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Final Gas Long-Term Plan

New York State Electric & Gas
and Rochester Gas and Electric

Case 23-G-0437

April 26, 2024

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I.

Introduction

I. Introduction

A. Background

New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") (collectively, the "Companies") present this Final Gas Long-Term Plan ("LTP" or "Long-Term Plan") in accordance with the New York Public Service Commission's ("Commission" or "PSC") May 12, 2022 Order Adopting Gas System Planning Process ("Gas Planning Order").[1] The Gas Planning Order establishes a gas system planning process for natural gas local distribution companies ("LDCs") in New York and includes, among other things, a requirement for each LDC to file a long-term plan. The Companies filed their Initial LTP on October 2, 2023 and their Revised LTP on February 16, 2024.

B. LTP Objectives

The Gas Planning Order provides context for the Companies' LTP by identifying the overall objectives for the gas planning process (see Figure I-1), including requiring that gas planning be consistent with the Climate Leadership and Community Protection Act ("CLCPA") and establishing a robust stakeholder engagement process to inform the development of LDC long-term plans.[2]

Figure I-1: Long-Term Plan Objectives[3]

- Ensure that residents of New York can continue to meet their energy needs in the long term.
- Provide a foundation to ensure that New York continues to reduce greenhouse gas ("GHG") emissions.
- Conduct planning consistent with the CLCPA.
- Provide information for customers in a way that promotes effective customer planning, reduces confusion, and avoids inequities or the appearance of inequities.
- Provide information to the Commission, other government entities and agencies, and stakeholders related to the promotion of effective planning and consideration of gas alternatives, thereby reducing costs and emissions while minimizing impacts on economic development.
- Improve the ability of the Commission, Staff of the Department of Public Service ("DPS Staff" or "Staff"), and stakeholders to examine LDC long-term plans to ensure those plans are cost-effective for ratepayers and consistent with state policies.

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1 *Order Adopting Gas System Planning Process ("Gas Planning Order") issued on May 12, 2022, in Case No. 20-G-0131.*

2 *Gas Planning Order, p. 10.*

3 *Gas Planning Order.*

NYSEG and RG&E present a realistic, achievable LTP that provides safe, reliable, and more affordable energy service and delivers sustainable reductions in GHG emissions while preserving customer choice. The LTP also provides a foundation for requests for approval of specific investments and programs, with particular focus on necessary actions during the next three years. In short, the LTP must be technically feasible and provide valid projections of costs, bill impacts, and GHG emission reductions that can inform subsequent utility proposals and decisions. New developments related to policy, markets, technology, customer behavior, infrastructure development, and other changes to the business or regulatory environment will be incorporated into future LTP filings. Given this evolution, optionality is a key aspect of the LTP to avoid prematurely eliminating options that could be important to ensuring responsible decarbonization in the future.

The Companies have developed a list of "Guiding Principles" that are consistent with Gas Planning Order objectives and NYSEG and RG&E's own mission to ensure energy security and affordability for its customers while also reducing GHG emissions. The Guiding Principles identify the primary goals of the LTP and support a methodology that incorporates the analysis of scenarios and stakeholder feedback to produce insights that have been relied on to construct the LTP. In particular, the methodology is designed to produce insights regarding the tradeoff between environmental and affordability objectives. The contributions of the LTP to reductions in GHG emissions and costs are estimated by comparing the LTP to a "Reference Case" that is based on pre-LTP business-as-usual activities.

C. Avangrid's Commitment to Reducing GHG Emissions

Avangrid, Inc., ("Avangrid"), NYSEG and RG&E's corporate parent, has GHG emission reduction goals that align with New York's CLCPA. More specifically, Avangrid has established a goal of achieving carbon neutrality in Scopes 1 and 2 emissions by 2030. This aggressive goal is consistent with Avangrid's network platform to connect renewable energy to over 3 million customers in the Northeast, as well as Avangrid's position as the 3rd largest wind operator in the US. Achieving Avangrid's carbon neutrality goal will require significant actions by every Avangrid business unit, including its utility subsidiaries. Recognizing this need, the Avangrid Board of Directors adopted a Climate Action Policy and a Sustainability Development Policy in February 2023.

The Climate Action Policy sets forth the following corporate commitment:

> AVANGRID seeks to contribute actively and decisively to a low-carbon and sustainable future, delivering clean, low emission energy, minimizing the environmental impact of our activities and supporting and promoting actions that address climate change. Such efforts must be compatible with social and economic growth.[4]

Avangrid's Sustainability Development Policy establishes specific objectives that contribute to sustainable outcomes across the businesses as well as for the communities and customers that it serves. For example, the policy calls for Avangrid to "promote access to affordable energy for low income and rural communities,"[5] a

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4 *Avangrid Climate Action Policy, February 16, 2023, p. 1.*

5 *Avangrid Sustainable Development Policy, February 16, 2023, p. 3.*

commitment that is particularly relevant in the NYSEG and RG&E service areas, which include relatively high proportions of both.

Avangrid's 2022 Sustainability Report describes the progress toward Avangrid's corporate-wide goal of achieving carbon neutrality in Scopes 1 and 2 emissions by 2030.[6] The 2022 Sustainability Report also identifies several actions that are being taken by Avangrid's utility businesses, including NYSEG and RG&E, that will reduce the GHG emissions associated with (1) operating the existing gas infrastructure, and (2) heating and other customer energy requirements, including:

- replacement of leak-prone pipe;[7]
- investments in advanced leak detection and gas capture technologies;
- connection of renewable natural gas ("RNG") from farms, wastewater treatment facilities and landfills;
- studying the blending of green hydrogen with natural gas in distribution facilities;[8]
- facilitating the adoption of electric heat pumps and other cleaner, less-emissions-intensive heating options as part of a beneficial electrification strategy; and
- helping residential, commercial, industrial, and institutional customers increase their energy efficiency while lowering their energy costs and environmental emissions.[9]

Avangrid Renewables expects to invest $4.3 billion by the end of 2025 to support US emissions reductions including significant growth in renewable capacity such as solar and onshore wind as well as innovation and emerging technologies such as offshore wind, green hydrogen, and storage.

Avangrid's 2023 Sustainability Report includes a discussion of Avangrid's Just Transition framework that reflects input and progress from its subsidiaries, including NYSEG and RG&E.[10] The Just Transition framework identifies the principles that guide the performance of all Avangrid's utility and non-utility subsidiaries and ensures that customers, communities, and workers are not left behind in the energy transition. The report also documents a Just Transition framework to best address social, economic, and environmental challenges with a focus on four core areas: customers, workforce, communities, and suppliers. Many of the actions identified in this LTP report and included in Chapter VII contribute to Avangrid's Just Transition objectives.

6 *Avangrid 2022 Sustainability Report, "Our ESG Goal Scorecard - 2022 Results and 2025/2030 Goals", p. 7.*

7 *The Joint Proposal in Case 22-E-0317, et. al., ("Rate Case JP") reflects an agreement to continue NYSEG and RG&E's leak-prone pipe replacement over the next 3 years, albeit at a slower rate than in recent years as the Companies are nearing the end of their program.*

8 *NYSEG and RG&E are monitoring blending pilot projects in other jurisdictions.*

9 *Avangrid 2022 Sustainability Report, p. 33 and 35.*

10 *Avangrid 2023 Sustainability Report, p. 18 and 41-43.*

D. Stakeholder Engagement

The Gas Planning Order establishes a robust stakeholder engagement process to inform the development of NYSEG and RG&E's LTP. NYSEG and RG&E's Final LTP is shaped by extensive stakeholder engagement, which includes participation by stakeholders, Staff, and Staff's independent consultant, Charles River Associates ("CRA"). The contribution of the stakeholder engagement process to the development of NYSEG and RG&E's LTP is addressed throughout this report and a list of stakeholder and CRA recommendations that were incorporated into the Companies' analysis, report and appendices is provided in Chapter V, Section C.

1. Stakeholder Participants

The following stakeholder organizations have either submitted written comments or actively participated in at least one stakeholder meeting, or both:

- Alliance for a Green Economy and Co-Signers ("AGREE")
- Campaign for Renewable Energy
- Climate Solutions Accelerator of the Genesee-Finger Lakes Region
- Fossil Free Tompkins
- International Brotherhood of Electrical Workers Local 10 and 36 ("IBEW")
- Multiple Intervenors ("MI")[11]
- New York Department of State Utility Intervention Unit ("UIU")
- New York Geothermal Energy Organization ("NY-GEO")
- New York State Energy Research and Development Authority ("NYSERDA")
- New Yorkers for Clean Power
- Ratepayer and Community Intervenors ("RCI")
- Sierra Club and Earthjustice ("SC/EJ") and their consultant, Strategen Consulting ("Strategen")
- Tompkins County Department of Planning and Sustainability ("Tompkins County")

Several individuals have also filed comments in the docket.

2. Filings

Table I-1 lists the major filings made to date by NYSEG and RG&E, CRA, and stakeholders in the NYSEG and RG&E LTP docket (23-G-0437).

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11 *Multiple Intervenors is comprised of approximately 55 large industrial, commercial, and institutional energy consumers with manufacturing and other facilities located throughout New York State, including in NYSEG and RG&E service territories.*

Table I-1: NYSEG and RG&E, CRA, and Stakeholder Filings

Date	Filing	Participant
October 2, 2023	Initial LTP	NYSEG and RG&E
November 22, 2023	CRA Initial Findings Report	CRA
November 29, 2023	Stakeholder Comments	IBEW
December 13, 2023	Stakeholder Comments	Tompkins County
December 14, 2023	Stakeholder Comments	RCI
December 18, 2023	Stakeholder Comments	MI, AGREE, EJ/SC, Strategen
January 19, 2024	Reply Comments	NYSEG and RG&E
February 16, 2024	Revised LTP	NYSEG and RG&E
March 14, 2024	CRA Preliminary Findings Report	CRA
March 26, 2024	Stakeholder Comments	NY-GEO
March 28, 2024	Stakeholder Comments	NYSERDA
March 29, 2024	Stakeholder Comments	EJ/SC, Fossil Free Tompkins, AGREE, NY-GEO (revised)
April 26, 2024	Final LTP	NYSEG and RG&E

Note: CRA is currently scheduled to file its Final Report on May 24, 2024.

3. *Meetings and Technical Conferences*

The stakeholder engagement process began with an informational session prior to the filing of NYSEG and RG&E's Initial LTP. The purpose of this and many additional stakeholder meetings, responses to data requests, and filing of comments and reply comments is to enhance transparency and enable stakeholders' effective participation in the long-term planning process.

Table I-2 lists the meetings and technical conferences that have been held to date with stakeholders, Staff and CRA in compliance with requirements of the Gas Planning Order or to accommodate requests from Staff, CRA, and stakeholders.

Table I-2: Stakeholder, Staff and CRA Meetings

Date	Topic	Participants
September 13, 2023	Background Information Session	NYSEG and RG&E, Staff, CRA, Stakeholders
November 21, 2023	Initial LTP Model Review	NYSEG and RG&E, Staff, CRA
November 29, 2023	Review of Initial LTP	NYSEG and RG&E, Staff, CRA, Stakeholders
December 8, 2023	Confidentiality of LTP Model	NYSEG and RG&E, Staff, CRA, SC/EJ, Strategen
December 13, 2023	Electrification and Heat Pump Adoption	NYSEG and RG&E, Staff, CRA, Stakeholders
January 4, 2024	Hydraulic Modeling and Vulnerable Areas	NYSEG and RG&E, Staff, CRA, Stakeholders
January 18, 2024	Hydraulic Modeling (continued) and Non-Pipe Alternatives ("NPAs")	NYSEG and RG&E, Staff, CRA, Stakeholders
January 23, 2024	CRA and Stakeholder Scenarios	NYSEG and RG&E, Staff, CRA, Stakeholders
January 23, 2024	Hydraulic Modeling	NYSEG and RG&E, Staff, CRA

Date	Topic	Participants
January 25, 2024	Gas and Electric Prices, CRA/Stakeholder Scenarios	NYSEG and RG&E, Staff, CRA, Stakeholders
January 30, 2024	Hydraulic Modeling (continued)	NYSEG and RG&E, Staff, CRA
January 31, 2024	Geothermal /Ground Source Heat Pumps	NYSEG and RG&E, Staff, CRA, Stakeholders
February 2, 2024	Capacity Reserve Margin	NYSEG and RG&E, Staff, CRA
February 13, 2024	Tompkins County	NYSEG and RG&E, Staff, CRA, Stakeholders
February 28, 2024	Bill Impacts and Affordability	NYSEG and RG&E, Staff, CRA, Stakeholders
March 25, 2024	CRA Data Request and Additional Scenarios	NYSEG and RG&E, Staff, CRA

4. *Discovery*

In addition to the information shared at the technical conferences, stakeholders and CRA have been encouraged to submit data requests to help them better understand the Companies' filing and underlying analysis. NYSEG and RG&E has posted responses to 213 data requests submitted by CRA (141), SC/EJ (36), and NYSERDA (36) to a SharePoint site that is maintained by the Companies. Responses that do not contain confidential information are available to all stakeholders; confidential responses are available to those that have executed confidentiality agreements. Staff and CRA have been provided access to limited proprietary, highly confidential materials and the Companies have met with Staff and CRA to answer questions and walk through these materials to ensure transparency. NYSEG and RG&E also maintain a public website that provides access to the LTP report, executive summary, and appendices, and copies of presentations from the technical conferences.

E. Policy Guidance

The LTP is influenced by policy guidance that takes many forms. It includes the CLCPA legislation and the associated compliance proceeding, the Commission's Gas Planning Order and the Order regarding National Fuel Gas Distribution Corp.'s ("NFG") LTP, the recent order in the Companies' 2022 rate proceeding, and other ongoing Commission proceedings that address specific elements of the LTP (e.g., energy efficiency, RNG, utility thermal energy networks). Relevant cases are summarized below:

1. *CLCPA Legislation and Compliance Proceeding (Case 22-M-0149)*

Under New York Public Service Law, gas and electric utilities have the obligation to provide service that is "safe and adequate and in all respects just and reasonable."[12] In 2019, the CLCPA established New York state-wide goals to reduce GHG emissions from a 1990 baseline by 40 percent by 2030 and 85 percent by 2050. The CLCPA codified specific objectives for the electricity sector but did not establish GHG emissions reductions targets for the gas sector or for specific gas LDCs.[13] The Commission has recognized that the CLCPA "contains no mandates or guidelines directly related to emissions associated with the State's gas distribution system or gas supplied by

12 *New York Public Service Law – PBS §65.1.*

13 *CLCPA § 66-p (2), p. 17.*

utilities."[14] The Gas Planning Order also declined to establish specific GHG emissions reductions goals for the gas sector or individual LDCs, stating that, "the CLCPA does not impose specific requirements on the State's gas distribution system," and instead indicated that, "planning must be conducted in a manner consistent with the recently enacted Climate Leadership and Community Protection Act (CLCPA)..."[15] Moreover, the Gas Planning Order clarified that requests to establish "clear goals for gas reduction" were beyond the scope that had been established in the Order Initiating Proceeding.[16]

The CLCPA also established the Climate Action Council ("CAC"), which was tasked with developing a scoping plan to outline recommendations on regulatory measures and other state actions to ensure attainment of the statewide CLCPA goals.[17] The CAC adopted the final scoping plan on December 19, 2022 ("Final Scoping Plan").[18] While the Final Scoping Plan provides economy-wide and sector-specific recommendations, its recommendations are not legally binding. Further, the recommendations require subsequent actions by state and local organizations and governments, including the New York State Legislature, before they can be implemented.[19] The Final Scoping Plan also recognized the challenges and need to balance multiple priorities as part of natural gas decarbonization efforts and recommends a well-planned and strategic transition of the gas system. The Final Scoping Plan notes that this transition will require integrated planning to coordinate with the buildout of the electric generation, transmission, and distribution systems to meet increases in electricity demand, while ensuring the transition is equitable and cost-effective for workers and consumers without compromising reliability, safety, energy affordability, and resiliency.[20]

The Final Scoping Plan also recommends establishing a Cap-and-Invest program that will set an annual limit on the amount of greenhouse gas emission emitted in New York. In December 2023, the New York Department of Environmental Conservation ("DEC") and NYSERDA issued a Pre-Proposal Outline detailing initial program leanings for stakeholder feedback. Similarly, in January of 2024, DEC and NYSERDA published preliminary scenario analyses for pre-proposal consideration and to support program development and associated rulemakings.[21]

The CLCPA also requires state agencies to take actions to ensure that: (1) at least 35% of benefits from energy program spending (e.g., energy efficiency and electrification) be directed to disadvantaged communities ("DACs") with a goal of 40% and (2) their decisions will not "disproportionately burden disadvantaged communities."[22] The

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14 *Case 22-M-0149, In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act ("CLCPA Compliance Proceeding"), Order on Implementation of the Climate Leadership and Community Protection Act (issued May 12, 2022), p. 23.*

15 *Gas Planning Order, p. 4.*

16 *Gas Planning Order, p. 18.*

17 *CLCPA § 75-0103 (13), p. 9.*

18 *Available at: https://climate.ny.gov/-/media/project/climate/files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf .*

19 *See pages 21-22 of the Final Scoping Plan for a description of some of the activities required to implement its recommendations.*

20 *New York State Climate Action Council, "New York State Climate Action Council Scoping Plan," December 2022, Chapter 18. Gas System Transition, p. 350.*

21 *Given that Cap-and-Invest is in the "pre-proposal" stage, it is premature to quantitively assess the impact of this initiative. The Companies will continue to monitor the developments associated with Cap-and-Invest and provide relevant updates in future LTP filings.*

22 *CLCPA § 75-0117 Investment of funds, p. 16; CLCPA §7 Climate change actions by state agencies, p. 19.*

Commission noted that LDCs should provide necessary information to assess the potential benefits and burdens of their long-term plans on DACs.[23]

On May 12, 2022, the Commission initiated a proceeding (Case 22-M-0149) to measure and track compliance with and development of the provisions of the CLCPA and established several key workstreams including one to develop an annual GHG Emissions Inventory Report.[24] In December 2022 and supplemented in May 2023, the Joint Utilities' filed initial proposals for Annual GHG Emissions Inventory filings and guidance on emission inventory reporting, including annual reporting of attributable emissions, avoided emissions, upstream emissions, and end-user combustion related to the natural gas distribution system.[25] The Companies have continued to participate in and monitor the developments this workstream and have incorporated these insights into the GHG emissions accounting methodology used in this LTP.

2. *Gas Planning Proceeding (Case 20-G-0131) and NFG LTP Order (Case 22-G-0610)*

As discussed above, the Commission issued the Gas Planning Order on May 12, 2022, which establishes a gas system planning process for gas LDCs in New York and requires each LDC to file a long-term plan. The Gas Planning order directs that Commission, Staff, and stakeholders have the information necessary to appropriately evaluate the potential GHG emissions of gas utility long-term plans and alternatives.[26] The process established in the Gas Planning Order requires each LDC to file a 20-year long-term plan every three years plus annual updates on May 31st in the interim years. The three-year cycle is designed to provide for future comprehensive updates to reflect new information and insights that inform the long-term plan. Therefore, while the Companies' LTP necessarily incorporates a 20-year forecast of many data inputs and assumptions, the focus should be on whether the Companies' three-year action plan is reasonable given current facts and circumstances. The Gas Planning Order also addresses the methodology to be applied when performing a benefit-cost analysis ("BCA").[27]

On December 14, 2023, the Commission issued an order addressing the first gas long-term plan filed pursuant to the Gas Planning Order.[28] While the order necessarily focuses on the specific circumstances facing NFG, the NFG LTP Order bears some relevance on filings of other LDCs, including the Companies' Final LTP. Notably, the Commission reaffirmed overriding policy objectives by stating: "[t]he Commission recognizes that progress toward decarbonization will take time and must be done with care to ensure that customers continue to have access to

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23 *Gas Planning Order, p. 39-40.*

24 *Case 22-M-0149, In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, Order on Implementation of the Climate Leadership and Community Protection Act, pp. 47-49.*

25 *Case 22-M-0149, In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act, Joint Utilities' Supplement to Proposal for an Annual Greenhouse Gas Emissions Inventory Report, pp. 1-2.*

26 *Gas Planning Order, p. 47.*

27 *The Commission directs LDCs to apply the methodology established in the BCA Framework Order, Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).*

28 *Case 22-G-0610, In the matter of a Review of the Long-Term Gas System Plan of National Fuel Gas Distribution Corporation ("NFG LTP Proceeding"), Order Implementing Long-Term Gas Plan with Modifications (issued December 14, 2023) ("NFG LTP Order").*

safe, adequate, and reliable gas service as allowed under the State's laws."[29] The Commission also reaffirmed its standard of "consistency with CLCPA" for LTPs rather than requiring a specific level of GHG emissions reductions in the NFG LTP Order.[30] Moreover, among other things, the Commission indicated a desire to have long-term plans address reliability, provide bill impacts for various service classifications, incorporate RNG and hydrogen, include a no-infrastructure scenario, address demand response and energy efficiency, incorporate NPAs, and provide results for the Rate Impact Measure ("RIM") and Utility Cost Test ("UCT") tests.[31] The Commission also directed NFG to prepare a BCA handbook that will be subject to review as part of a collaborative process.[32] These directives have shaped the Companies' Final LTP filing.

3. NYSEG and RG&E Rate Case Order (Case 22-E-0317, et. al)

On May 26, 2022, the Companies announced a proposed rate increase to become effective on May 1, 2023. Settlement negotiations resulted in a Joint Proposal.[33] The proposal was supported (in total or in part) by the Companies and eight other parties.[34] On October 12, 2023, after the filing of the Initial LTP, the Commission issued an order adopting the Rate Case JP ("Order Adopting Rate Case JP").[35] The Rate Case JP impacts several areas of the Companies' businesses, including updates to the Companies' electric and gas revenue requirements, capital expenditure forecasts, depreciation factors and rates, cost of capital, safety and reliability, DACs, and NPAs. These factors have been incorporated into the LTP modeling. The Rate Case JP includes several commitments that are relevant to the LTP, including topics addressing geothermal energy, the Companies' pipe replacement program, piloting of air source heat pumps, and reporting requirements for DACs, which are discussed throughout the Final LTP.

4. Other Commission Proceedings

Discussed below are several other ongoing Commission proceedings that are addressing topics that are relevant to specific areas of the Companies' LTP:

- **Energy Efficiency and Building Electrification (Case 18-M-0084):** Initiated in February 2018, this

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29 NFG LTP Order, p. 24-25.

30 NFG LTP Order, p. 59.

31 NFG LTP Order.

32 NYSEG and RG&E's most recent electric BCA Handbook was filed on June 30, 2023. The Companies file an updated electric BCA Handbook as part of periodic DSIP filings.

33 The Joint Proposal was filed on June 14, 2023 (the "Joint Proposal" or "Rate Case JP") in Case No. 22-E-0317, et al; Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service. The Joint Proposal sets forth a three-year rate plan for electric and gas service at the Companies commencing May 1, 2023, and continuing through April 30, 2026 ("Rate Plan"). Rate Year 1 ("RY1"), Rate Year 2 ("RY2") and Rate Year 3 ("RY3") are defined as the 12 months ending April 30, 2024; April 30, 2025; and April 30, 2026, respectively.

34 The New York State Department of Public Service Staff ("Staff"); Convergent Energy and Power LP; International Brotherhood of Electrical Workers, Local Union 10 ("IBEW"); Multiple Intervenors ("MI"); New York Power Authority ("NYPA"); Nucor Steel Auburn, Inc. ("Nucor"); Utility Intervention Unit of the Division of Consumer Protection at the Department of State ("UIU"); and Walmart, Inc. (collectively, the "Signatory Parties").

35 Case No. 22-E-0317, et al, Order Adopting Joint Proposal, October 12, 2023.

proceeding is addressing issues related to energy efficiency targets and policy.[36] Most recently, on July 20, 2023, the Commission issued an Order Directing Energy Efficiency and Building Electrification ("EE/BE") Proposals.[37] The EE/BE Order requires NYSERDA and the Utilities to submit budget bounded EE/BE portfolio proposals for 2026 through 2030.[38] The Companies filed their original proposal in response to the EE/BE Order on November 1, 2023 and filed an update on January 16, 2024.[39,40] As discussed later in this report, the residential weatherization program proposed in the Companies' LTP uses data from the Companies' January 2024 EE/BE Portfolio Proposal.

The EE/BE Order also requires all utilities to provide an annual report on investments that have been made since the enactment of the CLCPA to track progress towards meeting the DAC requirements.[41] The Companies filed initial DAC data on November 17, 2023, and supplemented it on December 29, 2023, January 26, 2024, and March 14, 2024.[42,43] The Companies' DAC metrics are discussed later in this report.

- **Non-Pipeline Alternatives (several dockets):** In July 2017, NYSEG filed a petition to construct a natural gas compressor pilot to address safety, pressure and reliability issues related to serving existing customers in the Lansing area of Tompkins County.[44] After multiple RFPs, in June 2021, the Commission approved the Lansing NPA portfolio, a collection of projects consisting of various NPA solutions. NYSEG is in the process of implementing these projects.[45] The Lansing NPA portfolio has informed the LTP by providing insights into the planning and implementation process associated with NPAs.

  In accordance with directives from the Commission in the Lansing NPA Order and discussion with DPS Staff, the Companies are required to submit a quarterly NPA Report.[46] As detailed in the quarterly NPA Reports, the Companies continue to review all gas capital projects for applicability of NPA solutions. In the most recent report (2023Q4), the Companies provided updates related NYSEG's Lansing NPAs, as well as

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36 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Notice of New Case Number and Announcing Stakeholder Forums, p.1.*

37 *Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund and Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiatives, Order Directing Energy Efficiency and Building Electrification Proposals ("EE/BE Order"), July 20, 2023.*

38 *EE/BE Order pp. 92-94.*

39 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Energy Efficiency Portfolio Proposal (filed January 16, 2024) ("EE/BE Portfolio Proposal").*

40 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, EE-BE Proposal Supplemental Information Request FINAL.*

41 *EE/BE Order pp. 25-26.*

42 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiatives, NYSEG & RGE DAC Reporting Data Collection EE BE EV EAP Redacts (Filed November 17, 2023, December 29, 2023, and January 26, 2024).*

43 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, NYSEG and RGE DPS NYSERDA Climate Act DAC Reporting Data Collection EE BE EV EAP EV Redacted, March 14, 2024.*

44 *Case 17-G-0432, Petition of New York State Electric & Gas Corporation for Authorization to Construct a Natural Gas Compressor Pilot Project in Tompkins County, New York and to Include the Costs Associated with the Project in Its Capital Rate Base as an Addition to Gas Plant, and to Defer Any Incremental O&M Costs Associated with the Compressor Project, pp. 1-2.*

45 *The status of each project approved in the Lansing NPA portfolio is provided in Table II-5.*

46 *Case 19-G-0379, Proceeding on Motion of the Commission as to the Rates, Charges, Rule and Regulations of New York State Electric & Gas Corporation for Gas Service, Non-Pipes Alternative 2021 Third Quarter Report, p. 2.*

related to RG&E's recent whole home electrification leak prone main NPA project. The report contains updates on the status and operating cost incurred, and identifies benefits associated with each project. These reports have informed the development of LTP as they provide information related to the implementation of NPAs.

- **Utility Thermal Energy Networks (Case 22-M-0429):** On September 15, 2022, the Commission issued an Order requiring New York's largest gas utilities to submit utility thermal energy network ("UTEN") pilot project proposals for Commission review, and to comply with the requirements of the 2022 Utility Thermal Energy Network and Jobs Act ("UTENJA").[47] The UTENJA Order is intended to advance broader and more scalable approaches to building electrification including active engagement of regulated utilities, and to ultimately inform the Commission's rulemaking decisions with respect to utility-owned thermal energy networks.

  On October 7, 2022, NYSEG and RG&E submitted a compliance filing describing their proposal to advance three UTEN pilot projects to be sited in Ithaca, Norwich, and Rochester.[48] On January 9, 2023, the Companies made a subsequent filing that provided additional details regarding the Companies' three proposed UTEN pilot projects.[49]

  On September 14, 2023, the Commission issued an Order Providing Guidance on Development of UTEN Pilot Projects ("UTEN Guidance Order") which established a staged implementation framework to support advancement of UTEN pilot projects.[50] The UTEN Guidance Order requires additional detail to justify approval, including establishing the following stage-gating process with five phases to advance UTEN pilot projects:[51]

  Stage 1: Pilot Scope, Feasibility, and Stakeholder Engagement

  Stage 2: Engineering Design & Customer Protection Plan

  Stage 3: Customer Enrolment and Pilot Construction

  Stage 4: Pilot Operation and Maintenance

  Stage 5: Pilot Review, Recommendations, and Conclusion

  On December 15, 2023, the Companies filed Final UTEN Pilot Project Proposals for Norwich, Ithaca, and

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47 *Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act, Order on Developing Thermal Energy Networks Pursuant to the Utility Thermal Energy Network and Jobs Act, ("UTENJA Order") (issued and effective September 15, 2022).*

48 *Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act, New York State Electric & Gas Corporation's and Rochester Gas and Electric Corporation's Proposals for Thermal Energy Network Pilots (filed October 7, 2022).*

49 *Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act, New York State Electric & Gas Corporation's and Rochester Gas and Electric Corporation's Proposals for Thermal Energy Network Pilots (filed January 9, 2023).*

50 *Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act ("UTENJA Proceeding"), Order Providing Guidance on Development of Utility Thermal Energy Network Pilot Projects (issued and effective September 14, 2023).*

51 *Guidance Order, p. 51.*

Rochester for consideration by the Commission to advance these UTEN pilot projects to Stage 2. On April 8, 2024 the Companies filed a letter withdrawing the Norwich pilot project due to a combination of customer interest challenges, the advancement of similar projects elsewhere in the State, and cost considerations.[52] On April 9, 2024, Staff issued approval letters for NYSEG and RG&E to proceed to Stage 2 for the Ithaca and Rochester pilots, respectively.[53] Data from the Companies' remaining two UTEN Pilot Project Filings have provided inputs into the modeling of UTENs in the Companies' LTP.

F. The Report and Appendices

The NYSEG and RG&E LTP Report is presented in seven chapters, plus an Executive Summary. This Introduction includes the long-term plan objectives, Avangrid's commitment to reducing GHG emissions, a description of the stakeholder engagement process, and a discussion of relevant legislation and dockets in New York that shape the development of the Companies' LTP. Chapter II describes the characteristics of NYSEG and RG&E's service territories that influence the LTP. Chapter III presents the base case, Reference Case forecast. Chapter IV describes practical aspects of the decarbonization transition that must be considered when developing the action plan. Chapter V explains the methodology that NYSEG and RG&E employed to develop the LTP, including scenarios defined by the Companies as well as scenarios proposed by CRA and stakeholders as part of the stakeholder engagement process. Chapter VI presents the results of quantitative analyses and describes the decarbonization actions that comprise the LTP. Finally, Chapter VII presents NYSEG and RG&E's conclusions, including a near-term action plan.

In addition, NYSEG and RG&E's LTP includes the following appendices:

- Appendix A – Modeling of Decarbonization Actions
- Appendix B – Energy Prices
- Appendix C – Benefit-Cost Analysis Methodology
- Appendix D – Scenario and LTP Modeling Outputs
- Appendix E – Reference Case Documentation
- Appendix F – Suggested CRA and Stakeholder-Driven Scenarios (January 30, 2024)
- Appendix G – Revised CRA DR-8 (March 25, 2024)

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52 *Case 22-M-0429, NYSEG's Norwich Utility Thermal Energy Network Pilot Project Proposal Withdrawal Filing, April 8, 2024.*

53 *Case 22-M-0429, UTEN Stage 1 Compliance Letters, April 9, 2024. In addition to NYSEG and RG&E, several other utilities' pilot projects also received approval letters.*

II.

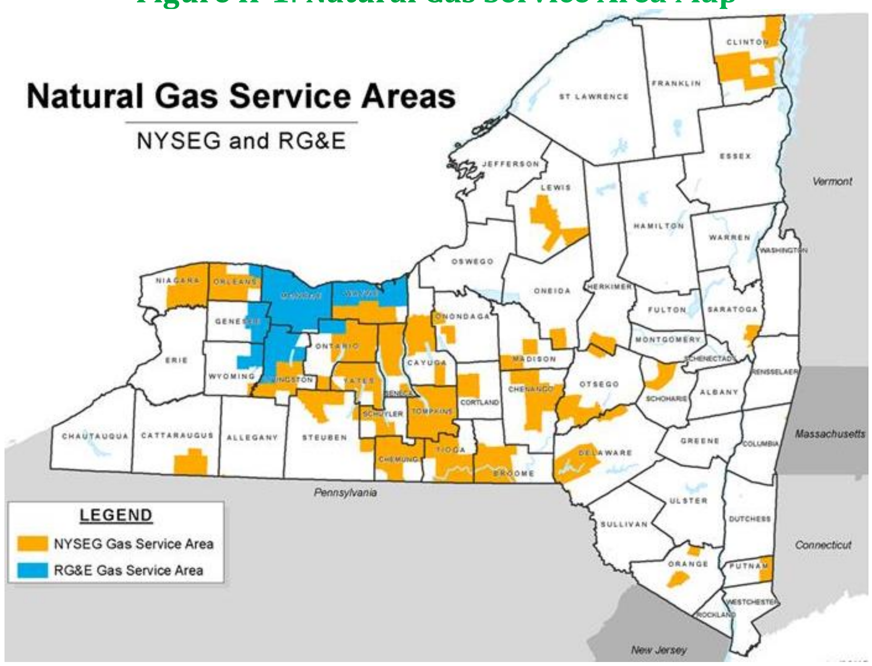
Service Area Characteristics

II. Service Area Characteristics

A. Natural Gas Service Areas

NYSEG's service area is spread throughout New York, serving approximately 270,000 natural gas customers in 30 counties and 91 cities and villages (illustrated in orange in the map below). The majority of NYSEG's gas customers are located in central New York, with isolated pockets in four corners of the State. In contrast, RG&E's natural gas service area is concentrated in Western New York, serving approximately 323,000 natural customers in 7 counties and 25 communities around Rochester (illustrated in blue in the map below).

Figure II-1: Natural Gas Service Area Map



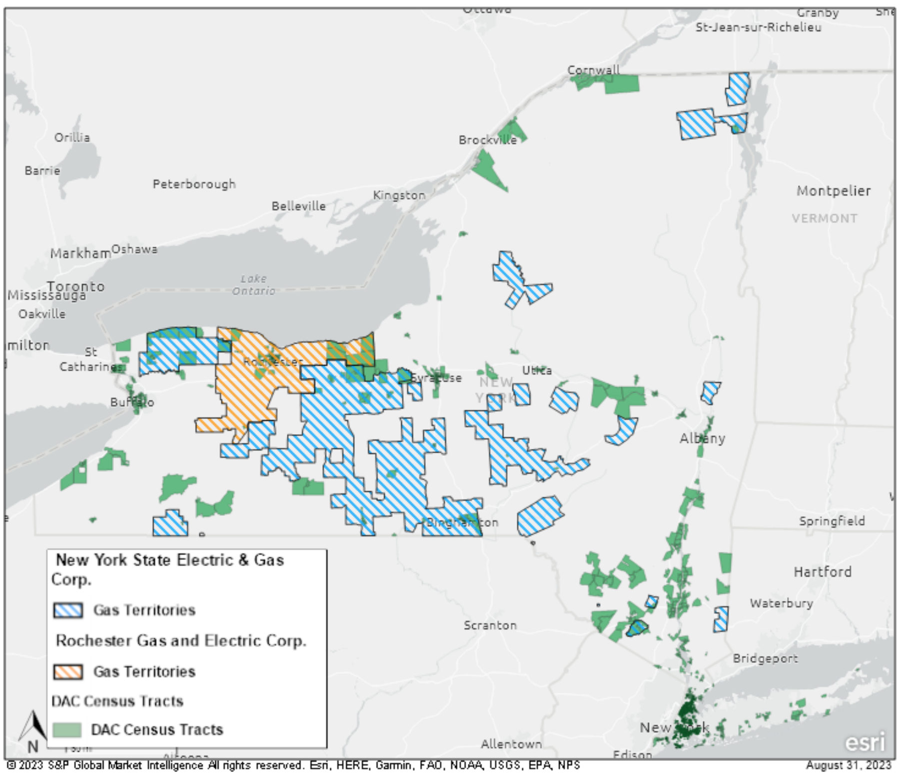
B. Disadvantaged Communities and Low and Moderate Income Customers

As discussed, the CLCPA (passed in 2019) requires state agencies to take actions to ensure that: (1) at least 35% of benefits from energy program spending (e.g., energy efficiency and electrification) be directed to DACs with a goal of 40% and (2) their decisions will not "disproportionately burden disadvantaged communities".[54] The percent of benefits requirement is statewide and utility sector requirements have not been established, let alone targets for NYSEG and RG&E. Pursuant to the CLCPA, the CAC established a Climate Justice Working Group tasked with developing a set of criteria to define DACs. These criteria include socioeconomic, environmental, public

54 *CLCPA § 75-0117 Investment of funds, p. 16; CLCPA §7 Climate change actions by state agencies, p. 19.*

health, and other considerations, identifying specific metrics that guide the determination of DACs.[55] NYSERDA applied the criteria to identify DACs at the census tract level in March 2023.[56] Figure II-2 presents the Companies' natural gas service territories (NYSEG in blue and RG&E in orange) with DACs overlayed (in green).

Figure II-2: DACs Map



RG&E has a greater proportion of the total census tracts in its gas service territory identified as DACs (38%) compared to NYSEG (26%). However, RG&E has less of its gas customer base living in DACs (31%) compared to NYSEG (36%). NYSEG's DACs are comprised of 25% urban, 40% suburban, and 35% rural communities. RG&E's DACs are comprised of 77% urban, 16% suburban, and 7% rural communities. The Companies also have Low- and Moderate-Income ("LMI") customers that do not reside within DACs. NYSERDA defines LMI as earning less than 80% of the Area Median Income and 80% of State Median Income.[57] The Companies will continue to pursue LMI focused energy efficiency and clean energy programs regardless of whether these customers reside within a DAC.

While the formal definition of a "Disadvantaged Community" may be relatively new, the notion of supporting populations of varying socio-economic characteristics is not. Low and Moderate Income ("LMI") programs have

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55 *New York State Climate Justice Working Group Draft Disadvantaged Communities Criteria and List Technical Documentation March 9, 2022, p. 5.*

56 *New York State Climate Justice Working Group Finalizes Disadvantaged Communities Criteria to Advance Climate Justice, New York Department of Environmental Conservation, Press Release, March 27, 2023.*

57 *NYSERDA "Low-to-Moderate-Income Market Characterization Study Special Topic Report- Income Status for LMI Households", 2016, p. 3.*

been supported statewide for over twenty years. DACs are a newer concept that incorporates not only socio-economic indicators, but also environmental burdens, climate change risks, and health vulnerabilities. In support of this new focus on DACs, DPS Staff, DPS, and the Joint Utilities are collaborating on how to define and report metrics related to DACs, including how to measure the benefits being directed to DACs. Consistent with Commission requirements in "CLCPA– Disadvantaged Communities Investment and Reporting Guidance," NYSEG and RG&E have filed several reports with DAC data such as DAC-related funding from 2020-2023, as summarized in Table II-1 below. [58,59] As shown, the Companies DAC/low-income spending significantly increased from 2020 to 2023. The Companies will continue to collaborate with DPS, the Joint Utilities, and other relevant agencies to support efforts to gather data on DACs. In addition, the Companies will continue to focus DAC spending and will update DAC metrics on an annual basis, consistent with Commission requirements.

Table II-1: DAC/Low-Income Funding[60]

Year	NYSEG Gas	RG&E Gas
2020	$6,629,039	$5,675,586
2021	$9,049,900	$7,546,221
2022	$9,910,437	$8,108,780
2023	$10,947,112	$8,604,195

The Companies also provide information about capital projects located in DACs in their Five-Year Capital Investment Plans. In the 2023-2027 capital investment plan, NYSEG anticipates eleven gas capital projects in DACs, including in Binghamton, Oneonta, and Cayuga. RG&E anticipates one gas capital project in a DAC, in the city of Rochester. These projects include regulator station rebuilds, leak prone main replacement, and critical valve installations.[61] Many of these projects produce benefits to DACs by reducing leaks and the risk of leaks, therefore resulting in improved safety and lower emissions.

The Companies have also proposed three new DAC-focused energy efficiency programs in their recent, *Energy Efficiency Portfolio Proposal.*[62] First, "DAC Community Outreach and Distribution and DAC School Outreach" establishes a program to work with Customer Advocates to provide bundled energy savings measures ("energy kits") and educational materials about statewide energy efficiency initiatives in DACs. Second, the "Landlord Outreach to DAC Renters" will conduct targeted outreach to landlords in DACs to provide customized value propositions. Finally, the "Enhanced Incentives in DACs for Key Programs" offers enhanced rebates to customers

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58 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, NYSEG and RGE DAC Reporting Data Collection EE BE EV EAP Redacted, January 26, 2024.*

59 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, NYSEG and RGE DPS NYSERDA Climate Act DAC Reporting Data Collection EE BE EV EAP EV Redacted, April 16, 2024.*

60 *Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, NYSEG and RGE DAC Reporting Data Collection EE BE EV EAP Redacted, January 26, 2024, and April 16, 2024.*

61 *NYSEG and RG&E Five-Year Capital Investment Plan 2023-2027 June 30, 2023, Appendix C.*

62 Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative,* Energy Efficiency Portfolio Proposal 2026-2030, January 16, 2024.

located in DACs and participating in non-LMI programs such as NYS Clean Heat, Non-Residential Rebates, and Small Business programs.

