Revised Gas System Long-Term Plan

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nationalgrid

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1.1. National Grid's Commitments to Climate Action and to our Customers

1.1.1. Our Commitment to Climate Action

National Grid strongly supports New York's ambitious and essential climate action goals. Climate change is the defining challenge of our time, and National Grid has a critical role to play in reducing greenhouse gas ("GHG") emissions by enabling an effective, affordable, and equitable clean energy transition.

In 2019, New York enacted the Climate Leadership and Community Protection Act ("CLCPA"), one of the most ambitious climate laws in the United States, requiring New York to reduce statewide GHG emissions 40% from 1990 levels by 2030 and 85% by 2050. In 2022, the Climate Action Council's Scoping Plan made comprehensive recommendations for actions to achieve the CLCPA's targets. National Grid is fully committed to enabling New York to achieve its climate action and environmental justice goals under the CLCPA and supports the Scoping Plan's recommendations including a coordinated statewide plan to decarbonize the gas system.

In 2020, National Grid published our "Net Zero by 2050" plan[1] and our first Responsible Business Charter,[2] setting our own emissions targets aligned with New York State's. We have built on these commitments with our 2022 "Clean Energy Vision"[3] and "Climate Transition Plan,"[4] which set out actions for reducing the Scope 1, 2, and 3 GHG emissions associated with the Company's gas and electric networks in the US. In 2023, we increased our ambition by aligning our near-term emissions reductions targets with the internationally recognized pathway necessary to avoid the worst effects of climate change.[5] These updated near-term targets call for even greater emissions reductions across our Scope 1, 2 and 3 GHG emissions. In 2023, National Grid published a refreshed Responsible Business Charter[6] including the following commitments relative to a 2018/19 baseline: (i) reduce Scope 1 and 2 GHG emissions 60% by 2030; (ii) reduce Scope 3 GHG emissions (excluding electricity sold), which includes the gas National Grid's customers use, by 37.5% by 2034; and (iii) achieve net zero by 2050 for Scope 1, 2 and 3 GHG emissions. Most recently in 2024, National Grid published a refreshed "Climate Transition Plan,"[7] which set out the updated actions to achieve our vision of a clean, fair, and affordable energy future.

National Grid has a long track record of supporting and enabling GHG emissions reductions. A list of current and pending clean energy projects can be found in Appendix 11.8. At the federal level,

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[1] National Grid Net Zero by 2050 Plan, available at https://www.nationalgridus.com/media/pdfs/our-company/netzeroby2050plan.pdf

[2] National Grid Responsible Business Charter 2020, available at https://www.nationalgridus.com/media/pdfs/our-company/usnationalgridresponsiblebusinesscharter2020us.pdf

[3] National Grid Clean Energy Vision, available at https://www.nationalgrid.com/document/146251/download

[4] National Grid Climate Transition Plan, available at https://www.nationalgrid.com/document/146726/download

[5] The Science Based Target initiative ("SBTi") is a partnership between CDP, the UN Global Compact, World Resources Institute, and World-Wide Fund for Nature. Accreditation of targets by SBTi is the most credible form of GHG commitment to investors and other stakeholders. Science-based targets give companies a clearly defined path to reduce greenhouse gas emissions in line with limiting global warming to 1.5°C. They define how much and how quickly a business must reduce its emissions to be in line with the Paris Agreement goals. https://sciencebasedtargets.org/.

[6] National Grid Responsible Business Charter 2023, available at https://www.nationalgrid.com/document/150371/download

[7] National Grid Climate Transition Plan 2023/24, available at http://www.nationalgrid.com/document/151931/download

National Grid supports an economy-wide carbon price to advance cost-effective emissions reductions and provide a sustained source of revenue to fund efforts that help to lower the costs of decarbonization. National Grid supports the Paris Climate Agreement and encourages the U.S to remain engaged. We are working with various federal agencies in support of implementation of the Infrastructure Investment and Jobs Act and Inflation Reduction Act.

Further, our commitment is demonstrated through the development and scaling of programs that we offer to our customers that enable them to reduce their consumption of fossil fuels. These programs are collectively referred to as the demand-side management ("DSM") portfolio since they reduce annual and peak demand for fossil fuels. The two primary pillars of that portfolio are energy efficiency and heat electrification; the first enables customers to use less energy, while the second encourages the use of electric heat pumps. These programs are discussed in detail in Section 5.

