forecasting are fundamental drivers to long-term planning, and they can potentially lead to significant cost decisions. The Company and the Division will meet to review its design planning and related forecasting methodologies. If these can be approved in a timely manner, such standards and related forecasts will be used in the Company's 2019 LRP and GCR submissions. Otherwise, the Company will use its current standards and related forecasting methods in its 2019 LRP and GCR submissions while the Company and Division continue their discussions, and any modifications or updates will appear in the Company's LRP and GCR submissions in 2020 and beyond, subject to each Party's right to take whatever position it deems appropriate in any related PUC proceedings if agreement cannot be reached.

Another item that needs to be reviewed is the impact to the portfolio from the Company's largest customers (FT-1), including those that the Company partially plans for as well those that the Company does not plan for (capacity exempt customers). These important items need to be fully vetted so that both the Company and the Division are comfortable using them in the forecasting and planning process going forward.

Once the forecasting and planning process is fully reviewed and vetted, the Company will be able to incorporate the agreed-upon results into the future annual process described below, resulting in a comprehensive LRP (Comprehensive LRP).

Subsequent Annual LRP Filings:

Once the Comprehensive LRP is fully vetted and approved, the Company will incorporate all elements of the Comprehensive LRP into subsequent annual LRP filings, which will be scaled-down versions of the Comprehensive LRP, but will include concrete information about how the Company is planning to address supply and capacity needs for the upcoming winter season as well as what the Company is pursuing for the remaining four-year period.

The annual LRP filings would be submitted in June, as soon as practical, following the release of the Company's annual forecast, permitting the Company to base its annual forecast on the most recent customer usage data and prior to the Company's annual GCR filing. These annual LRP filings will include such information as:

- Retail volume forecast by rate group for normal weather;
- Retail meter count forecast by rate group for normal weather;
- Rhode Island Economic Forecast variables for normal weather;
- Wholesale volume forecast by rate group for normal and design weather;
- SENDOUT[®] forecasts (normal and design weather) for capacity planning purposes for volumes and costs;
- Updated portfolio information showing all changes to the portfolio (capacity/supply/LNG), including:
 - Updated Chart IV-C-2 (schematic) if any changes have occurred;
 - Updated Chart IV-C-3 (a description of the contracts within the portfolio, including expiration date and evergreen provisions);
 - A consolidated version of Sections IV.C. (Available Resources), IV.C.2. (Underground Storage Services), and IV.C.3. (Peaking Resources); and
 - A consolidated version of Section IV.C.3.b. (e.g., LNG and/or CNG Contracts);
- Detailed information on needs for upcoming winter season, including SENDOUT[®] analysis showing derivation of need;
- Discussion of subsequent four-years and associated need and what the Company is pursuing with potential suppliers and pipelines to meet customer requirements, as well as expected costs of options;
- Provide historic (5-10 years) and projected (out 5 years) annual wholesale load duration curves showing the following:
- Stack existing supply resources (by path) against the daily wholesale load duration curve for historic period;
 - Stack proposed supply resources (by path) against the daily wholesale load duration curves for the projected periods;
 - Stack existing supply resources (by path) against the daily wholesale load duration curves for the historic November-March period;
 - Stack proposed supply resources (by path) against the wholesale load duration curves for the projected November-March periods; and
 - The Company will endeavor to develop equivalent hourly wholesale load duration curves;

-
- For individually metered high load factor Transportation customers, the Company will develop aggregated annual historic (5-10 years) and projected (out 5 years) load duration curves. For those customers with hourly metering, the Company will endeavor to provide the historic (5 years) aggregated hourly load duration curve;
 - The Company will provide fixed cost of existing supply resources on a dollar per dekatherm (Dth) per day basis (annualized). Once individualized, then the Company will provide the same annualized information by path;
 - For each existing supply resource (by path), the Company will provide an estimated effective Fixed Cost (on a Dth per day basis) (i.e., taking into account load factor utilization) for the current period and forecasted time periods for both its normal and design weather scenario, which is the basis of the Company's decision-making;
 - For each proposed supply resource (by path), the Company will provide an estimated effective Fixed Cost (on a Dth per day basis) (i.e., taking into account load factor utilization) for the current period and forecasted time periods both for its normal and design weather scenario, which is the basis of the Company's decision-making; and
 - For the gas commodity for each of the next five years of projected periods (annual and November through March), the Company will provide, by month for each projected period, the dollar per Dth for the gas estimated to be used on each path under both normal and design weather. The Company will also present the effective citygate gas (variable) cost by month of each path accounting for usage rates and fuel under both normal and design weather.

Subsequent to the annual LRP submission, the Company and the Division will jointly review the LRP submission, and the Company will keep the Division abreast of its plans for the portfolio for the upcoming GCR year.

With a firm basis founded in the review of the Comprehensive LRP filing, the Parties believe that these annual LRP filings would satisfy the statutory requirement of biannual submissions and will provide the Division with sufficient time to review the GCR filing without the need to seek additional time past the GCR hearing to investigate gas costs.

GCR Filing:

The annual GCR filing will reflect the final costs and volumes that are derived from the annual LRP filings. The Company will prepare a comparison of volumes and costs presented in its GCR filing in the same form (i.e., presentation format) as its annual LRP filing from June of the same year and identify any differences. By the time the GCR is filed, these items found in the Company's LRP submission will have already been fully vetted, and the Division will only

need to review any changes that have occurred in the interim or are projected by Company to occur during the upcoming GCR period, subject to the Division's right to review and dispute any costs in the GCR that were not approved in accordance with the process identified in this Joint Memorandum or otherwise.

Attachment 3

NYPSC Case Nos. 19-G-0309 & 19-G-0310, *In the Matter of The Brooklyn Union Gas Company d/b/a National Grid NY & KeySpan East Gas Corporation d/b/a National Grid*,
National Grid Response to Data Request No. EDF-7 (Feb. 8, 2021)

Submitted by Environmental Defense Fund

May 3, 2021

NYPSC Case 20-G-0131

Date of Request: January 29, 2021
Due Date: February 8, 2021

Request No. EDF-7
NG Request No. NG-1499

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case Nos. 19-G-0309 & 19-G-0310
Gas Utilities Rates

Request for Information

FROM: Environmental Defense Fund, Erin Murphy

TO: National Grid, Owen Brady-Traczyk

SUBJECT: Future of Heat

Request:

How will the Company's peak demand evolve in light of the Future of Heat programs and New York's climate and energy policies?

- a. Does the Company expect demands of different customer groups (e.g., electric generators) to change going forward? If yes, please explain how those demands will change.
- b. How will these changes affect the Company's ability to source gas from its system and transport it across their transmission system?

Response:

The Company presented its current long-term natural gas demand forecast in Case 20-G-0131 (see the Company's July 17, 2020, filing). That forecast reflects current New York climate and energy policies—e.g., New Efficiency New York gas energy efficiency and heat electrification. As additional policies are implemented, the Company will update its annual long-term natural gas demand forecast appropriately.

See also the response to EDF-4 regarding the Company's analyses of how climate and energy policies may affect natural gas demand.

With regard to (a) and (b) above, with few exceptions, the Company's electric generator customers are interruptible customers for whom the Company solely transports gas procured by the generator. The Company does not forecast design day demand or procure gas capacity. As such, for purposes of design day reliability planning, any potential decrease in power generators' natural gas consumption as a result of climate and energy policies would not generally provide for additional gas capacity to meet firm customers' requirements.

Name of Respondent:
Stephen Caldwell

Date of Reply:
February 8, 2021