In addition, both of the Companies' UTEN pilot projects are located within DACs. Development of these UTENs in DACs supports Avangrid's Just Transition and represents a strategic and transformative approach to delivering substantial investment in transitioning customers from fossil fuel to clean energy systems. The overarching goal of these UTEN pilot projects is to generate positive impacts that extend beyond the environmental benefits. By creating economic development opportunities, these projects stimulate local economies in DACs. By implementing low-emission technology in these communities, the UTEN pilot projects also play a role in addressing environmental justice concerns.

C. Customers and Demand

Residential customers comprise the majority of gas customers for both NYSEG and RG&E, followed by commercial customers as summarized in Table II-2. Specifically, NYSEG's residential customers account for approximately 89% of customers, commercial customers comprise just over 10%, and industrial and municipal customers combined account for just over 1%. RG&E has a similar customer mix of 93% residential, 7% commercial, and industrial and municipal customers combining to represent less than 1%.

Table II-2: Number of Customers by Customer Segment (2022)[63]

	NYSEG		RG&E	
	Customers	% of Total	Customers	% of Total
Residential	240,835	88.7%	299,498	92.8%
Commercial	27,455	10.1%	21,435	6.6%
Industrial	485	0.2%	493	0.2%
Municipal	2,842	1.0%	1,280	0.4%
Total	271,616		322,706	

The residential sector also represents the highest proportion of demand for both NYSEG and RG&E, followed by commercial demand, as shown in Table II-3. Residential demand comprises over half of RG&E's demand while residential demand is a comparatively smaller proportion for NYSEG.

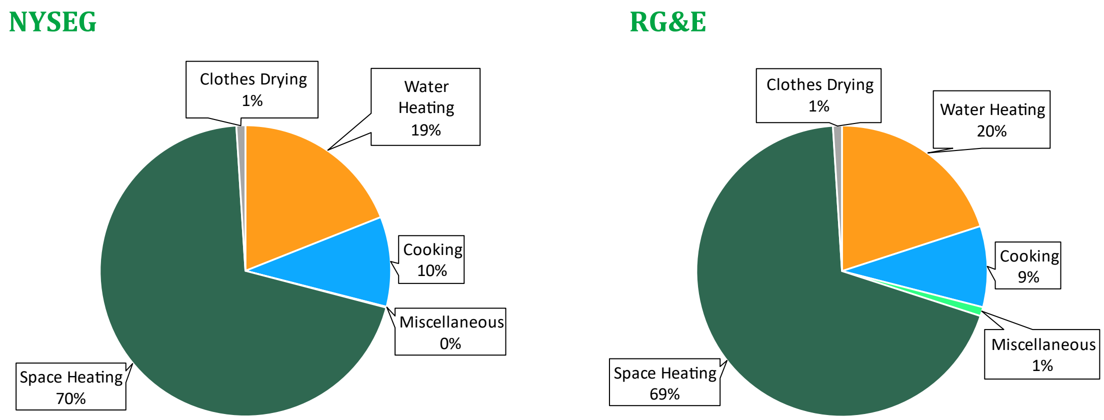
63 *Rounding may affect the totals in tables throughout the report.*

Table II-3: Demand by Customer Segment (2022)

	NYSEG		RG&E	
	Demand (Dth)	% of Total	Demand (Dth)	% of Total
Residential	22,439,522	40.9%	26,078,967	53.9%
Commercial	14,887,682	27.1%	13,401,067	27.7%
Industrial	11,880,813	21.6%	6,324,615	13.1%
Municipal	5,670,994	10.3%	2,594,270	5.4%
Total	54,879,010		48,398,919	

Space heating accounts for approximately 70% of residential gas use, followed by water heating at 20% and cooking at 10% for both NYSEG and RG&E, as shown in Figure II-3.

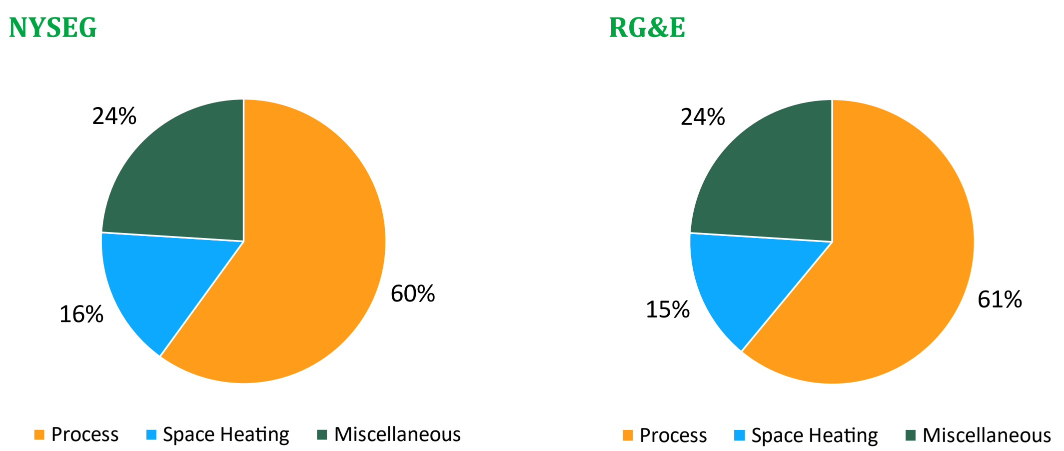
Figure II-3: Residential Load by End Use[64]



The Companies' industrial gas use is mostly comprised of process load. Figure II-4 displays NYSEG and RG&E's end use shares of industrial load.

64 *NYSEG and RG&E Energy Efficiency Potential Study: 2018 to 2027, April 2020, p. 43, Figure 4-16.*

Figure II-4: Industrial Load by End Use[65]



The Companies' industrial load is mostly comprised of the power generation, glass manufacturing, metal, food, and chemical industries. Table II-4 shows the industries represented by NYSEG and RG&E's largest industrial customers by percent of industrial volume.

Table II-4: Largest Industrial Load by Industry

NYSEG

Glass Manufacturing	31%
Primary Metal Industries and Fabricated Metal Products	21%
Food and Kindred Products	19%
Chemicals and Allied Products	15%
Asphalt, Stone, and Construction Materials	5%
Pulp and Paper Mills	2%
Other	7%
Total	100%

RG&E

Power and Fuel Generation	63%
Primary Metal Industries and Fabricated Metal Products	11%
Food and Kindred Products	11%
Health and Pharmaceutical Products	4%
Asphalt, Stone, and Construction Materials	3%
Chemicals and Allied Products	2%
Other	5%
Total	100%

D. Demand-Side Management and Energy Efficiency Programs

NYSEG and RG&E currently offer a range of gas energy efficiency programs, and the Rate Case JP includes terms related to enhancing education to increase awareness and participation in energy efficiency programs.[66] The Companies' existing energy efficiency programs and proposed changes to these programs are discussed below.

1. Residential Energy Efficiency Programs (2019-2025)

The Companies' residential rebate program allows customers to receive rebates for the installation of highly efficient gas equipment including boilers, furnaces, clothes dryers, water heaters, and smart controls. Residential

[65] *NYSEG and RG&E Energy Efficiency Potential Study: 2018 to 2027, Date: April 2020, p. 59, Figure 4-20.*

[66] *Joint Proposal, Case 22-E-0317, et al., p. 58.*

rebates for efficient gas equipment will be discontinued after 2025, consistent with the July 20, 2023 Order in the New Efficiency: New York ("NE:NY") case.[67]

The Companies also maintain a Smart Solutions website designed to facilitate the purchase of energy-saving products and services by offering instant rebates at the time of purchase. Rebates are available for products such as Wi-Fi and smart thermostats, water-saving products, and energy savings kits. This platform allows customers to make informed purchasing decisions. The site also promotes other energy efficiency efforts such as weather sealing, heat pumps, and low-income outreach and education.

NYSEG and RG&E also provide a behavioral energy efficiency offering in the form of home energy reports that provide customers with insights and advice on how to reduce their energy usage.

The Companies also offer a Multi-Family program that provides direct-install measures for in-unit and common areas at low-to-no-cost to the customer. The program offers measures such as programmable and Wi-Fi enabled thermostats as well as pipe wrap upgrades.

The Companies also participate in statewide energy efficiency initiatives with the other New York utilities and NYSERDA that are focused on reaching LMI customers. For example, the Companies support the NYSERDA EmPower+ Program for income-eligible owners and renters of 1-4 family homes and the statewide Affordable Multifamily Energy Efficiency Program ("AMEEP") that focuses on measures in multifamily buildings with at least 5 units.

2. Non-Residential Energy Efficiency Programs (2019-2025)

The Non-Residential Rebates program offers incentives to commercial and industrial customers to improve the efficiency of their facilities through the installation of new, high-efficiency technologies and equipment. The program consists of two distinct offerings: Non-Residential Rebate Prescriptive and Non-Residential Rebate Custom. The prescriptive rebate is a fixed, predetermined incentive based on standard technologies and equipment. The custom rebate offering provides incentives calculated based on site-specific engineering and cost analysis for specific technologies and equipment. NYSEG and RG&E also offer a Small Business Program where small businesses are offered incentives to install new, highly efficient technologies and equipment and to replace existing, less efficient equipment.

NYSEG and RG&E also plan to launch three new non-residential programs in 2024: the Commercial Instant Discount, Retro-Commissioning, and Energy Management Partnership. The Commercial Instant Discount program offers incentives directly to distributors and manufacturers in an effort to eliminate the price gap between traditional and high efficiency equipment and allow customers to purchase higher quality and more efficient products. The Retro-Commissioning Program is a systematic process for optimizing an existing building's system performance. This full-service approach offers low-cost and no-cost facility improvement measures that result in energy savings and load management opportunities. The Energy Management Partnership is a program designed to collaborate with NYSERDA's Strategic Energy Management Program ("EMP"). This program aims to help

[67] *Order Directing Energy Efficiency and Building Electrification Proposals July 20, 2023, Case 14-M-0094 and 18-M-0084.*

customers learn how their building operates and gives customers the tools to manage energy within their organization.[68]

3. Proposed Energy Efficiency Portfolio (2026-2030)

On January 16, 2024, pursuant to the Commission EE/BE Order, NYSEG and RG&E filed an Energy Efficiency Portfolio Proposal for 2026-2030, which includes the expansion of existing programs as well as the development of new programs. The existing programs that will continue include the NYS Clean Heat program, Non-Residential Rebate program, Small Business program, Commercial Instant Discount program, Retro-Commissioning program, Energy Management Partnership program, and Market Rate Multi-Family program. The Companies are also offering the following new programs and changes to existing programs:[69]

Table II-5: Proposed Energy Efficiency Programs

Program	Description
Home Insulation and Air Sealing	This program will offer a midstream incentive to market rate residential single-family homeowners who install various forms of insulation and air sealing.
Retail Products	This existing program will empower residential customers with the option to purchase and install small-scale and DIY energy efficiency measures at a reduced cost.
Market Rate Residential New Construction	This program will provide proactive education for builders of newly constructed homes by assisting in building homes above code. This includes elements such as more effective insulation, higher performance windows, and proactive referrals to heat pump appliances.

The Home Insulation and Air Sealing Program is designed to establish an open installation contractor network. The program's focus on market rate customers is meant to provide solutions to customers who are not eligible for the LMI programs offered through NYSERDA's EmPower+ Program. Similarly, while the NYS Clean Heat program includes a category (Category 4a) that couples weatherization with heat pump system installation, the program proposed here is designed for customers who are not ready or otherwise do not wish to install a heat pump at this time. The Companies will make this program available to all residential customers. Incentives will be coordinated with the Comfort Home program currently offered by NYSERDA. While this program is slated to launch in 2026, a pilot program will be offered in 2024 with certified, non-Comfort Home contractors. This pilot program will inform the Companies on program design elements such as incentive design, refinement of future coordination with existing programs (e.g. NYS Clean Heat and Comfort Home) and obtain feedback from trade allies.

The Retail Products Program is an existing program in the Companies' portfolio that allows residential customers to purchase and install small-scale and DIY energy efficiency measures at a reduced cost. The Companies engage with product manufacturers and retailers who agree to lower the purchase price of select weatherization and

[68] *NYSEG & RG&E October 2023 SEEP Filing, Docket 18-M-0018, filed on April 1, 2024.*

[69] *Energy Efficiency Portfolio Proposal, January 16, 2024, Docket 18-M-0084.*

other air dealing products at retail stores within the service area. The Companies envision this program will expand in the upcoming years and become a key component of future insulation and air sealing efforts.

The Market Rate Residential New Construction Program will focus on providing proactive education for builders of newly constructed homes and/or homes planned for construction. The program plans to partner with Home Energy Rating System ("HERS") Raters or conduct some other form of analysis to determine best practices for building homes above regular building code. The Companies intend to conduct general outreach and advising to home builders, residential customers, and home builder associations. To begin this process, the Companies will issue an RFI and/or RFP to collect information regarding the development of a pilot program and ideal program design for implementation by 2026.

The Companies are also proposing to discontinue several existing gas-related programs that conflict with the directives of the EE/BE Order, including: the Residential Gas Rebate program that provides incentives to customers for the purchase of natural gas fired equipment, the behavioral program that provides customized home energy reports to encourage energy usage reductions, and the Smart Solutions Marketplace that is designed to facilitate the purchase of energy-saving products and services through instant rebates.[70]

In developing the EE/BE Proposal, the Companies focused on designing programs to connect with customers and education them on the value proposition of the next generation of energy efficiency choices through community outreach and other approaches. The Companies intend to deploy local messaging to promote awareness about the portfolio offerings and intend for the education to be proactive. NYSEG and RG&E's Energy Efficiency Portfolio Proposal is pending Commission approval.

4. *Demand Response*

The Companies are planning a residential demand response pilot in the form of a "bring your own thermostat" ("BYOT") program and anticipate submitting an implementation plan soon. The pilot program will be similar to the Connecticut Natural Gas Smart Savers Rewards program with adjustments for New York service areas and is anticipated to begin in 2025. The program would utilize smart thermostats to adjust customers' home temperature when a demand response event is called, which would typically last four hours. Events would be called based on a predetermined threshold and a forecast from the Companies' Gas Supply Team with the intent of shifting load during peak times. The Companies are also investigating the use of advanced metering infrastructure ("AMI") in collecting relevant information on customer usage, including time of day and seasonal patterns, to inform added benefits as well as potential new tariff offerings for its residential customers. New tariff offerings, such as modifications to rate design and payment structures, might incentivize consumer participation in demand response programs and allow for prolonged engagement in the Companies' planned BYOT program. The Companies are also collaborating with other New York gas utilities to gain insights and lessons learned from their gas demand response programs. Further information on the implementation of the Companies' residential demand response pilot and lessons learned will be provided in future LTP filings and annual updates.

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70 *Energy Efficiency Portfolio Proposal, January 16, 2024, Docket 18-M-0084, pp. 33-34.*

5. Non-Residential Geothermal and Air Source Heat Pump Pilot Program

As part of the Rate Case JP, the Companies have a program to offer grants to non-residential customers to install geothermal or air source heat pump systems as an alternative to natural gas heating systems. These grants are intended to supplement other NYSEG and RG&E programs as well as incentives that may be offered by NYSERDA. The Rate Case JP provides that the amount of grant assistance for each project will be equal to the lesser of 25% of the New York State Clean Heat Program incentive or $200,000.[71]

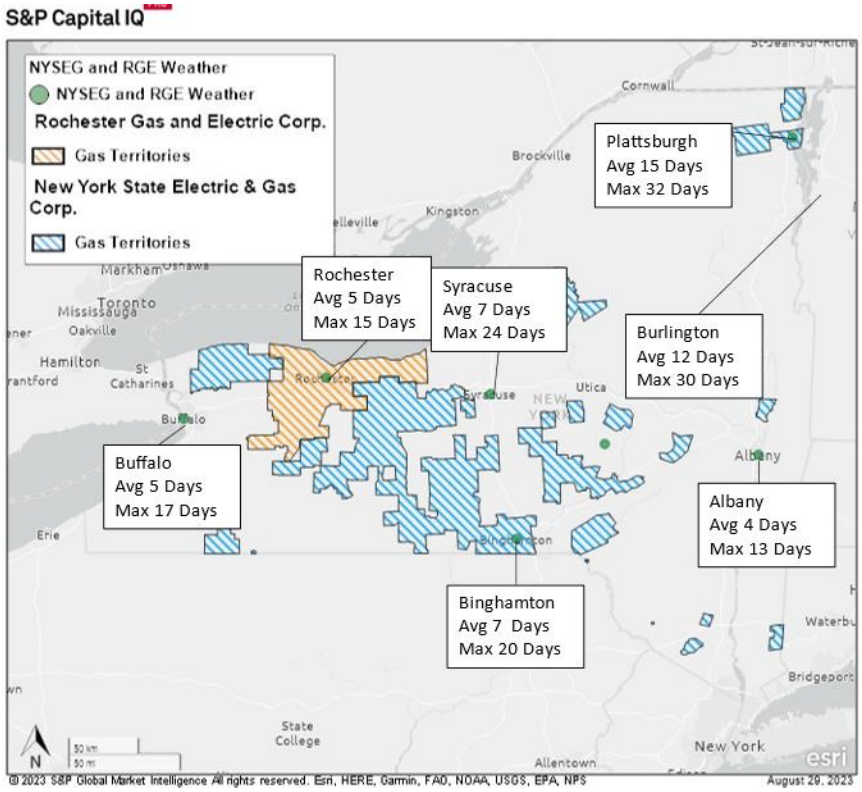
E. Climate Conditions

As discussed, NYSEG provides gas service to customers that are geographically dispersed across upstate New York, while RG&E provides gas service to customers primarily in the metro-Rochester area. Weather patterns can be different across these areas, thereby requiring the use of weather data from several locations for planning. RG&E relies on weather data from Rochester Airport (KROC). NYSEG relies on weather data from several locations.[72] The map below demonstrates that NYSEG and RG&E's customers frequently experience very cold days for prolonged periods of time, with some areas typically experiencing one to two weeks per year with average daily temperatures at or below 10 degrees. In extreme years, some of these locations can experience a month or more of days with average temperatures at or below 10 degrees.

71 *The customer would have to invest at least 30 percent towards the total investment of the project.*

72 *Binghamton/Broome County Regional Airport (KBGM) for the market areas served by the Eastern Gas Transmission and Columbia Pipeline systems; Buffalo International Airport (KBUF) for the Lockport area; Burlington International Airport (KBVT) for daily forecasts for the Plattsburgh and Lowville market areas; and Poughkeepsie (Dutchess County Airport) (KPOU) for the Brewster and Goshen/Walden market areas.*

Figure II-5: Annual Winter Days with an Average Temperature at or Below 10°F[73]



The likelihood of cold weather across the service territories affects the Companies' gas planning, as reliability concerns during winter storms and cold weather can impact building electrification decisions. Reliability of heat is critical due to the potential consequences and safety issues associated with an extended electric outage that coincides with extremely cold temperatures in the Companies' service territories.

F. Economic Conditions

Local economic conditions are a distinguishing feature of the Companies' service territories. Cities such as Binghamton and Elmira in NYSEG's territory, and Rochester in RG&E's territory have experienced loss of manufacturing industry, which has produced economic hardship in the form of job loss and little job growth opportunity.[74] While many of these cities and towns have replaced manufacturing with other industries such as education and healthcare to help stabilize the economy, they still experience little job growth. As detailed in Table II-6 several cities located within the Companies' service territories have experienced lower rates of job growth over the past 5 years compared to the state average.

73 *These temperatures represent the 15-year (2008-2022) average as reported by NOAA.*

74 *Manhattan Institute, The Other New York: Can Upstate Escape Stagnation? April 22, 2022.*

Table II-6: 5-Year Job Growth[75]

City	Job Growth, 5-Year Change
Binghamton	-8.1%
Elmira	-8.0%
Ithaca	-6.2%
Rochester	-5.5%
New York City	-3.0%
State of New York	-4.1%

It is important to consider the economic conditions of the cities and towns the Companies serve as energy affordability and accessibility will be important for local industries and businesses that provide employment opportunities.

G. Supply Portfolio

The Companies maintain portfolios of gas supply, transportation, storage, and peaking assets necessary to reliably serve customers, even on the coldest days of the year. The majority of both NYSEG and RG&E's portfolios are comprised of long-term contracts for flowing supplies (i.e., supplies delivered via upstream transportation) and storage. RG&E relies on winter delivered citygate peaking contracts, whereas NYSEG relies on compressed natural gas ("CNG") at one site for peaking supplies. The Companies' territories are grouped into pooling areas for the purpose of supply planning based on the pipelines that supply the area.

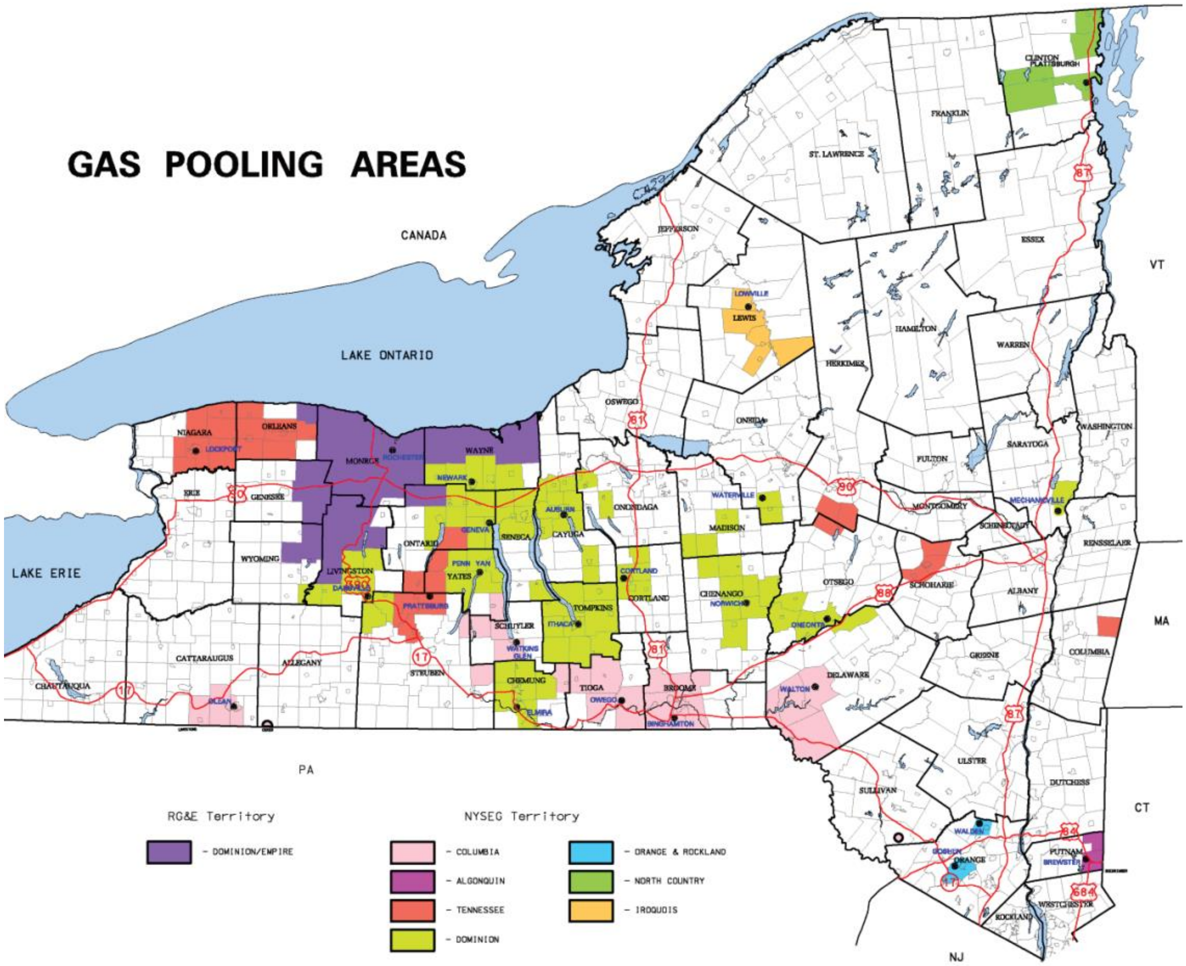
NYSEG holds long-term upstream pipeline capacity contracts on Algonquin Gas Transmission ("AGT"), Eastern Gas Transmission and Storage ("EGTS"), Empire Pipeline ("Empire"), Iroquois Gas Transmission ("Iroquois"), North Country Gas Pipeline ("North Country"), Columbia Gas Transmission ("TCO"), Tennessee Gas Pipeline ("TGP"), and TransCanada PipeLines ("TCPL"), and long-term storage contracts on Arlington Storage Company ("ASC"), EGTS, TCO, and TGP. As noted, NYSEG also relies on CNG for peaking supplies. RG&E holds long-term upstream pipeline capacity contracts on EGTS, Empire, and TCPL, and long-term storage contracts on EGTS and Empire. RG&E also relies on firm delivered citygate contracts for peaking supplies.[76]

Figure II-6 contains a map of the Companies' service territories with gas pooling areas indicated. Figure II-7 contains a breakdown of the Companies' portfolios by asset type.

75 *Federal Reserve Bank of New York Regional Economy Profiles.*

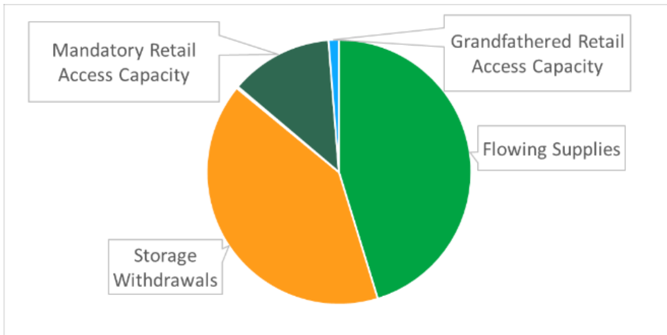
76 *Case 23-M-0230, 2023-2024 Winter Supply Plan, July 19, 2023, Table 4.*

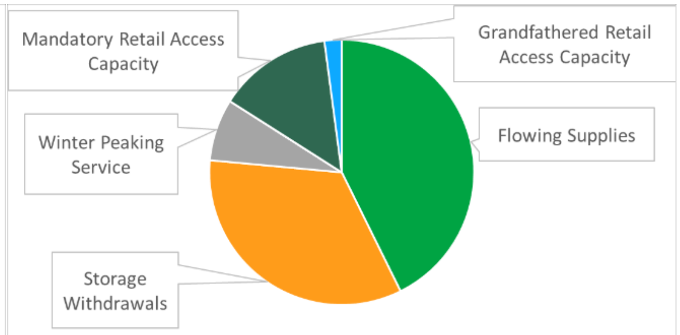
Figure II-6: NYSEG and RG&E Gas Pooling Area Map[77]



77 *"Gas Transportation Operating Procedures Manual," NYSEG and RG&E, October 1, 2021, p. B-2.*

Figure II-7: 2023-24 Winter Total System Firm Peak Day Capacity





Maintaining a portfolio of sufficient firm supply, storage, and transportation assets is key to providing reliable firm service to customers. Expected changes in gas demand, both increases and decreases, could impact the Companies' portfolio. The Companies continuously evaluate the portfolio's ability to meet forecasted demand and consider factors that include the cost, quantity, reliability, diversity, flexibility, duration, contract begin and end dates, likelihood of re-contracting in the future, and operational issues associated with each resource individually as well as for the portfolio. This evaluation is especially important when contracts are approaching the end of term. Staff is made aware of how this evaluation affects contracting decisions through periodic meetings to discuss the Companies' portfolio.

If decarbonization policies or other market changes cause sustained reductions to firm peak demand, NYSEG and RG&E will need to restructure their respective supply portfolios to better align with observed customer demand. Once capacity is turned back, it is unlikely to be reacquired if it is needed in the future because the pipelines in and around New York on which the Companies hold capacity are constrained. As a result, premature restructuring creates risks that the portfolio may be unable to meet customer demand, which will cause serious safety and reliability issues. Therefore, as the Companies consider their contract restructuring strategy, the ability to maintain a safe and reliable source of energy to serve customers today and in the future must remain top priority.

NYSEG and RG&E will begin decreasing their firm capacity portfolio when meaningful reductions in demand have been observed within distinct locations for prolonged periods. Contract restructuring decisions will also have to consider the timing in which relevant existing contracts are set to expire or enter re-negotiation. It is important to note that NYSEG's non-contiguous service areas create unique challenges associated with contract restructuring. Due to the dispersed nature of NYSEG's customer base and gas pooling areas, supplies from one pooling area or citygate often cannot be used to serve another area. Therefore, prolonged demand reductions must be experienced within distinct areas, rather than be dispersed across the entire system. Contract restructuring may unfold differently at RG&E compared to NYSEG because RG&E's service area is one contiguous territory with more flexibility to transport gas across the territory. Contract restructuring for both utilities will depend not only on the location where demand is reduced, but also on the timing of contracts' renewal dates within that location. To the extent possible, the Companies will adopt the following strategy in restructuring firm contracts:

1. Quantify observed reductions in customer demand within one of NYSEG and RG&E's pooling areas or citygates.

2. Confirm such reductions in demand have occurred for a prolonged period such that demand is not expected to increase, to ensure that capacity is not turned back prematurely.

3. Once prolonged, material reductions occur within an area, review the contracts serving that area to identify options to restructure contracted capacity. This step will depend on contract renewal dates and negotiations with pipelines. If multiple contracts supplying an area are approaching their end of term, the Companies will evaluate each contract based on factors such as flexibility, target reduction volume, access to storage, and price.

In addition, the Companies will continue to execute available capacity release transactions to reduce costs for customers and evaluate all portfolio opportunities. Updates to the Companies' portfolios will be provided in future LTPs and Winter Supply Plans.

H. Vulnerable Locations and Moratorium

1. Vulnerable Locations

A vulnerable location is defined as, "a portion of the system where gas may not be able to be delivered safely and reliably within the next five years."[78] Vulnerable locations can be supply-related, distribution-related, or caused by other factors.[79] Supply-related vulnerable locations are areas of the distribution system that are served by upstream pipelines that have constraints and cannot provide additional capacity necessary to serve current or expected demand. Distribution-related vulnerable locations are areas where distribution infrastructure is not sufficient to reliably deliver gas supplies to customers. The Companies utilize hydraulic modeling to help identify distribution-related vulnerable locations. The maximum allowable operating pressure ("MAOP") represents the upper pressure bound at which segments of pipeline can operate and operating at close to MAOP (>70%) is desirable. Areas that operate at 50-70% MAOP are flagged as a reliability concern and solutions will begin to be considered for the longer term. Areas that operate at <50% MAOP are flagged as a distribution-related vulnerable location because they have limited ability to serve new load and/or have increased risk of reliable service to existing customers. Vulnerable locations warrant close monitoring and/or exploration of a traditional and/or non-traditional solution to address the pressure concerns. The Companies pursue three approaches to address vulnerable locations: the development of non-traditional pipeline solutions such as an NPA, the development of traditional pipeline solutions such as a pipeline reinforcement project, and monitoring. If the issue causing the

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78 *NYSEG and RG&E's Supply and Demand Analysis Related To Service Areas With Known Supply Constraint Vulnerabilities, Docket 20-G-131 July 17, 2020.*

79 *Other factors include customer interest in switching from their current fuel to natural gas, the prospect of large economic development projects in a particular location, and the varying degree of reliability of supply from specific sources, including CNG delivered by truck and short-term contracts to rely on pipeline deliveries using capacity that is held by marketers and other third parties.*

vulnerability cannot be resolved, a moratorium on new customers or increased load from existing customers may be required to maintain safe and reliable service.

The Companies filed an initial list of vulnerable locations in July 2020.[80] Since the 2020 filing, the Companies have internally monitored and updated the designation of vulnerable areas. Most recently, the Companies identified supply and demand-related vulnerable locations as detailed below in Table II-7. The Companies will continue to evaluate the system for vulnerable locations, monitor developments associated with identified areas, and actively pursue resolution when necessary. NYSEG and RG&E will work to proactively conduct community outreach and education as a part of this process, and will provide updates on vulnerable locations in future LTP filings.

Table II-7: Vulnerable Locations

Location	Reason	Status
NYSEG: Lansing	Distribution-Related: Operating below 50% MAOP.	NPA Portfolio currently being implemented. Additional detail provided in the Moratorium section below.
NYSEG: Canandaigua	Distribution-Related: district regulator stations feeding the distribution system are at capacity and there is growth in the area.	NYSEG issued a solicitation for an NPA RFP. The outcome of this solicitation is further detailed in the NPA section below.
NYSEG: Dix, Marshall, Seneca/Gorham, Vestal, Somerset/Baker, Newfane, Pendleton	Distribution-Related: Operating below 50% MAOP.	No imminent action required. NYSEG will monitor and review the area annually as there is minimal growth in the area.
NYSEG: Goshen	Supply-Related: intermediary pipeline capacity concerns in addition to new/ incremental customer load.	NYSEG is currently evaluating options to address these concerns.
NYSEG: Carlisle, Canaan, and Richfield Springs Citygates	Supply-Related: concerns about system capacity and pipeline operational flexibility in addition to new/ incremental customer load.	NYSEG is currently monitoring this area.
RG&E: Hamling/Kendall, Greece	Distribution-Related: Operating below 50% MAOP	No imminent action required. RG&E will monitor and review the area annually as there is minimal growth in the area.
RG&E Avon Citygate	Supply-Related: concerns about station/MDDO capacity in addition to new/ incremental customer load.	RG&E is currently monitoring this area.

80 *New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation's Supply and Demand Analysis Related to Service Areas with Known Supply Constraint Vulnerabilities, Docket 20-G-0131 July 17, 2020.*

2. *Lansing Moratorium*

In 2015, NYSEG issued a moratorium for the Lansing area due to significant growth leading to unacceptably low delivery pressures during peak conditions and reliability concerns. NYSEG has 2,210 gas customers in Lansing. Prior to issuing the moratorium, NYSEG explored many options to address the growth in Lansing. In 2013, the Company proposed a Pipeline Reinforcement Project. However, the Company failed to gain the necessary easements and was forced to explore other options. In 2015, the Company studied installing four compressors to boost system pressure during peak conditions, but they were never installed.[81]

In December 2017, NYSEG issued an RFP for an NPA seeking new supply or load relief equivalent to 430 MCFH (MCF per hour) to improve system pressures in Lansing. NYSEG received 13 proposals, however none of the responses met all the requirements of the RFP, leading NYSEG to issue a Request for Information ("RFI") in 2018, followed by a second RFP for potential NPA solutions in 2019. The second RFP produced 16 potential NPA solutions including heat pumps (including air-source, ground-source, water, and communal loop systems), supply-side solutions (hydrogen, CNG, liquified natural gas ("LNG"), and RNG), demand response, outreach and education, and energy efficiency measures. NYSEG worked with Staff to compile a portfolio of seven NPA projects that in combination would provide 56 MCFH of peak hour load relief at a cost of $9.7 million. Several updates have been made since the approval of the Lansing portfolio including developers withdrawing several proposals. As a result, costs have decreased to $9.0 million.[82] The NPA projects will be phased in over multiple years and all, except for the ground source heat pump community loop, are expected to be completed prior to the 2025/2026 heating season.[83] Currently, the Lansing portfolio is comprised of five projects summarized in Table II-8. Contracts have been executed for most programs, but one is still in the contracting phase.[84] Seven years after the initial NPA RFP for 430 MCFH, it is expected that the Lansing NPA portfolio will deliver approximately 49 MCFH of relief (11% of the initial request), which illustrates the challenges associated with executing NPAs.

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81 *Case 15-G-0284 Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (issued June 15, 2016).*

82 *The Lansing area NPA portfolio was approved June 21, 2021 (Docket 17-G-0432). This proceeding approved seven NPA projects with the intention to reduce hourly demand by 54.6 MCFH and ultimately remove the moratorium in the area. The seven projects in the portfolio are all currently in the contracting state with varying commencement dates still to be determined.*

83 *Case 22-G-0318 Non-Pipes Alternatives 2023 Fourth Quarter Report February 23, 2024.*

84 *Case 22-G-0318 Non-Pipes Alternatives 2023 Fourth Quarter Report February 23, 2024.*

Table II-8: Lansing NPA Portfolio

NPA	Description	Hourly Gas Demand Savings (MCFH)	BCA	Project Activity/Status	Proposed In-Service Date
Active Projects					
Residential Heat Pumps	Installation of residential heat pumps with supportive energy efficiency solutions	42.7	0.72	Contract executed in June 2022	Q3 2022-Q3 2025
Non-Residential Heat Pump	Implementation at a single non-residential building of a ground source heat pump and energy efficiency solutions	0.41	0.09	Contract executed in August 2022	Q4 2024
Ground Source Heat Pump Community Loop	Installation of a community loop ground source heat pump project along with gas energy efficiency for a specific neighborhood in the highest impact zone	2.05	0.25	Contract negotiations underway	TBD
Gas Energy Efficiency	Implementation of gas energy efficiency solutions at two buildings and installation of new energy efficient boilers at one of the buildings.	4.08	0.07	Contract executed in October 2022	Q4 2024
Education and Outreach	Education and outreach program in the Lansing School District area coupled with additional heat pump incentives for interested households to switch from gas to electric.	0	0	Contract executed in June 2022	Q4 2022
Cancelled or Withdrawn Projects					
Industrial Waste Heat Recovery	Implementation of a waste heat recovery solution for an industrial gas customers located in the zone of highest impact	n/a	n/a	Cancelled	n/a
Non-Residential fuel switching	Implementation of a demand response salutation of serval non-residential customers switching fuel from natural gas to electric.	n/a	n/a	Cancelled	n/a

I. Distribution System Operations

NYSEG operates and maintains approximately 8,485 miles of distribution mains in its service territory, while RG&E operates and maintains approximately 9,345 miles.

1. *Safety and Reliability*

The Companies provide performance metrics related to gas safety and reliability. The Rate Case JP identifies metrics that apply to the Leak Prone Main ("LPM") Replacement Program, Leak Backlog Management, Emergency Response, Gas Safety Violations, and Damage Prevention.[85]

[85] *Joint Proposal, Case 22-E-0317, et al., Appendix L.*

As described in further detail below, NYSEG and RG&E have low leak rates because they have been proactively replacing at-risk gas infrastructure through their LPM Replacement Program. As demonstrated in the following tables, NYSEG had a backlog of 2 potentially hazardous leaks (Types 1, 2A, and 2)[86] and a backlog of 3 total leaks in 2022,[87] which represent 4.5% of the backlog of potentially hazardous leaks and 0.04% of the total backlog of leaks in New York State. Similarly, RG&E had a backlog of 3 potentially hazardous and a backlog of 8 total leaks in 2022, which is 6.8% of the backlog of potentially hazardous leaks and 0.1% of the total backlog of leaks in New York State.

Table II-9: Backlog of Potentially Hazardous Leaks (Type 1, 2, and 2a)[88]

	2018	2019	2020	2021	2022
NYSEG	**3**	**4**	**1**	**0**	**2**
RG&E	**1**	**0**	**0**	**0**	**3**
Total NY	32	32	45	41	44

Table II-10: Backlog of Total Leaks (Type 1, 2, 2a, and 3)[89]

	2018	2019	2020	2021	2022	2023
NYSEG[90]	**10**	**14**	**8**	**3**	**3**	**2**
RG&E[91]	**14**	**23**	**10**	**6**	**8**	**5**
Total NY	13,381	11,490	9,866	8,454	7,315	n/a[92]

86 *2022 Pipeline Safety Performance Measures Report, Office of Energy System Planning and Performance Pipeline Safety Section, June 22, 2023, CASE 23-G-0224, p. 29, footnote 10: The backlog of leaks requiring repair is defined as active leaks in the system consisting of: Type 1, requiring immediate effort to protect life and property, continuous action to eliminate the hazard, and repairs on a day-after-day basis or the condition kept under daily surveillance until corrected; Type 2A, monitored every two weeks and repaired within six months; and Type 2, monitored every two months and repaired within one year.*

87 *NYSEG and RG&E Annual Gas Safety Report April 11, 2023. 2022 Pipeline Safety Performance Measures Report, Office of Energy System Planning and Performance Pipeline Safety Section, June 22, 2023, CASE 23-G-0224, p. 30: Total leak backlogs include all potentially hazardous leaks, as identified above, and Type 3 leaks. In the State's pipeline safety regulations, Type 3 leaks are defined as not potentially hazardous at the time of inspection and are reasonably expected to remain that way. However, Type 3 leaks must be reevaluated during the next regularly scheduled required leakage survey or annually, whichever is less, though they have no mandatory repair timeframe.*

88 *2022 Pipeline Safety Performance Measures Report, Office of Energy System Planning and Performance Pipeline Safety Section, June 22, 2023, CASE 23-G-0224, Appendix H, p. 56.*

89 *2022 Pipeline Safety Performance Measures Report, Office of Energy System Planning and Performance Pipeline Safety Section, June 22, 2023, CASE 23-G-0224, Appendix K, p. 59.*

90 *NYSEG and RG&E Annual Gas Safety Report April 11, 2023, p. 4.*

91 *NYSEG and RG&E Annual Gas Safety Report April 11, 2023, p. 4.*

92 *2023 Pipeline Safety Performance Measures Report not yet filed.*

2. *Pipe Replacement Program*

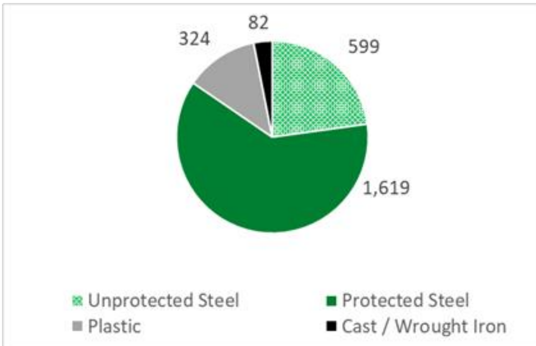
The Companies proactively replace at-risk infrastructure through the LPM Replacement Program, which identifies and ranks LPM segments though a risk-based assessment in accordance with the Companies' Distribution Integrity Management Program. By targeting the pipe segments that are the most likely to leak, the Companies are proactively addressing potential future methane emissions. LPM are replaced rather than repaired because it is known that these pipes degrade over time creating safety and reliability risks. Repairing leaks does not eliminate the safety and reliability risks of leak-prone pipe; therefore, where LPM are necessary to serve customers, they must be replaced. As a result of their LPM Replacement Program, the Companies do not have cast iron remaining in their distribution systems and the Companies are targeting 100% replacement of remaining wrought iron and bare steel gas mains by 2030. In its Order Adopting the Rate Case JP, the Commission states "We agree with the Companies that the proposed LPM removal targets appropriately balance their obligation to maintain a safe and reliable gas distribution system with the interest to mitigate cost impacts on customers and the State's goals to decrease greenhouse gases from the environment."[93] Figures II-8 and II-9 compare the miles of main by material and the number of services by material for 1990 and 2022 for both NYSEG and RG&E and demonstrate that the amount of cast iron/wrought iron (shaded black) and bare/unprotected steel (shaded light green) has decreased greatly while plastic (shaded in gray) has increased since 1990.