Both energy efficiency and heat electrification are crucial levers that enable the Company and its customers to reduce GHG emissions. Under the state's New Efficiency: New York ("NE:NY") transformation of utility energy efficiency programs, National Grid's total annual gas energy efficiency savings across the state have grown year-over-year since 2021. The savings associated with the Company's heat electrification in Upstate New York ("Upstate NY" or "UNY") show significant year-over-year increases since the inception of the statewide Clean Heat Program in 2019. Overall, since 2016, the Company's gas energy efficiency and heat pump programs resulted in lifetime GHG emissions reductions of approximately 8.7 million metric tons of carbon dioxide equivalent ("CO_2e").[8] This is equivalent to removing almost 2.1 million gasoline-powered cars from the road for one year; removing 23 natural gas-fired power plants from service for one year; eliminating the annual GHG emissions from over 1.1 million average residential homes; or the GHG emissions avoided by approximately 2,300 wind turbines running for a year.[9] Further, the DSM portfolio reduces the demand for natural gas on peak days, thereby helping to ensure safe and reliable service and enabling the Company to avoid the construction of new gas infrastructure.[10] The Company is committed to doing all it can, using the funding available for the programs in that portfolio, to continue to administer those programs to achieve emissions reductions. As detailed in Section 5.3, the Company is also continuing to identify levers that can accelerate the uptake of DSM by customers.

National Grid is also taking action to reduce emissions by modernizing natural gas infrastructure and implementing advanced leak detection and repair programs. Since 2008, we have reduced annual emissions from leaks in New York by more than 35%, avoiding emissions of more than 5.5 million metric tons of CO_2e.[11] This is equivalent to removing more than 1.3 million gasoline powered cars from the road, shutting down 14 natural gas fired power plants, eliminating GHG emissions from

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[8] Lifetime GHG emission reduction figures obtained from the NYSERDA Clean Energy Dashboard. Note that these figures do not include (a) GHG reductions from the Company's electric energy efficiency programs, the inclusion of which would cause GHG emissions reductions to rise to 22.1 million tons CO_2e and (b) GHG emissions associated with the Company's other clean energy programs such as those that enable the installation of electric vehicle charging infrastructure in its Upstate NY territory.

[9] Equivalencies computed using EPA's Greenhouse Gas Equivalences Calculator. If the Company's achievements via its electric energy efficiency programs are included, the figures rise to 5.3 million cars, 59 natural gas-fired power plants, 2.9 million homes, or 5,800 wind turbines.

[10] As an example, the Company estimates that between 2020 and 2023 its downstate NY DSM portfolio enabled 65 MDth/D of cumulative peak reduction capacity. This is roughly equivalent to the design day supply capacity of four CNG injection facilities (discussed in more detail in section 4.4.2). Thus, in theory, had the Company not been scaling its DSM programs, it would have had to seek to site, permit, and construct the equivalent capacity in downstate NY.

[11] Annual methane emissions from unprotected steel, protected steel, plastic, and cast-iron gas mains are calculated using factors from NY Department of Environmental Conservation. CO_2e is calculated using the Intergovernmental Panel on Climate Change ("IPCC") AR5 20-year global warming potential ("GWP") factor for methane of 84.

over 700,000 homes, or operating more than 1,400 wind turbines for a year.[12]

1.1.2. Our Commitment to our Customers

National Grid is New York State's largest natural gas distribution utility. We provide safe, reliable, and affordable energy to more than 2.5 million customers across the state. From hard-working families to businesses large and small, National Grid's customers depend on us to heat their homes and businesses and to fuel the state's growing economy. Today, the natural gas network is essential for our customers' lives and livelihoods, especially on the coldest days when customer gas demand is at its peak. Natural gas provides more than 68% of New York's heating fuel. Heating fuel for buildings and industry is the largest segment of our energy economy, accounting for approximately as much total energy as the electricity and transportation segments combined.[13] On a peak day in the winter, New York City's natural gas system delivers *triple* the amount of energy as the electric system on its peak day in the summer.[14] Annually, National Grid's gas distribution system alone delivers more energy to customers in New York than is generated by all of New York's fossil fuel and nuclear power plants combined.[15]