93 *Cases 22-E-0317, et al., Order Adopting Joint Proposal, p 64-65.*

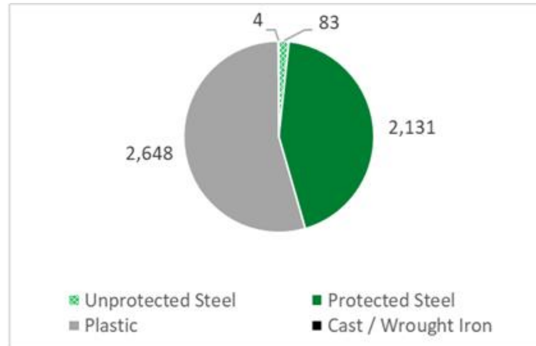
Figure II-8: NYSEG Pipe-Replacement Progress, 1990-2022

Miles of Mains by Material

NYSEG, 1990

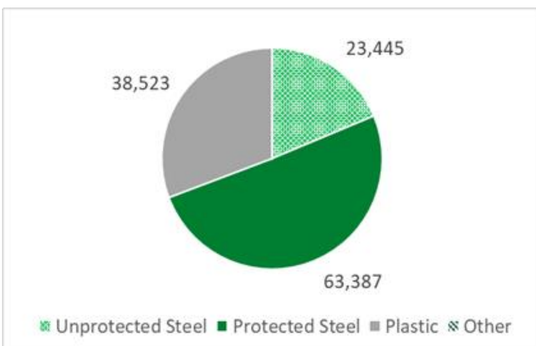


NYSEG, 2022



Number of Services by Material

NYSEG, 1990



NYSEG, 2022

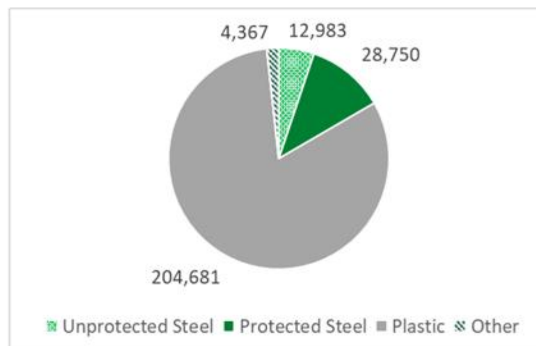
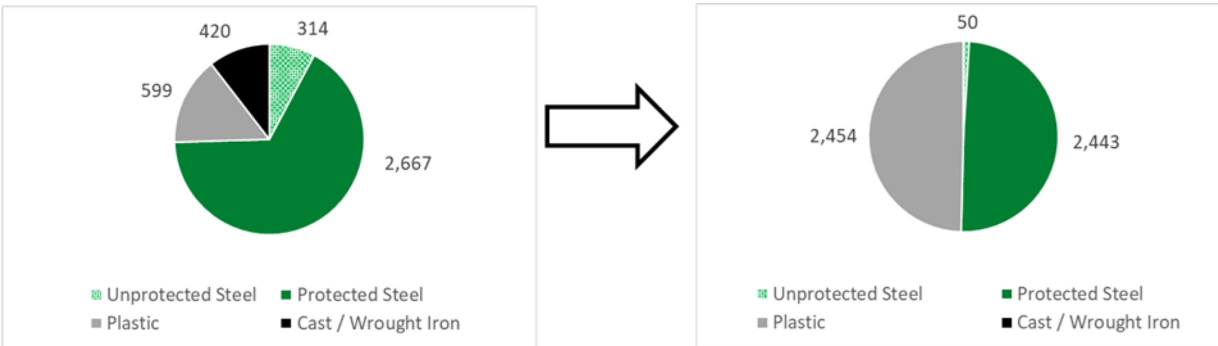


Figure II-9: RG&E Pipe-Replacement Progress, 1990-2022

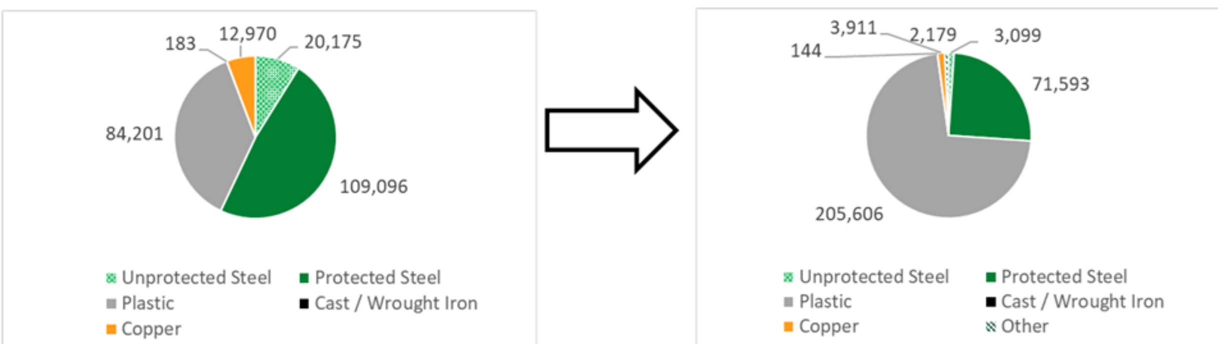
Miles of Mains by Material

RG&E, 1990 RG&E, 2022



Number of Services by Material

RG&E, 1990 RG&E, 2022



Under the Rate Case JP, traditional leak prone main replacement targets will continue for each company, with replacement of 30 miles in 2023, 27 miles in 2024, and 24 miles in 2025.[94] In addition, both Companies plan to continue to replace Leak Prone Services in conjunction with the replacement of Leak Prone Mains.

The Companies screen all LPM projects for NPA applicability in accordance with the NPA Screening and Suitability Criteria. As discussed below, RG&E recently completed an NPA which allowed it to retire a segment of LPM instead of replacing it.

3. Non-Pipe Alternatives

NPAs utilize third party solutions to defer or avoid certain traditional natural gas capital projects (i.e., pipes) that are needed to address natural gas system reliability needs. As detailed in the Companies' NPA Screening and Suitability Criteria, NPAs are considered "for reliability needs that would normally result in pipeline infrastructure

94 *Cases 22-E-0317, et al., Joint Proposal, Appendix L, p. 1-2.*

projects including the replacement of leak prone main."[95] The Companies focus on four main elements when considering NPA solutions: cost effectiveness, providing reliable alternatives to natural gas, reflecting full cost recovery and earnings opportunities for the Companies, and compliance with regulatory directives and state environmental policy. Consistent with Commission directives, the Companies use a two-prong approach for evaluating NPAs. For projects over $2 million, NPAs are evaluated through a competitive solicitation process and include a BCA framework. For projects under $2 million, NPAs may be evaluated using a streamlined process to shorten the project timelines. In addition, in the Rate Case JP, the Companies agreed to explicitly consider factors other than cost-effectiveness when evaluating potential NPAs located within a DAC, including income levels in the target area. As a result, respondents to NPA RFPs are required to provide information on how their proposals will benefit customers within DACs.[96]

The Companies have explored and implemented NPA solutions in both of its service areas. For example, in NYSEG's service area NPA solutions are being executed in Lansing, as discussed above. In addition, NYSEG's Canandaigua area is fed by distribution equipment that is reaching capacity and the area is experiencing demand growth, as noted above in the discussion of vulnerable locations. In July 2022, NYSEG issued an NPA RFP to avoid the need for the construction of the otherwise planned Canandaigua Feeder Reinforcement Project. NYSEG recently informed the Commission it would no longer be pursuing an NPA for Canandaigua due to the lack of technically and economically viable solutions produced through the NPA solicitation process.

RG&E is exploring NPAs to achieve full electrification of buildings using gas located on certain LPM replacement projects to enable retirement of sections of gas main.[97] RG&E's first Whole Home Electrification NPA project was completed in 2023 and fully electrified three homes in Irondequoit, NY, retiring 119 feet of LPM and achieving a design day demand reduction of approximately 0.173 MCFH.[98]

The Companies are continuing to evaluate LPM projects for potential NPA viability. Factors that are considered include the impacts on the rest of the distribution system of decommissioning the pipe segment, the number and type of load served by the segment of pipe, and the impact of additional load on the electric grid. The Companies have identified several additional areas to target for the LPM NPA Whole Home Electrification Program. Letters, brochures, and a dedicated webpage have been developed and distributed to customers within these targeted areas.

While RG&E's first Whole Home Electrification NPA received positive feedback from its participants, the Companies learned that it ultimately resulted in relatively high costs compared to traditional LPM replacement. The Companies also learned that full customer participation is a significant hurdle for electrification NPAs. Identifying portions of the system where projects of this type can be implemented and obtaining consent from all customers can be difficult. These challenges are important for the Companies to consider as they continue to evaluate the potential of electrification NPAs to address LPM. The Lansing and Canandaigua NPA processes

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95 *Gas Planning Proceeding, New York State Electric and Gas Corporation's and Rochester Gas and Electric Corporation's Proposal for Non-Pipe Alternatives Screening and Suitability Criteria, August 10, 2022, p. 4.*

96 *Case 22-E-0317, et al., Joint Proposal, Appendix HH, p. 5.*

97 *Full electrification includes the installation of an air source heat pump, electric hot water heater, induction cooktop, and conversion of other natural gas equipment as applicable.*

98 *NYSEG and RG&E Non-Pipes Alternative 2023 Third Quarter Report*

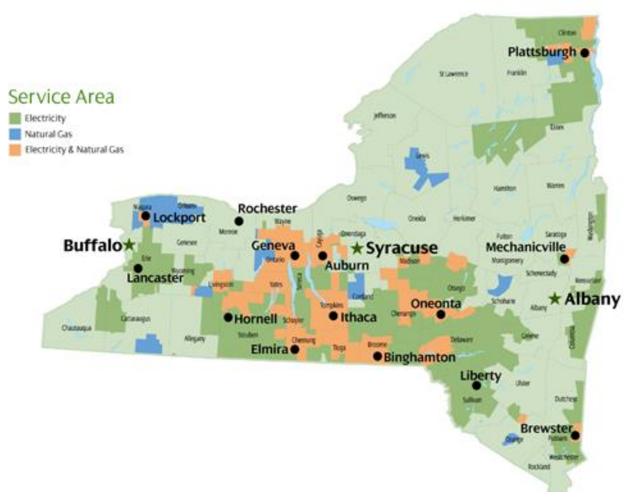
demonstrated the challenges associated with finding technically and economically viable NPA solutions in a timely manner. Nevertheless, the Companies have and will continue to screen all main-related capital projects for the applicability of NPA projects and will provide updates on NPA projects in future LTP filings.

J. Overlapping Natural Gas and Electric Service Areas

NYSEG and RG&E have both natural gas and electric distribution operations in New York. The maps in Figure II-10 show that a considerable amount of NYSEG and RG&E's gas territories overlap with their electric service territories (see the orange "overlap"). Blue areas represent locations where NYSEG or RG&E have gas operations, but electricity is provided by another utility. NYSEG provides electric service to approximately 75% of its gas customers (203,000/270,000 customers) and RG&E provides electric service to approximately 85% of its gas customers (275,000/323,000 customers). These overlapping areas are potentially relevant for this gas LTP as joint gas-electric planning efforts will become increasingly necessary to achieve the State's decarbonization goals.

Figure II-10: Electric and Gas Service Area Maps

NYSEG



RG&E

III.

Reference Case

III. Reference Case

The Reference Case represents the Companies' baseline, business-as-usual expectations over the next 20 years (2024-2043) and does not include the impact of CLCPA actions that have not yet been planned or implemented. In that vein, passed legislation and Commission orders implementing programmatic changes have been incorporated into the Reference Case forecast, but proposed legislation and proposed programs are not reflected in the Reference Case forecast. For example, the Reference Case includes the impacts of legislation passed in May 2023 that prohibits the installation of fossil-fuel equipment in new buildings not more than seven stories and less than 100,000 sq ft starting in 2026 and in all buildings starting in 2029.[99] In addition, the Reference Case includes the impact of the Commission's July 2023 Order that ends the Companies' energy efficiency programs that provided residential rebates for efficient gas equipment and rebates for commercial gas cooking equipment starting in 2026.[100]

As discussed in more detail below, the Reference Case forecast addresses total distribution system demand, supply and GHG emissions (i.e., associated with retail sales customers plus transportation customers) since NYSEG and RG&E's distribution systems deliver gas to both retail sales and transportation customers, regardless of what entity is responsible for procuring the natural gas. As will be discussed in the LTP Methodology Chapter, the Reference Case provides a baseline that can be used to measure the impact of the LTP on the Companies' operations, costs, and GHG emissions. More detailed information about the Reference Case methodology and results is presented in Appendix E.

A. Demand Forecast

The Companies' Reference Case natural gas demand forecasts are based on trends in historical customer count and usage, and do not reflect the potential impacts of future decarbonization efforts. As stated above, the Reference Case represents the Companies' baseline, business-as-usual expectations over the next 20 years. Customer counts are forecasted for four segments (i.e., residential, commercial, industrial, and municipal) for NYSEG and RG&E separately and summed to produce totals for each company. The Reference Case forecast assumes no growth in residential and commercial customer counts starting in 2026 and no growth in municipal and industrial customer counts starting in 2029 due to the passage of legislation in May 2023 regarding the prohibition of fossil fuel in new buildings.

Usage is also forecasted for the same four segments for NYSEG and RG&E separately and summed to produce totals for each company. The Companies' existing gas energy efficiency rebate programs have had measurable impacts on customer usage and historically the Companies' gas demand forecasts have been adjusted to account for reductions in annual demand expected from energy efficiency measures accumulating in the future. However, as discussed above, many existing gas energy efficiency programs are being eliminated. Therefore, the Reference

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99 *S4006C containing amendments to New York Energy Law §11-104 and New York Executive Law §378, passed May 2023.*

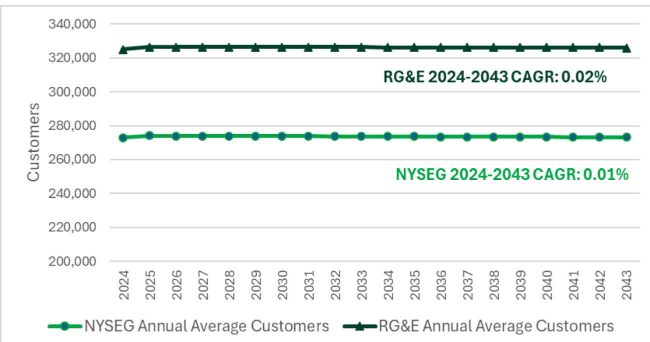
100 *CASE 14-M-0094 and CASE 18-M-0084 – Order Directing Energy Efficiency and Building Electrification Proposals, July 20, 2023.*

Case residential forecast contains an energy efficiency adjustment for only 2025 and reflects the elimination of all residential rebates for efficient gas equipment starting in 2026. The Reference Case commercial forecast contains a full energy efficiency adjustment for 2025 and a reduced energy efficiency adjustment after 2025 to reflect the elimination of rebates for gas cooking equipment. The energy efficiency adjustment to the Reference Case does not include adjustments for programs targeting building envelope improvements as these will be considered as part of the LTP as discussed below.

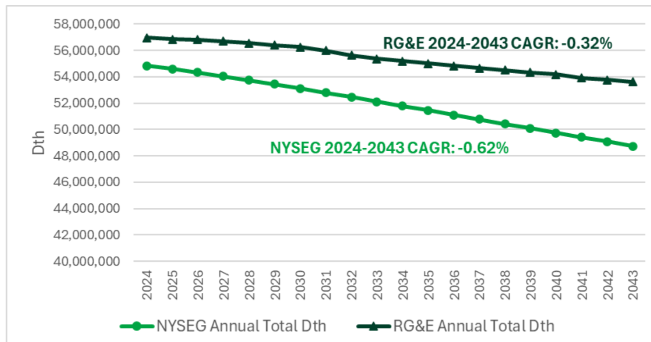
The charts below show that Reference Case total gas customer counts are expected to remain flat for both NYSEG and RG&E, and Reference Case annual demand is expected to decrease at a rate of 0.62% per year for NYSEG and 0.32% per year for RG&E.

Figure III-1: Reference Case Annual Customer Count and Annual Demand

Customer Count



Annual Demand (Dth)



As shown in Table III-1, both NYSEG and RG&E's Reference Case customer counts remain flat.

Table III-1: NYSEG and RG&E Reference Case Customer Counts

	NYSEG				RG&E			
	2024	2030	2043	2024-2043 CAGR	2024	2030	2043	2024-2043 CAGR
Residential	242,752	243,918	243,918	0.03%	301,877	303,378	303,378	0.03%
Commercial	26,893	26,708	26,307	-0.12%	21,414	21,341	21,184	-0.06%
Industrial	447	340	109	-7.16%	461	367	163	-5.32%
Municipal	2,848	2,883	2,883	0.06%	1,295	1,365	1,365	0.28%
Total	272,940	273,849	273,217	0.01%	325,047	326,451	326,090	0.02%

As shown in Table III-2, Reference Case annual demand for all segments is expected to decline for both NYSEG and RG&E, except for commercial demand for RG&E, which is expected to be almost flat.

Table III-2: NYSEG and RG&E Reference Case Annual Demand (Dth)

	NYSEG			RG&E		
	2024	2043	CAGR	2024	2043	CAGR
Residential	22,242,389	19,274,770	-0.75%	26,996,997	25,449,018	-0.31%
Commercial	14,904,631	14,774,879	-0.05%	14,347,620	14,369,999	0.01%
Industrial	11,890,772	9,538,156	-1.15%	12,881,334	12,081,957	-0.34%
Municipal	5,788,753	5,149,426	-0.61%	2,752,462	1,732,942	-2.41%
Total	54,826,544	48,737,232	-0.62%	56,978,412	53,633,915	-0.32%

B. Design Day Demand and Supply/Demand Balance

Natural gas demand is highest on the coldest days of the winter due to the current reliance on natural gas as a fuel for heating in New York. As such, the consequences of a natural gas outage can be severe and even life-threatening. Therefore, maintaining deliveries during several-day cold snaps, the coldest day, and the highest use peak hours is critical. LDCs address this requirement by developing design planning criteria to meet demand on a "design day" (i.e., an extremely cold day for which utilities ensure they can serve demand). It is imperative to plan for enough supply on the coldest days when there is the most demand, otherwise the supply portfolio may be unable to meet customer needs, which would cause serious safety and reliability issues for customers.

The Companies' design day weather is based on the coldest weather experienced historically at several weather stations throughout the state, which correspond to the Companies' service areas. The coldest days date back to February 1979. An analysis is conducted after each winter to determine whether a new coldest day has occurred that would change the design day weather for future years.

NYSEG and RG&E address the risks associated with climate change and the vulnerabilities to climate-driven risks within its service territories in the Companies' 2023 Climate Change Vulnerability Study. The main climate hazards include extreme temperatures, flooding, wind, and wind-and-ice. It was determined that there is a high degree of uncertainty in future trends regarding ice storms. Although models project decreasing frequency of ice storms, the intensity of such ice storms could increase.[101] The impacts from climate change are expected to be significant to NYSEG and RG&E's assets and the communities they serve, so it is of the utmost importance that the Companies support the delivery of safe and reliable energy to its customers through measures such as appropriate design day planning. Given the potential that winter storm intensity could increase, if a less conservative design day is used, there is a chance that the Companies would not plan for enough supply, which would put reliability at risk, and reliability is non-negotiable. Therefore, it is appropriate to plan for the coldest weather experienced historically.

Design day weather is measured in heating degree days ("HDD"), which is defined as 65 degrees minus the average daily temperature (with a floor of zero when the temperature is above 65 degrees). For example, 85 HDD corresponds to a day with an average temperature of negative 20 degrees and zero HDD is a day with an average temperature of 65 degrees or higher. The Companies' design day HDD for each weather location is provided in Table III-3.

[101] *Case No. 22-E-0222, Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans, NYSEG and RG&E Climate Change Vulnerability Study, September 22, 2023, pp. 8, 34.*

Table III-3: Design Day HDD

Area	Design HDD
Binghamton / Olean	75
Brewster	71
Goshen	71
Lockport	74
Lowville	85
Plattsburgh	85
Rochester	75

Separate design day demand forecasts are developed for seven pooling areas for NYSEG and one for RG&E. NYSEG and RG&E update the design day demand forecast annually to ensure it incorporates current information about customer usage. The design day demand forecast for the first year is based on the relationship between historical daily sendout and daily weather. The change in forecasted design day demand over time is based on forecasted annual demand growth.

As shown in Table III-4, Reference Case design day demand is expected to decline over time for both NYSEG and RG&E.

Table III-4: NYSEG and RG&E Reference Case Design Day Demand (Dth)

	NYSEG			RG&E		
	2024	2043	CAGR	2024	2043	CAGR
Total	456,944	401,119	-0.68%	506,391	475,830	-0.33%

The following figures compare NYSEG and RG&E's Reference Case design day demand and peak firm capacity portfolio over the 20-year period. Both NYSEG and RG&E are expected to have sufficient resources to meet the Reference Case design day demand on a total system basis.

Figure III-2: NYSEG Total System Firm Peak Day Capacity and Design Day Demand

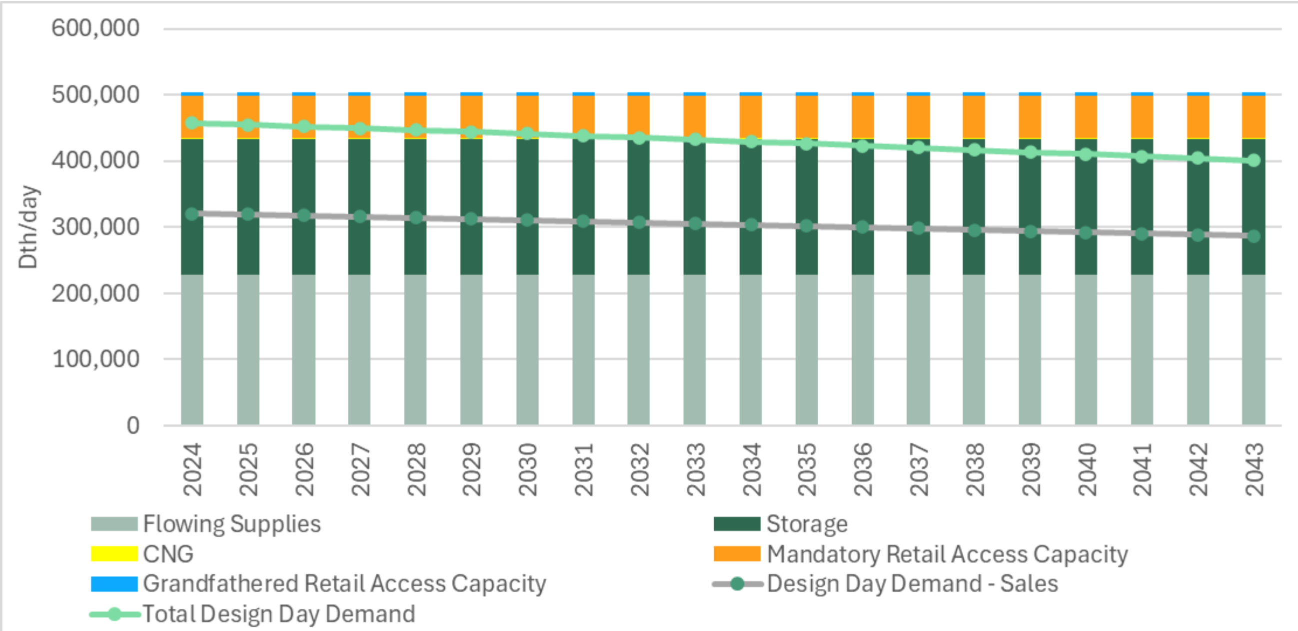
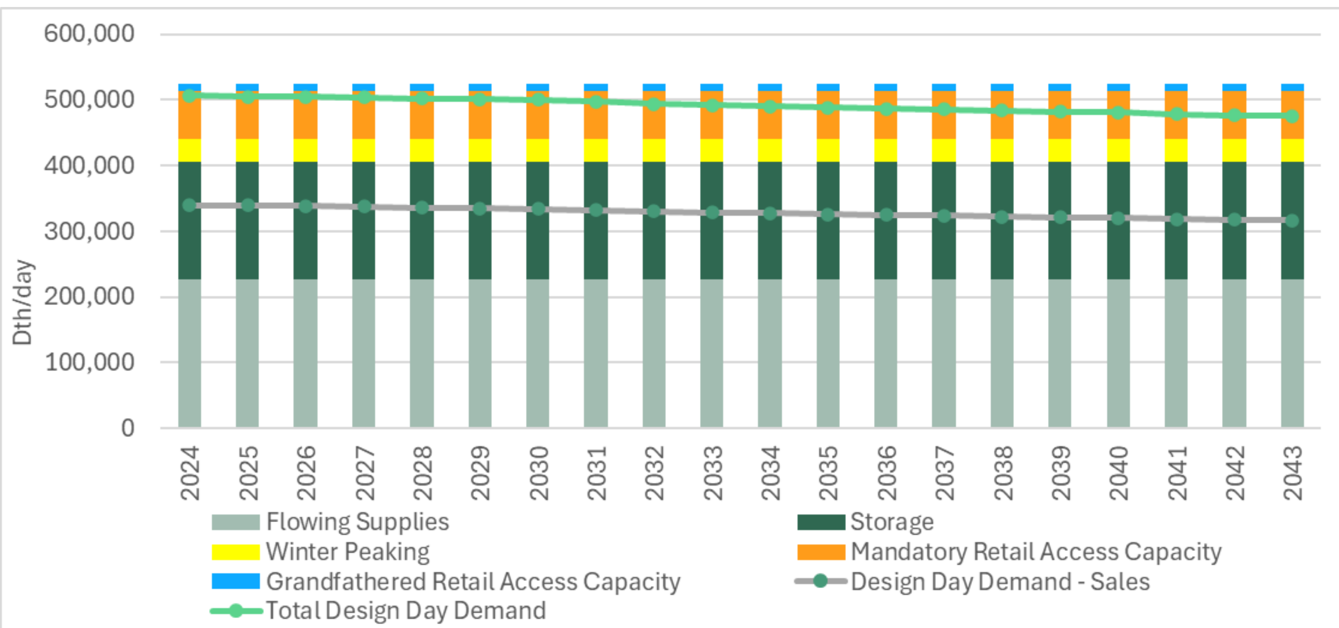


Figure III-3: RG&E Total System Firm Peak Day Capacity and Design Day Demand

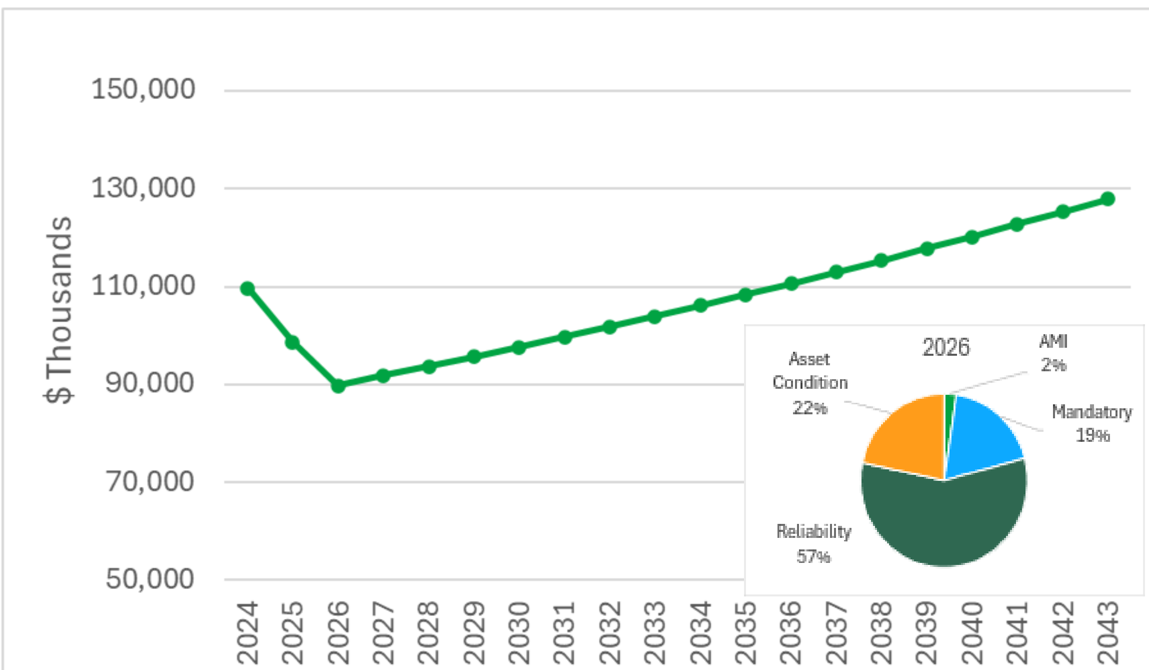


C. Capital Expenditure Forecast

Figures III-4 and III-5 show the gas capital expenditure forecasts for the next 20 years for NYSEG and RG&E, respectively. The forecasts for 2024 through 2026 are sourced from the Companies' Rate Case JP, and the longer-term forecast increases with inflation as continuing capital investment is necessary to maintain safe and reliable service to customers that remain on the gas system. Beginning in 2026, the capital expenditure forecast is reduced to account for avoided new meters and services resulting from removal of customer growth.

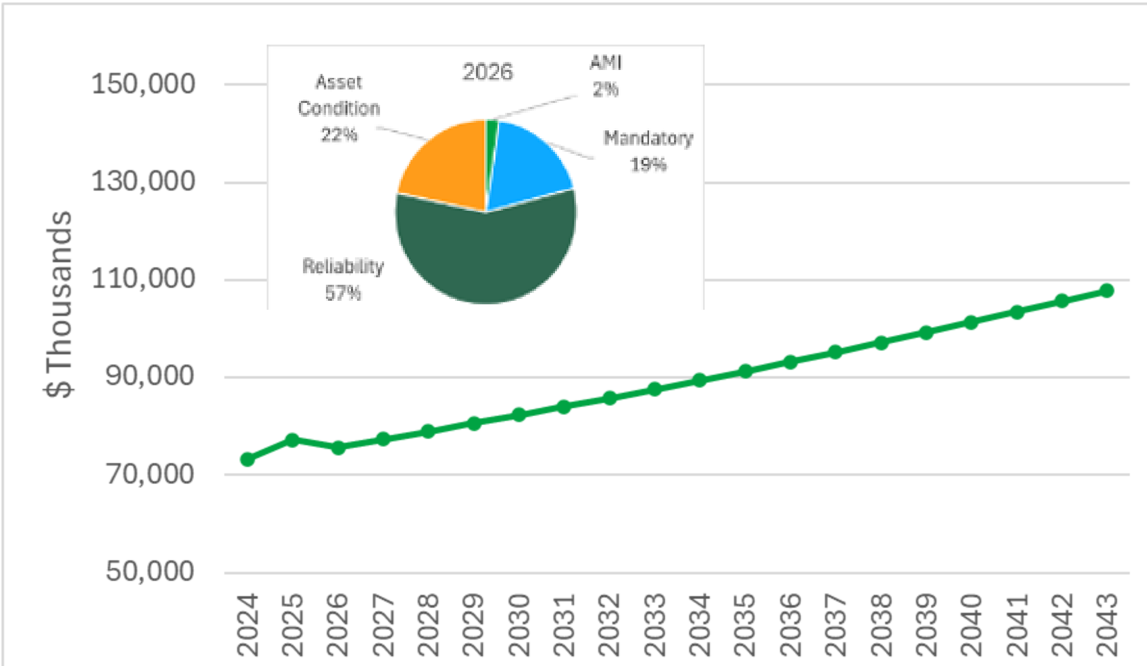
The pie charts show the forecasted breakdown of 2026 capital expenditures. As shown in the figures, reliability (which includes investments for replacement of leak-prone mains and services) has the highest amount of spend, demonstrating the Companies' commitment to reliable infrastructure and reduced emissions. While replacement of traditional leak prone main is anticipated to be complete in 2030, non-traditional leak prone main replacement and other capital projects will continue for the foreseeable future due to asset condition, damage caused by third parties, conflicts with certain existing or proposed construction, and other miscellaneous field conditions. Mandatory projects, which include municipal projects that are required to maintain right-of-way permits, are another large category of capital expenditures. Mandatory projects are adjusted to account for avoided new meters and services resulting from removal of customer growth. As noted above, the Companies continue to review all gas mains projects for applicability of NPA solutions.

Figure III-4: NYSEG Gas Capital Expenditures Forecast ($ Thousands)[102]



[102] *Total Including Common Allocation; Source through 2026: Joint Proposal, Case 22-E-0317, Appendix R.*

Figure III-5: RG&E Gas Capital Expenditures Forecast ($ Thousands)[103]



D. Reference Case GHG Emissions

GHG emissions associated with the Companies' Reference Case are estimated for the entire natural gas lifecycle from production through consumption. The categories of emissions are defined below.

- **Scope 1:** Emissions from Company-owned and controlled resources such as mains and services (pipes), metering and regulator stations, combustion units (heaters, etc.), and fleet vehicles (gasoline, diesel, natural gas, etc.)
- **Scope 2:** Emissions released from use of "purchased" electricity in Company-owned systems such as business offices, measuring and regulator stations, and corrosion systems
- **Scope 3:** Emissions from non-Company-owned "upstream and downstream" entities such as production and transmission of natural gas and customer usage/combustion of natural gas

Reference Case GHG emissions for this LTP are projected using NYSEG and RG&E's Reference Case forecasted system characteristics including the number of customers, energy use, and supply. Therefore, Reference Case emissions are reduced due to the impacts associated with reduced customer counts and demand resulting from the May 2023 legislation that prohibits fossil fuel in certain new buildings. Emissions are computed by applying appropriate emission factors to projected system characteristics based on the Companies' proposed Annual GHG

103 *Total Including Common Allocation; Source through 2026: Joint Proposal, Case 22-E-0317, Appendix R.*

Emissions Inventory filings.[104] Annual emissions are presented for carbon dioxide (“CO2”), methane (‘CH4”), and nitrous oxide (“N2O”). Total CO2 equivalent (“CO2e”) emissions are calculated by converting CH4 and N2O emissions to CO2e assuming a 20-year global warming potential (“GWP”)[105]

As depicted in Table III-5, over 90% of NYSEG and RG&E’s Reference Case CO2e emissions are associated with Scope 3. Over time, Scope 1 emissions are projected to decline as the Companies continue to replace leak-prone mains and services. Scope 2 emissions are projected to decline over time due to projected changes in the emissions associated with electric generation. Scope 3 emissions are projected to decrease over time as demand decreases.

Table III-5: NYSEG and RG&E Reference Case GHG Emissions (MT CO2e)

	NYSEG		RG&E	
	2024	2043	2024	2043
Scope 1	361,282	319,203	298,906	286,860
Scope 2	810	540	561	374
Scope 3				
End User	2,923,640	2,598,926	3,038,389	2,860,043
Imported Gas	1,224,073	1,088,191	1,276,787	1,201,845
Scope 3 Total	4,147,713	3,687,117	4,315,175	4,061,888
Total Emissions	4,509,806	4,006,860	4,614,642	4,349,122

As shown in Figures III-6 and III-7, NYSEG and RG&E’s CO2e emissions are primarily comprised of emissions from end user combustion of natural gas, followed by emissions associated with production and transportation of gas. End user combustion accounts for 65% of CO2e emissions in 2024 for NYSEG and 66% for RG&E. Figures III-6 and III-7 also contain NYSEG and RG&E’s 1990 level of CO2e emissions (red dashed line), which serves as the baseline for CLCPA GHG emission reductions reporting.

104 *As discussed above, the Commission directed Staff to work with the utilities to develop a proposal for GHG emissions reporting that is consistent with the CLCPA requirements. Proposals were filed on December 1, 2022 and supplemented in May 2023, and await a decision by the Commission. (Case 22-M-0149)*

105 *The GWP allows comparisons of the global warming impacts of different gases that have different effects on the Earth’s warming (e.g., CO2, CH4, and N2O). Two factors include the ability to absorb energy ("radiative efficiency"), and how long they stay in the atmosphere ("lifetime"). Specifically, GWP is a measure of how much energy the emissions of 1 ton of a gas will absorb relative to the emissions of 1 ton of CO2 over a specific period of time. NYSEG and RG&E reported CO2e emissions using the 20-year GWP as defined in the CLCPA. (ECL § 75-0101(2)) The 20-year GWP AR5 values are 1 for CO2, 84 for CH4 and 265 for N20. As an illustrative example, a measure with GHG emissions of 1 Metric Ton (“MT”) of CO2, 1 MT of CH4, and 1 MT of N20, would result in a C02e value of 350 MT, which is equal to 1 x 1 MT CO2 + 84 x 1 MT CH4 + 265 x 1 MT N20. Many sources report CO2e using a 100-year GWP, so care should be used when comparing the GHG emissions numbers in this report with other sources.*

Figure III-6: NYSEG Reference Case GHG Emissions

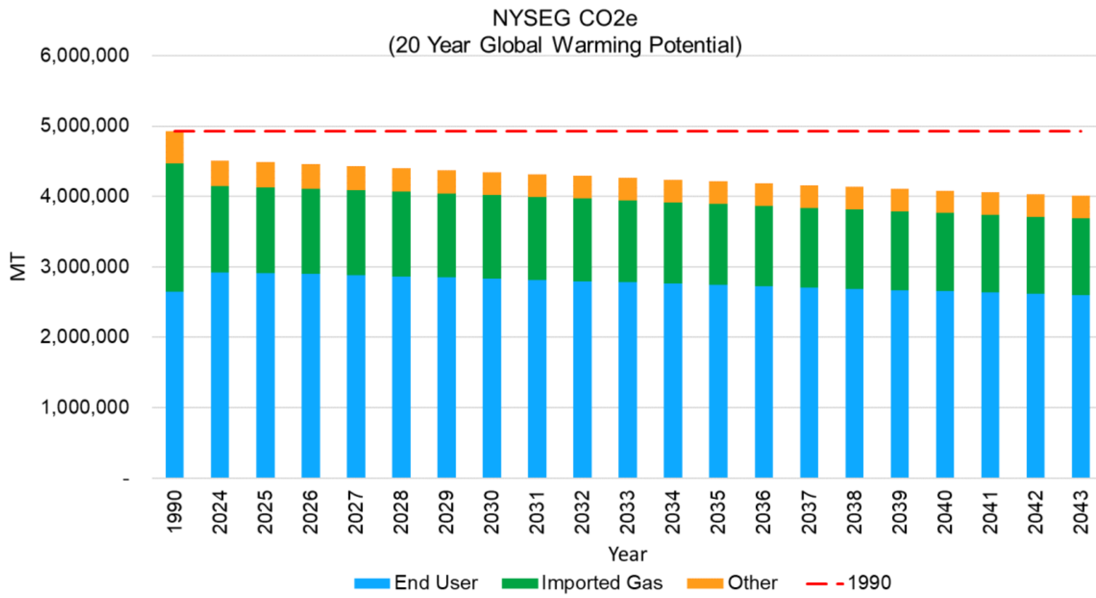
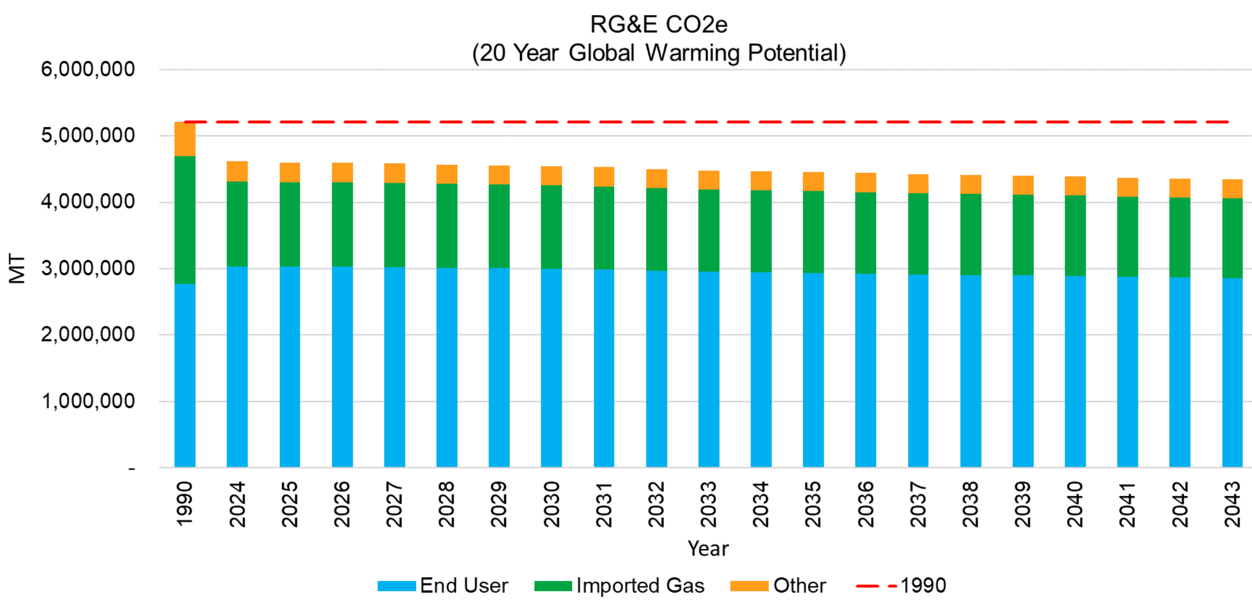


Figure III-7: RG&E Reference Case GHG Emissions



The approximate 8% and 11% decline in GHG emissions from 1990 to 2024 for NYSEG and RG&E, respectively, primarily relates to reductions in methane emissions driven by the Companies' leak-prone pipeline replacement and system modernization programs, plus a shift to procuring gas supplies from the Marcellus and Utica shales.

IV.

Decarbonization Transition

IV. Decarbonization Transition

The decarbonization transition of New York's economy has evolved over the past decade or longer, leading to the establishment of economy-wide GHG emissions reduction targets with the enactment of the CLCPA in 2019. It is evident that reducing emissions from existing residential and commercial buildings, as well as electrification of the transportation sector, will be required to meet these targets. This recognition, and the fact that a large proportion of New York's existing buildings currently rely on natural gas for heating, contributed to the 2020 decision by the Commission to initiate a gas planning proceeding and the requirement for New York LDCs to prepare long-term plans.

The Companies' LTP, presented in Chapter VI, includes a quantitative assessment of six decarbonization actions revealing the projected individual and collective contributions of these actions to reductions in GHG emissions as well as the projected cost of achieving them. Although there is uncertainty regarding key assumptions over the 20-year LTP period, the math is relatively straightforward.[106]

Decarbonizing the existing building stock, however, will be anything but straightforward or easy to accomplish. It will require investment decisions by customers and utilities, as well as enabling actions by federal, state, and local governments and agencies. NYSERDA estimates that New York will need a plan to accommodate two million "climate-friendly" homes by 2030.[107] To put this in context, less than 30,000 heat pumps were installed across New York State in 2022.[108] Decarbonizing existing buildings will require individual building owners to assess energy efficiency and heating/cooling packages, consider incentives, secure financing, and select a contractor. Decarbonizing existing buildings will also require developers and contractors to provide design and construction services throughout New York. Achieving the CLCPA's 2040 zero emission goal for electric generation will require an unprecedented level of investment in offshore wind generation and the transmission facilities needed to deliver renewable generation across the state.

As shown on Figure IV-1, the heat pump market is particularly complex, involving many unregulated entities including manufacturers, HVAC contractors, financial institutions, and the ultimate decision-makers: individual building owners.

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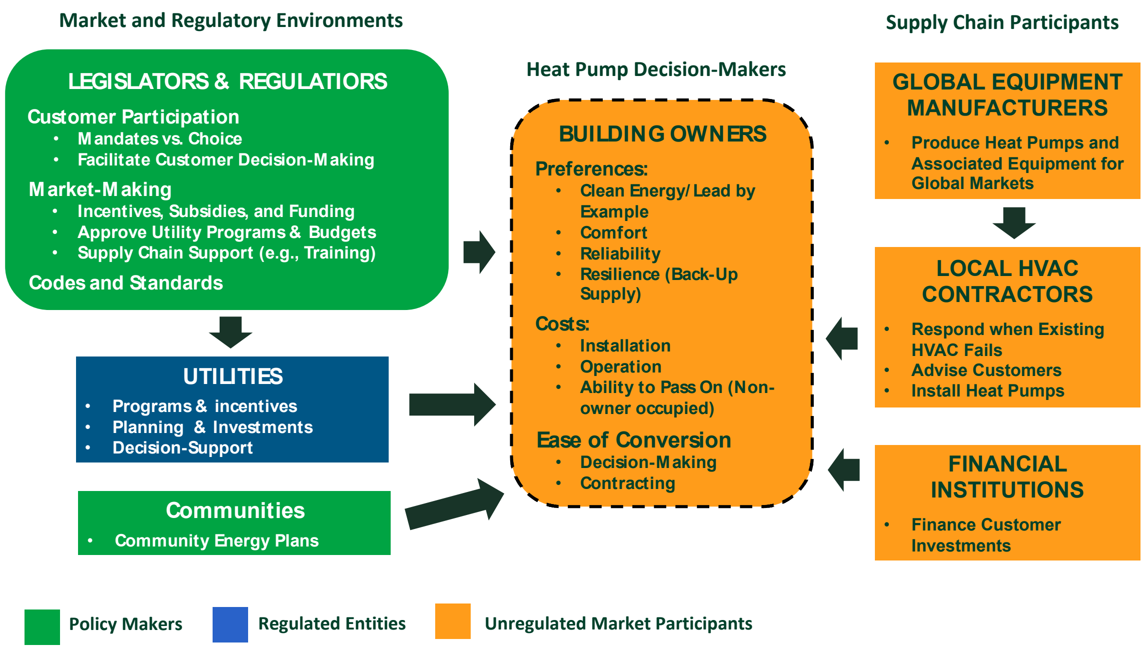
106 *For example, projected incremental GHG emissions reductions for residential electrification are the product of GHG emissions reductions related to electrifying one residential home times the number of homes projected to be electrified in any year.*

107 *"The Big Heat Pump Push – How Programs, Contractors, and the Grid are Responding," a NYSERDA presentation by Courtney Moriarta, December 2022.*

108 *"U.S. Heat Pump Sales Surpass Gas Furnaces. Efficient and Emission-Free Heat Pumps are Gaining Popularity in New York and Beyond," NYSERDA website, downloaded August 30, 2023.*

Figure IV-1: Heat Pump Market Environment



A. Unregulated Participants

Real-world complications, many of which are outside of the control of utilities, regulators, and legislators, will impact the execution of the Companies' LTP as well as the timing and cost of the statewide decarbonization effort. Addressing these complications should guide the actions of policy makers and utilities as they develop policies and programs to pursue opportunities and address challenges. In this regard, it is useful to examine the challenges from the perspectives of several constituencies that are not regulated yet that are assumed to be willing and key participants in the implementation of decarbonization efforts, including building owners, HVAC contractors and manufacturers, and financial institutions.

1. Building Owners

Building owners are a diverse constituency in many respects. The differences span a variety of factors including: (1) who resides in the building (owner-occupied versus rental/lease); (2) whether the occupants are residential, commercial, industrial, and/or institutional customers; (3) the proportion of energy costs relative to income levels, profitability, or operating budgets; (4) owner preferences among fuels for heating, cooling, industrial processes, and other end-uses; (5) owner concerns related to the impacts of climate change; and (6) owner tolerance of the potential impacts of decarbonization on the cost of energy. If the approach to decarbonizing existing buildings relies primarily on customer choice and less on mandates, all of these considerations are relevant. Customer preferences will clearly matter, particularly if conversion is perceived to impact customer convenience, comfort, cost, and reliability of heat. When recently asked about the conversation around gas bans and the upheld decision striking down Berkeley, California's ban, American Gas Association ("AGA") CEO Karen Harbert said "…[t]he practical reality is creeping into the conversations… the customers are starting to speak up. They're terrified. Nobody can afford that type of change… the reality is you've got half the country saying, "I want choice." [109] Some building owners in New York may feel that same way.

Residential building owners will likely need significant financial incentives to encourage the level of building decarbonization contemplated by the CLCPA, but financial support is not the only concern. Lack of knowledge regarding energy choices and logistical challenges must also be addressed. Building owners can best benefit from accurate and complete information regarding energy efficiency and electrification, and that knowledge must be provided well in advance of equipment failure. They will also benefit from logistical support as they arrange for one or more contractors to convert all or a portion of their energy demand to electricity. This is important because once a customer chooses this path, careful planning, contracting, and investment will be required to successfully realize the benefits promised by the technology.

Electrification of multifamily and rental housing is likely to continue to face barriers related to "split-incentives" between building owner and renter (e.g., up-front investments made by building owners versus ongoing energy bills paid by renters). In addition, the Internal Revenue Service has provided guidance indicating that owners must reside in their homes to qualify for energy efficiency and clean energy investment tax credits that are provided by the Inflation Reduction Act.[110]

There are also distinctions between commercial and industrial customers. Many commercial customers are renters, so the split-incentives barrier may exist. In addition, most commercial businesses focus intently on the bottom line and may be reluctant to invest in clean energy options, particularly if they face local competition. The industrial sector often faces competition for capital within the corporation and perhaps external national and international competition. However, some industrial customers may be part of corporations that have Environmental, Social, Governance ("ESG") goals. Harbert also said in recent comments that natural gas provides a solution for a lot of energy-intensive industries (e.g., chip manufacturers, battery manufacturers, data centers).[111]

2. *HVAC Contractors and Manufacturers*

Conversion of existing buildings, if carried out on a large scale, will provide a potential economic boon to local and regional contractors. Local contractors are typically family-owned businesses that provide HVAC services to residential, multi-family, and small commercial customers in relatively small geographic markets. There is reason to believe that larger entities will enter New York and other leading states, and that the HVAC contractor industry will be consolidated. In theory, firms and the workforce will respond to the market opportunities.

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[109] *S&P Global Market Intelligence, Q&A: Gas utilities to play key role in US manufacturing revival – industry group CEO, January 24, 2024, By Tom DiChristopher, Commodity Insights.*

[110] *"The coming battle between Americans who want to go electric and their landlords," Washington Post, May 23, 2023.*

[111] *S&P Global Market Intelligence, Q&A: Gas utilities to play key role in US manufacturing revival – industry group CEO, January 24, 2024, By Tom DiChristopher, Commodity Insights.*

March 2023 data published by the Justice Transition Working Group projects that approximately 150,000 new jobs will be created to address decarbonization of residential and commercial buildings in New York by 2030.[112] However, there are national concerns regarding the current and future availability of a trained labor force that are directly relevant to New York.

Contractors will also be dependent on the ability of national and international suppliers to fulfill the demand for heat pumps, building weatherization materials, and other equipment. Industry experts project that U.S. demand for heat pumps may grow at approximately 9% per year over the next decade.[113] The demand for heat pumps in New York is likely to exceed the national average given New York's strong decarbonization goals. The ability of the equipment market to meet this demand, while continuing to improve efficiencies, limit equipment costs, and meet a likely world-wide increase in demand will be key to New York's timely decarbonization transition.

3. *Financial Institutions*

Many building owners will require financing to supplement funds that may be available from utility incentives, tax credits or other sources. Financial institutions are motivated by the ability to earn a profit and will be attracted to markets that are likely to grow and to customers with strong credit ratings. Finally, while these incentives may enable projects to move forward, the benefits of such incentives and credits may not flow to building occupants.

B. Communities

Many cities across the United States have adopted net zero targets and/or taken actions that contribute to decarbonization including purchasing electric vehicles, installing EV charging facilities, and installing rooftop solar arrays. In fact, Ithaca was one of the first cities in the United States to announce its intention to decarbonize its buildings, including residential and commercial buildings.[114] Ithaca's strategy relies on private financing and government incentives.

Communities can make substantial contributions to the efficiency (cost and timing) of the transition and the ability to achieve the CLCPA goals in several ways. Communities can enforce or amend existing building codes and permitting requirements that enable decarbonization. They can also advocate for local engagement by and coordination between natural gas and electric utilities. In addition, communities can coordinate with policy makers and utilities to demonstrate commitments to clean energy (leading by example), encourage customer participation in decarbonization actions, and relay community objectives and concerns.

With respect to the latter point, communities and their elected officials may be appropriately concerned about the potential economic impacts of decarbonization on residential customers and local businesses. There may also be a concern about disruption from infrastructure development including utility projects and conversions in

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112 *2021 Jobs Study, Justice Transition Working Group, December 2021, Table 16, p. 76; March 2023 Update, Table 16, p. 65.*

113 *See, for example, U.S. Heat Pump Market Size - By Product (Air Source, Ground Source, Water Source), By Application (Residential, Commercial, Industrial) COVID-19 Impact Analysis & Forecasts, 2023 – 2032.*

114 *"Ithaca, New York becomes first U.S. city to begin 100% decarbonization of buildings, an urban climate change milestone," CNBC, November 4, 2021.*

densely populated neighborhoods including DACs, significant commercial areas, and/or key industrial sites. While these concerns will be particularly important for community leaders in DACs, they are likely to be considerations in many situations.

C. New York's Response

New York's policy makers and leaders are keenly aware of these opportunities and challenges. The State government has initiated and funded a wide range of programs that address each of these constituencies. These include the publication of materials on the NYSERDA website to help customers understand heat pump options and navigate the decision-making process.[115] They also include $250 million of low-cost capital for community funders of local clean energy and building electrification to reduce GHG emissions in DACs.[116] In compliance with the CLCPA, labor representatives are active participants in numerous initiatives that have a potential impact on their members.[117] The Companies expect to collaborate with government and other New York stakeholders to enable the clean energy transition, particularly as it relates to supporting customer decision making, and working with DACs and other communities.

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115 *Refer by way of example, to the NYSERDA Heat Pump Program ("NYS Clean Heat") webpage with information for both customers and contractors. https://cleanheat.ny.gov/*

116 *"Launch of $250 Million Community Decarbonization Fund Announced," Governor Hochul Press Release, April 28, 2023.*

117 *"Roundtable Advances New York State's Efforts to Meet Just Transition Targets under Climate Leadership and Community Protection Act," NYSERDA Press Release, August 22, 2023.*

V.

LTP Methodology

V. LTP Methodology

A. Overview and Guiding Principles

The LTP methodology is designed to examine and communicate how alternative "decarbonization actions" contribute to GHG emissions reductions and how the most promising and efficient options can best be sized and staged to make a significant contribution to New York's statewide environmental objectives in a responsible manner (i.e., maintaining safety, reliability, resilience, energy affordability, and customer choice throughout the plan period).[118] Policy makers are also responding to evidence of the impact of climate change in New York, including an increase in the frequency and severity of storms, by placing greater emphasis on the resilience of energy networks and the reliability of energy supply on the coldest and hottest days of the year.[119]

It is notable that each LDC is required to submit a long-term "plan" as opposed to a "pathway study" as there are clear distinctions. A decarbonization pathway study evaluates hypothetical strategies to achieve pre-determined GHG emissions reductions targets over time. In contrast, the LDCs are expected to develop long-term plans that will allow them to make meaningful progress toward GHG emissions reductions subject to safety and reliability requirements, cost pressures, and other practical considerations. The LTP cannot be merely aspirational; it must be technically feasible and provide valid projections of costs, bill impacts, and GHG emissions reductions to inform subsequent utility proposals and Commission decisions. Furthermore, a long-term plan must focus on what is "achievable," reflecting realistic expectations of customer acceptance and adoption, infrastructure development and implementation challenges, market and technology availability, and costs. The Commission acknowledged the need for LDC plans to be subject to real-world limitations when it noted in the Gas Planning Order, "[w]e appreciate the planning processes developed by Synapse, PIOs and others, but these entities do not have an obligation to ensure reliability when an LDC's system experiences peak demand conditions."[120] Moreover, the LTP must achieve an appropriate balance among objectives (e.g., meaningful emissions reductions will require significant investment, which will necessarily challenge affordability). This balance is especially important given the increased reliance on both natural gas and electric systems for the advancement of the State's economy.

The development of any long-term plan begins with establishing a clear vision of the desired outcomes for the Companies' customers and communities served. Figure V-1 presents the Guiding Principles that the Companies used to develop and evaluate their LTP. The LTP must reflect a judicious balance among the set of principles as well as address each principle on its own.

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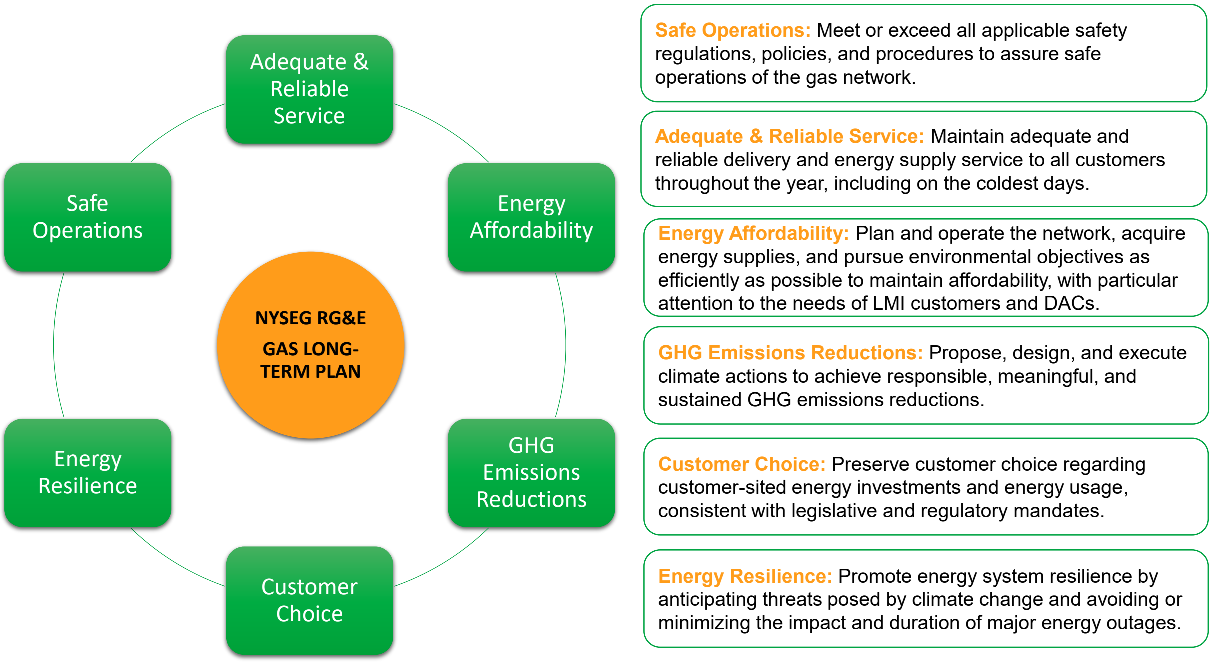
118 *This gas LTP focuses on the Companies' potential contribution to New York's clean energy targets as gas LDCs; this gas LTP does not optimize across all sectors of the economy, including electric generation, transportation, and agriculture, for example. However, it does consider the potential contribution of the Companies to electrify building heating of its gas customers, even though the execution and cost of this strategy will depend critically on a buildout of electric generation, transmission, and distribution infrastructure.*

119 *See, for example, "Climate Change Vulnerability Study, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation," Case 22-E-0222, September 22, 2023.*

120 *Gas Planning Order, pp. 29-30.*

Figure V-1: NYSEG and RG&E’s Guiding Principles



Some principles are absolute requirements, with "Safe Operations" as perhaps the best example for an LDC. With respect to the other principles, a balancing is required resulting in an LTP that provides safe, reliable, and affordable energy service that delivers sustainable reductions in GHG emissions while preserving customer choice.

The “Adequate & Reliable Service” principle applies to the mix of energy sources that customers rely on. This principle takes on a particularly critical role when considering the electrification of heating due to the potential consequences of an extended electric outage that coincides with extremely cold temperatures. As discussed in Chapter II, NYSEG and RG&E’s customers frequently experience cold temperatures for prolonged periods of time, reinforcing the importance of adequate and reliable service. Such weather conditions also raise questions about the ability of cold-climate heat pumps to adequately perform under severe conditions.

The “Customer Choice” principle reflects the Companies’ awareness of the strong preferences of both residential and business customers to make their own decisions with respect to end-use equipment and energy usage. Mandates that restrict choice are likely to be met with opposition, particularly if they are accompanied by meaningful customer expense or inconvenience. This is an example of an “on-the-ground reality” that could shape the path to decarbonization.

These LTP Guiding Principles are consistent with Commission approvals of rate case settlements as they relate to the CLCPA. The Commission has found that a rate settlement complies with the CLCPA’s emissions reduction goals to the extent it “appropriately balance[s] the interests in reliability, public safety, and reasonable rates with emission reductions and clean energy objectives” and serves as “an important step in the ongoing process of achieving the CLCPA’s greenhouse gas limits, one that will be built upon in future rate cases and other Commission proceedings."[121] Additionally, the Rate Case JP includes several provisions that will contribute to emissions reductions in a manner consistent with the CLCPA and actions proposed in this LTP. These include specific program enhancements, pilots, and investments that are identified along with other LTP action items.[122] The Rate Case JP also provides funding for investments throughout NYSEG and RG&E's service areas, including DACs, that will improve the reliability and resiliency of the system, enhance safety, and result in reduced GHG emissions. Finally, with direct relevance for gas planning and the LTP, the Companies have agreed in the Rate Case JP to "structuring their gas planning with the objective of achieving a zero-net increase in billed gas use, normalized for temperature, in their service territories" over the three-year term of the agreement.[123]

The LTP methodology incorporates quantitative analyses, qualitative assessments related to customer behaviors and feasibility, consideration of customer and stakeholder perspectives, and evaluation of risks and uncertainties. This work starts with an examination of the current business circumstances (markets, asset base, customer programs, policies, and regulation) and ultimately produces an LTP that achieves desired future outcomes as delineated by the Guiding Principles.

The Companies have employed an analytical model to support the development of the LTP. The model results are driven by assumptions that define the capability of individual decarbonization actions to produce desired results (timing, amount, and cost) as well as global assumptions that apply across decarbonization actions, including fuel prices and inflation. All assumptions are documented in Appendices A through E. The model produces estimates of GHG emissions reductions and the costs to achieve them over the 20-year period of 2024-2043. The model also produces a forecast of the incremental impact of the LTP on NYSEG and RG&E's gas and electric revenue requirements and customer rates as compared to the Reference Case that does not include the impact of CLCPA actions that have not yet been planned or implemented. Rate impacts are estimated based on existing cost recovery ratemaking principles and assume that the Companies will recover an authorized return on invested capital with a return of investment based on NYSEG and RG&E's existing depreciation methodologies.[124]

B. Long Term Plan Process

The development of NYSEG and RG&E's LTP follows a three-step process, as presented in Figure V-2. Step 1 involves specifying decarbonization actions that can contribute to reducing GHG emissions. Step 2 involves performing scenario analysis to understand the relative costs and emissions impacts associated with alternative assumptions regarding the amount and timing of each decarbonization action and collections of decarbonization actions. Step 3 involves developing the Companies' LTP based on insights derived from the scenario analysis, including ensuring that the LTP is (1) based on the best available information and (2) feasible and achievable. This Final LTP reflects input and feedback from stakeholders. Each step is described in more detail below the figure.

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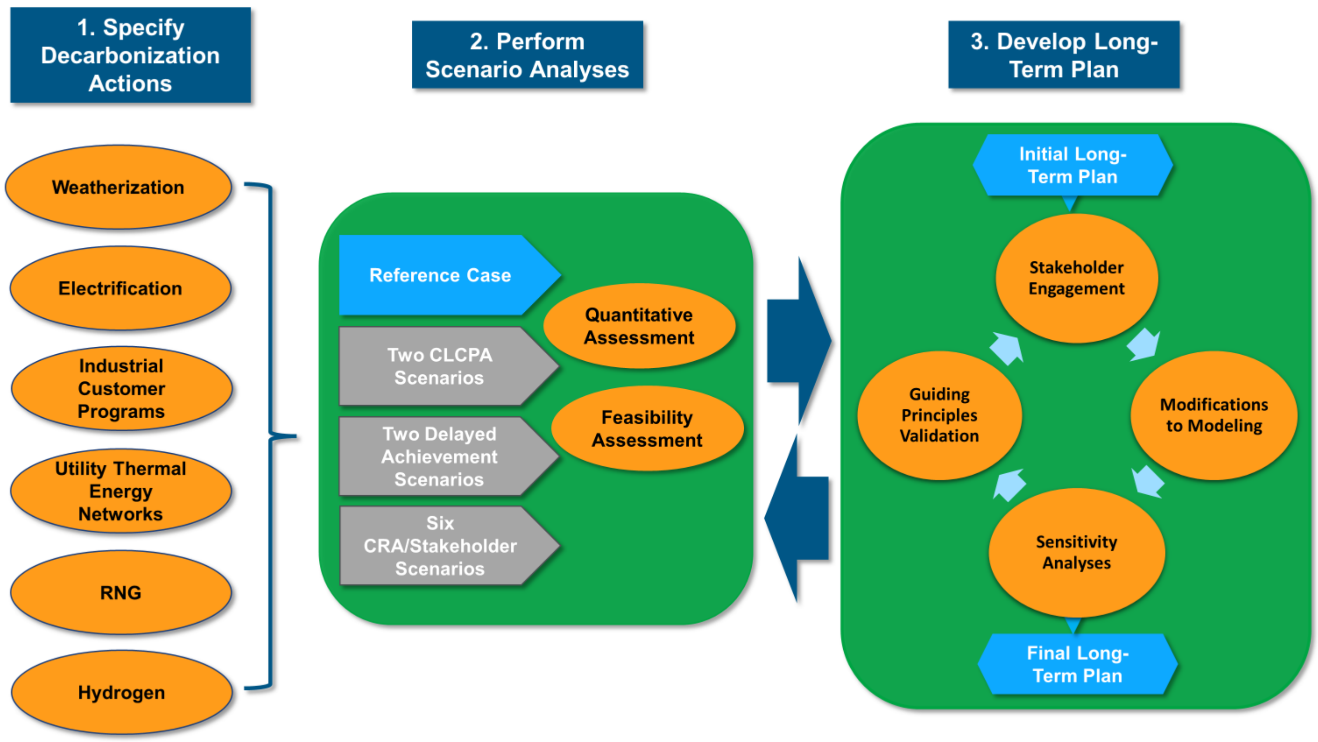
[121] *Case 20-E-0380 et al. – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service, Order Adopting Terms of Joint Proposal, p. 83 (Jan. 20, 2022) ("Niagara Mohawk Rate Order").*

[122] *For example, the Rate Case JP includes commitments to implement energy efficiency and electric heat pump programs and continue aggressive leak repair practices along with other commitments related to climate change.*

[123] *Case 22-E-0317, et al., Joint Proposal, Appendix M.*

[124] *Gas Planning Order, p. 60.*

Figure V-2: Development of NYSEG and RG&E's Long-Term Plan



1. *Specify Decarbonization Actions – Step 1*

Decarbonization actions are actions that NYSEG and RG&E can implement to reduce GHG emissions. The Companies have modeled six categories of decarbonization actions that can reduce GHG emissions associated with the Companies' natural gas businesses. Each decarbonization action is defined by several parameters: the starting year and annual amount (adoption rate), the per unit installation or procurement costs, and changes in energy use. Several actions have a direct per-unit impact on gas demand. Electrification options also have a per-unit-impact on the demand for electricity. The model also includes certain global assumptions that impact the calculation of key outcome metrics (GHG emissions reductions, natural gas rates, and total costs). These global assumptions include the discount rate and the GHG emissions per unit of gas or electricity consumed. Each of the modeled decarbonization actions are described in the following paragraphs with additional modeling details provided in Appendix A.

1. **Weatherization:** Installing weatherization measures (such as insulation) at residential, commercial, and municipal customer premises will reduce energy use, and therefore reduce GHG emissions. Upfront costs to install weatherization measures are typically funded through a combination of utility incentives, state and federal incentives, and participating customer contributions. The Companies model new weatherization programs targeting the residential, commercial, and municipal customer

segments. The key weatherization assumptions include program start date and annual participation rates.

The residential weatherization model reflects assumptions regarding the cost per natural gas usage reduction ($/MMBtu) and gas usage reduction per home associated with installing insulation and air sealing measures based on the new weatherization program included in the Companies' EE/BE Portfolio proposal.[125] Customer participation ramp rates are developed using Company-specific data regarding the number of homes in need of insulation. It is assumed that more customers will participate each year as customer awareness and the number of qualified contractors increase.

The commercial and municipal weatherization program is based on assumptions regarding cost per unit of natural gas usage reduction consistent with National Grid's New York Total Building Comfort Program.[126] In many instances, weatherization will become an element of a customized clean energy solution for individual commercial and municipal customers.

2. **Electrification:** Electrifying existing natural gas heating systems by installing either air source heat pumps ("ASHP") or ground source heat pumps ("GSHP") and electrifying other existing gas appliances will reduce natural gas use and increase electricity use, providing a net decrease in GHG emissions, assuming the use of traditional natural gas and that electric generation has low GHG emissions. Upfront costs to install electric heating equipment and appliances are typically funded through a combination of utility incentives, state and federal incentives, and participating customer contributions. For example, the federal government has several incentives to spur development and reduce the cost of both ASHP and GSHP for customers including the 2022 Inflation Reduction Act ("IRA") and the High Efficiency Electric Home Rebate Act ("HEEHRA"). The Companies model the electrification of existing gas space heating loads for residential, commercial, and municipal customer segments.[127] The model allows the Companies to modify the start date, annual customer participation levels, type of building (e.g., by current heat source or by age of building), and type of heating system to be installed (e.g., full electrification (i.e., with a cold climate ASHP ("ccASHP") or GSHP), or a hybrid heating system (i.e., with a standard ASHP or ccASHP paired with an efficient gas furnace or mini-split paired with a gas boiler). The Companies assume that electrification of heat occurs at the end of expected life of heating systems or the end of expected life of central air conditioning equipment. Electrification of other residential gas appliances (water heating, dryer, and cooking ranges) are assumed to occur at the end of expected life for each appliance.

   The Companies reference New York State and NYSEG/RG&E-specific residential demographic data to identify key segments for residential customers, including (1) older homes (80+ years old) versus

[125] *Case 18-M-0084,* In the Matter of a Comprehensive Energy Efficiency Initiative, *NYSEG and RG&E Energy Efficiency Portfolio Proposal 2026-2030, Appendix A (filed January 16, 2024) ("EE/BE Portfolio Proposal Appendix A").*

[126] *"National Grid - NY Total Building Comfort Program," National Grid, 2023.*

[127] *The Companies have reflected in the Reference Case the legislation that prohibits fossil fuel equipment in new buildings, therefore, the electrification decarbonization action only applies to existing buildings.*

newer homes,[128] (2) homes heating with furnaces versus boilers,[129] and (3) homes with central air conditioning versus those without.[130] A standard ASHP is not considered a viable sole heating source for the Companies' customers. Standard ASHPs are typically found in warmer climates, such as the southern and southwest U.S., and are not designed or built to operate effectively in colder climates including NYSEG and RG&E's service territories. Therefore, ccASHPs supplemented with electric resistance heat, GSHPs, and hybrid heating solutions (standard ASHP or ccASHP paired with an efficient gas furnace for backup) are modeled.

Key assumptions include the incremental per unit up-front cost to convert to electric equipment and the per unit annual change in natural gas and electric use resulting from electrification for an average-sized home.[131] Costs for ccASHP and mini-splits are sourced from the Companies' Clean Heat Database. Costs and usage assumptions for GHSP were provided by stakeholders. Other usage and cost data is sourced from National Fuel's Final LTP and calibrated to NYSEG and RG&E's housing stock and weather.[132] For residential heating, the Companies analyzed the different costs and impacts associated with electrifying (1) older homes (80+ years old) compared to newer homes, (2) furnaces as compared to boilers, and (3) full electrification with ccASHP compared to GSHP and hybrid heating. Similarly, NYSEG and RG&E considered the different costs and impacts associated with electrifying furnaces compared to boilers for commercial and municipal customers.

3. **Industrial Customer Programs:** The industrial sector is generally recognized as the most challenging sector to decarbonize, particularly with respect to process loads that require extremely high temperatures and for facilities that face internal and external competition. However, some industrial customers are part of larger, global entities with decarbonization commitments that are aligned with the Paris Agreement, and therefore may be more likely to invest in GHG emissions reduction activities.

   The model considers three forms of decarbonization actions for industrial customers: (1) performing energy efficiency on process loads; (2) electrifying space heating loads; and (3) applying carbon capture on loads in certain industries.[133] Furnace and boiler-based heating systems are addressed

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128 *"Natural Gas and Grid Modernization Study Appendix N Special Study #5," ICF, May 16, 2022.*

129 *"NYSERDA Single-Family Building Assessment, Residential Building Stock Assessment," October 2019, prepared by Cadmus Group.*

130 *"NYSERDA HVAC Market Characterization, Residential Building Stock Assessment," September 27, 2019, NYSERDA.*

131 *Each home will have specific characteristics that will impact the costs and savings associated with electrification. For example, some larger homes may have higher installation costs and higher energy savings and some smaller homes may have lower installation costs and lower energy savings. For the purposes of estimating overall costs in its models, NYSEG and RG&E necessarily relied on average cost and savings data.*

132 *Residential per-unit cost assumptions for ccASHP and mini-splits are based on the NYSEG and RG&E Clean Heat Database average cost of single-family gas furnace to ccASHP and gas boiler to mini-split conversion projects installed between April 2020 through October 2023. Cost assumptions for the standard ASHP and energy use assumptions for both the standard ASHP and ccASHP are sourced the "Final Long-Term Plan," National Fuel Gas Distribution Corporation, Appendix A, Tables A-11 – A-15, July 17, 2023, Case No. 22-G-0610. Appendix A contains the accompanying calibrations to NYSEG and RG&E's housing stock and weather.*

133 *NYSEG and RG&E will also engage with industrial customers to discuss other potential decarbonization solutions including industrial heat pumps and the direct use of RNG, LNG, and hydrogen.*

separately to reflect their unique attributes. Key assumptions for all three actions include the start date and annual customer participation levels.

Energy efficiency of process loads reflects assumptions regarding cost per unit of natural gas usage reduction. Electrification of industrial space heating loads is modeled similar to the modeling of electrification of commercial space heating loads, reflecting assumptions regarding the up-front per unit incremental cost to convert to electric equipment and the per unit annual change in natural gas and electric use resulting from electrification.

The carbon capture specification assumes removal of end-use carbon emissions associated with the combustion of natural gas. The Companies assume that the ethanol, cement, steel, and refinery industries will be targeted for carbon capture.[134] Key assumptions include start date, customer participation rates, the per unit cost of carbon emissions captured, and the associated transportation and storage costs.

4. **Utility Thermal Energy Networks ("UTENs"):** GHG emissions could also be reduced by replacing natural gas heating systems with ground source heat pumps served by underground geothermal networks or other thermal resources; however, UTENs face siting and other development challenges. As discussed above, the Companies are in the process of developing and proposing two UTEN pilot projects. Information and data for these two UTEN pilot projects have been incorporated into this Final LTP.[135] The development of these pilot projects, and others that are being planned and implemented in New York and other jurisdictions, will inform the UTEN assumptions in the Companies' future LTP filings.

   For the purposes of this LTP, NYSEG and RG&E modeled the development of a hypothetical, generic UTEN project in an existing community. The generic UTEN project uses the average number of residential and non-residential buildings, expected change in energy usage (gas and electric), installation cost and annual O&M per project from the Companies' UTEN pilot projects. Other key assumptions include the start date and the number of generic UTEN projects per year.

5. **RNG:** RNG is biogas that has been converted into pipeline-quality gas and is considered a "drop-in" replacement for natural gas. Using RNG as a substitute for natural gas eliminates the GHG emissions from the biogas feed source that would have otherwise been emitted into the atmosphere. The Commission has repeatedly supported RNG as a method of reducing emissions,[136,137] thus it is important to include RNG in the LTP modeling.

134 *"Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments," February 2023, EFI Foundation.*

135 *Case 22-M-0429, NYSEG's Final Ithaca Utility Thermal Energy Network Pilot Project Proposal and RG&E's Final Rochester Utility Thermal Energy Network Pilot Project Proposal, filed December 15, 2023; NYSEG Norwich UTEN Pilot Project Proposal Withdrawal, filed April 8, 2024; UTEN Stage 1 Compliance Letter Approving RG&E's Rochester Pilot Project and UTEN Stage 1 Compliance Letter Approving NYSEG's Ithaca Pilot Project, filed April 9, 2024.*

136 *Order Granting Certificate of Public Convenience and Necessity and Providing for Lightened Regulation, Petition of Bluebird Renewable Energy, LLC for an Original Certificate of Public Convenience and Necessity and Establishing a Lightened Regulatory Regime (Case 21-G-0576), p. 27 (November 18, 2022)*

137 *NFG LTP Order p. 29.*

NYSEG and RG&E quantified the RNG potential within their service territories for biogas feed sources including landfill gas, animal manure, wastewater, and food waste based on data from a recent NYSERDA study.[138] Thermal gasification is not market-ready, therefore only RNG from anaerobic digestion-based feedstocks is included in this LTP. Thermal gasification will be re-evaluated in future LTPs.

One of the benefits of RNG is that it can be easily blended into the gas supply and does not require building-by-building installations of equipment. Supply availability, timing, and per unit production cost assumptions for the development of RNG are based on NYSERDA's recent study and an RNG Special Study specific to NYSEG and RG&E's service territories.[139] Table V-1 summarizes various levels of projected RNG availability in New York State and within the Companies' service territories based on these studies. As shown in Table V-1, the amount of RNG that is projected to be available in New York under the Optimistic Growth scenario represents approximately 52% of the Maximum Potential RNG, and the amount of RNG that is projected to be available under the Achievable Deployment scenario represents approximately 41% of the Maximum Potential RNG.

Table V-1: Projected RNG Availability in New York in 2040 (tBtu/yr)

	Landfill Gas	Animal Waste	Food Waste	Waste Water	Total
Maximum Potential					
New York State	50.50	20.20	6.10	7.10	83.90
NYSEG	2.91	3.59	0.68	1.15	8.34
RG&E	6.14	1.30	0.31	0.42	8.17
Optimistic Growth					
New York State	24.80	12.10	4.30	3.20	44.40
NYSEG	1.43	2.15	0.48	0.57	4.64
RG&E	3.02	0.78	0.22	0.20	4.21
Achievable Deployment					
New York State	19.30	9.10	3.40	2.40	34.20
NYSEG	1.11	1.62	0.38	0.51	3.63
RG&E	2.35	0.59	0.17	0.003	3.11

The Companies assume that they will procure RNG from within their service territories, as well as a small share of the RNG from Pennsylvania and Ohio.[140] Table V-2 summarizes various levels of projected RNG availability in Ohio and Pennsylvania. The maximum potential is based on a study for the American Gas Foundation. The Companies applied the Optimistic Growth and Achievable Deployment percentages from the NYSERDA study to develop more conservative and realistic

138 *"Potential of Renewable Natural Gas in New York State," Final Report, Report Number 21-34, ICF Resources, L.L.C., April 2022.*

139 *"Renewable Natural Gas Special Study," NYSEG and RG&E, August 2021.*

140 *Availability of RNG from outside New York is based on a study performed for the American Gas Foundation. "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," ICF, December 2019.*

projections of RNG for these states, and assume that NYSEG and RG&E will only access a small share of the out-of-state RNG due to expectations of competition from other entities.

Table V-2: Projected RNG Availability in Ohio and Pennsylvania in 2040 (tBtu/yr)

	Landfill Gas	Animal Waste	Food Waste	Waste Water	Total
Maximum Potential					
OH & PA Combined	125.72	36.02	27.13	8.93	197.80
NYSEG	2.81	0.80	0.61	0.20	4.42
RG&E	2.87	0.82	0.62	0.20	4.51
Optimistic Growth					
OH & PA Combined	61.74	21.58	19.12	4.02	106.46
NYSEG	1.38	0.48	0.43	0.09	2.38
RG&E	1.41	0.49	0.44	0.09	2.43
Achievable Deployment					
OH & PA Combined	48.05	16.23	15.12	3.02	82.41
NYSEG	1.07	0.36	0.34	0.07	1.84
RG&E	1.10	0.37	0.35	0.069	1.88

All RNG is assumed to be produced from existing sources and transported via pipeline. It is assumed that the Companies procure and hold the environmental attributes associated with the RNG (i.e., the attributes are not resold), therefore, the emissions benefits from RNG are incorporated into the modeling.