With a sustained trend over the last 10 years of roughly 16,000 customers per year choosing to connect to our network, National Grid must ensure that our portfolio of natural gas supply, gas distribution network infrastructure, and DSM programs can meet our diverse customers' energy needs year-round and around the clock. We design our gas distribution system and plan our gas resource portfolio to meet forecasted customer demand on a "Design Day" (i.e., the coldest winter day that brings the highest daily customer demand for which the Company plans) and under "Design Hour" conditions (i.e., the peak hourly demand on such a Design Day). In New York, National Grid operates its gas system with a zero allowable contingency or reserve margin to guard against extreme weather or unexpected disruption to gas supply, gas infrastructure, or demand-side resource availability.[16] The energy service interruptions caused by the February 2021 Winter Storm Uri in Texas and Winter Storm Elliott in December 2022 serve as powerful reminders of the importance of planning for severe weather conditions, given their likelihood and the magnitude of potential economic and health impacts to customers from loss of heat during extreme cold, which can tragically include loss of life. Climate change is expected to make extreme weather even more frequent, raising the stakes for maintaining safety and reliability as we work toward a clean energy future. National Grid must meet this profound obligation to deliver life-sustaining energy to our customers at the same time as we plan for a future where the use of conventional natural gas will decline as New York takes action to reduce greenhouse gas emissions and fight climate change.

National Grid is committed to working transparently and collaboratively with stakeholders and communities to support equity and environmental justice in the clean energy transition and has

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[12] Calculated using EPA's Greenhouse Gas Equivalencies Calculator.
[13] EIA State Energy Data System (SEDS): 1960-2021 (complete), available at https://www.eia.gov/state/seds/seds-data-complete.php Comprehensive state-level estimates of energy production, consumption, prices, and expenditures by source and sector.
[14] New York City Mayor's Office of Sustainability, "Pathways to Carbon-Neutral NYCPathways to Carbon-Neutral NYC." available at https://www.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf, p. 19.
[15] In FY2023 (April 1, 2022 – March 31, 2023) National Grid's gas distribution system delivered 362 million Dth of natural gas, equivalent to 105,000 GWh of electricity; According to the 2023 NYISO Gold Book, fossil-fueled electricity generation accounted for 64,151 GWh, and nuclear electricity generation accounted for 26,883 GWh in calendar year 2022.
[16] "Zero contingency" means that the plans for balancing gas demand and supply have no supply contingency or reserve margin. In other words, the system is designed to balance supply and demand with no disruption and assumes forecasted peak demand is not exceeded and that all available gas capacity resources will be available.

developed a draft Equity and Environmental Justice Stakeholder Engagement Framework that summarizes our principles and intentions for meeting this commitment. The Company is working to advance the CLCPA's goals to deliver the benefits of clean energy to Disadvantaged Communities ("DAC"). More broadly, the Company is working to ensure customers in DACs benefit from improved infrastructure, expanded outreach to provide accessible, authentic engagement and representation in our processes, expanded participation in energy efficiency and affordability programs that can help customers manage their bills, and specific community economic benefits through programs such as workforce development grants as well as our shareholder-funded community initiatives. In addition, National Grid is especially mindful of the long-term affordability challenges that may impact vulnerable low- to moderate-income ("LMI") and DAC customers as we work to enable net zero and is actively working to advance actions that mitigate those challenges.

Meeting the CLCPA's emissions reduction targets will not be easy. Building a clean energy future will require unprecedented transformation across the entire energy system, including the eventual elimination of all fossil fuels like conventional natural gas. National Grid embraces the challenge, and aims to leverage the existing infrastructure, capabilities, and people who enable us to deliver safe, reliable, and affordable energy to New York families and businesses today to meet those same essential standards in a decarbonized future. Fully achieving these important and ambitious targets will require transformative policy, regulatory, market, and technology innovations. This Long-Term Plan recognizes that while many of these necessary changes are beyond National Grid's direct control, we are committed to working collaboratively with stakeholders, policymakers, and regulators to reach our shared emissions reduction targets and equitable clean energy transition goals.