Emissions accounting is a policy matter that is not fully developed in New York and the Commission has not weighed in on specific aspects of quantifying RNG emissions benefits. For the purposes of the LTP modeling, GHG emissions impacts attributable to RNG are captured on a life-cycle basis. This approach is consistent with the CAC's Final Scoping Plan[141] as well as the California Low Carbon Fuel Standard ("CA LCFS"). This approach is also consistent with the life-cycle, basin-specific method used to estimate upstream natural gas emissions proposed by the Joint Utilities Greenhouse Gas Emission Inventory Working Group in Case 22-M-0149.[142] The Companies' will continue to monitor developments associated with GHG emission accounting, especially regarding RNG.

RNG created from different feedstocks has different emissions impacts. Separate emissions factors are used for each feedstock in the LTP modeling to capture the changing GHG emissions impacts over time as various RNG feedstocks develop at different rates. Capturing the granularity of emissions associated with different RNG feedstocks is important to understanding the impact different types of RNG will have on GHG emissions reductions. RNG sourced from out-of-state is assumed to have higher emissions than RNG sourced from within the Companies' service territories due to the added

[141] *Climate Action Council, Scoping Plan, p. 213.*

[142] *CLCPA Compliance Proceeding, Joint Utilities' Supplement to Proposal for an Annual Greenhouse Gas Emissions Inventory Report, p. 2.*

use of upstream transportation to deliver the out-of-state RNG. The start date and annual quantities of RNG blended into the system are also key assumptions for each feedstock.

6. **Green Hydrogen:**[143] Blending green hydrogen into natural gas for redelivery to customers reduces GHG emissions associated with combustion of traditional natural gas. There are several examples of hydrogen blending projects that are successfully delivering hydrogen enriched natural gas to customers. For example, Hawaii Gas has been blending up to 15% hydrogen into its system for decades.[144] One of the benefits of hydrogen is that it can be blended into the gas supply and does not require building-by-building installations of equipment at low blending levels. Hydrogen may also be a viable option for direct use for industrial process loads; however, direct use of hydrogen has not been modeled. Recent federal legislation contains several incentives to spur development and reduce the cost of clean hydrogen including the IRA and the Bipartisan Infrastructure Law. Key model assumptions include the start date and annual proportion of natural gas that is replaced by hydrogen.[145] Per-unit costs of hydrogen are sourced from a 2021 ICF study that contains annual cost projections.[146]

Implementing many individual decarbonization actions and other elements of the LTP will require changes to business practices, new or modified customer programs, and adjustments to regulatory policies.

2. *Perform Scenario Analyses – Step 2*

Scenario analyses inform the LTP by assessing the relative GHG reductions and costs of potential decarbonization actions and combinations of actions. An individual scenario is not a "plan" and is distinct from the LTP as a scenario is not subject to real-world constraints and may be defined to test alternative decarbonization pathways or the impact of alternative cost assumptions. In contrast, the LTP is developed by combining various levels of decarbonization actions with assumptions that are based on the best available information to produce a feasible plan that is projected to achieve GHG emissions reductions as cost-efficiently as possible while satisfying objectives that are expressed in the Guiding Principles. The Companies developed four scenarios: a "CLCPA Full Electrification Scenario," a "CLCPA Hybrid Heating Scenario," a "Delayed Achievement Full Electrification Scenario," and a "Delayed Achievement Hybrid Heating Scenario." In addition, the Companies have modeled six scenarios that were jointly specified by CRA and Stakeholders. Each scenario is comprised of specific levels of each of the six decarbonization actions and is measured relative to the Reference Case. The development of the Reference Case and the scenarios is depicted in Figure V-3 and further defined below.

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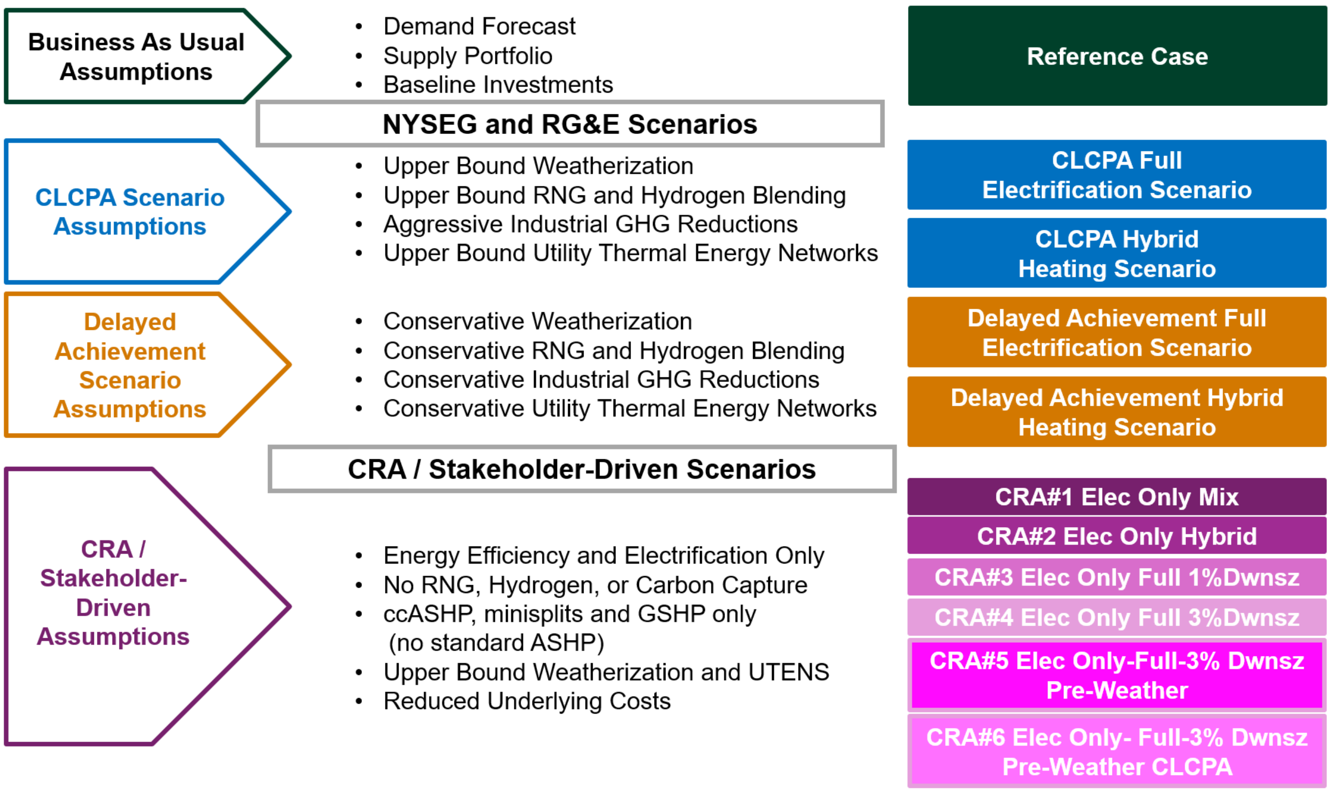
143 *"Green Hydrogen" is produced by splitting water into its hydrogen and oxygen elements using electrolysis that is powered by renewable energy sources (e.g., wind and solar energy).*

144 *"Hawaii Gas Issues Request for Proposals for Renewable Natural Gas and Renewable Hydrogen," Hawaii Gas, April 6, 2023.*

145 *The total amount of hydrogen that can be safely blended into a specific gas distribution system will require significant system-specific analysis to determine the make-up and condition of the existing pipelines and other equipment that may be affected by the introduction of hydrogen.*

146 *"Examining the current and future economics of hydrogen energy," ICF, August 13, 2021.*

Figure V-3: Reference Case and Scenarios

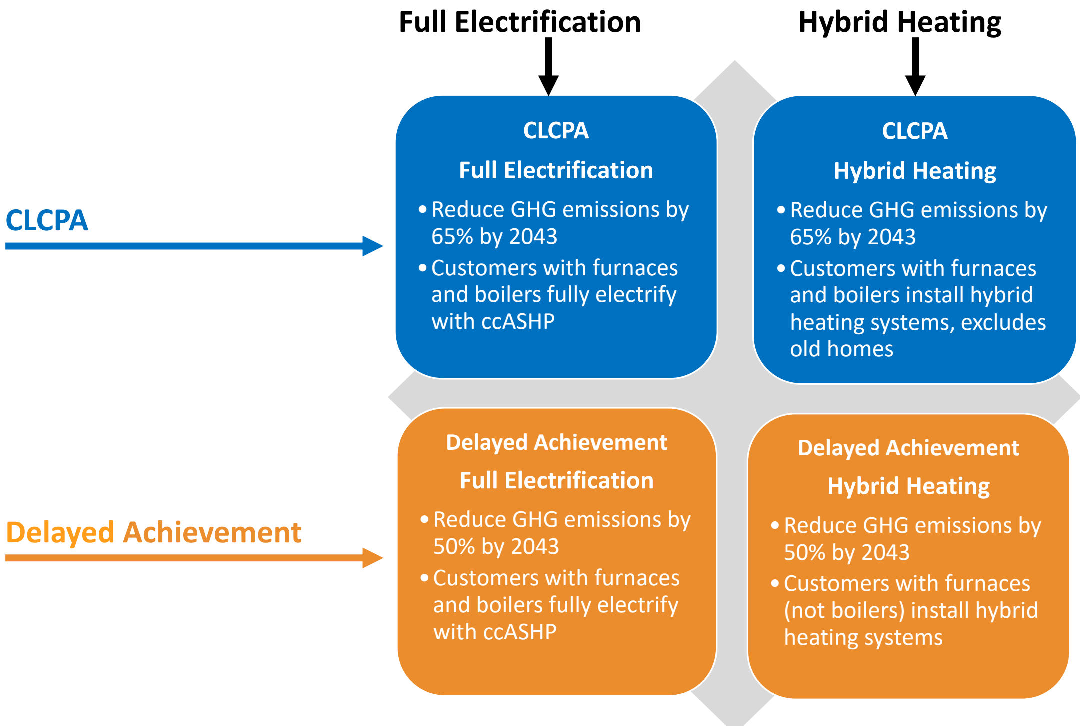


- The **Reference Case** is a 20-year (2024-2043) representation of NYSEG and RG&E's current market and business profile. The Reference Case does not include the impact of CLCPA actions that have not yet been planned or implemented and assumes that none of the Companies' identified decarbonization actions have been implemented. Rather, the Reference Case is the baseline against which the collection of decarbonization actions that define each scenario and the LTP will be compared. As discussed, the Reference Case incorporates the impacts of legislation prohibiting fossil fuel in new buildings, and the Commission Order ending customer incentives for efficient gas equipment. A summary of the Reference Case is provided in Chapter III and a detailed description of the Reference Case methodology and results is presented in Appendix E.

Companies' Scenarios

Each of the Companies' scenarios include all six decarbonization actions – that is, all of the Companies' scenarios include some amount of weatherization, electrification, industrial customer programs, UTENs, RNG, and green hydrogen. The specification of the Companies' scenarios can be thought of as a 2 x 2 matrix with the rows representing achieving different levels of GHG emissions reductions and the columns representing different approaches to electrification, as exemplified in Figure V-4. The CLCPA Scenarios reflect more aggressive implementation of each decarbonization action compared to the Delayed Achievement Scenarios. The Full Electrification scenarios assume customer fully electrify with ccASHP while the Hybrid Heating Scenarios assume customers install hybrid heating systems comprised of standard ASHP paired with gas heating equipment.

Figure V-4: Illustration of NYSEG and RG&E Scenarios



Each of the Companies' scenarios are described below and in Table V-1.

- The CLCPA Full Electrification Scenario reflects implementing all six decarbonization actions at a pace that puts the Companies on the path toward achieving the CLCPA final target of 85% reduction in GHG emissions from 1990 levels by 2050.[147] This scenario assumes that achieving GHG emissions reductions of 65% from 1990 levels by 2043 will be sufficient to reach the 85% reduction goal by 2050. This scenario implicitly assumes that the national, regional, and local economy can deliver labor, technologies, customer equipment, and infrastructure to enable decarbonization of New York's economy within the timing specified in the CLCPA, including meeting the 2040 goals for full decarbonization of electricity production and maintaining pace to achieve the 2050 economy-wide emissions reductions targets. In this scenario, 1% of residential customers are assumed to weatherize in 2027, with annual participation increases of 0.25%/year, resulting in 5% of residential customers weatherizing in 2043. Weatherization is assumed to reduce commercial heat loads by 0.5%/year and municipal heat loads by 1%/year starting in 2027. Industrial process loads are assumed to be reduced

[147] *The CLCPA does not impose specific requirements on New York's gas utilities or gas distribution system. However, meeting the CLCPA's emissions reductions targets for the entire economy will require some level of emissions reductions from the gas distribution system.*

by 0.5%/year through energy efficiency starting in 2027, and carbon capture is expected to reduce industrial loads by 0.5%/year starting in 2028. One UTEN project connecting 24 existing residential buildings and 8 existing non-residential buildings per year is assumed starting in 2035. RNG is procured at optimistic growth levels within the Companies' service territories (i.e., 52% of maximum potential), and the Companies each procure approximately 2% of the optimistic growth levels of RNG in Pennsylvania and Ohio starting in 2026. Hydrogen blending starts in 2028 at an incremental rate of 1.25%/year by volume. Lastly, all customer segments are assumed to install ccASHP (supplemented with electric resistance heat for cold days) to heat their homes and businesses with electricity every day of the year, thus increasing the winter electric peak and necessitating additional electric infrastructure buildout. Boilers and furnace-based heating systems are electrified for all customers. Electrification starts at a modest rate and is assumed to ramp up at a pace necessary to hit the specified GHG emissions reductions targets.

- The **CLCPA Hybrid Heating Scenario** is also specified to achieve GHG emissions reductions of 65% from 1990 levels by 2043, and reflects the same assumptions presented in the CLCPA Full Electrification Scenario with the exception that all customer segments are assumed to install hybrid heating systems (i.e., standard ASHP paired with gas furnaces or mini-splits paired with gas boilers). Hybrid heating will allow for heating with gas on the coldest days of the year, thus reducing the winter electric peak and requiring less electric buildout. Boilers and furnace-based heating systems are converted for all customers, excluding old homes. Electrification starts at a modest rate and is assumed to ramp up at a pace necessary to hit the specified GHG emissions reductions targets.
- The **Delayed Achievement Full Electrification Scenario** reflects implementing all six decarbonization actions with lower adoption rates, which results in delays in achieving the CLCPA emissions reductions goals due to labor and resource constraints, reduced customer participation, delayed market development and/or delayed technology development. This scenario is specified to achieve 50% GHG emissions reductions from 1990 levels by 2043. All customer segments fully electrify using ccASHP (with resistance heat) to replace furnaces and boilers. Electrification starts at a modest rate and is assumed to ramp up at a pace necessary to hit the specified GHG emissions reductions targets.
- The **Delayed Achievement Hybrid Heating Scenario** is also specified to achieve 50% GHG emissions reductions from 1990 levels by 2043 and reflects the same assumptions presented in the Delayed Achievement Full Electrification Scenario with the exception that all customer segments are assumed to electrify using hybrid heating systems (standard ASHP paired with a gas furnace) and only furnace-based heating systems are converted. Electrification starts at a modest rate and is assumed to ramp up at a pace necessary to hit the specified GHG emissions reductions targets.

As shown in Table V-3, each of the Companies' scenarios is comprised of varying levels of all six decarbonization actions. Unless otherwise specified, each decarbonization action is assumed to start in 2027.

Table V-3: Specification of CLCPA and Delayed Achievement Scenarios

Action	The CLCPA Scenarios 65% GHG emissions reduction by 2043	The Delayed Achievement Scenarios 50% GHG emissions reduction by 2043
Weatherization	• **Residential**: 1% of homes/year in 2027, incremental participation growing by 0.25%/year • **Commercial**: 0.5% heat load reduction/year • **Municipal**: 1% heat load reduction/year	• **Residential**: 0.5% of homes/year in 2027, incremental participation growing by 0.125%/year • **Commercial**: 0.25% heat load reduction/year • **Municipal**: 0.5% heat load reduction/year
Electrification Full	• **Furnaces:** ccASHP with electric resistance • **Boilers:** full electrification with mini-splits, all homes • **Pace:** to hit target GHG emissions reductions	
Electrification Hybrid Heating	• **Furnaces:** ASHP with gas furnace • **Boilers:** Mini-splits with gas boiler, excluding old homes • **Pace:** to hit target GHG emissions reductions	• **Furnaces:** ASHP with gas furnace • **Boilers:** none • **Pace:** to hit target GHG emissions reductions
Industrial Customer Programs	• **Energy Efficiency of Process Load**: 0.5% process load reduction/year • **Electrify Space Heating**: furnace/heater and boiler conversions to ccASHP at a pace necessary to hit target • **Carbon Capture:** (large customers) 0.5% carbon capture/year starting in 2028	• **Energy Efficiency of Process Load**: 0.25% process load reduction/year • **Electrify Space Heating**: furnace/heater (not boiler) conversions to hybrid heating at a pace necessary to hit target • **Carbon Capture:** (large customers) 0.25% carbon capture/year starting in 2028
UTENs	• 2035 start, one project of 24 residential and 8 non-residential buildings per year	• 2035 start, one project of 24 residential and 8 non-residential buildings every other year
RNG	• 2026 start, Optimistic Growth level of RNG in LDC territory; 2% of RNG in PA and OH	• 2026 start, Achievable Deployment level of RNG in LDC territory; 1% of RNG in PA and OH
Hydrogen	• 2028 start, blend incremental 1.25%/year	•2030 start, blend incremental 1%/year

The following key assumptions apply across all of the Companies' scenarios:

- **Incentives** – Up-front participating customer costs for weatherization and electrification are assumed to be reduced as a result of several incentives. For the purposes of modeling, all incentive programs are assumed to (1) have sufficient funding to cover all eligible customers, (2) be renewed through the entire 20-year study period, (3) maintain current per customer/project incentive levels, (4) have full participation by eligible customers. These are all major assumptions, which will be reviewed for reasonableness and updated in future LTPs. Modeling assumptions include:
    - Residential Weatherization Incentives

- Federal: High Efficiency Electric Home Rebate Act ("HEEHRA") point-of-sale rebates of 100% for low-income customers and 50% for moderate-income customers and tax credits from the 2022 Inflation Reduction Act ("IRA") of 30% for non-LMI customers.
- Utility/NYSERDA: 80% of weatherization costs

o Non-Residential Weatherization Incentives

- Utility/NYSERDA: 70% of weatherization costs

o Residential Electrification Incentives

- Federal: Appliance specific HEEHRA point of sale rebates of 100% for low-income customers and 50% for moderate-income customers and tax credits from the IRA of 30% for non-LMI customers.
- State: 25% of GSHP installed cost up to $5,000.
- Utility/NYSERDA: $5,400 rebate for GSHP, 20% of $2024 heat pump installation cost for ASHP systems, including water heaters and hybrid systems.

o Non-Residential Electrification Incentives

- Federal: 40% tax credit for commercial GSHP
- Utility/NYSERDA: 20% of $2024 heat pump installation cost for commercial and municipal.

o Industrial Customer Programs Incentives

- Utility/NYSERDA: 20% of $2024 installation cost for heating load electrification. 20% of process load energy efficiency and carbon capture costs.

➢ **Equipment Cost and Technology Improvements** – Equipment costs and technology are based on the best information available today. Consistent with assumptions used by the U.S. Energy Information Administration ("EIA"),[148] the Companies assume heat pump technology and costs remain flat during the 20-year forecast period.

➢ **Pipeline and Storage Fixed Costs** – Pipeline and storage providers will likely seek to recover costs associated with lower contracts from remining customers, resulting in per-unit-increases that may largely offset declines in demand with little change to total fixed costs for shippers. As a result, the Companies assume total pipeline and storage fixed costs remain constant.

➢ **System Downsizing** – Downsizing the gas distribution system through targeted full electrification NPAs requires identification of LPM segments that are not necessary to serve downstream customers and convincing 100% customers on those segments to electrify. The Companies' experience to date indicates that NPAs have allowed for the retirement of 119 feet of distribution main, and the cost of fully electrifying the three necessary customers was higher than the cost to replace the main (i.e., the project was not cost-

[148] *EIA Updated Buildings Sector Appliance and Equipment Costs and Efficiencies, Appendix A and B, Residential Air Source Heat Pumps, "EIA – Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case (and Advanced Case)," prepared by Guidehouse and Leidos (March 3, 2023).*

effective). NPA challenges have also been noted in California. Therefore, the Companies assume that the gas distribution system remains the same size (i.e., customers who choose to fully electrify are assumed to be located throughout the system, so there is no system downsizing). As a result, capital expenditures are not reduced for assumed reduction in miles of gas mains.[149] However, Companies assume that the Reference Case capital expenditure forecast is reduced for each existing customer who leaves the gas system due to avoiding the need to replace their service and meter in the future. Therefore, capital expenditures are affected by the annual customer count reductions in each scenario.

- **Customer Choice** – Consistent with the Guiding Principles, the Companies assume that customers maintain choice and intend to design programs for reducing GHG emissions that are flexible and responsive to the desires of their customers. Customers will choose different approaches to decarbonize their homes and businesses based on their individual circumstances (e.g., not all customers who electrify will choose full electrification just as not all customers will choose hybrid heating). However, the Companies have modeled scenarios with the goal of isolating the impacts of different types of electrification, therefore all customers in a particular segment are assumed to install the same type of equipment.
- **Adoption Rates** – The relationship between incentives and customers choosing to install emission reducing technologies will depend upon many factors including (1) the level of incentives offered, (2) the size of budgets approved for incentives, (3) an understanding of free ridership, (4) customer awareness of the incentives, and (5) customers having the desire/bandwidth to pursue the incentives. Incentives are an important consideration; however, there is not yet sufficient insight to develop an algorithm that reliably depicts the relationship between incentives and adoption rates. Therefore, customer adoption rates are an input in the Companies' models and adoption rates are not dependent upon assumed incentives.[150] Customer adoption of decarbonization technologies is a key uncertainty that will be closely monitored and updated in future LTPs when more information is available.

CRA/Stakeholder-Driven Scenarios

CRA and Stakeholders collaborated to specify six scenarios, of which four scenarios were provided to the Companies on January 30, 2024[151] and two additional scenarios were requested on March 25, 2024.[152] All six of the CRA/Stakeholder scenarios are "energy efficiency and electrification-only" scenarios and ***exclude*** RNG, hydrogen, and industrial carbon capture. The CRA/Stakeholder scenarios incorporate the same assumptions for weatherization as the Companies' CLCPA Scenarios, and the same assumptions for UTENs as the Companies' Delayed Achievement Scenarios. However, the CRA/Stakeholder scenarios have different assumptions for

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149 *Contrary to stakeholder claims, reduced gas demand due to full electrification by itself will not decrease the need for safety and reliability spending on the gas distribution system.*

150 *While some utilities have anecdotal evidence that sometimes incentives that cover 100% of the incremental equipment installation costs are not enough to convince customers to participate, the calculation of costs assumes that incentives would not exceed 100%.*

151 *The CRA/Stakeholder January 30, 2024 document is provided as Appendix F.*

152 *The CRA/Stakeholder March 25, 2024 document is provided as Appendix G*

electrification as compared to the Companies' scenarios and assume reduced costs as compared to the Companies' scenarios.[153] Each of the CRA/Stakeholder scenarios is described below and in Table V-2.

- The **CRA#1 Electrification Only - Mix Scenario ("CRA 1")** reflects electrifying with a mix of full electrification and hybrid heating based on the type of existing heating system. The majority of customers heating with gas furnaces are assumed to fully electrify with ccASHP supplemented with electric resistance heat for cold days to heat their homes and businesses with electricity every day of the year, thus increasing the winter electric peak and necessitating additional electric infrastructure buildout. Starting in 2028, 0.5% of existing residential, commercial, and municipal customer conversions of furnace systems are assumed to adopt GSHP, increasing 0.5% annually through 2043. All customers with boilers are assumed to install mini-splits with a gas boiler for backup. Electrification is assumed to ramp up at a pace of 5.4%/year for residential customers, 3.6%/year for municipal customers, and 2.1%/year for commercial and industrial customers. In addition, it is assumed that heat pump costs decrease at a rate of 1%/year (nominal), and costs associated with pipeline and storage fixed reservation charges decrease at a rate of 0.5%/year starting in 2028.
- The **CRA#2 Electrification Only - Hybrid Scenario ("CRA 2")** reflects electrifying most customers with hybrid heating and a subset of residential, commercial, and municipal furnace electrification customers adopting GSHP. The majority of customers heating with gas furnaces are assumed to install ccASHP supplemented with gas furnaces for cold days. All customers with boilers are assumed to install mini-splits with a gas boiler for backup. Electrification ramp rates, assumed percentages of customers adopting GSHPs, heat pump cost decreases, and pipeline and storage fixed cost decreases are the same as CRA#1 Electrification Only - Mix Scenario described above.
- The **CRA#3 Electrification Only - Full 1% Downsizing ("CRA 3")** reflects fully electrifying both furnaces and boilers for all customers with ccASHP or GSHP. Electrification ramp rates and heat pump cost decreases are the same as CRA#2 Electrification Only - Hybrid Scenario described above. In addition, it is assumed that costs associated with pipeline and storage fixed reservation charges decrease at a rate of 1%/year starting in 2028, and strategic downsizing allows for a reduction in O&M costs and capital expenditures of 1%/year starting in 2028.
- The **CRA#4 Electrification Only - Full 3% Downsizing ("CRA 4")** reflects fully electrifying both furnaces and boilers for all customers, like the CRA#3 Electrification Only - Full 1% Downsizing Scenario described above, but ramp rates are the same as the Companies' CLCPA Full Electrification Scenario. Heat pump cost decreases and incentives are the same as CRA#2 Electrification Only - Hybrid Scenario described above. In addition, it is assumed that costs associated with pipeline and storage fixed reservation charges decrease at a rate of 3%/year starting in 2028, strategic downsizing allows for a reduction in O&M costs and capital expenditures of 3%/year starting in 2028, and residential ccASHP

[153] *The CRA/Stakeholder scenarios also identified specific incentives and tax credits to be included for residential weatherization and electrification. The Companies have adopted these assumptions for all eight scenarios and discuss them in more detail below.*

and mini-splits for full electrification start at a cost of $15,378 (in 2023 dollars) based on data for a 3.5-ton residential ccASHP from a study performed for Public Service Company of Colorado.[154]

- The **CRA#5 Electrification Only – Full 3% Downsizing Pre-Weatherization Scenario ("CRA 5")** reflects fully electrifying both furnaces and boilers for all customers, like the CRA#4 – Full 3% Downsizing Scenario described above, but assumes all residential customers weatherize homes prior to electrification, allowing for reduced electric usage and 50% of electrifying customers to install a 3-ton heat pump (rather than the 3.5-ton heat pump modeled in CRA#4) at a capital cost of $1,000 less than the 3.5-ton heat pump. In addition to the 3%/year reduction in pipeline and storage fixed reservation charges, O&M costs, and capital expenditures starting in 2028 as modeled in CRA#4, this scenario also includes equal reduction in mileage of natural gas distribution pipe resulting in per mileage GHG emission reductions. This scenario assumes that all ASHP (i.e., standard ASHP, ccASHP, and mini-splits) efficiency improves over time consistent with NYSERDA's "Modeling Managed Building Electrification in New York State" October 18, 2023 presentation, which results in an approximate 3%/year efficiency improvement through 2030 and a 1%/year efficiency improvement thereafter for residential ASHPs and an approximate 2%/year efficiency improvement through 2030 for commercial ASHPs.
- The **CRA#6 Electrification Only – Full 3% Downsizing Pre-Weatherization CLCPA Scenario ("CRA 6")** uses same assumptions as CRA#5, except electrification adoption rates are adjusted such that emissions reduction is on pace to meet the 2050 CLCPA goal of 85% below 1990 levels, (i.e., 2043 GHG emissions are 65% below 1990 levels) similar to the Companies' CLCPA scenarios.

Table V-4 provides a summary of the six CRA/Stakeholder scenarios. Unless otherwise specified, it is assumed that each decarbonization action starts in 2027.

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[154] *Average installation costs of ccASHP within the Companies' service territories in 2020-2023 for homes with existing gas heat were $23,247 ($2023) for a 4-ton ccASHP and $16,445 ($2023) for a 3-ton ccASHP. The Companies assume a 4-ton ccASHP is necessary to heat homes in its service territories without gas heating backup on the coldest winter days in their Full Electrification Scenarios. The CRA 4 Scenario is modeled with the 3.5-ton ccASHP cost from Colorado as requested, but no changes were made to electricity use.*

Table V-4: Specification of CRA/Stakeholder-Driven Scenarios

<table>
<tr><th>Action</th><th>CRA #1
Electrification Only-Mix</th><th>CRA #2
Electrification Only-Hybrid</th><th>CRA #3
Electrification Only-Full-1% Downsizing</th><th>CRA #4
Electrification Only-Full-3% Downsizing</th><th>CRA #5
Electrification Only-Full-3% Downsizing
Pre-Weather</th><th>CRA #6
Electrification Only- Full-3% Downsizing Pre-Weather
CLCPA</th></tr>
<tr><td rowspan="2">Weatherization</td><td colspan="4">• Residential: 1% of homes/year in 2027, incremental participation growing by 0.25%/year</td><td colspan="2">• Residential: All weatherize prior to electrification. Participation is greater of electrification or 1% of homes/year in 2027 with incremental participation growing by 0.25%/year</td></tr>
<tr><td colspan="6">• Commercial: 0.5% heat load reduction/year
• Municipal: 1% heat load reduction/year</td></tr>
<tr><td rowspan="2">Electrification</td><td colspan="6">• Furnaces: 0.5% of residential, commercial, and municipal furnace conversions adopt GSHP in 2028, growing by 0.5%/year.</td></tr>
<tr><td>• Furnaces:ccASHP w elec resistance
• Boilers: mini-splits w gas boiler
• Ramp Rate:
• Res: 5.4%/yr
• Com: 2.1%/yr
• Muni: 3.6%/yr</td><td>• Furnaces: ccASHP w gas furnace
• Boilers: mini-splits w gas boiler
• Ramp Rate:
• Res: 5.4%/yr
• Com: 2.1%/yr
• Muni: 3.6%/yr</td><td>• Furnaces: ccASHP w elec resistance
• Boilers: full elec w mini-splits
• Ramp Rate:
• Res: 5.4%/yr
• Com: 2.1%/yr
• Muni: 3.6%/yr</td><td colspan="2">• Furnaces: ccASHP w elec resistance
• Boilers: full elec w mini-splits
• Pace: same as CLCPA Full</td><td>• Furnaces: ccASHP w elec resistance
• Boilers: full elec w mini-splits
• Pace: to hit target GHG emissions reductions</td></tr>
<tr><td rowspan="3">Industrial Customer Programs</td><td colspan="6">• Energy Efficiency of Process Load: 0.5% process load reduction/year</td></tr>
<tr><td>• Electrify Space Heating: furnace/heater conversions to ccASHP and boiler conversions to mini-splits w gas boiler ramping up at 2.1%/yr</td><td>• Electrify Space Heating: furnace/heater conversions to ccASHP w gas furnace and boiler conversions to mini-splits w gas boiler ramping up at 2.1%/yr</td><td>• Electrify Space Heating: furnace/heater and boiler conversions to ccASHP ramping up at 2.1%/yr</td><td colspan="2">• Electrify Space Heating: furnace/heater and boiler conversions to ccASHP at CLCPA Full pace</td><td>• Electrify Space Heating: furnace/heater and boiler conversions to ccASHP at pace to hit target GHG emission reductions</td></tr>
<tr><td colspan="6">• Carbon Capture: none</td></tr>
<tr><td>UTENs</td><td colspan="6">• 2035 start, one project of 24 residential and 8 non-residential buildings every other year</td></tr>
<tr><td>RNG</td><td colspan="6">• none</td></tr>
<tr><td>Hydrogen</td><td colspan="6">• none</td></tr>
<tr><td colspan="7">CRA/STAKEHOLDER SCENARIO-SPECIFIC ASSUMPTIONS (i.e., differences from assumptions in the Companies' scenarios)</td></tr>
<tr><td rowspan="3">Heat Pump Cost & Efficiency Improvements</td><td colspan="6">Reduce heat pump costs 1%/yr nominal</td></tr>
<tr><td></td><td></td><td></td><td colspan="3">• Reduce ccASHP start cost to $15,378 (2023$)</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2">• 50% of residential customers downsize ccASHP from 3.5 ton to 3-ton with cost reduction of $1000.
• ASHP efficiency improves 3%/yr through 2030 and 1%/yr thereafter for residential and 2%/year through 2030 for commercial.</td></tr>
<tr><td>Pipeline & Storage Fixed Costs</td><td colspan="2">• Reduce by 0.5%/yr starting in 2028</td><td>• Reduce by 1%/yr starting in 2028</td><td colspan="3">• Reduce by 3%/yr starting in 2028</td></tr>
<tr><td>O&M and CapEx</td><td></td><td></td><td>• Reduce by 1%/yr starting in 2028</td><td colspan="3">• Reduce by 3%/yr starting in 2028</td></tr>
<tr><td>Distribution System Emissions</td><td></td><td></td><td></td><td></td><td colspan="2">• Reflect 3%/yr reduction in miles of gas distribution pipe starting in 2028</td></tr>
</table>

The Commission confirmed in the NFG LTP Order that a true no-infrastructure scenario would meet all growth in demand with NPAs.[155] None of the Companies' or the CRA/Stakeholder scenarios forecast growth in demand. Therefore, none of these scenarios require gas infrastructure to accommodate load growth and each of these scenarios qualifies as a no-infrastructure scenario to satisfy the Gas Planning Order's requirement that "LDCs shall be expected to include a 'no-infrastructure scenario' in their long-term plans."[156] However, pipeline reinforcement projects may be considered to address specific vulnerable locations if NPA solutions cannot resolve the issue.

3. Develop the Long-Term Plan – Step 3

The Companies' objective is to develop an LTP that satisfies the overall set of Guiding Principles as well as each Guiding Principle on its own. The cost of each decarbonization action relative to the amount of GHG emissions reductions it produces as well as the performance of the collection of actions are major considerations in developing the LTP. The alternative scenarios provide insights into the effect of individual decarbonization actions on key outcomes and inform the development of an LTP that achieves a balance between GHG emissions reductions and the cost of achieving them. The level of each decarbonization action included in the LTP is determined based on its cost relative to other actions, impact on reliability and resilience, overall LTP cost, and the specific characteristics of the Companies' system, service territories, customer base, and market. In addition, the LTP incorporates assumptions that reflect the best available information and results in a plan that is feasible and achievable.

The LTP was developed using an assessment that incorporates three key metrics, recognizing that there are tradeoffs among desired outcomes. The most important tradeoff is between achieving GHG emissions reductions and maintaining safe, reliable, resilient, and affordable energy for all customers and competitive energy prices for industrial customers. Three key model outputs enable consideration of these tradeoffs: reductions in GHG emissions, NYSEG and RG&E gas bill impacts, and Decarbonization Policy Costs. The measurement of each is described in more detail below:

- **Reductions in GHG Emissions –** Annual GHG emissions are estimated for the entire supply and delivery chain from gas production through gas consumption for all NYSEG and RG&E gas customers in order to provide a comprehensive representation of the emissions associated with the Companies' supply and demand. Scope 1, 2, and 3 GHG emissions are calculated and reported in CO2e for the Reference Case and for 1990 to establish a baseline for emissions reduction measurements. Annual GHG emissions reductions relative to the Reference Case are calculated for each decarbonization action, converted to CO2e using the same methodology as the Reference Case, and summed to derive total emissions reductions by year for each scenario and the LTP.
- **NYSEG and RG&E Gas Bill Impacts –** Gas bill impacts reflect incremental costs that are likely to be recovered through the gas rates paid by the Companies' customers and will affect NYSEG and RG&E's revenue requirement and/or cost of gas. These increased costs are primarily comprised of incremental supply costs from the blending of RNG and hydrogen into the gas distribution system, utility incentive

155 NFG LTP Order, p. 24.

156 Gas Planning Order, p. 36-37.

rebate programs, and the capital costs and operating associated with UTENs. These increased gas utility costs are primarily offset by reductions in capital expenditures, O&M expenses, and pipeline and storage fixed costs, as applicable.

Gas rate impacts also reflect effects on billing determinants from changes in gas throughput attributable to decarbonization actions (e.g., energy efficiency or electrification). The impacts to NYSEG and RG&E's gas rates reflect the impact of each decarbonization action on both revenue requirements (numerator) and throughput (denominator). It is assumed that the existing ratemaking principles continue through the forecast period (i.e., the Companies have not postulated any changes to cost allocation principles, rate design, or depreciation). Bill impacts are calculated for a typical residential heating customer that has not participated in electrification (a "non-participant"). In response to stakeholder requests, bill impacts are also calculated for typical non-participants currently taking general service and small/large firm transportation service. For NYSEG, bill impacts are provided for residential SC1S/SC13T, general service SC2S/SC14T, small firm transportation SC5T, and large firm transportation SC1T. For RGE, bill impacts are provided for SC1/SC5 general service for both typical residential and non-residential customers, and large firm transportation SC3. All bill impacts assumed fixed usage over time.

- **Decarbonization Policy Costs –** Decarbonization Policy Costs are costs incurred as a result of the Companies' decarbonization actions but subject to recovery that will be determined by policy makers. For an existing gas customer who chooses to fully electrify, Decarbonization Policy Costs include (1) the cost to purchase and install new electric equipment,[157] (2) minus the replacement cost of retired gas equipment, (3) minus gas cost savings enabled by the investments, (4) plus increases in electricity bills for participating customers attributable to increased demand, infrastructure improvements to achieve clean energy objectives, and newly electrified end-uses.[158]

  The contribution of increased electric bills to the estimate of Decarbonization Policy Costs reflects only the increased costs of converting existing gas loads to electricity. The model does not include the impact of higher electric prices on other electric loads (e.g., refrigerators, lights, EV charging). Electric prices reflect costs that may be incurred by the Companies to accommodate increases in electric load from electrification. As described in the following section and in Appendix B, the electric prices used in this analysis are based on projected expendSitures by the Companies to maintain network reliability and resilience, serve incremental loads, integrate renewable and distributed resources, and fund ongoing CLCPA-related programs. Estimates of necessary electric capital expenditures and resulting electric prices may be higher than assumed in this analysis once the Companies have more data from performing the necessary detailed planning studies that consider large-scale electric transmission and distribution infrastructure investments and localized impacts of electrification on the electric system.

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157 *As discussed above, the Companies assume that a portion of incremental equipment costs for weatherization and electrification will be covered by some combination of federal and state tax credits, rebates, utility program incentives, and rate subsidies, and the remaining amount will be covered by participating customer contributions.*

158 *Decarbonization Policy Costs would also include any natural gas system costs that may become stranded as a result of decarbonization policy actions, should there be any.*

C. Incorporating Stakeholder and CRA Input

The Companies' Final LTP has been shaped by extensive stakeholder engagement, which has included participation by stakeholders, Staff, and CRA. As described in Chapter I, stakeholders and CRA have had many opportunities to provide feedback and input, including two rounds of written comments after Initial and Revised LTP reports were filed and multiple technical sessions organized by Staff. Numerous Staff, CRA and stakeholder recommendations have been incorporated into the Final LTP filing. Notably, NYSEG and RG&E modeled six new "CRA/Stakeholder Scenarios," expanded bill impact calculations to include non-residential customers, performed UCT and RIM tests to supplement existing BCA analyses, modeled sensitivities, and provided all results as requested. The following is a detailed list of stakeholder and CRA recommendations that have been incorporated into the Companies' analysis, report, and appendices.

Reference Case:

- Removed all customer growth and associated throughput and design day demand from the Reference Case starting in 2026 for residential and commercial customers and 2029 for municipal and industrial customers to reflect the impact of legislation passed in May 2023 that prohibits the installation of fossil-fuel equipment in new buildings not more than seven stories and less than 100,000 sq ft starting in 2026 and in all buildings starting in 2029.
- Reduced Reference Case capital expenditure forecast for avoided new meters and services resulting from removal of customer growth.
- Reduced Reference Case GHG emissions resulting from removal of customer growth.
- Adjusted the Reference Case demand and GHG emissions forecast to reflect the impact of the Commission's July 2023 Order that ends the Companies' energy efficiency programs that provided residential rebates for efficient gas equipment and rebates for commercial gas cooking equipment starting in 2026.

Specification of Decarbonization Actions:

- Modified residential weatherization installation costs and reduction in gas usage assumptions to reflect the Companies' Energy Efficiency Portfolio Proposal filed in January 2024, and accelerated the rate of residential weatherization.
- Accounted for the impact of federal, state, and utility incentives on participating customer contributions to weatherization and electrification costs and on gas utility revenue requirements.
- Added functionality to residential, commercial, and municipal electrification modeling to allow for a proportion of furnace conversions to use GSHP instead of ASHP.
- Modified UTENs assumptions (including costs, number of participants, energy use changes, and start date) based on changing developments in the Companies' pilot projects as reflected in the UTENs case.
- Changed residential electrification assumptions to reflect NYSEG and RG&E specific data whenever possible.

- Pushed back weatherization and electrification start dates from 2026 to 2027 to reflect the time necessary to design, propose, and implement programs.

Fixed Costs:

- Decreased fixed pipeline and storage costs in proportion with sustained decreases in design day gas demand in the LTP.
- Decreased capital expenditures due to avoiding future replacement of the gas meter and gas service for the number customers leaving the gas system due to full electrification in each scenario and the LTP.

Additional Benefits and Costs:

- Added functionality necessary to calculate Utility Cost Test ("UCT") and Rate Impact Measure ("RIM") as additional BCAs.
- Conducted and provided results of UCT and RIM for all scenarios and LTP
- Accounted for the differing impacts of federal, state, and gas utility incentives as appropriate in the SCT, UCT and RIM
- Calculated and reported lost utility revenues as part of RIM

Sensitivities:

- Calculated sensitivity for +/- 10% in gas commodity prices and provided results
- Calculated sensitivity for +/-20% in all-in electric prices and provided results
- Calculated sensitivity for +1% and inflation /-1% year changes installation costs for heat pumps and provided results

Additional Model Outputs:

- Provided additional model detail and outputs, including annual weatherization and electrification conversions, capital expenditures for each scenario, rate base for each scenario, \$/MT CO_2e GHG emissions reductions for each decarbonization action for each scenario, \$/MT CO_2e GHG emissions reductions for residential electrification for each scenario, gas and electric price components
- Added functionality and provided additional bill impact analyses for non-residential customer classes

CRA/Stakeholder Scenarios:

- Modeled six new scenarios as specified by CRA/Stakeholders and provided all results consistent with the Companies' scenarios, including:
    - Elimination of all RNG, hydrogen, and industrial carbon capture.
    - Adoption of individual residential, commercial, and municipal GSHP.

- Adoption of hybrid natural gas boiler / ccASHP mini-split systems for all customer segments.
- Elimination of the limit on the maximum participation rates for electrification.
- Reductions in O&M, capital expenditures and fixed pipeline and storage costs
- Reductions in distribution pipe mileage dependent emissions.
- Reductions in ccASHP installed cost over time
- Improvements in ccASHP efficiencies over time.
- Assumptions that weatherization occurs prior to electrification, resulting in 50% of residential customers installing 3-ton heat pumps rather than 4-ton heat pumps.

Additional Information:

- Included discussion of several other ongoing Commission proceedings that are addressing topics that are relevant to specific areas of the Companies' LTP
- Expanded discussion of the Companies' design day forecast methodology
- Added discussion of Companies approach and criteria regarding contract restructuring
- Updated vulnerable locations and provided information on reliability metrics and trigger values
- Included additional information on the Companies' Energy Efficiency Portfolio Proposal
- Included additional discussion of DACs as well as provided additional DAC data
- Expanded details around NPA projects, provided updates and lessons learned.
- Expanded discussion of how NYSEG and RG&E are working to better understand the role of their industrial customers in their LTP process.
- Included list of changes made as a result of Stakeholder and CRA requests

Action Items

- Included joint planning as an action item
- Committed to filing a Gas BCA Handbook in next LTP

D. Impact of Building Electrification on Electric Infrastructure and Rates

Gas long-term plans must consider the impact of decarbonization on the level of electric infrastructure investments required, the timing of those investments, and the resulting impact on electricity rates. The potential conversion from natural gas (and other fuels) to electricity for heating and achieving the CLCPA's clean energy goals will require significant investment in every electric segment: generation, transmission, and distribution.

The CLCPA's clean energy goals will require significant investment in zero-emission generation and the necessary transmission to deliver clean energy to load centers. For example, $44 billion of customer funding has already been committed to implement clean energy objectives,[159] and it is estimated that these costs could add approximately $400 million to NYSEG's electric revenue requirement and $180 million to RG&E's electric revenue requirement by 2043.[160] These investments will be necessary, regardless of the gas LTP and the approach to building electrification.

Electric generation, transmission, and distribution infrastructure are planned and constructed to meet peak electric demands, which determine the level of infrastructure necessary, and the resulting fixed costs recovered from electric customers. Regional power demand, as reported by the New York Independent System Operator ("NY-ISO"), has historically peaked on hot days in the summer. Although there is some peak demand diversity among distribution planning areas and individual circuits in upstate New York, NYSEG and RG&E's areas have also been summer peaking historically.

There is consensus that the New York electric grid will become winter-peaking if heating loads are "fully" electrified (e.g., using a ccASHP with electric resistance backup for cold winter days). The implications for peak demand on NYSEG and RG&E's electric networks will depend on the approach to clean heat, regardless of whether the natural gas service is provided by NYSEG, RG&E, or an unaffiliated LDC. The impacts of full electrification on peak electricity demand and the need to invest to increase capacity on electric transmission and distribution systems will be substantial, particularly in areas of the system that are already operating close to or above rated capacity.[161] The impacts on electric peak demand will be significantly tempered if customers install hybrid heating systems (e.g., an ASHP coupled with a natural gas furnace for the coldest days of the year).[162] Under hybrid heating, the natural gas heating equipment operates as an electric demand response solution that reduces the electric peak in the winter, and therefore reduces the investment in capacity required on the electric system.

A critical conclusion to be informed by the Companies' analysis is the relative impact of hybrid heating vs. full electrification solutions. The costs and benefits associated with these investments will significantly impact the overall LTP as well as the necessary build-out of the electric system. Full electrification of heating loads (e.g., using ccASHP with electric resistance backup for cold winter days) will require substantial investments to increase capacity on the electric system to accommodate the additional peak load on cold winter days. For example, the Companies estimate that approximately $34 billion (in 2022 dollars) of investment in NYSEG and RG&E's electric

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159 *Case 22-M-0149, Proceeding on Motion of the Commission Assessing Implementation of a Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act (CLCPA Compliance Proceeding), New York State Department of Public Service First Annual Informational Report on Overall Implementation of the Climate Leadership and Community Protection Act, July 20, 2023.*

160 *See Appendix B, Table B-8.*

161 *Electric transmission and distribution systems have a finite amount of capacity to transmit electricity from generators to end-users. As electric peak loads grow and approach the existing capacity, upgrades are needed to increase the capacity of the system. These upgrades could require some combination of new or larger local distribution circuits and related equipment, substations, and transmission circuits and related equipment. The specific upgrades necessary and the associated cost requires detailed studies and is dependent upon the specific location and size of the increased peak loads.*

162 *The impact on the need for electric investment in a particular area will also depend on several factors including the current capacity status of substation and circuit infrastructure, additions to demand from electric vehicle charging, and projected load profiles based on the demands by customers.*

transmission and distribution infrastructure would be required by 2050 to meet approximately 6,160 MW in projected winter peak demand growth.[163]

The Companies' modeling relies on these data as inputs to the projection of high-level, order of magnitude, system-wide electricity costs and rate impacts that are important cost components of the Companies' gas decarbonization actions.[164] It is clear, however, that a location-specific analysis that considers the current and projected loading on individual substations and circuits will be required to fully understand the actual cost of electrification on the electric system. Electric distribution utilities' planning functions will need to incorporate location-specific incremental capacity requirements from building electrification in their planning processes, along with the many other drivers of electric infrastructure investments.

E. Addressing Uncertainty

The Companies' LTP addresses the shifting nature of market and technology developments, infrastructure capabilities, and policy. The three-year planning cycle prescribed in the Gas Planning Order will ensure that the Companies' LTP evolves over time and reflects the latest information and insights.

There are five categories of major unknowns that require assumptions to produce an LTP. Each category is discussed below, along with how the Companies are addressing it in this LTP. These categories will be revisited in future LTPs. Although the Companies' LTP includes a 20-year forecast of many data inputs and assumptions, the focus should be on whether the Companies' three-year action plan is based on the best available information and is reasonable given current facts and circumstances.

- **Policy Developments:** There are numerous new laws, regulations, directives, and other policies as well as changes to existing laws, regulations, directives, and other policies that will shape decarbonization approaches for gas utilities in the years to come. These developments could originate from any one of several branches and departments of the federal, state, and local governments. Topics could include, among others, GHG emissions targets, least cost gas procurement, cap-and-invest programs, non-pipe-alternative suitability criteria, and customer incentive levels and budgets. Any long-term plan must acknowledge the impact of potential future legal and policy developments. For the purposes of developing this LTP, the Companies have relied on a few key concepts related to policy developments. First, consistent with the Guiding Principles, the Companies' LTP strives to provide safe, reliable, and affordable energy service while delivering sustainable GHG emissions reductions and preserving customer choice. Second, there is a difference between a "mandate" where the mandating body can control compliance and a "target" that is dependent upon choices made by third party entities upon which the mandating body has little control. Third, existing policies will change, but no one can accurately predict when and how. Therefore, NYSEG and RG&E have not attempted to predict future policy direction or restrict its LTP based on potential policy limitations. Instead, the Companies' LTP is designed to maintain optionality and be flexible enough to evolve with future legal and policy direction.

[163] *Natural Gas and Grid Modernization Study, Appendix N, Special Study #5, filed on May 17, 2022, in Case 19-E-0378, et. al., Exhibit 7.*

[164] *See Appendix B for additional details on energy price forecasts used in the analysis.*

- **Technology Development:** The impact and cost effectiveness of all types of decarbonization actions will be significantly influenced by future technology development. For example, the technical capabilities of heat pumps, hydrogen production and blending, dispatchable emissions-free electric generation resources, and thermal energy networks may improve over time, but no one can accurately predict when and to what extent. As a result, the Companies have based their assumptions regarding technical capabilities for all decarbonization actions on information for current commercially available technology and did not attempt to predict future improvements. Therefore, NYSEG and RG&E did not base their LTP on the promise of improved technology in the future, but rather technology with evidence of success today. However, the Companies have complied with CRA/Stakeholder requests to assume ASHP technology improvements in CRA/Stakeholder Scenarios #5 and #6. The Companies will incorporate commercially available technological improvements in future LTPs.
- **Customer Behavior**: There is considerable uncertainty with respect to customer behavior related to decarbonization. Many decarbonization actions will require individual customers to choose to make a change. The behavior of some large industrial customers will likely be impacted by corporate decarbonization commitments. It is difficult to predict specific customer adoption rates for any decarbonization action as there are barriers must be addressed. For example, what level of economic incentive will be necessary to overcome the disruption associated with electrifying a heating system? How will customers react to the inevitable increased energy costs from decarbonization? Customer adoption rates are assumed to start at a modest level and increase on an annual basis. Adoption rates are not modeled to achieve 100% unless a mandate is assumed to be in place (e.g., the Reference Case assumes that 100% of new residential and commercial customers fully electrify starting in 2026 due to the prohibition of fossil-fuel equipment in new buildings up to 7 stories). It is assumed that customer adoption is not hindered by insufficient incentive levels or incentive budgets. The Companies are not aware of any relevant studies that would inform assumptions related to customer behavior associated with incentive levels for specific decarbonization actions and acknowledge that there is a need for studies and insights regarding customer behavior that can be incorporated in future LTPs.
- **Electric Infrastructure Development:** Although the CLCPA established targets for electric sector emissions and economy-wide decarbonization levels, achieving these targets is uncertain and depends on unprecedented levels of development of electric generation, transmission, and distribution infrastructure. Progress on each of these fronts will significantly impact the ability of the economy to decarbonize, which depends on electric capacity being developed in time to accommodate electricity demand growth attributed to decarbonization. The LTP reflects increases in electric load at a reasonable pace over time to acknowledge the real-world challenges of major electric infrastructure build-out.
- **Cost:** Achieving the State's decarbonization goals will be incredibly expensive and it is important that policy decisions be based on realistic cost assessments. However, there is significant uncertainty regarding costs to implement and operate various decarbonization actions. Costs for all decarbonization actions will change over time as supply and demand balances change, as technology develops, and as labor markets develop. Costs that will have a significant impact on future LTPs include costs associated with heat pump equipment and installation, electricity, natural gas, hydrogen, RNG, and carbon capture. NYSEG and RG&E's cost assumptions are based on the best information available from reliable industry

resources, and generally do not attempt to anticipate how markets, technology, and resulting costs will evolve over time.[165] However, the Companies have complied with CRA/Stakeholder requests to assume heat pump costs decrease 1%/year (nominal) in all CRA/Stakeholder scenarios. The Companies recognize that costs will change and will incorporate updated cost information into future LTPs.

[165] *The CRA/Stakeholder-Driven Scenarios include assumptions about heat pump costs decreasing at 1%/year (nominal).*

VI.

Model Results and Long-Term Plan

VI. Model Results and Long-Term Plan

A. Objectives

Consistent with the Guiding Principles, the Companies' LTP strives to provide safe, reliable, and affordable energy service while delivering sustainable GHG emissions reductions and preserving customer choice throughout the plan period. The key metrics are GHG emissions reductions and costs (total costs and gas bill impacts). In general, the Companies strive to be as aggressive as possible with respect to achieving GHG emissions reductions, subject to total cost and energy affordability concerns.

The Companies' LTP was developed using a bottom-up approach to estimate incremental costs and benefits for each decarbonization action. Incremental costs include equipment costs and changes in energy bills per participating customer, as well as the incremental cost above conventional supplies per unit of RNG and hydrogen. Incremental benefits include decreased emissions per participating customer and decreased emissions per unit of RNG or hydrogen. An estimate of the relative efficiency of each decarbonization action in contributing to GHG emissions reductions is produced by comparing its incremental costs to its benefits. This relative efficiency is expressed as $/metric ton ("MT") of GHG emissions reduction ("CO2e"), with both numerator and denominator expressed as NPV values. There are meaningful variations among the decarbonization actions with respect to their economic efficiency in reducing GHG emissions. The total cost of the LTP is the sum of the incremental impact on NYSEG and RG&E's revenue requirements (relative to the Reference Case) and the Decarbonization Policy Costs.

B. Insights from Scenario Analyses

As discussed in Chapter IV, scenario analyses inform the LTP by assessing the relative GHG reductions and costs of potential decarbonization actions, both individually and combined. An individual scenario is not a "plan" and is distinct from the LTP as a scenario is not subject to real-world constraints and may be defined to test alternative decarbonization pathways or the impact of alternative cost assumptions. In contrast, the LTP is developed by combining various levels of decarbonization actions with assumptions that are based on the best available information to produce a feasible plan that is projected to achieve GHG emissions reductions as cost-efficiently as possible while satisfying objectives that are expressed in the Guiding Principles. Insights gained from the scenarios regarding cost impacts, overall GHG emissions reductions, the relative efficiency of the individual decarbonization actions in achieving GHG emissions reductions, and the impact on reliability of energy inform the Companies' LTP.

The six Guiding Principles in Figure V-1 represent the individual and collective goals of the LTP. Since there are likely to be conflicts between affordability and other principles, achieving balance among principles is appropriate. Perhaps the most important assessment in developing the LTP, particularly on the margin, is balancing whether GHG emissions reductions are accompanied by costs that are reasonable for all customers and affordable for LMI customers. A metric that reflects cost per unit of GHG emissions reduction in $/MT CO2e is produced for each decarbonization action plus the collection of actions that comprise a scenario. These results inform the LTP because they reveal the impacts of individual decarbonization actions on the efficiency of achieving GHG emissions reductions.

Table VI-1 below contains summary results for the Companies' four scenarios as well as the six CRA/Stakeholder scenarios. A comparison of various metrics, like the cost per GHG emissions reductions, 2043 GHG emissions reductions relative to 1990, total cost, and winter electric peak demand impact, can provide valuable insights into the major questions that need to be addressed by the long-term plan, setting aside the issue of whether individual scenarios are achievable or based on reasonable assumptions. For example, a comparison of these metrics helps assess the relative cost of the Companies' two CLCPA scenarios as compared to the two Delayed Achievement scenarios. Similarly, comparing these metrics between a full-electrification scenario and a hybrid heating scenario (assuming that other factors are equal) helps assess the relative costs to customers and the respective impacts on the electric system of different forms of building electrification. More detailed results that show the cost and emissions reductions for each decarbonization action within each scenario are presented in Appendix D.

Table VI-1: Summary Results for Scenarios

	Cost per GHG Emission Reduction ($/MT CO2e)	2043 GHG Reduction (% vs. 1990)	Total Cost 2024-43 (NPV $M)	2043 Electric Winter Peak Demand Impact (MW)
NYSEG				
CLCPA–Full Electrification	$743	-65%	$6,648	862
CLCPA–Hybrid Heating	$614	-65%	$ 5,940	35
Delayed–Full Electrification	$761	-50%	$4,671	582
Delayed–Hybrid Heating	$425	-50%	$2,880	39
CRA1-Elec Only-Mix	$1,184	-46%	$4,467	633
CRA2-Elec Only-Hybrid	$1,075	-42%	$3,471	37
CRA3-Elec Only-Full 1% Downsize	$1,169	-48%	$4,666	948
CRA4-Elec Only-Full 3% Downsize	$1,018	-46%	$3,845	872
CRA5-Elec Only-Full 3% Downsize Pre-Weather	$892	-43%	$3,142	546
CRA6-Elec Only-Full 3% Downsize Pre-Weather CLCPA	$1,014	-65%	$9,294	1,162
RG&E				
CLCPA–Full Electrification	$829	-65%	$7,550	1,330
CLCPA–Hybrid Heating	$589	-65%	$6,100	50
Delayed–Full Electrification	$862	-50%	$5,385	991
Delayed–Hybrid Heating	$ 439	-50%	$3,229	61
CRA1-Elec Only-Mix	$1,065	-45%	$4,314	750
CRA2-Elec Only-Hybrid	$890	-42%	$3,183	44
CRA3-Elec Only-Full 1% Downsize	$1,047	-47%	$4,438	1,122
CRA4-Elec Only-Full 3% Downsize	$941	-52%	$4,647	1,331
CRA5-Elec Only-Full 3% Downsize Pre-Weather	$790	-46%	$3,390	781
CRA6-Elec Only-Full 3% Downsize Pre-Weather CLCPA	$863	-65%	$8,472	1,343

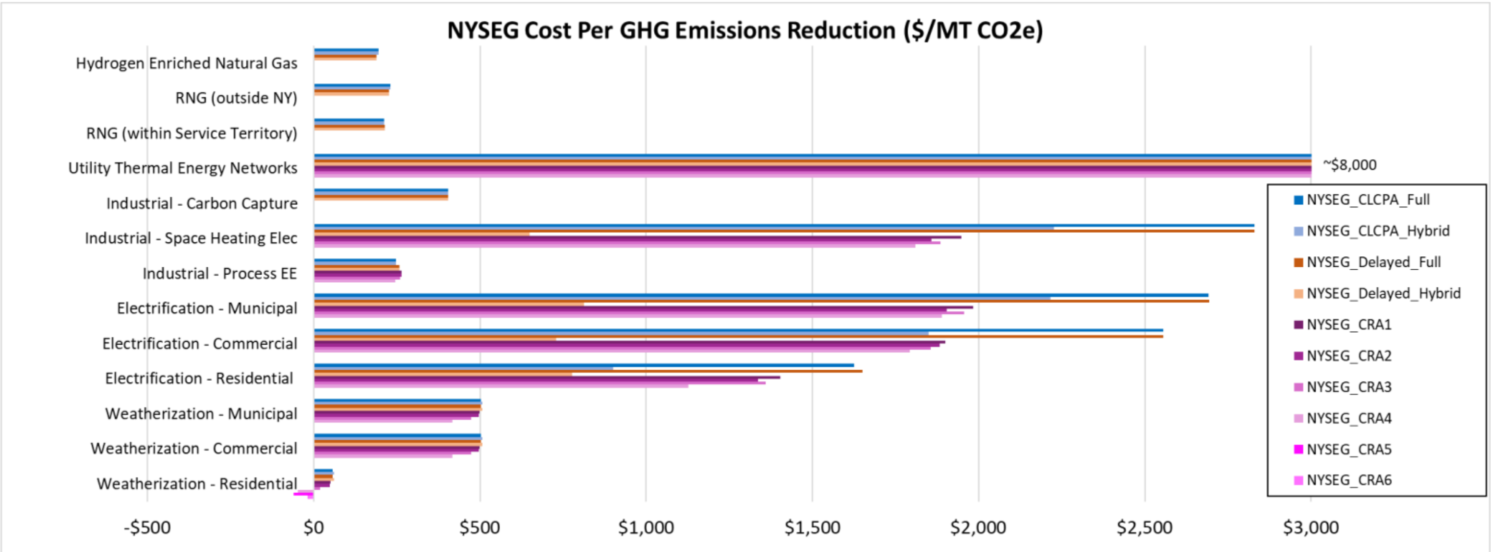
The CLCPA Scenarios are designed to achieve 65% reductions in GHG emissions from 1990 levels by 2043, while the Delayed Achievement scenarios are designed to achieve a 50% reduction by 2043. As would be expected, the total costs are higher in CLCPA Scenarios compared to the Delayed Achievement Scenarios across both types of heating and across both utilities as shown in Table VI-1 (e.g., for NYSEG, the total cost of the CLCPA-Full Electrification Scenario is $6.6 billion compared to $4.7 billion for the Delayed Achievement-Full Electrification Scenario).

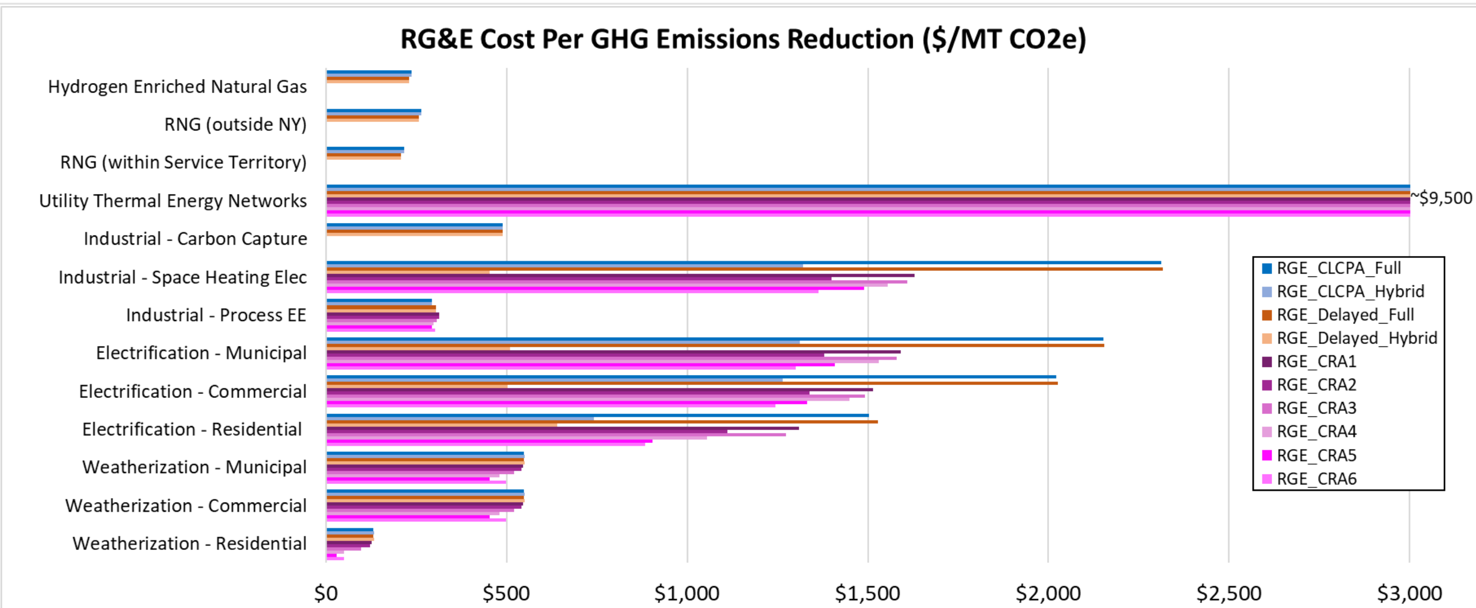
Also as shown in Table VI-1, the Companies' Full Electrification Scenarios are less efficient in terms of cost per GHG emissions reduction than the Companies' corresponding Hybrid Heating Scenarios. For example, the CLCPA-Full Electrification Scenario for RG&E has a total cost of $7.6 billion and a cost per GHG emissions reduction of $829/MT CO2e compared to the CLCPA-Hybrid Heating Scenario which produces the same emissions reductions at a cost of $6.1 billion and a cost per GHG emissions reduction of $589/MT CO2e.

There are four fundamental differences between the six CRA/Stakeholder Scenarios and the Companies' four scenarios. First, the CRA/Stakeholder scenarios restrict the decarbonization actions to eliminate RNG, hydrogen, and industrial carbon capture. Second, the CRA/stakeholder scenarios assume lower costs for electrification (i.e., nominal heat pump costs decline at a rate of 1%/year and ASHP efficiency improves in some CRA/Stakeholder scenarios). Third, the CRA/Stakeholder scenarios include costs of GSHP for some electrifying customers. Fourth, the CRA/Stakeholder Scenarios assume various amounts of reductions in utility costs (pipeline and storage demand charges, capital expenditures, and O&M expenses) depending on the scenario. Even with lower electrification and utility cost assumptions, the CRA/Stakeholder Scenarios have higher cost per GHG emissions reduction compared to the Companies' scenarios (CRA/Stakeholder Scenario results range from $790 to $1,184/MT CO2e compared to $425 to $862/MT CO2e for the Companies' scenarios across both utilities). The CRA/Stakeholder higher costs are likely due to the elimination of RNG, hydrogen and industrial carbon capture from their scenarios. Investigating the cost per GHG emissions reduction for each decarbonization action will provide additional insight.

Figure VI-1 below shows the cost per GHG emissions reduction in $/MT CO2e for each decarbonization action within each scenario. As shown in the graphs, weatherization for residential customers is the most cost-effective decarbonization action across all scenarios at less than $133/MT CO2e. RNG (both within service territory and outside NY) and hydrogen are the next most cost-effective decarbonization actions across all scenarios in which they were included. Industrial process energy efficiency, industrial carbon capture, and weatherization for commercial and municipal customers are also relatively inexpensive decarbonization actions. All forms of electrification for all segments have higher costs per GHG emissions reductions, and UTENs are the most expensive across all scenarios.

Figure VI-1: Cost per GHG Emissions Reduction by Decarbonization Action and Scenario

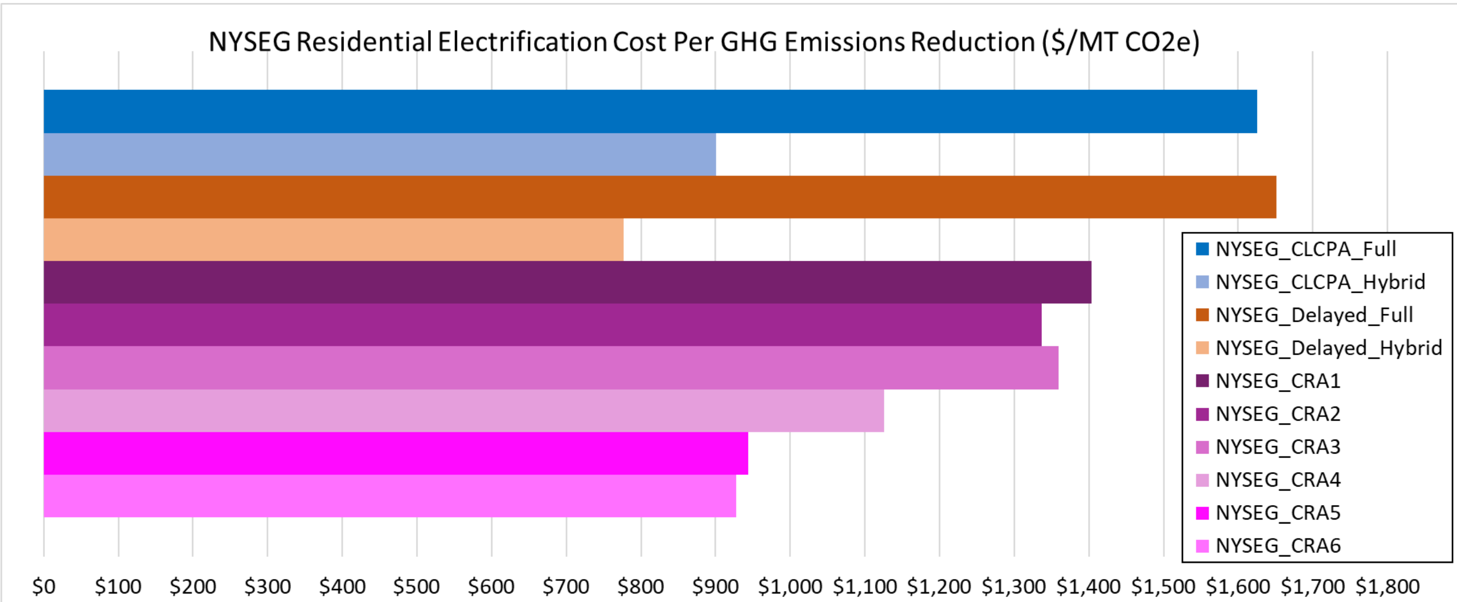


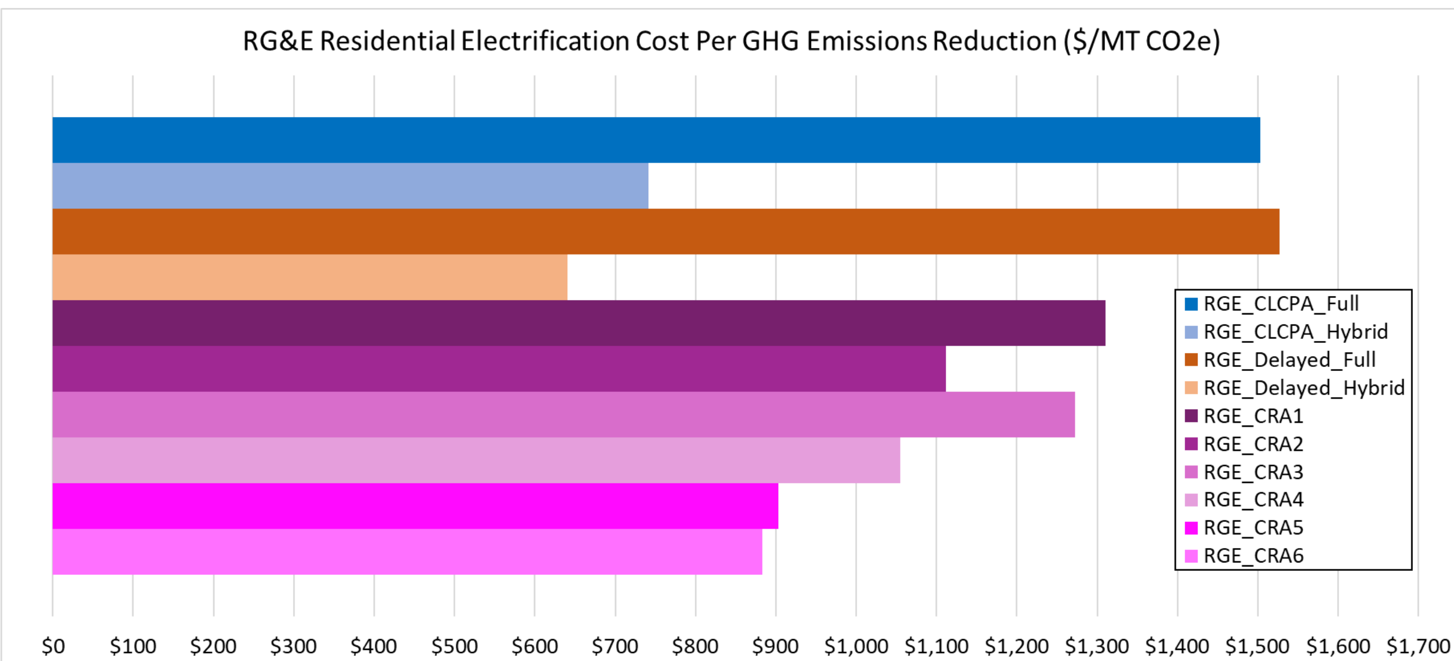


These scenario results demonstrate that the relative cost effectiveness of reducing GHG emissions differs considerably across decarbonization actions. Focusing efforts on decarbonization actions that have relatively low cost per GHG emissions reductions will provide benefits to customers by addressing affordability concerns. For example, RNG and hydrogen have a cost of approximately $225/MT CO2e compared to electrification that has a cost of approximately $1,500/MT CO2e. Therefore, it will be more affordable to reduce GHG emissions with RNG and hydrogen as compared to electrification.

Figure VI-1 also demonstrates that the cost per GHG emissions reduction within many decarbonization actions is similar across scenarios (e.g., the bars for municipal weatherization have similar lengths). However, there is considerable variability within electrification (the bars have different lengths) due to different approaches to electrification. Figure VI-2 shows the residential electrification cost per GHG emissions reduction in more detail and illustrates the different $/MT CO2e across the ten scenarios.

Figure VI-2: Cost per GHG Emissions Reduction for Residential Electrification





As shown in Figure VI-2, residential electrification using hybrid heating has a lower cost per GHG emissions reduction than full electrification as shown in the other scenarios. Moreover, the Companies' hybrid heating scenarios have lower cost per GHG emissions reductions than CRA/Stakeholder electrification scenarios, many of which have ASHP cost and emissions improvement assumptions plus cost reductions due to assumed gas system downsizing that are not included in the Companies' hybrid heating scenarios. In addition, hybrid heating using standard ASHP in homes with furnaces instead of boilers (Delayed Hybrid) has lower cost per GHG emissions reduction than hybrid heating with ccASHP (CRA 2) and hybrid heating systems in homes with boilers (CLCPA Hybrid and CRA 2). Moreover, among the three scenarios that use hybrid heating, the CLCPA Hybrid and Delayed Hybrid scenarios have lower cost per GHG emissions reductions than CRA 2 when CRA 2 has assumed lower costs. This demonstrates that using ccASHP in hybrid heating and installing hybrid heating for customers with boilers (as assumed in CRA 2) are significantly more expensive per GHG emissions reduction than installing hybrid heating using standard ASHP for customers with existing gas furnaces (as assumed in CLCPA Hybrid and Delayed Hybrid).

Figures VI-3 and VI-4 on the following pages depict the GHG emissions reductions over time for each decarbonization action for each scenario for NYSEG and RG&E, respectively.

Figure VI-3: NYSEG GHG Emissions Reductions by Decarbonization Action and Scenario (Million MT CO2e)

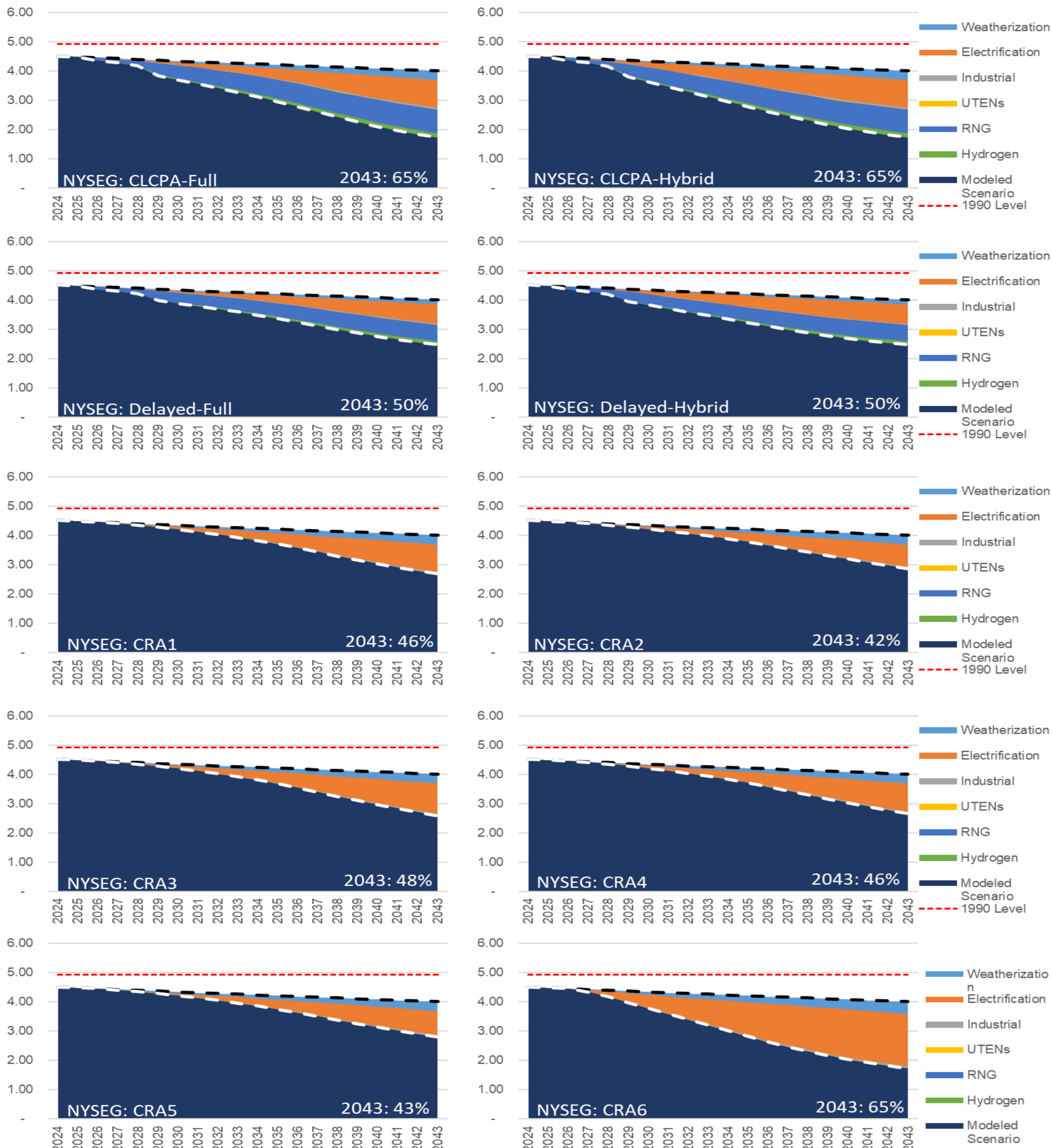
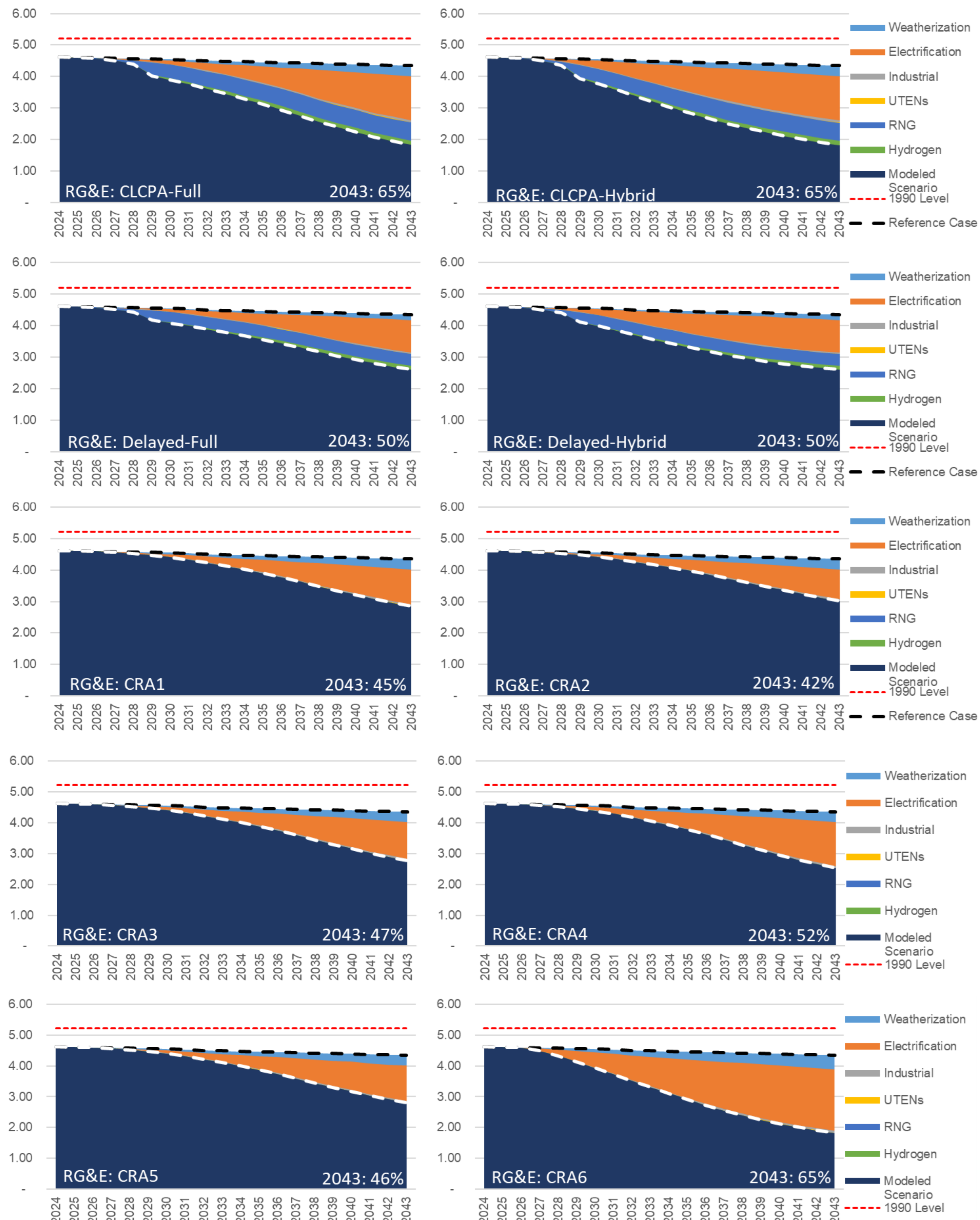


Figure VI-4: RG&E GHG Emissions Reductions by Decarbonization Action and Scenario (Million MT CO2e)



As shown in Figures VI-3 and VI-4, all ten scenarios have modest impacts on GHG emissions in the early years, with increased impacts in the later years as programs ramp up and impacts accumulate. The largest emissions reductions accrue from electrification (orange wedge) and RNG (medium blue wedge) under all the Companies' scenarios for both utilities. The largest emissions reductions accrue from electrification (orange wedge) under all the CRA/Stakeholder scenarios. In general, the Companies' scenarios have greater GHG emissions reductions in 2043 than the CRA/Stakeholder scenarios because the CRA/Stakeholder scenarios exclude RNG (along with hydrogen and carbon capture).