1.2. Our Long-Term Plan Approach

This Long-Term Plan is structured to first provide an overview of National Grid, our customers, and the communities we serve. We then provide a detailed assessment of forecasted demand and supply, followed by a detailed review of our existing DSM programs and planned enhancements to those programs. A detailed assessment of Greenpoint Energy Center follows, illustrating this crucial asset's role today and in the future. Next, we provide detailed analyses of our Long-Term Plan scenarios, including assessments of projected bill impacts and benefit-cost analysis, followed by detailed recommendations for the policy and regulatory innovations needed to achieve the CLCPA's targets rooted in our scenario analysis findings. We conclude with a summary of key findings and how National Grid is taking action today, our stakeholder engagement plan, and procedural next steps.

National Grid's long-term plan is to transform our New York gas utilities to enable economy-wide decarbonization while ensuring our customers have equitable access to safe, reliable, and affordable energy. This Long-Term Plan document establishes the current operating conditions for National Grid's gas utilities, expresses our vision for the future of gas in New York, and articulates the steps the Company and the state need to take to put New York on track to achieve the CLCPA's emissions goals. This Long-Term Plan filing is intended to build a foundation for the regulatory and policy innovations necessary to reshape New York's energy economy and enable economy-wide decarbonization that is affordable, equitable, and maintains the safety and reliability of the gas system and the energy system overall.

Our analysis finds that the necessary conditions do not exist today to decarbonize the energy currently delivered by the gas network. Challenges and barriers are discussed in Section 1.3 and throughout this document, and we recommend policy and regulatory innovations necessary to overcome them in Section 8.3.

This Long-Term Plan illustrates possible future states for National Grid's gas network through three scenarios, designed to illustrate the range of potential future states – the Reference Case, the Clean Energy Vision, and the Accelerated Electrification scenario:

- The *Reference Case* represents a continuation of current policies based on the best available forecasts, including actions National Grid can take without legislative or policy changes to support decarbonization. The Reference Case does not achieve New York's or National Grid's objectives for a decarbonized and fossil fuel-free gas network by 2050.

- The *Clean Energy Vision* ("CEV") is National Grid's vision for the future of gas in New York. This scenario decarbonizes the energy currently delivered by National Grid's gas system with the lowest cost to customers and the highest benefit-cost ratio according to our analysis. The CEV represents a hybrid approach where the majority of heating demand in 2050 is met through electrification and energy efficiency, while the existing gas network is transformed to play a complementary role to deliver low-carbon alternative fuels.

- The *Accelerated Electrification* ("AE") scenario is based on Scenario 3 from the Climate Action Council's Integration Analysis, which is designed to "push harder on accelerated electrification" to achieve economy wide decarbonization.[17] The AE scenario uses significant volumes of low-carbon alternative fuels, albeit at lower levels than the CEV, and assumes higher levels of electrification. This scenario decarbonizes the energy currently delivered by National Grid's gas system at a higher cost and with a lower benefit-cost ratio than the CEV according to our analysis.

1.3. Key Challenges and Barriers

Below is a summary of key challenges and barriers to achieving National Grid's and New York's shared gas decarbonization objectives. None of these barriers are insurmountable. Although there are steps National Grid and our peer gas utilities can take today to build toward a clean energy future, achieving the CLCPA's targets will require a collective effort on the part of utilities, regulators, policymakers, communities, and individual New York families and businesses.

1.3.1. Customer demand for gas is growing and is projected to continue to grow in the future despite ambitious existing energy efficiency and heat electrification programs.