C. LTP Decarbonization Actions and GHG Emissions Reductions

Insights from the scenario analyses were used to determine the specific levels, types, and timing of each decarbonization action included in the Companies' LTP based on relative cost efficiencies and the specific characteristics of the Companies' system, service territory, customer base, and market. The Companies strive to be as aggressive as possible with respect to achieving GHG emissions reductions, subject to affordability concerns as well as confidence that the LTP could be executed.

Given the significant uncertainty associated with major factors that impact decarbonization timing and outcomes, including future policy developments, technology development, customer behavior, electric infrastructure development, and costs, the Companies believe it is appropriate to preserve optionality by including all decarbonization actions in its LTP. For example, the LTP includes modest levels of UTENs, the most expensive decarbonization action per unit of GHG emissions reductions, recognizing that UTENs, along with hydrogen, are an option being seriously considered within New York State, the U.S., and around the world, and UTENs are expected to provide jobs benefits that have not been quantified.

In addition, it is important that the LTP maximizes implementation of decarbonization actions that have the lowest cost per GHG emissions reductions (weatherization, industrial energy efficiency and carbon capture, RNG, and hydrogen as shown above) as these actions have the "biggest bang for the buck" for customers. Unfortunately, these lower cost per GHG emissions reduction decarbonization actions are expected to have a limited impact on emissions reductions given current technologies (e.g., RNG is limited by the quantity of existing feedstocks and is not expected to be produced in large enough quantities to replace all existing traditional gas use). Therefore, it is necessary to balance between including higher-cost decarbonization actions to increase GHG emissions reductions and considering the associated costs. The LTP also recognizes the importance of electrifying buildings in the most cost-effective manner. The specific assumptions for each decarbonization action included in the Companies' LTP are described below.

1. *Weatherization*

Overall Approach: *Design programs to achieve the highest feasible participation rates and GHG emissions reductions. More specifically, design programs to achieve:*

- **Residential**: Participation rates of 1% of residential customers in the first year (2027), with annual participation increases of 0.25%/year, resulting in 5% of residential customers weatherizing in 2043 and cumulative participation of 51% through Year 20.

- **Commercial**: Savings of 0.5% incremental heat load reduction/year, achieving a cumulative 8.5% load reduction by Year 20.
- **Municipal**: Savings of 1% incremental heat load reduction/year achieving a cumulative 17% load reduction by Year 20.

Reasoning:

Residential weatherization has the lowest cost per GHG emissions reduction among decarbonization actions and commercial and municipal weatherization also have relatively low costs. These results are consistent with others that have indicated that reducing energy use is among the best approaches to achieve GHG emissions reductions. For these reasons, the LTP incorporates weatherization at the greatest levels the Companies believe can be achieved given current information. Residential weatherization costs and savings are based on the Companies' January 16, 2024 EE/BE Portfolio Proposal, however the LTP contemplates a much more extensive weatherization program and extends weatherization beyond the end of the period included in the EE/BE Portfolio Proposal. Residential weatherization participation in the LTP starts at a level that is more than double what is included in the Companies' EE/BE Portfolio Proposal and ramps up faster than the Companies' EE/BE Portfolio Proposal. It is assumed in the LTP that residential participation starts in 2027 at 1%, and increases at a rate of 0.25%/year, resulting in 5% of residential customers weatherizing in 2043 and cumulative participation of 51% through 2043. This accelerating participation rate is adequate to add insulation to the proportion of homes in NYSEG and RG&E's service areas that that the Companies have identified as needing additional insulation by the end of the 20-year forecast period. Efforts to significantly ramp up weatherization will be challenging as progress will be impacted by contractor availability and customer awareness, but the Companies believe both will improve with greater visibility in the marketplace. The LTP also assumes that weatherization budget increases will be necessary to make meaningful and efficient impacts on GHG emissions reductions.

There is limited experience with non-residential weatherization programs, and there is also greater diversity among customers than in the residential sector. Based on current information, weatherization of commercial and municipal customers appears to be relatively cost-effective, and it has been included in the LTP at relatively aggressive levels. It is further assumed that municipal customers achieve double the participation of commercial customers as government policies may be easier to implement in municipal buildings than for commercial customers that face competitive pressures. Existing weatherization program proposals and budgets will need to be expanded to include commercial and municipal customers to implement this decarbonization action.

2. *Building Electrification*

Overall Approach: *Design flexible programs to start in 2027 that will encourage existing gas customers to choose to convert gas heating and other gas equipment to run on electricity. Accommodate customer preferences for types of conversion, including maintaining gas heat for use on cold days for reliability and safety reasons and to minimize electric system impacts. Focus building electrification efforts for all customer segments on converting existing customers with furnaces to hybrid heating systems (standard ASHP paired* *with gas furnaces). Boiler-based heating systems are not an initial focus because it is less economic to convert boiler-based systems, but boiler customers will not be excluded from programs. More specifically, design programs with the following focus:*

- **Residential**: Convert customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnace) at equipment end-of-life (heating or air conditioning system) at a pace that ramps up at 5.4%/year until it reaches a peak of 75% of customers with equipment failures converting/year in 2040 through 2043.
- **Commercial**: Convert customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnace) at equipment end-of-life (heating or air conditioning system) at a pace that ramps up at 2.1%/year until it reaches a peak of 30% of customers with equipment failures converting/year in 2040 through 2043.
- **Municipal**: Convert customers with furnaces to hybrid heating systems (standard ASHP with gas furnace) at heating equipment end-of-life at a pace that ramps up at 3.6%/year until it reaches a peak of 50% of customers with equipment failures converting/year in 2040 through 2043.

Reasoning:

Because electrification has a relatively high cost per GHG emissions reduction overall, the Companies' LTP assumes that electrification programs prioritize conversions that have a relatively low cost per GHG emissions reduction, which is the installation of hybrid heating systems (standard ASHP paired with gas furnaces) for existing customers with gas furnaces. Focusing on hybrid heating has a secondary, but important, benefit of providing a gas backup for the coldest days of the year, preserving reliability of heat and maintaining greater comfort compared to full electrification. There are reliability, energy resilience, and public safety concerns associated with reliance on full electrification for residential customers, especially during cold winter periods that are experienced in the Companies' service territories. In addition, full electrification with ccASHP will place additional strain on the local and regional electric system and add significantly to customer energy bills, as more electric system build-out will be required to meet heating demand on cold days. While full electrification with GSHPs would result in less electrical load requirements than full electrification with ccASHPs, the high up-front installation costs and land requirements of GSHPs are notable barriers. NYSEG and RG&E's NYS Clean Heat database indicates an average installed cost for a 4-ton GSHP system of $51,118 per home, which is more than double the average installed cost of a 4-ton ccASHP and more than eight times the cost of a standard 3-ton ASHP. The Companies' LTP will initially focus on electrifying newer homes that currently heat with furnaces (which represent almost 60% of the Companies' residential customers) because homes with boilers are more expensive to convert. Although there are cost and market challenges, no customer will be prevented from fully electrifying and the Companies' electrification programs will not exclude customers who choose to fully electrify or customers currently heating with gas boilers or any other existing gas customers. In addition, the Companies' electrification and weatherization programs will work together accommodate customers who would benefit from and want to weatherize prior to electrification but will not exclude customers who may not want to or cannot weatherize. These customer service focused program design elements that demonstrate flexibility are consistent with the Guiding Principle that values customer choice. The Companies' LTP is simply acknowledging that, at least in the short term, converting existing gas furnaces to hybrid heating systems is the most cost-effective and favorable option for reducing GHG emissions through electrification.

There is considerable uncertainty regarding the rate at which customers will choose to electrify, in large part due to the high up-front cost, and lack of awareness of electrification options by both customers and contractors. While conversion rates are modest today, it is expected that with greater awareness and greater incentives, conversion rates will increase in the future. For purposes of the LTP, the Companies assume that programs start to demonstrate savings in 2027 with conversion rates increasing linearly until they reach a peak in 2040 and remain flat for the final years of the analysis. Residential conversions are assumed to reach a peak of 75% of customers with heating or central AC equipment failures converting, while commercial and municipal conversions are expected to reach a peak of 30% and 50%, respectively. Residential customers are assumed to reach a peak of 75% because it is assumed that 100% participation will not be achievable without a mandate. Commercial customers are assumed to achieve lower conversion rates than municipal customers because they face significant competitive pressures whereas some municipalities that favor electrification may choose to lead by example.

3. *Industrial Customer Programs*

Overall Approach: *Design and implement three programs to address industrial customer emissions related to burning gas. Design energy efficiency programs for industrial process load (to start in 2027) and carbon capture (to start in 2028) to achieve forecasted participation rates and GHG emissions reductions. Focus heating electrification efforts starting in 2027 on converting existing customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnaces). Boiler-based heating systems are not an initial focus because it is less economic to convert boiler-based systems. More specifically:*

- **Energy Efficiency of Process Load**: 0.5% incremental process load reduction/year starting in 2027 achieving 8.5% process load reduction by Year 20.
- **Electrification of Heating Load:** Convert customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnace) at heating equipment end-of-life starting in 2027 at a pace that ramps up at 2.1%/year until it reaches a peak of 30% of customers with equipment failures converting/year in 2040 through 2043.
- **Carbon Capture for Large Customers**: 0.5% carbon capture/year starting in 2028 achieving 8% carbon capture by Year 20.

Reasoning:

Industrial customers are extremely cost-sensitive for competitive, cash flow, and financing (access and cost) reasons. Industrial businesses typically require paybacks of 1-3 years and many corporations have options to move production to existing plants in other states or to another country in the mid- to long-term. However, certain industrial customers that are part of larger entities with corporate sustainability goals may be more likely to invest in decarbonization. Under all circumstances, the cost and effectiveness of projects to reduce emissions for industrial customers are dependent on the nature of the business and site-specific factors. The Companies' LTP focuses on process load energy efficiency and carbon capture because these two actions are the most cost-efficient methods of reducing GHG emissions for industrial customers. As with the residential and commercial sectors, the LTP focuses on converting customers with furnaces to hybrid heating systems rather than on converting boilers.

The Companies have identified engagement with industrial customers to assess their individual circumstances as an implementation action item in order to gain greater understanding of the potential to reduce GHG emissions from this sector. This process will involve meeting with industrial customers to gain further insights into their current and anticipated future operations. This will include the role of gas in industrial operation and the viability of decarbonization actions such as energy efficiency, electrification of heat, carbon capture, industrial heat pumps, and the direct use of RNG and hydrogen in their processes. It will also include gaining a better understanding of the importance of reliability and affordability of energy within their processes. The Companies intend to use these insights to inform future planning in areas such as participation rates and program offerings for industrial customers.

4. *UTENs*

Overall Approach: *Complete one utility thermal energy network project representing connection of 24 residential buildings and 8 non-residential buildings every other year starting in 2035.*

Reasoning:

As shown in Figure VI-1, UTENs have the highest cost per GHG emissions reduction of all decarbonization actions. For this reason, the Companies' LTP includes one UTEN every other year to acknowledge New York State's support for development of UTENs. UTENs are also considered to provide an opportunity to install clean energy projects in DACs, contributing to DAC decarbonization goals. In addition, UTENs provide an opportunity to retrain and employ members of an existing gas union workforce that may suffer job losses if large numbers of customers fully electrify. UTENs may also be eligible for IRA and other incentives. The Companies include UTENs in the LTP starting in 2035 to provide time for the existing proposed UTEN pilot projects to be built and have opportunities to incorporate lessons learned into future UTEN project design and regulatory constructs. The Companies will monitor the development prospects and cost of UTENs through pilot programs in New York and in other states, regions, and countries, with particular attention paid to similar climates.

5. *RNG*

Overall Approach: *Design programs to start in 2026 that will promote the development of RNG projects such that forecasted quantities of RNG from anaerobic digestion (i.e., excluding thermal gasification) can be achieved. Assume the Companies can each access the RNG produced in their service territories, plus 2% of the RNG produced in Pennsylvania and Ohio.*

Reasoning:

RNG has one of the lowest costs per GHG emissions reduction, can be easily scaled based on existing technology, and allows for meaningful decarbonization at reasonable costs without having to implement changes at individual customer premises. For this reason, the LTP includes optimistic, but realistic, quantities of RNG, given projected RNG resources in New York and neighboring states. Although RNG is more expensive than traditional natural gas, it has a significantly lower cost per GHG emissions reduction than electrification, as shown in Figure VI-1.

The ability to produce RNG is limited by availability of RNG feedstocks. The Companies' LTP relies on agricultural and landfill biogas feedstocks (anaerobic digestion) and excludes RNG potential associated with thermal gasification, as it is not as market-ready as anaerobic digestion-based RNG. The Companies' LTP assumes that NYSEG and RG&E will connect RNG within their respective service territories at levels that represents approximately 52% of the maximum potential RNG quantities. These levels start at modest amounts and increase over time. It is further assumed that New York RNG supplies will be supplemented by a relatively small percentage of RNG supplies from Pennsylvania and Ohio that are delivered using the Companies' upstream gas transportation contracts.

The Companies' distribution systems currently receive RNG from Lawnhurst Farms, Sprucehaven Farms, and El-Vi Farms. The Companies have executed agreements and are constructing interconnection facilities with two additional dairy farms on their systems: Lincoln Dairy and Marks Farms. Four additional RNG projects in the Companies' service territories are in various stages of development (three additional dairy farms and one landfill site). One significant challenge to further RNG development is the regulatory constraint that prevents LDCs from procuring RNG at a premium to traditional natural gas prices. With increased contractual flexibility, the Companies envision a large potential to inject RNG into their distribution systems resulting in significant GHG emissions reductions.

There is considerable support for RNG within New York and in other states. National Grid has been accepting RNG from the Fresh Kills landfill for decades and recently added RNG from the Newtown Creek project. The Commission recently confirmed the GHG emissions benefits of RNG in the NFG LTP Order stating, "the Commission has generally accepted RNG as a method of reducing emissions, as demonstrated in the Bluebird Order."[166] In addition, other jurisdictions have recognized the potential benefits of these no- and low- carbon fuels and have created policies that encourage gas utilities to pursue their development. For example, Minnesota passed the Natural Gas Innovation Act In 2021, which allows gas utilities to pursue and recover prudently incurred costs related to innovative resources aimed at reducing GHG emissions and meeting renewable energy goals, which include biogas, RNG, and power-to-hydrogen, among others.[167] Florida also passed legislation in 2021 that provides for the cost recovery of RNG procurement by a gas utility.[168] In addition, California and Oregon have renewable gas standards and Vermont has a clean heat standard that encourages the development of alternate fuels.

6. *Green Hydrogen*

Overall Approach: *Pursue green hydrogen blending starting at a level of 1.25% in 2028, increasing by 1.25%/year, and achieving a blend of 20% by volume in 2043.*

166 *NFG LTP Order, p. 29.*

167 *H.F. No. 164 June 2021 - Natural Gas Innovation Act, Article 8 Sec.20.*

168 *SB 896 approved June 29, 2021. Page 4. Chapter No. 2021-178.*

Reasoning:

Although hydrogen is more expensive than purchasing traditional natural gas, hydrogen has one of the lowest costs per emissions reduction of the decarbonization actions, and a significantly lower cost per GHG emissions reduction than electrification, so therefore it is included in the Companies' LTP. The LTP assumes 1.25% hydrogen blending by volume starting in 2028, increasing by 1.25%/year, and reaching a maximum of 20% by volume in 2043. The LTP's slow ramp rate will be accompanied by validation that increased blending levels can be accommodated by the gas system. A 20% blending of green hydrogen in the Companies' distribution systems is not assumed to be achieved until 2043 and hydrogen blending is not to begin until 2028. The Companies will continue to explore the role hydrogen can have in lowering GHG emissions in a safe and reliable manner.

Current technology and the current composition of U.S. gas distribution systems suggests that up to 20% hydrogen could be blended into natural gas systems. Specific engineering and safety studies are required to identify the amount of hydrogen that can safely be blended into the Companies' distribution systems without creating operational issues. However, because the Companies have completed the replacement of all cast iron mains and will soon replace the remaining wrought iron and bare steel gas mains, the Companies' distribution systems should be more adaptable to hydrogen blending. The 2022 IRA contains subsidies for clean hydrogen production, which are expected to facilitate additional hydrogen development. Further, there are several hydrogen blending projects that are successfully delivering hydrogen-enriched natural gas to customers throughout North America. For example, Hawaii Gas has been blending up to 15% hydrogen into its system for decades.[169] New Jersey Natural Gas has been blending hydrogen into its system since October 2021.[170] Enbridge Gas has been blending up to 2% hydrogen into its gas distribution system in Markham, Ontario for over a year.[171] In addition, National Grid has proposed a hydrogen blending project in its current rate case.[172]

In light of these positive results and the amount of public and private resources being dedicated to the pursuit of hydrogen as a decarbonization tool, it is premature to eliminate hydrogen blending as a viable, cost-effective decarbonization action. Introduction of hydrogen into the Companies' systems will be carried out using a technical and systematic approach that considers safety, O&M requirements, the impact of hydrogen's properties, material compatibility, system capacity analysis, end-user equipment, and other factors. As hydrogen research advances and demonstration projects are being undertaken globally, increased understanding and lessons learned will be incorporated into future LTPs.

A summary of the Companies' LTP, organized by each decarbonization action, is presented in Table VI-2. All decarbonization actions are assumed to start producing savings in 2027 unless otherwise noted.

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169 *"Hawaii Gas Issues Request for Proposals for Renewable Natural Gas and Renewable Hydrogen," Hawaii Gas, April 6, 2023.*

170 *"NJNG's Green Hydrogen Project," New Jersey Natural Gas.*

171 *"Enbridge Gas Announces the Launch of the First-of-its-Kind Hydrogen-Blending Project in North America," Cummins Newsroom, January 13, 2022.*

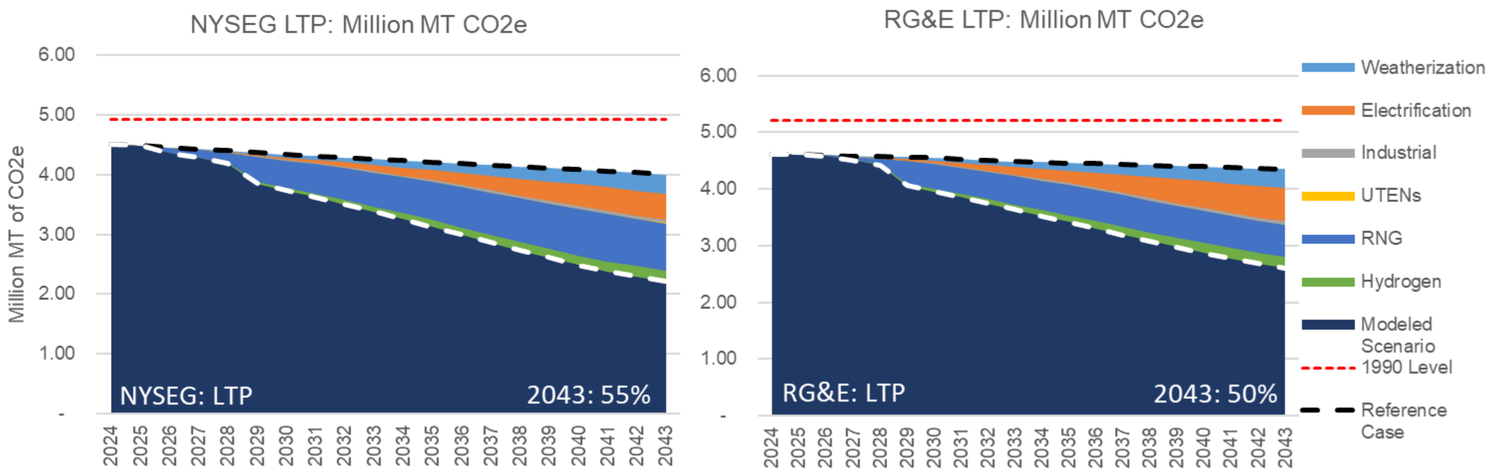
172 *Case 23-G-0225, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service, Rebuttal Testimony of Gas Infrastructure and Operations Panel, pp 33-37.*

Table VI-2: Specification of the Companies' LTP

	Action	Recommended LTP
1	**Weatherization**	• **Residential:** 1% of homes/year in 2027, incremental participation growing by 0.25%/year. • **Commercial:** 0.5% incremental heat load reduction/year • **Municipal:** 1% incremental heat load reduction/year
2	**Electrification**	• All segments convert customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnace) at equipment end-of-life • **Residential:** Pace ramps up at 5.4%/year until it reaches a peak of 75% **Commercial**: Pace ramps up at 2.1%/year until it reaches a peak of 30% **Municipal**: Pace ramps up at 3.6%/year until it reaches a peak of 50%
3	**Industrial Customer Programs**	• **Energy Efficiency of Process Load:** 0.5% process load reduction/year • **Electrify Space Heating**: Convert customers with furnaces to hybrid heating systems (standard ASHP paired with gas furnace) at equipment end-of-life at a pace that ramps up at 2.1%/year until it reaches a peak of 30% • **Carbon Capture:** (large customers) 0.5% carbon capture/year starting in year 2028 achieving 8% carbon capture by 2043
4	**UTENs**	• 2035 start, one project of 24 residential and 8 non-residential buildings every other year
5	**RNG**	• 2026 start, Optimistic Growth level of RNG in LDC territory. plus 2% of RNG in PA and OH
6	**Hydrogen**	• 2028 start, blend incremental 1.25%/year

Taken together, the decarbonization actions included in the Companies' LTP will make substantial contributions toward achieving New York's decarbonization goals. The LTP is projected to reduce emissions by 55% for NYSEG and 50% for RG&E by the end of the 20-year horizon (2043) compared to 1990 levels as shown in Figure VI-5 and Table VI-3. The emissions reductions start modestly and increase over time as constraints on deploying technology are resolved. Emissions reductions are expected to continue after 2043, through 2050 and beyond. Where necessary, the Companies will seek appropriate regulatory approval(s) for implementation of these initiatives. Based on the likely time necessary to obtain regulatory approvals and design and implement programs or projects, all decarbonization actions, except for RNG, are scheduled to start in 2027 or later.

Figure VI-5: LTP Contributions to GHG Emissions Reductions



It is too soon to definitively determine which technologies represent the most viable, cost-effective approaches over the long term, so it is important to embark on activities that have the potential to push the energy transition forward while maintaining customer optionality and balancing the cost and risk associated with prematurely selecting a single action. As a result, the Companies' LTP emphasizes the decarbonization actions that represent more cost-effective approaches to reducing GHG emissions and includes some level of all six decarbonization actions. The Companies will update the level of various decarbonization actions in future LTPs to reflect the evolution of decarbonization action costs, technology enhancements, and their relative efficiencies. For example, should the Companies determine through their UTEN pilot projects that UTENs become cost competitive with other decarbonization actions, the Companies could consider increasing the number of UTENs installed per year.

D. LTP Cost and Bill Impacts

The Guiding Principle associated with affordability requires careful consideration of total costs and bill impacts for non-participating customers. As demonstrated by the modeling, achieving meaningful GHG emissions reductions for NYSEG and RG&E will cost billions of dollars. The cost of the LTP is significantly affected by the decarbonization actions included (as discussed in the previous section) as well as the underlying costs. The LTP modeling must include valid projections of costs to inform subsequent utility proposals and Commission decisions. Therefore, the LTP must be based on the best cost information available, while recognizing that many aspects of decarbonization are uncertain. In that vein, the Companies chose to take different approaches to certain issues in their LTP modeling compared to the approaches identified in the CRA/Stakeholder scenarios on issues related to (1) heat pump cost and technology improvements, (2) strategic downsizing, and (3) pipeline and storage contract restructuring, each of which is discussed below.

- **Heat Pump Cost and Technology Improvements:** As noted above, the Companies have assumed in the LTP modeling that current heat pump costs remain flat in constant dollars and that heat pump technology remains at current levels, rather than adopting the CRA/Stakeholder scenario assumption that the cost of heat pumps declines at 1%/year and that heat pump technology (i.e., efficiency) improves at 3%/year through 2030 and

1%/year thereafter. The Companies' assumptions are consistent with information released by the U.S. Energy Information Administration ("EIA") in 2023, which shows little improvement in heat pump technology between 2023 and 2050 and flat to *increasing* installed costs in constant dollars.[173] The NREL study cited in the CRA/Stakeholder scenarios in support of the decreasing heat pump costs was based on data from 2017, and according to the study, the highest rate of technology improvement was to have already occurred. In addition, the NREL study specifically states:

> Where literature and expert opinion do not offer sufficient data, we develop our own ***speculative*** assumptions based on observed trends in equipment and appliance standards, research and development activity, and equipment evolutions. As a result, the cost and performance sensitivities developed under this effort ***do not represent predictions of the future costs and performance of technologies***, but rather alternative pathways of technology development that could occur with varying degrees of investment in R&D, technology breakthroughs, and other drivers of innovation. (emphasis added)[174]

Therefore, the Companies have not reflected in the LTP assumptions that heat pump costs and technology will improve each year over the next 20 years as assumed in CRA/Stakeholder scenarios. However, in response to stakeholder requests, the Companies have conducted a sensitivity that explores the impact of lower (and higher) heat pump costs on the LTP modeling results. Heat pump costs and technology improvements will be revisited in the next LTP.

- **Strategic Downsizing:** While the Companies reduce forecasted capital expenditures for the avoided replacement costs of meters and services for customers who fully electrify in the modeling, and the LTP modeling reflects significant reductions in gas consumption, the Companies do not assume that the decline in consumption affects distribution mains-related capital expenditures or O&M expenses (i.e., the Companies' scenarios and the LTP do not assume "strategic downsizing" of the gas distribution network). In contrast, most of the CRA/Stakeholder scenarios assume strategic downsizing of the gas system and corresponding reductions in capital expenditures, O&M expenses, pipeline mileage, and GHG emissions associated with gas distribution mains.

  There are fundamental questions regarding strategic downsizing of the gas distribution system that must be resolved before assuming reduced capital and O&M costs in the LTP modeling. First is whether the gas distribution system will be needed to support hybrid heating. With hybrid heating, the gas distribution system provides critical reliability and resilience value during the winter season and on the coldest days of the year. The gas distribution system also provides a hedge against the timing and cost of building the electric generation, transmission, and distribution infrastructure necessary to enable simultaneous electrification of transportation and building heating. The LTP promotes hybrid heating, which requires the use of the gas

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173 *EIA Updated Buildings Sector Appliance and Equipment Costs and Efficiencies, Appendix A and B, Residential Air-Source Heat Pumps, "EIA – Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case (and Advanced Case)," prepared by Guidehouse and Leidos (March 3, 2023).*

174 *Jadun, Paige, Colin McMillan, Daniel Steinberg, Matteo Muratori, Laura Vimmerstedt, and Trieu Mai, Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050 (2017). Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-70485, p. 37.*

distribution system on the coldest days of the year; therefore, the LTP does not assume capital expenditures and O&M costs are reduced over time related to strategic downsizing.

The second fundamental question relates to how strategic downsizing might be accomplished. While the Companies are actively looking for opportunities to strategically downsize the system, these projects are rare. For any segment to be eliminated without compromising safety or reliability two conditions must be satisfied: (1) 100% of the existing gas loads on that segment must be electrified; and (2) the targeted segment must not be relied on to deliver gas to customers downstream (i.e., it must be a "dead-end" of the system). Are policy makers willing to eliminate customer choice and mandate the conversion of specific existing buildings to accomplish strategic downsizing and if so, will the public accept this policy? Given that one of the Companies' Guiding Principles relates to preserving customer choice, the LTP does not assume that specific customers are required to electrify to effectuate strategic downsizing, and therefore the LTP and the Companies' scenarios do not assume capital and O&M cost reductions per year as a "proxy for downsizing" (other than costs associated with avoiding meter and service replacements for fully electrifying customers).

- **Pipeline and Storage Contract Restructuring:** In response to stakeholder feedback and consistent with concepts included in the CRA/Stakeholder scenarios, the Companies have reduced fixed pipeline and storage costs in the LTP forecast period to reflect the potential for contract restructuring as design day demand decreases. In reality, pipeline and storage contract restructuring will not likely occur at a steady rate that matches the decline in design day demand. Instead, the Companies will update their respective portfolios periodically as contracts approach their end-of-term dates (i.e., pipeline or storage contract restructuring will likely be "lumpy" as it will be subject to existing contract terms that include specific end dates and contract capacities). In addition, the amount of reduction in capacity will not match annual design day demand reductions, because the Companies' must be sure that design day demand reductions are sustained and permanent before capacity is reduced. Contract restructuring must also consider the dispersed nature of the Companies' customer base and contract capacity reductions must match the distinct locations where design day demand reductions have occurred. However, for purposes of this LTP, the LTP modeling simplifies contract restructuring to tie fixed pipeline and storage cost reductions to design day demand reductions that are sustained throughout the prior three-years. Specifically, in 2029 and each following year, the maximum design day demand over the prior three-year period is compared to 2024 design day demand and that percentage reduction is applied to the Companies' current fixed pipeline and storage costs. As a result, 2043 fixed pipeline and storage costs are reduced by 20% in NYSEG's LTP and 15% in RG&E's LTP. The approach of incorporating a fixed percent decrease in pipeline and storage costs year over year (e.g., 3%/year) used in the CRA/Stakeholder scenarios is less realistic as it is not tied to changes in design day demand, and in some cases fixed pipeline and storage costs in the CRA/Stakeholder scenarios are reduced faster than the decline in design day demand, which is illogical. Therefore, the Companies' approach of having pipeline and storage cost reductions be dependent upon experienced design day demand declines and incorporating a delay to ensure declines are sustained before costs are reduced is more appropriate.

Table VI-3 details the relative cost efficiency, 2043 GHG emissions reduction, and total cost (NPV of gas revenue requirements impact plus NPV of Decarbonization Policy Costs) for each decarbonization action in the Companies' LTP. The total incremental costs associated with the LTP are estimated to be approximately $2.5 billion for NYSEG and $2.4 billion for RG&E on a net present value basis over the next 20 years. The weighted average cost per GHG emissions reduction is estimated to be $330 for NYSEG's LTP and $350 for RG&E's LTP.

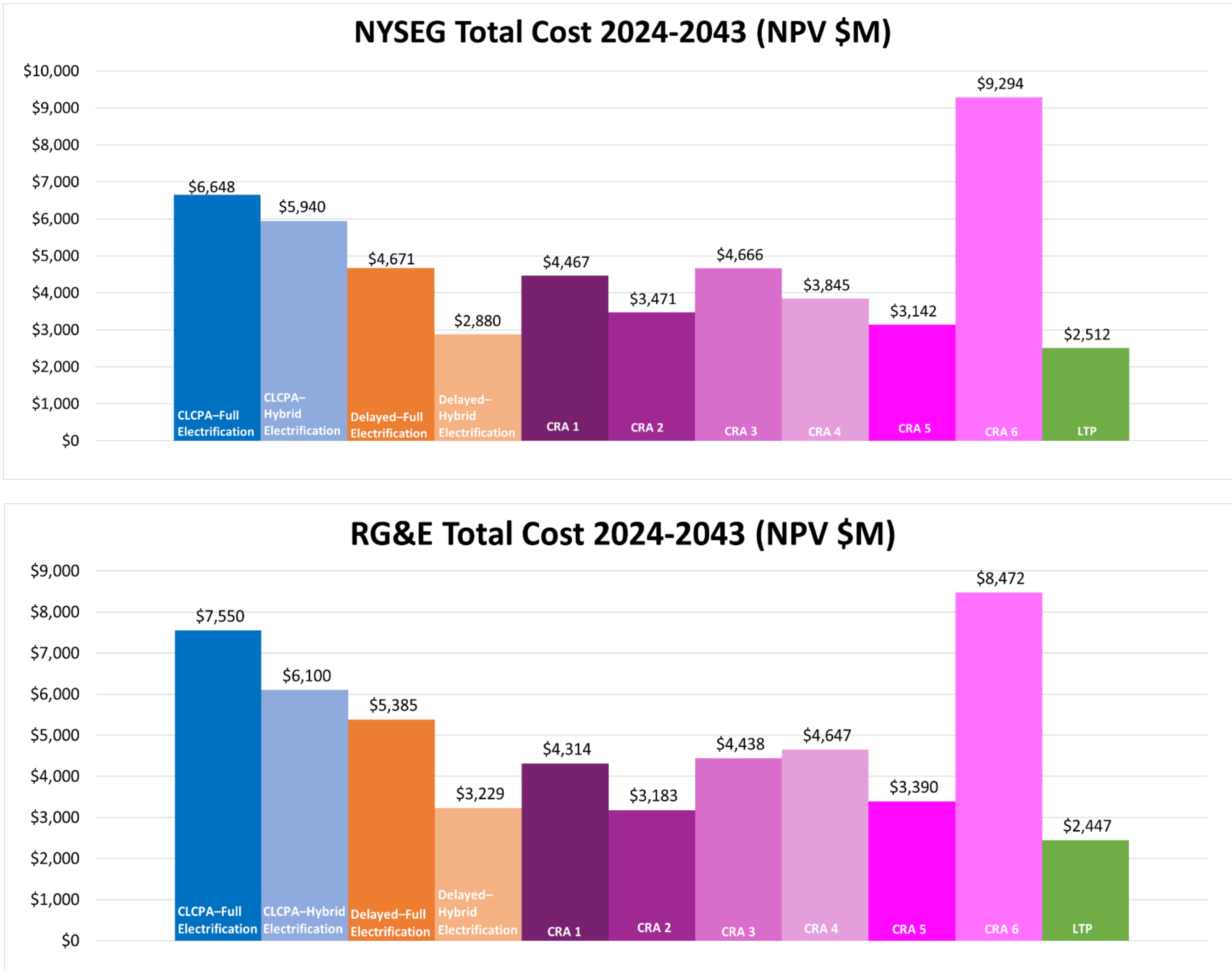
Table VI-3 LTP Decarbonization Actions and GHG Emission Reduction Efficiency

	NYSEG LTP			RG&E LTP		
	$/MT CO2e	2043 CO2e (000s MT)	Total Cost NPV ($M)	$/MT CO2e	2043 CO2e (000s MT)	Total Cost NPV ($M)
Reference Case	n/a	4,007	n/a	n/a	4,349	n/a
Weatherization						
Residential	$33	(199)	$18	$118	(248)	$76
Commercial	$485	(68)	$121	$538	(66)	$126
Municipal	$485	(53)	$94	$538	(25)	$48
Electrification						
Residential	$859	(358)	$830	$713	(497)	$933
Commercial	$822	(53)	$140	$560	(63)	$112
Municipal	$822	(32)	$86	$572	(20)	$35
Industrial						
Process Energy Efficiency	$243	(33)	$34	$291	(39)	$45
Space Heating Electrification	$652	(3)	$4	$513	(3)	$3
Carbon Capture	$404	(18)	$25	$489	(18)	$29
Utility Thermal Energy Networks	$ 8,040	(4)	$48	$9,397	(4)	$55
RNG						
RNG (within Service Territory)	$212	(605)	$695	$216	(370)	$493
RNG (outside NY)	$231	(190)	$278	$263	(194)	$319
Hydrogen Enriched Natural Gas	$193	(182)	$139	$235	(195)	$174
Scenario Total	$330	2,210		$350	2,608	
Change from Ref Case	n/a	(1,797)	$2,512	n/a	(1,741)	$2,447
% Change from 1990 Level		-55%			-50%	

The Companies' LTP performs well regarding GHG emissions reductions, reliability, resiliency, and affordability compared to alternatives. Major cost efficiency gains are achieved by focusing the LTP on decarbonization actions that are more cost-effective per GHG emissions reduction, including maximizing weatherization, RNG, and hydrogen, and strategically applying approaches to building electrification, including focusing on hybrid heating. The reliability and resilience of heat is likely to be substantially higher for the LTP due to using hybrid heating that has natural gas furnace backup rather than relying on electricity for heat every day of the year.

As illustrated in Figure VI-6, LTP costs are projected to be lower than all other scenarios. The Companies' CLCPA Scenarios are more than double the cost of the LTP and the CRA/Stakeholder CLCPA scenario (CRA6), is more than triple the cost of the LTP.

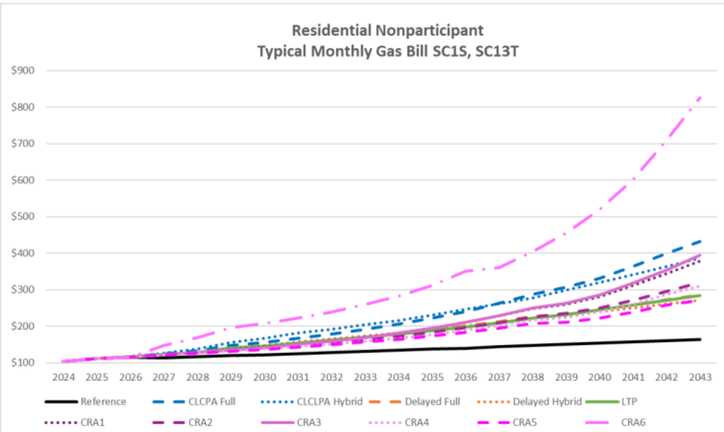
Figure VI-6: Total NPV Cost for Scenarios and LTP

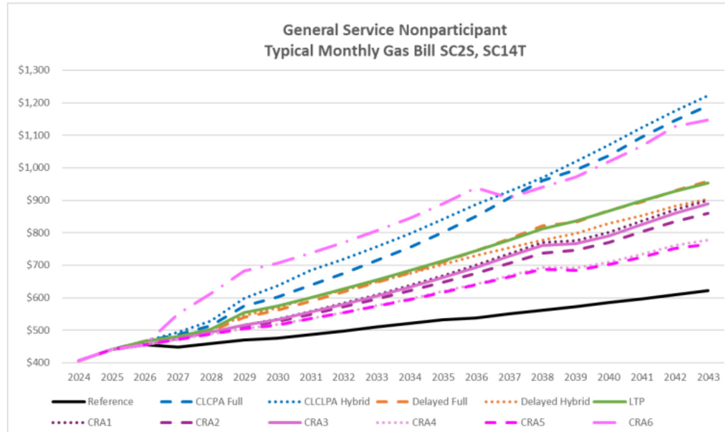


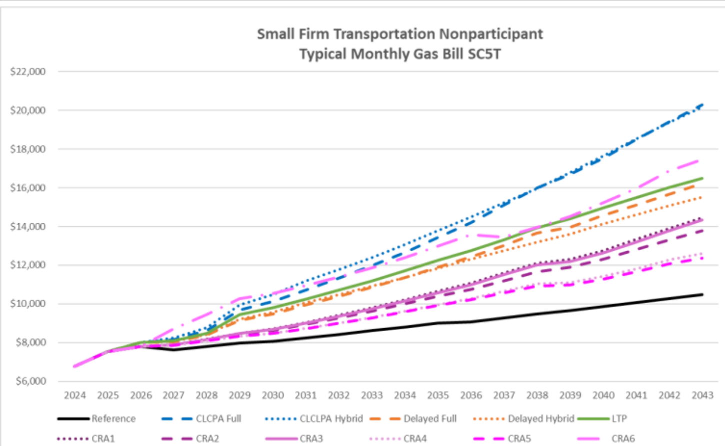
Gas bills for non-participating customers (i.e., customers whose gas usage remains the same because they do not choose to weatherize or electrify) will also increase as a result of decarbonization. These increases are due to (1) higher revenue requirements associated with building out UTENs (capital and operating expenses) and utility incentive programs, (2) recovering existing fixed costs over lower throughput, and (3) higher gas costs associated with RNG and hydrogen blending for the relevant scenarios. As shown in Figure VI-7, the LTP and scenarios show varying levels of bill impacts by service class for non-participating customers, for residential and non-residential customers as requested by stakeholders. Gas rate impacts are estimated based on existing cost recovery ratemaking principles and existing allocations of revenue requirement, and they assume that the Companies will recover an authorized return on invested capital and a return of investment based on NYSEG and RG&E's existing depreciation methodologies from the Rate Case JP. Changes to cost recovery and rate design issues are better addressed in the context of a rate case.