While DSM programs have had a meaningful impact on demand reduction, and consequently on emissions reductions, customer demand for gas continues to grow across National Grid's service territory. Our latest Adjusted Baseline demand forecast[18] projects that, absent significant policy or structural changes, Downstate New York ("Downstate NY") Design Day gas demand will increase approximately 0.88% per annum, from 2,829 MDth/day[19] in the winter of 2023/2024 to 3,551 MDth/day in the winter of 2049/2050. Similarly, absent significant policy or structural changes,

[17] See, Appendix G: Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan
[18] We take all relevant factors into account to forecast our customers' future gas demand, including historical usage, independent economic projections, and adjustments for factors such as state and local laws, energy efficiency, demand response and heat electrification programs. The Adjusted Baseline is our Baseline forecast adjusted for energy efficiency, demand response, heat electrification, and state and local laws. It is then utilized for system and gas portfolio planning. The latest version of this annual forecast was issued in June 2024.
[19] MDth = Thousands of Dekatherms. One dekatherm is equal to one million British thermal units ("Btu"). The energy content of 1,000 cubic feet of natural gas measured at standard conditions is approximately equal to one dekatherm.

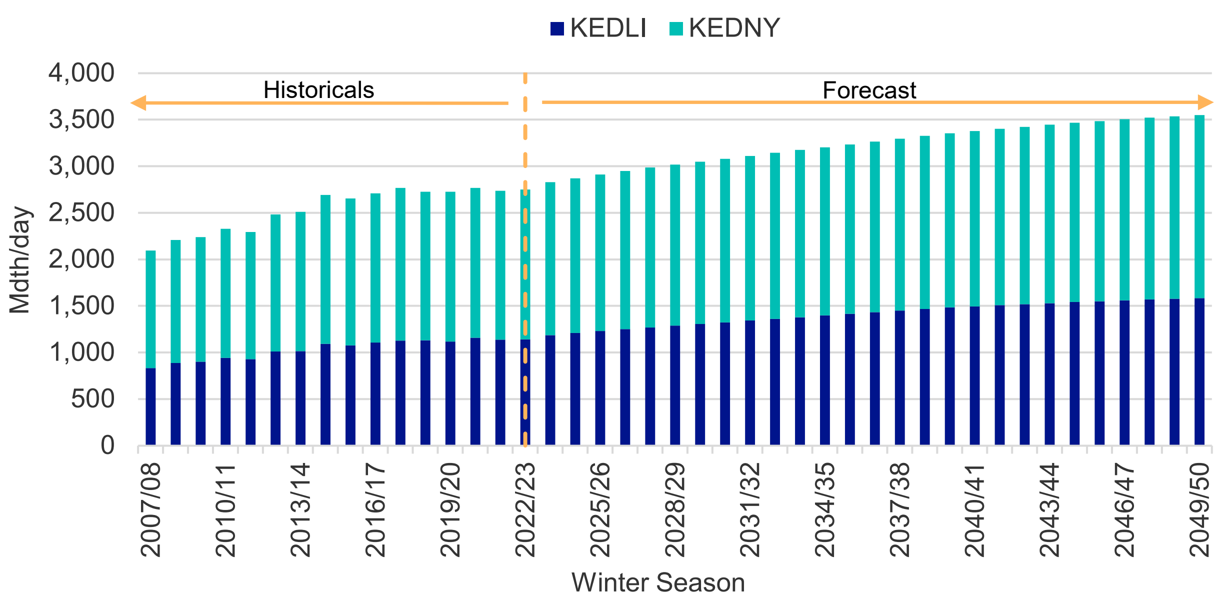
Upstate NY Design Day gas demand is also projected to increase approximately 0.53% per annum, from 952 MDth/day in winter 2023/2024 to 1,094 MDth/day in the winter of 2049/50.[20]

Growth in the Downstate NY Adjusted Baseline Demand Forecast, which underpins our Reference Case, is significantly less than the average growth rate experienced over the historical period, which was 1.2% per year from winter 2013/2014 to winter 2023/2024. Figure 1-1 below shows historical and projected growth for DNY Design Day gas demand.

Similarly, growth in the Upstate NY Adjusted Baseline Demand Forecast is significantly less than the average growth rate experienced over the historical period, which was 0.77% per year from winter 2013/2014 to winter 2023/2024. Figure 1-2 below shows historical and projected growth for Upstate NY Design Day gas demand.

These forecasts illustrate that while existing programs are having an impact, new policies and regulatory frameworks will be necessary to reach New York's important and ambitious decarbonization targets. New approaches that go beyond existing programs are needed to reduce gas demand through energy efficiency and electrification, and to ensure the availability of clean alternative fuels to meet hard-to-electrify energy uses. Without them, customer demand for conventional natural gas will continue to increase.

Figure 1-1: Historical Period and Forecasted DNY Design Day Demand



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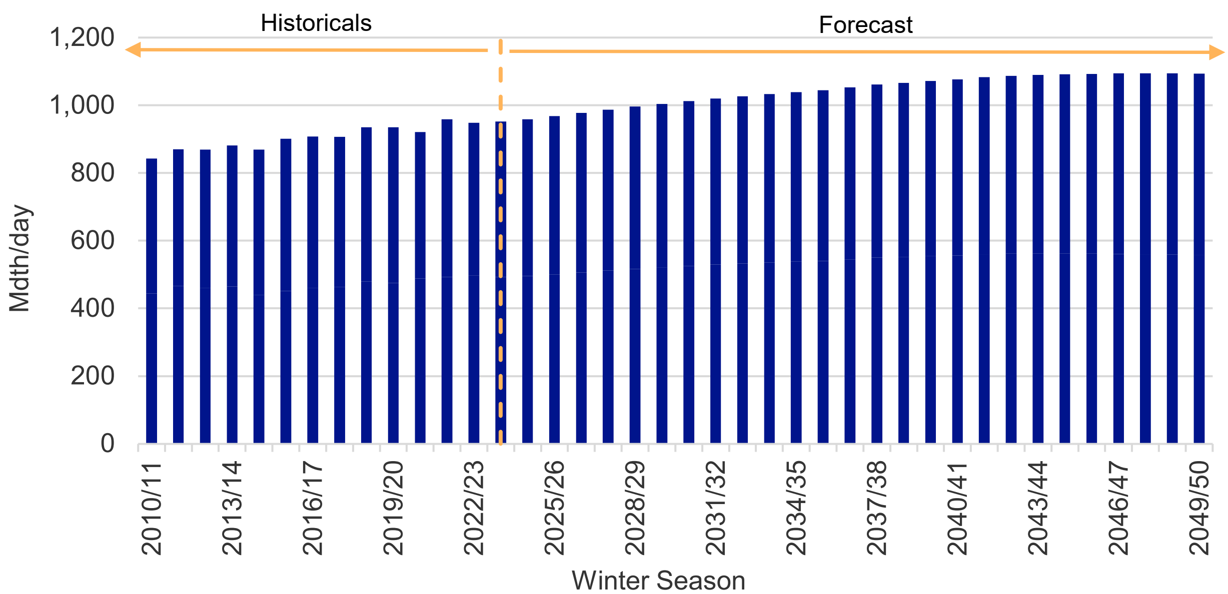
[20] National Grid's New York gas business is divided into three operating companies with The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") operating in Downstate NY and Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC") operating in Upstate NY. Further detail is available in Section 2.

Figure 1-2: Historical Period and Forecasted Upstate NY Design Day Demand



Customer peak gas demand will soon exceed available gas capacity in National Grid's Downstate[21] and Upstate service areas.[22]

Based on the Companies' latest Adjusted Baseline Demand Forecast, National Grid projects that a gap between total customer peak gas demand will emerge in the winter of 2027/28 in Downstate NY, and in the winter of 2030/31 in Upstate NY, with the gap continuing to grow thereafter. The Companies have confidence in these estimates as, typically, the Companies forecasts have been within its +/- 3 percent tolerance on seasonal demand.

National Grid, on behalf of its Downstate NY customers, has delivered several on-system supply projects in recent years according to our operations plan, including the construction of five new and expanded compressed natural gas ("CNG") transfer sites that, when fully scaled, will be capable of delivering up to 2,200 Dth/hour by winter 2025/2026, or 88 MDth/Day when used for the Companies' experienced peak periods. National Grid has also secured additional long-term contracts for capacity on existing interstate pipelines. The total portfolio of available gas capacity (the "Existing Capacity") now stands at 2,957 MDth/day by 2023/2024 as shown on Table 1-1 below.