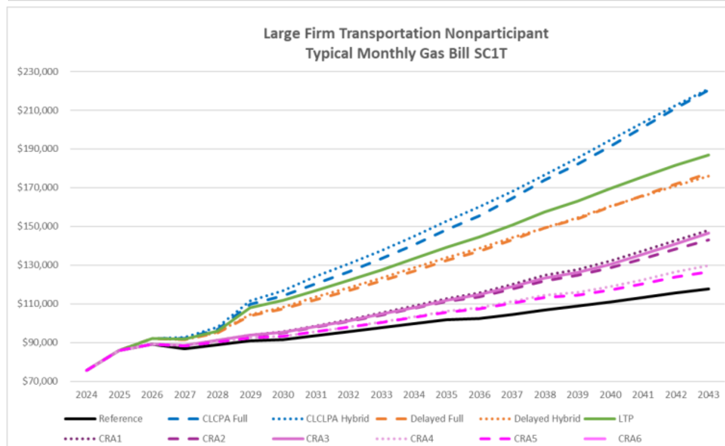
Figure VI-7: Bill Impacts for Scenarios and LTP

NYSEG

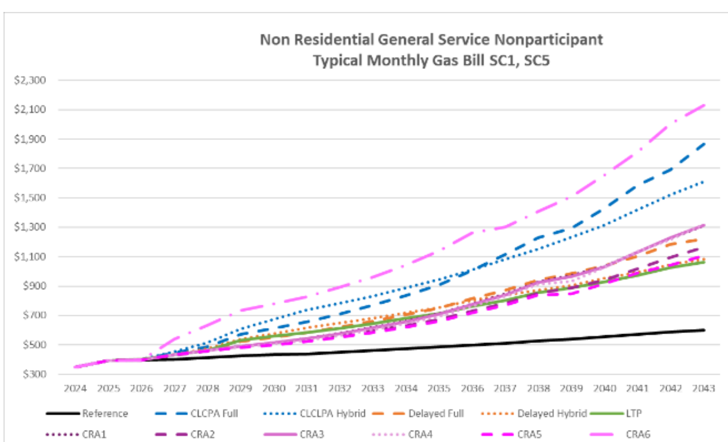


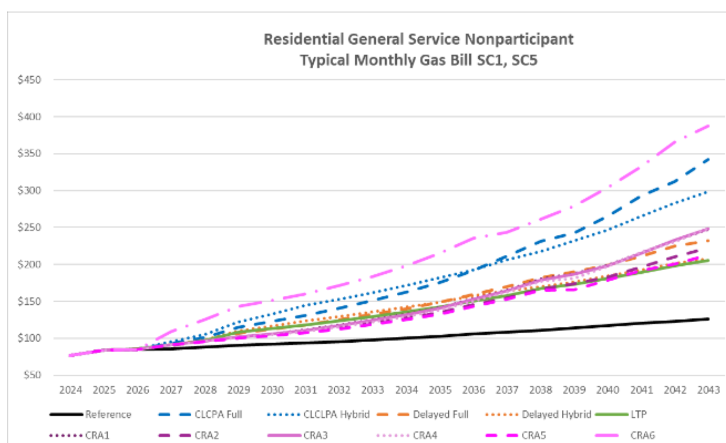


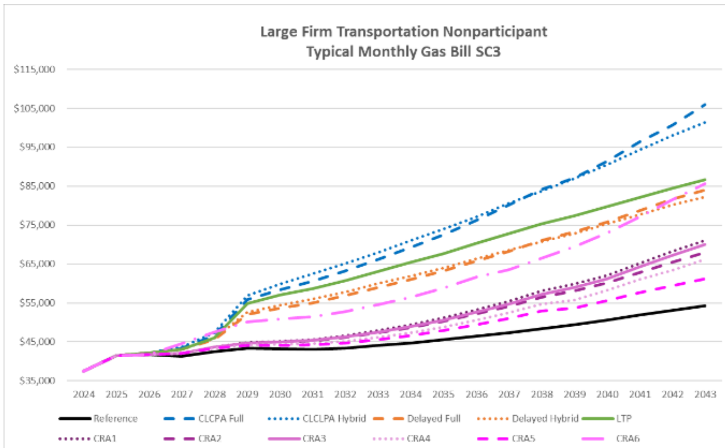




RG&E







E. Benefit-Cost Analysis

While customers are focused on the impact of decarbonization on their individual financial situations (e.g., up-front costs, impacts on gas and electric bills), the Gas Planning Order also requires gas utilities to include a BCA in their long-term plan filings. The Commission's BCA Framework Order[175] designated the Societal Cost Test ("SCT") as the primary BCA method. Stakeholders requested that the Companies also perform the Utility Cost Test ("UCT") and Ratepayer Impact Measure ("RIM"). The SCT is the broadest measure and attempts to quantify all the benefits and costs with the goal of determining whether society is better off as a whole as a result of implementing the plan. The SCT includes measures of direct costs and benefits (e.g., capital costs, customer installation costs, avoided gas costs, incremental electric costs) as well as broader indirect costs and benefits (e.g., avoided cost of GHG emissions). The UCT focuses on how gas utility costs will be affected by the plan and only includes costs that flow through the gas utility. The UCT excludes avoided costs of GHG emissions, customer installation costs, electricity costs, and federal and state incentives. The UCT could have a higher or lower result than the SCT, depending on the relative size of the cost and benefit items that are excluded. The RIM focuses on how gas utility rates will be affected by the plan. The RIM is similar to the UCT, but the RIM includes the impacts of lost gas utility revenues on remaining customers. Since the RIM is the same as the UCT with added costs, the RIM will always result in a lower Benefit Cost Ratio result than the UCT.

The Companies concur with the Commission's desire to focus on the SCT in LDC long-term plans because the SCT attempts to capture all costs to society. Given that implementing plans to significantly reduce GHG emissions for gas utility operations will likely involve some level of electrification, it is important to consider the impact of increased electricity costs as well as full up-front installation costs when conducting a BCA. Both of these costs (as well as the value of GHG emissions impacts) are eliminated from the UCT and RIM, which demonstrates the limited value associated with those test results compared to the SCT.

Nevertheless, to respond to Stakeholder requests, all three BCA tests (SCT, UCT, and RIM) were performed for the Companies' LTP by comparing the NPV of each LTP's relevant incremental benefits and costs relative to the Reference Case over the 20-year planning horizon. The Benefit Cost Ratio must exceed 1.0 to "pass." The LTPs

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[175] *Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, issued January 21, 2016.*

do not pass the SCT test with a Benefit Cost Ratio of 0.42 for NYSEG and 0.38 for RG&E, and UCT and RIM results for the LTPs are lower. Assumptions used in the BCA are described in Appendix C. SCT, UCT, and RIM results for the Companies' LTP are shown in Table VI-4. SCT, UCT, and RIM results for all scenarios are provided in Appendix D.

Table VI-4: BCA Results

Benefit Cost Analysis – NPV ($) (Discount Rate 6.58%)	NYSEG LTP SCT	NYSEG LTP UCT	NYSEG LTP RIM
Benefit: Avoided Gas Costs ($)	$(580,325)	$(580,325)	$(580,325)
Benefit: Avoided Gas System O&M and CapEx Rev Req ($)	$(7)	$(7)	$(7)
Benefit: Avoided Pipeline and Storage Fixed Costs ($)	$(28,030)	$ (28,030)	$(28,030)
Benefit: Avoided Emissions, Societal Cost ($)	$(717,263)	N/A	N/A
Total Benefit ($)	$(1,325,625)	$(608,362)	$(608,362)
Cost: Incremental Electricity Cost ($)	$791,357	N/A	N/A
Cost: Weatherization Cost ($)	$349,269	$252,771	$252,771
Cost: Weatherization Cost- Federal & State Incentive	$53,914	N/A	N/A
Cost: Weatherization Cost ($) – Utility Incentive	$252,771	$252,771	$252,771
Cost: Weatherization Cost ($) – Participant Customer	$42,584	N/A	N/A
Cost: Net Installed Cost ($)	$457,037	$166,516	$166,516
Cost: Net Installed Cost- Federal & State Incentive	$246,461	N/A	N/A
Cost: Net Installed Cost ($) -Utility Incentive	$166,516	$166,516	$166,516
Cost: Net Installed Cost ($) – Participant Customer	$44,060	N/A	N/A
Cost: UTENs Revenue Requirement ($)	$46,403	$46,403	$46,403
Cost: Hydrogen Cost ($)	$206,051	$206,051	$206,051
Cost: RNG Production Cost ($)	$1,269,864	$1,269,864	$1,269,864
Cost: Lost Utility Revenue- Base Distribution	N/A	N/A	$181,616
Cost: Lost Utility Revenue- Pipeline and Storage Fixed Costs	N/A	N/A	$44,704
Cost: Increased Emissions, Societal Cost ($)	$ 2,494	N/A	N/A
Total Cost ($)	$3,122,474	$1,941,605	$2,167,925
Benefit/Cost Ratio	0.42	0.31	0.28

Benefit Cost Analysis – NPV ($) (Discount Rate 6.80%)	RG&E LTP SCT	RG&E LTP UCT	RG&E LTP RIM
Benefit: Avoided Gas Costs ($)	$(352,378)	$(352,378)	$(352,378)
Benefit: Avoided Gas System O&M and CapEx Rev Req ($)	$ (4)	$ (4)	$ (4)
Benefit: Avoided Pipeline and Storage Fixed Costs ($)	$(15,994)	$(15,994)	$(15,994)
Benefit: Avoided Emissions, Societal Cost ($)	$(705,732)	N/A	N/A
Total Benefit ($)	$(1,074,108)	$(368,376)	$(368,376)
Cost: Incremental Electricity Cost ($)	$789,011	N/A	N/A
Cost: Weatherization Cost ($)	$315,911	$233,201	$233,201
Cost: Weatherization Cost - Federal & State Incentive	$74,672	N/A	N/A
Cost: Weatherization Cost ($) – Utility Incentive	$233,201	$233,201	$233,201
Cost: Weatherization Cost ($) – Participant Customer	$8,038	N/A	N/A
Cost: Net Installed Cost ($)	$461,884	$168,473	$168,473
Cost: Net Installed Cost - Federal & State Incentive	$308,935	N/A	N/A
Cost: Net Installed Cost ($) -Utility Incentive	$168,473	$168,473	$168,473
Cost: Net Installed Cost ($) – Participant Customer	$(15,523)	N/A	N/A
Cost: UTENs Revenue Requirement ($)	$52,837	$52,837	$52,837
Cost: Hydrogen Cost ($)	$213,931	$213,931	$213,931
Cost: RNG Production Cost ($)	$981,727	$981,727	$981,727
Cost: Lost Utility Revenue - Base Distribution	N/A	N/A	$183,574
Cost: Lost Utility Revenue - Pipeline and Storage Fixed Costs	N/A	N/A	$42,239
Cost: Increased Emissions, Societal Cost ($)	$3,172	N/A	N/A
Total Cost ($)	$2,818,472	$1,650,168	$1,875,981
Benefit/Cost Ratio	0.38	0.22	0.20

The majority of the SCT benefits accrue from avoided emissions as well as avoided gas costs, while the majority of the SCT costs accrue from incremental electric costs, RNG production costs, and net installed costs (which is primarily comprised of the up-front costs associated with electrification).

The BCA Framework Order referenced in the Gas Planning Order was developed for the purposes of calculating BCAs for electric utilities. A corresponding BCA framework for gas utilities that addresses gas-specific issues, including treatment of RNG, has not been established. To respond to Stakeholder requests, the Companies will develop and include a gas BCA Handbook as an exhibit to their next LTP filing.

The Companies applied the electric BCA Framework Order when calculating the SCT but acknowledge that some items do not have clear guidelines, including the accounting of GHG emissions impacts associated with RNG. The Companies accounted for the GHG emissions impacts of RNG in the SCT using the same emissions factors and life-cycle accounting methodology used to account for the GHG emissions impacts of RNG in the LTP modeling for consistency. In addition, the Companies accounted for life-cycle emissions associated with out-of-state RNG production consistent with how they account for life-cycle emissions of natural gas production.

Up-front installation costs for weatherization and electrification are split into costs covered by federal and state incentives, costs covered by utility incentives, and costs not covered by incentives (i.e., covered by participant customers). Federal incentives are supported by all taxpayers, including New York State residents. In addition, "society" is not limited to the State of New York (e.g., the societal benefits associated with GHG emissions from avoided natural gas production located outside of New York are included in the SCT). Further, the Commission's longstanding policy as reflected in all utility BCA Handbooks, including NYSEG and RG&E's, advises inclusion of federal incentives as costs in the SCT (i.e., "the cost of market interventions (e.g., state and federal incentives)" are components of costs in the SCT).[176] Thus, the Companies include all incentives (including federal incentives) in the SCT as an offset participant customer costs. Federal incentives, state incentives, and participant customer costs do not flow through the gas utility, so these costs are eliminated in the UCT and RIM, but the costs associated with utility incentives remain.

There are several items in the SCT that were not included as they are difficult to quantify, including changes in reliability/resiliency, non-energy benefits, non-energy costs, and health benefits. In the BCA Framework Order, the Commission concludes that other societal non-energy benefits, such as public health benefits, are "speculative" and "would not be reasonable to include in the BCA Framework."[177] Therefore NYSEG and RG&E have not included the quantification of health benefits in the BCA. In addition, the increased electric costs included in the SCT include higher electric rates resulting from decarbonization for the end-uses related to converting gas equipment to electric, but increases in electric costs due to electric rates increasing for all customers for other electric use (e.g., to run existing electric equipment such as refrigerators or new EVs) were not quantified or included in the SCT.

The SCT results for both companies are <0.50 despite efforts to achieve GHG emissions reductions at a low cost. Given the high costs associated with most of the decarbonization actions, it is unlikely that most decarbonization actions would pass a SCT with a value greater than or equal to 1.0. Notwithstanding this outcome, the Companies believe that the combination of decarbonization actions included in this LTP represent a responsible plan to reduce GHG emissions, enhance the resilience of the energy supply system, and deliver safe, reliable, and affordable energy service while preserving customer choice.

F. Other Elements of the Companies' LTP

Other important elements of the Companies' LTP that were not included in the quantitative modeling include the approach to DACs and LMI customers and NPAs. Each is discussed in more detail below.

1. *DACs and LMI Customers*

While Disadvantaged Community may be a relatively new defined term, the notion of supporting populations of varying socio-economic characteristics is not. LMI programs have been supported on a statewide level for over twenty years. DACs are a newer concept that incorporates not only socio-economic indicators, but also environmental burdens, climate change risks, and health vulnerabilities. In support of this effort, Staff, DPS, and the Joint Utilities are currently collaborating on how to best report metrics related to DAC, including how to

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176 *For example, the most recent BCA Handbooks (Version 4.0) filed separately by National Grid, Con Edison, NYSEG/RG&E, and Central Hudson in June 2023 include "the cost of market interventions (e.g., state and federal incentives)" as costs for purposes of the SCT. See also Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework (issued Jan. 21, 2016), Appendix C.*

177 *Order Establishing the Benefit Cost Analysis Framework, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Proceeding"), Case 14-M-0101 (January 21, 2016) ("BCA Framework Order"), p. 22.*

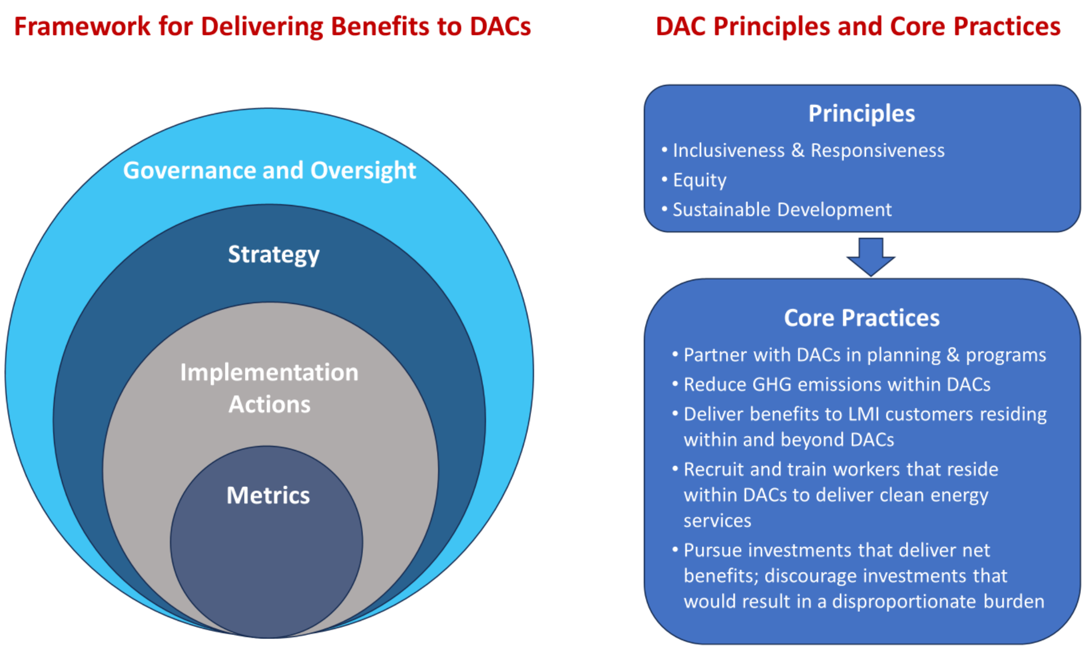
measure DAC benefits from energy program spending. The CLCPA established a statewide DAC spending requirement and there has not been guidance established to determine how this target could be allocated to the utility sectors, let alone NYSEG and RG&E specifically. The Commission addressed the obligations of LDCs as they relate to DACs in the Gas Planning Order:

> LDCs shall identify the disadvantaged communities in their service territories, explain the impacts to disadvantaged communities of any proposed projects, and explain how the LDC will ensure that an appropriate portion of the benefits of any proposed NPAs such as energy efficiency, demand response, and electrification accrue to disadvantaged communities.[178]

NYSEG and RG&E have filed multiple reports to support this effort and identify the number of DACs in their service areas as well as metrics such as DAC-related funding from 2020-2023 in Chapter II above. The Companies will continue to collaborate with DPS, the Joint Utilities, and other relevant agencies to support this effort.

As discussed previously, Avangrid is also in the process of developing an enterprise-wide Just Transition framework that will apply across the entire corporation, including utilities and other lines of business within and outside of New York. This framework is well-suited as an organizing framework for addressing the CLCPA's DAC requirements and the Companies' DAC/LMI aspirations.

Figure VI-8: Avangrid's Just Transition Framework



The framework will be applied to Avangrid's most important strategic initiatives with members of the leadership team assigned to serve in a governance and oversight role and oversee strategy development. A Steering

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178 *Gas Planning Order, p. 40.*

Committee will review and approve implementation actions, assuring that the initiatives are properly resourced and managed.

Pre-defined metrics provide accountability and identify challenges that require attention. The Companies have already committed to assessing how their operations affect DACs.[179] As part of the Rate Case JP, the Companies will file a report at the end of each "Rate Year" that provides participation, cost, and savings information related to energy efficiency and electrification programs, light-duty and heavy-duty electric vehicle charging facilities, participation and MW of demand response by customers located within DACs and LMI customers, and the number of projects and installed capacity for DER that interconnects to distribution facilities.[180] NYSEG and RG&E will track expenditures on investments that produce net benefits, energy efficiency programs, and other customer-facing clean energy programs. More work needs to be done to develop metrics that measure community engagement, environmental justice, and employment outcomes.

The three principles identified on the right-hand side of Figure VI-8 are corporate principles that apply to all businesses and all activities. Five "core practices" have been designed specifically to apply to delivering benefits to DACs that receive either natural gas or electric service (or both) from the Companies. Avangrid's purpose in developing the Just Transition is to deliver a more accessible clean energy model that promotes health sustainability through respectful engagement with communities (including DACs) and constituencies (including LMI customers). The goal is to achieve positive impacts that include economic development, community investments, employment opportunities, improvements in public safety, and creation of a clean energy future. This also includes avoiding investments that disproportionately burden disadvantaged communities.

NYSEG and RG&E are currently delivering GHG reduction and economic benefits to DACs and LMI customers through several policies and programs including:

- Energy efficiency and building electrification programs that deliver benefits to LMI customers.[181] These include the LMI Distributions program and the Retail Products LMI program, as well as other statewide initiatives such as the AMEEP multi-family program and the EmPower+ 1-4 family home program.
- Explicit consideration of DACs as part of the NPA process. As part of the Rate Case JP, the Companies have agreed to consider factors other than cost-effectiveness when evaluating potential NPAs that are located within a DAC, including income levels in the target area. In addition, respondents to NPA RFPs will be required to provide information on how their proposals will benefit customers within DACs.[182]
- Development of metrics to track performance related to DACs (i.e., to measure the extent to which clean energy program benefits are effectively directed to these communities).[183]

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179 *Case 22-E-0317, et. al., NYSEG RG&E Statement in Support of Joint Proposal, June 27, 2023, p. 22.*

180 *Joint Proposal, pp. 7-8.*

181 *The recently approved 2026-2030 Energy Efficiency and Building Electrification budgets are available to assist all eligible customers. The Commission did not separately earmark budgets for DACs or LMI customers, however the Companies will continue to estimate and report benefits to LMI customers and DACs.*

182 *Joint Proposal, Case 22-E-0317et. al., Appendix HH, p. 5.*

183 *This is reflected by an annual reporting requirement in the Joint Proposal to report on the impact of various programs in DACs, including clean energy spending, as well as reporting requirements in the EE/BE Order.*

- Procurement practices that result in 85% of vendor companies meeting sustainability standards based on a 43-factor ESG score.
- Continuation of the Residential Methane Detection Program that distributes devices to low-income customers to alert customers of the presence of methane in their homes, accompanied by safety outreach and education.

NYSEG and RG&E are currently focused on developing programmatic strategies that can be applied to its DACs. One of the highest priority items is a set of policies and practices that enable effective engagement and partnership with community leaders within DACs. Other priorities include:

- Supplemental programs designed to increase participation in existing LMI program offerings for customers that reside within DACs and for other LMI customers.
- Workforce development efforts to increase the proportion of company and contracted labor that resides in DAC communities.

Some of these programs may benefit from pilots to accelerate learning and the realization of positive impacts. These programs supplement clean energy programs that benefit all customers in all communities (i.e., system-wide programs).

While stakeholders have requested that the Companies quantify total LTP benefits to DACs and compare it to the total plan benefits, this is not feasible for this first iteration of the LTP process. Direct benefits to DACs will come from targeted capital investments, future UTENs projects, potential NPAs, energy efficiency and building electrification programs, etc. DACs will also benefit from system wide programs such as RNG and hydrogen blending. As discussed, the definition of DACs is very new, and Companies are actively collaborating with Staff and the other New York utilities to develop metrics to track performance related to DACs (i.e., to measure the extent to which program benefits are effectively directed to these communities), and therefore comprehensive data is not yet available.

2. NPAs

The Companies are committed to building a robust and diverse portfolio of NPA projects that will grow over time as new opportunities emerge to address traditional natural gas system needs through cost-effective and innovative NPA solutions. As discussed in Chapter II, the Companies have some experience pursuing NPAs to address vulnerable locations. However, this has been and continues to be a learning experience for the Companies and firms responding to NPA solicitations. The Companies are also gaining experience in what may be the most challenging step in the process: negotiating and finalizing contracts with winning bidders that provide a sufficient level of reliability at a final cost that is acceptable from the perspective of the Companies and their customers, the NPA provider, and by inference, the financial entity or entities that provide financial backing for the NPA provider.

The Companies are proactively considering strategic downsizing through employing NPAs in lieu of replacing leak-prone mains but note that it will be rare to find leak-prone main segments (1) that are not necessary to deliver gas to customers downstream of the segment, and (2) on which 100% of existing gas loads will electrify. However, Companies continue to evaluate all leak-prone main replacement projects for NPA suitability and have developed a comprehensive offer to encourage customers located in targeted leak prone main replacement areas to pursue whole-home electrification. To date, three customers have been electrified and 119 feet of distribution mains were decommissioned in Irondequoit, NY. An NPA is presumed to be the most economically viable when it can be used to offset a scheduled leak-prone pipe replacement project or new infrastructure project. While legislation prohibiting fossil fuels in new buildings has been enacted, mandating existing customer conversions to electricity in order to retire a segment of distribution pipe is likely to meet very strong opposition.

Due to the current limited nature of NPA solutions that allow for strategic system downsizing, it is premature to assume in the modeling that NPAs will significantly reduce the size of the distribution system. In the past two years, NYSEG/RG&E Gas System Planning evaluated 454 gas pipeline projects (442 LPM projects and 12 capital projects).

- 63 of the LPM projects passed initial screening and were sent to the Companies' NPA team for feasibility screening and 1 passed
    - Three RG&E customers have been electrified and 119-feet of LPM was decommissioned in Irondequoit, NY
- All 12 of the capital projects were sent to the Companies' NPA team for feasibility screening and 3 passed
    - NYSEG's Lansing NPA is being implemented
    - The RFP for NYSEG's Canandaigua project yielded no viable solutions from the market
    - RG&E's MF60 Southeast System NPA proposal is under review

In summary, over the past two years, while there have been 454 gas projects needed and screened for NPAs, only two have been successfully implemented, with the potential of a third, and only 119 feet of distribution main was decommissioned. As noted above, this is due to rarity of locations that allow for strategic downsizing. This notion is further supported by a recent study conducted in California which cites, an estimate of, "approximately 5-10% of gas distribution main miles may be eligible for capturing savings from strategic decommissioning over the next two decades." [184] Nonetheless, it is critical to test the presumption that strategic downsizing through NPAs is realistic and scalable, therefore, the Companies will continue to look for potential suitable NPAs that meet criteria that could result in targeted retirements of distribution system segments.[185] The Companies recognize that the Commission continues to address the NPA process on a generic basis in Case 20-G-0131 and the Companies will comply with any directives coming from that proceeding.

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[184] *California Energy Commission, Docket 23-ERDD-02, Workshop on Analytical Results for Strategic Gas Infrastructure Decommissioning, p. 8.*

[185] *The Companies, as part of the Joint Proposal in Case 22-E-0317, have agreed to continue to evaluate future gas projects, including leak-prone main replacement projects, for the applicability of NPAs. Joint Proposal, Case 22-E-0317, Appendix M.*

G. Key Uncertainties and Sensitivity Analysis

The LTP represents a 20-year perspective on a challenging future that will be characterized by continued evolution of policies, economic and environmental trends, and technological innovation. As such, most of the LTP's key drivers are subject to some level of uncertainty, including:

- Customer acceptance of building heating modernization related to fuel sources, equipment technologies, and conservation;
- Regulatory actions related to the CLCPA legislation and emission reduction targets that may impact the gas distribution system over the next 20 years;
- Continued evolution of New York energy policy and Commission regulatory requirements (e.g., allowing the cost of RNG and hydrogen to be recovered by utilities, policies to mitigate up-front cost barriers associated with installing equipment at customer premises to enable decarbonization);
- Technology advancement including the viability, scalability, and cost of several different technologies related to heat pumps, RNG, hydrogen, UTENs, and carbon capture and storage;
- Future all-in delivered cost of gas and electricity as well as changes to cost recovery and rate design that may influence customer decisions; and
- Market conditions including workforce training and availability, supply-chain issues, inflationary pressures, investor initiatives, and global energy instability.

The three-year LTP cycle prescribed in the Gas Planning Order provides for future comprehensive updates that reflect new information related to these uncertainties.

The impact of the uncertainty associated with certain input assumptions can be better understood by conducting a sensitivity analysis. As requested by stakeholders, the Companies quantified the impact of gas commodity prices, all-in electric prices, and heat pump costs through a sensitivity analysis. The sensitivity analysis was performed by increasing and decreasing one assumption at a time while keeping all other assumptions the same as in the LTP to isolate the impact of the one input assumption. Results are summarized below.

Table VI-5: Results of Sensitivity Analysis

	Cost per GHG Emission Reduction ($/MT CO2e)	2043 GHG Reduction (% vs. 1990)	Total Cost 2024-2043 (NPV $M)
NYSEG - LTP	**$ 330**	**-55%**	**$ 2,512**
Increase Gas Commodity Prices +10%	$ 322	-55%	$ 2,454
Decrease Gas Commodity Prices -10%	$ 337	-55%	$ 2,570
Increase Electricity Price +20%	$ 350	-55%	$ 2,670
Decrease Electricity Price -20%	$ 309	-55%	$ 2,353
Increase Heat Pump Costs +1%/year + Inflation	$ 338	-55%	$ 2,573
Decrease Heat Pump Costs -1%/year	$ 310	-55%	$ 2,361
RG&E - LTP	**$ 350**	**-50%**	**$ 2,447**
Increase Gas Commodity Prices +10%	$ 345	-50%	$ 2,412
Decrease Gas Commodity Prices -10%	$ 355	-50%	$ 2,482
Increase Electricity Price +20%	$ 372	-50%	$ 2,605
Decrease Electricity Price -20%	$ 327	-50%	$ 2,289
Increase Heat Pump Costs +1%/year + Inflation	$ 358	-50%	$ 2,501
Decrease Heat Pump Costs -1%/year	$ 331	-50%	$ 2,316

The Companies' sensitivity analysis demonstrates that +/- 10% changes in gas commodity prices impact the total cost and cost per GHG emissions reduction of the LTP by -/+ 2.3% for NYSEG and -/+ 1.4% for RG&E. Since this is only a cost change, the GHG emissions reductions are not affected. The impact is inverse (i.e., an increase in gas commodity prices decreases the total cost of the LTP) because reductions in gas costs are a benefit of the LTP. Higher gas prices produce higher benefits from reducing gas costs, which produces lower total costs.

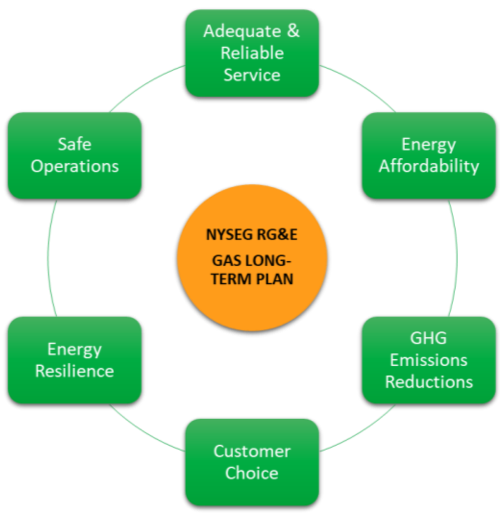
The Companies' sensitivity analysis demonstrates that a +/- 20% change in electricity prices impacts the total cost and cost per GHG emission reduction of the LTP by +/- 6.3% for NYSEG and +/- 6.5% RG&E, and again GHG emissions are not affected. Electric prices have a direct relationship to LTP total costs, so as electric prices increase, LTP total costs increase.

The Companies' also modeled the impacts of increasing heat pump costs by +1%/year plus inflation (similar to the Companies' scenarios and LTP) and decreasing heat pump costs by -1%/year (consistent with the CRA/Stakeholder scenarios). Increasing heat pump costs by +1%/year plus inflation increased total costs of the LTP by +2.4% for NYSEG and +2.2% for RG&E. Decreasing heat pump costs by -1%/year decreased total costs of the LTP by -6.0% for NYSEG and -5.4% for RG&E. Because the heat pump costs sensitivities are not symmetrical, the impacts are not symmetrical.

H. Consistency with the Guiding Principles

The final step in the development of the Companies' LTP is to validate compliance with the overall set of Guiding Principles and with each principle. This assessment is presented in Figure VI-9.

Figure VI-9: Compliance with Guiding Principles



GUIDING PRINCIPLES	LONG-TERM PLAN
Safe Operations: Meet or exceed all applicable safety regulations, policies, and procedures to assure safe operations of the gas network.	• LTP continues to prioritize safe operations.
Adequate & Reliable Service: Maintain adequate and reliable delivery and energy supply service to all customers throughout the year, including on the coldest days.	• LTP maintains adequate and reliable service because customers electrify with hybrid heating.
Energy Affordability: Plan and operate the network, acquire energy supplies, and pursue environmental objectives as efficiently as possible to maintain affordability, with particular attention to the needs of LMI customers and DACs.	• LTP materially increases typical gas bills and imposes significant costs that will need to be addressed by policy makers. However, it reflects substantial efficiencies by tailoring decarbonization actions, thus achieving material GHG emissions more efficiently than other scenarios modeled.
GHG Emissions Reductions: Propose, design, and execute climate actions to achieve responsible, meaningful, and sustained GHG emissions reductions.	
Customer Choice: Preserve customer choice regarding customer-sited energy investments and energy usage, consistent with legislative and regulatory mandates.	• LTP allows customers to make energy choices that are appropriate for their circumstances.
Energy Resilience: Promote energy system resilience by anticipating threats posed by climate change and avoiding or minimizing the impact and duration of major energy outages.	• LTP maintains the critical role of the natural gas system to provide heat on the coldest days of the year.

Despite the efforts to tailor decarbonization actions to achieve GHG emissions reductions cost-efficiently, there is concern that the costs to achieve the reductions will be unacceptably high as rates are reviewed and as policy makers address the recovery of Decarbonization Policy Costs. These concerns are consistent with the results of the BCA that do not pass the SCT (and do not pass the UCT or RIM).

VII.

Conclusions and Implementation Actions

VII. Conclusions and Implementation Actions

The Companies believe that the LTP represents a responsible plan based on reasonable assumptions given the information available today. Ultimately, the Companies will learn more about development of all decarbonization action markets, technologies, and costs over time and will adjust assumptions accordingly in future LTPs, consistent with the intent of the Gas Planning Order. While the Companies' LTP necessarily incorporates a 20-year forecast of many data inputs and assumptions, the focus should be on whether the Companies' three-year action plan is reasonable given current facts and circumstances. The Companies will pursue numerous actions in the next three years to develop capabilities and implement actions related to its LTP that relate to energy efficiency and electrification programs, DACs and LMI customers, investments that contribute to LTP outcomes, and pilot programs that will provide insights that inform future LTPs.

On October 12, 2023, the Commission approved the Rate Case JP that incorporates several commitments that are aligned with the LTP. In addition, certain other issues that are directly applicable to the implementation of the LTP have either recently been decided or are currently being addressed in Commission proceedings. The Companies will comply with these directives, as well as directives that are included in the Commission order in this proceeding.

A. NYSEG and RG&E's LTP Implementation Actions

The Companies will pursue numerous activities that are designed to develop capabilities and implement the decarbonization actions included in its LTP. These include the following near term action items and commitments. The ultimate timing and execution of many of these actions will depend upon several factors, including the success and timelines of obtaining necessary regulatory approvals.

1. Weatherization

- Design gas customer weatherization programs to achieve forecasted GHG emissions reductions
- Study the impact of various levels of weatherization incentives on customer adoption rates and pace of adoption over time, better understand unique characteristics of LMI/DAC communities including split incentives re: landlords/tenants and building maintenance issues that affect weatherization, and consider the relationship between the Companies' gas customer-focused weatherization programs and NYSERDA's programs
- Propose gas customer weatherization programs and related cost recovery approaches, and obtain regulatory approval from Commission in time for 2027 implementation
- Implement gas customer weatherization programs in 2027, including relevant customer, contractor, and community outreach
    - Outreach will include educating customers on the value proposition of weatherization and promoting awareness of weatherization offerings

- Collect data about weatherization program participation, project scope, project costs, project gas usage reductions, incentives provided, DAC participation, etc. and use it to inform future LTP filings
- Provide updates on the implementation of the Companies' residential demand response pilot and lessons learned in future LTP filings and annual updates.

2. *Electrification*

- Design gas customer electrification programs to achieve forecasted GHG emissions reductions while supporting customer choice
- Study the impact of various levels of electrification incentives on customer adoption rates, and pace of conversion over time, better understand the unique characteristics of LMI/DAC communities including split incentives re: landlords/tenants and building maintenance issues that affect electrification, consider the relationship between the Companies' gas customer-focused electrification programs, electric utility programs, and NYSERDA's programs, and consider the relationship between weatherization programs and electrification programs
- Propose gas customer electrification programs and related cost recovery approaches, and obtain regulatory approval from Commission in time for 2027 implementation
- Implement gas customer electrification programs in 2027, including relevant customer, contractor, and community outreach
    - Outreach will include educating customers on the value proposition of electrification and promoting awareness of the range of electrification offerings
- Collect data about electrification program participation, project scope, project costs, project gas usage reductions, project electricity usage increases, incentives provided, DAC participation, etc. and use it to inform future LTP filings

3. *Industrial Customer Programs*

- Engage with industrial gas customers regarding current and future energy profiles, priorities related to energy use, importance of gas to their business, the interest in and potential for energy efficiency of process load, electrification of space heating, carbon capture, industrial heat pumps, and other clean energy solutions.
- Design industrial gas customer programs for process load energy efficiency and space heating electrification (potentially combined with weatherization and electrification program proposal) to achieve forecasted GHG emissions reductions while supporting customer choice
- Study impact of various levels of incentives on industrial customer adoption rates, and pace of participation over time

- Propose industrial gas customer energy efficiency and space heating electrification programs and related cost recovery approaches, and obtain regulatory approval from Commission in time for 2027 implementation (potentially combined with weatherization and electrification program proposal)
- Implement gas customer energy efficiency and space heating electrification programs in 2027, including relevant customer, contractor, and community outreach (potentially combined with weatherization and electrification program proposal)
- Collect data about industrial customer participation in energy efficiency and space heating electrification programs, project scope, project costs, project gas usage reductions, project electricity usage increases, incentives provided, DAC participation, etc. and use it to inform future LTP filings
- Conduct a study to better understand the potential for carbon capture for industrial customers within the Companies' service territories and use that data to inform future LTP filings
- Design industrial gas customer program to achieve forecasted GHG emissions reductions for carbon capture
- Propose an industrial carbon capture program and related cost recovery approach, and obtain regulatory approval from Commission in time for 2028 implementation
- Implement industrial carbon capture program starting in 2028

4. Utility Thermal Energy Networks

- Continue to work through the design and regulatory approval stages of the existing proposed UTEN pilot projects
    - Continue to update expected costs, monthly energy use profiles, customer acceptance information, etc.
- After regulatory approval is granted, construct UTEN pilot projects
- Collect and study actual cost data, monthly energy use profiles, customer acceptance information, incentives provided, etc. and use it to inform Future LTP filings

5. RNG

- Propose an RNG procurement program and related cost recovery approach, and obtain regulatory approval from Commission in time for 2026 implementation
- Collect data about RNG availability for all types of feed stocks, project scope, project costs, RNG potential, etc. and use it to inform future LTP filings
- Procure RNG for delivery to customers starting in 2026
- Work with industrial customers to better understand how/if direct use of RNG can play a role in decarbonizing their operations.

6. *Hydrogen*

- Continue to follow (and sponsor) hydrogen research being conducted by others to better understand the role hydrogen blending can have in lowering GHG emissions in a safe and reliable manner, gas distribution system impacts, customer equipment impacts, costs, timing, project development process, etc.
- Propose a hydrogen blending program and related cost recovery approach, and obtain regulatory approval from Commission in time for 2028 implementation
- Implement program to blend hydrogen for delivery to customers starting in 2028
- Collect data about hydrogen availability, project scope, project costs, potential, etc. and use it to inform future LTP filings
- Work with industrial customers to better understand how/if direct use of hydrogen can play a role in decarbonizing their operations.

7. *NPAs*

- Continue to screen all main-related capital projects (including LPM projects) for the applicability of NPAs and provide updates on NPA projects in quarterly reports and future LTP filings.
- Continue to consider factors such as the impacts on the rest of the distribution system of decommissioning the pipe segment, the number and type of load served by the segment of pipe, and the impact of additional load on the electric grid when developing NPA projects.
- Build a robust and diverse portfolio of NPA projects that will grow over time as new opportunities emerge to address traditional natural gas system needs through cost-effective and innovative NPA solutions.
- Continue to look for potential suitable NPAs that meet criteria that could result in a targeted retirement of a segment of the distribution system.
- Comply with any directives in the generic NPA process proceeding (20-G-0131).
- Consider factors other than cost-effectiveness when evaluating potential NPAs that are located within a DAC, including income levels in the target area.

8. *DACs*

- Continue to develop and implement an enterprise-wide "Just Transition" framework that will apply across the entire corporation, including utility and other lines of business within and outside of New York.
- Continue collaborating with the Commission and other New York utilities to develop processes to track performance and progress toward DAC requirements.
- Develop a set of policies and practices that enable effective engagement and partnership with community leaders within DACs.

- Develop supplemental programs designed to increase participation in existing LMI program offerings for customers that reside within DACs and for other LMI customers.
- Participate in workforce development efforts to increase the proportion of Company and contracted labor that reside in DAC communities.

9. *Other*

- Continue to evaluate the gas distribution system for vulnerable locations, monitor developments associated with identified areas, actively pursue resolution when necessary, proactively conduct community outreach and education, and provide updates on vulnerable locations in future LTP filings;
- Monitor customer adoption of decarbonization technologies and update in future LTP filings when more information is available;
- Develop a gas-specific BCA handbook and include it as an appendix to its next LTP filing
- Continue to monitor the developments associated with Cap-and-Invest and provide relevant updates in future LTP filings;
- Continue to execute available capacity release transactions to reduce costs for customers and evaluate all gas supply and capacity portfolio opportunities. Update the Companies' portfolios in future LTP filings;
- Continue the Companies' Residential Methane Detection Program which distributes methane detection devices to low-income customers and provides outreach and educational support services;
- Develop a joint planning approach across NSYEG and RG&E's electric and gas utilities to better understand the impact of electrification of gas heating and appliances on the electric system, including on individual substations and circuits, and to help identify the most cost effective and efficient solutions for customers.
- Continue to invest in gas system safety, including replacement of leak prone mains and services, advanced leak detection, and gas capture technology.

B. NYSEG and RG&E's Next LTP

The Companies' LTP provides a foundation for requests for approval of specific investments and programs, with particular focus on necessary actions during the next three years. The three-year cycle is designed to provide for future comprehensive updates to reflect new information and insights that inform the long-term plan. In short, the LTP is technically feasible and provides valid projections of costs, bill impacts, and GHG emission reductions that can inform subsequent utility proposals and decisions. New developments related to policy, markets, technology, customer behavior, infrastructure development, costs, and other changes to the business or regulatory environment will be incorporated into future LTP filings. The Companies expect to collaborate with government and other New York stakeholders to enable the clean energy transition, particularly as it relates to supporting customer decision making, and working with DACs and other communities.