Table 1-1: Existing Downstate NY Capacity

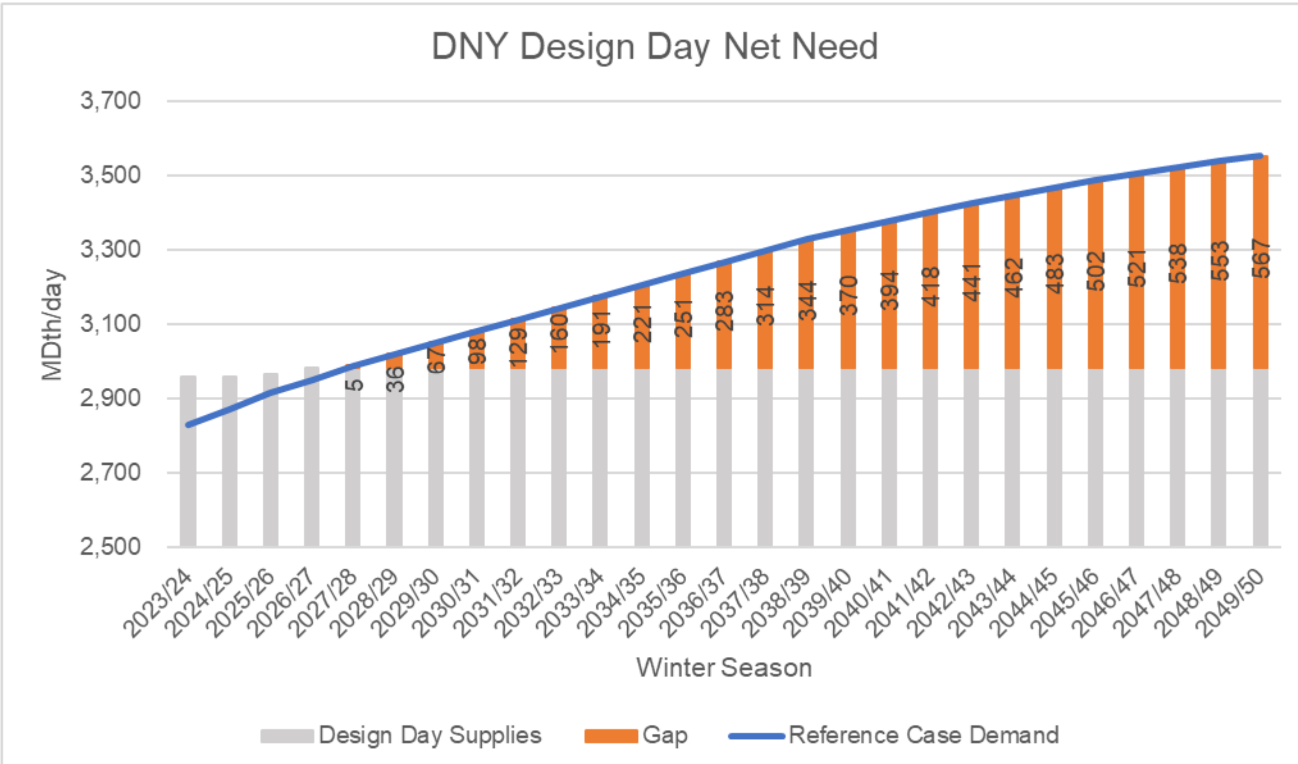
Supply Stack (MDth/day)	2023-24
Long-Term Fixed Pipeline & Storage	2,377
Liquified Natural Gas	395
Short-Term Contracted Peaking & Cogen	123
Compressed Natural Gas	62
Renewable Natural Gas	1
Total Gas Capacity	2,957

However, this existing capacity only meets customer demand through 2026/27. A gap between peak period gas demand under the Adjusted Baseline Demand Forecast and Existing Capacity (the

[21] Assumes the Company's Riverhead compressed natural gas facility capacity is doubled in 2026/27.
[22] Assumes the Company's Moreau compressed natural gas facility capacity is doubled in 2024/25 and a second CNG site is constructed and commissioned in the Albany region by 2026/27.

“Demand-Supply Gap”) of 5 MDth/day emerges in winter 2027/28 and continues to grow to 567 MDth/Day in 2049/50, as illustrated by Figure 1-3.[23]

Figure 1-3: Downstate NY Design Day Net Need



Note: Y-axis is broken to focus on gap at the margin

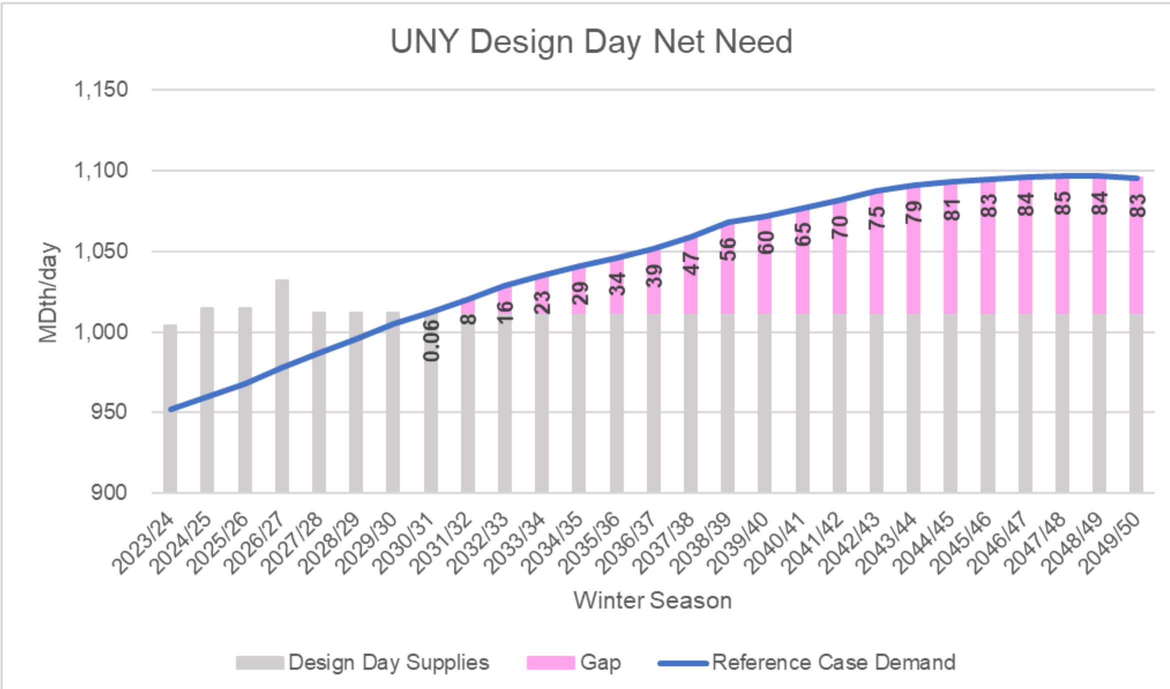
Similarly, in Upstate NY, the total portfolio of existing capacity stands at 1,004 MDth/day by 2023/24 as shown in Table 1-2 below. Barring any changes to the Adjusted Baseline Demand Forecast and the existing capacity, a demand-supply gap of 0.06 MDth/day emerges in winter 2030/31 and continues to increase to 83.4 MDth/day in 2049/50, as illustrated in Figure 1-4.

Table 1-2: Existing Upstate NY Capacity

Supply Stack (MDth/day)	2023-24
Long-Term Fixed Pipeline & Storage	964
Liquified Natural Gas	0
Citygate Peaking	20
Short-Term Contracted Peaking & Cogen	13
Compressed Natural Gas	7
Renewable Natural Gas	0
Total Gas Capacity	1,004

[23] This demand-supply gap assumes that all existing pipeline capacity is re-contracted. Moreover, this report compares total gas supply capacity against aggregate Design Day demand for the Company’s customers in Downstate NY to assess whether the Company faces a gas capacity constraint. However, the Company also must conduct detailed hydraulic modeling of its gas network jointly with Consolidated Edison annually to understand actual projected gas flows and any locational constraints or low-pressure concerns.

Figure 1-4: Upstate NY Design Day Net Need



Note: Y-axis is broken to focus on gap at the margin

The Company continues to seek new supply and demand options, including through its existing DSM programs (i.e., energy efficiency, gas demand response, and, in Upstate NY, electrification of heat), market solicitations for non-pipeline alternatives ("NPAs"), and innovative supply-side proposals to meet our customers' needs while pursuing decarbonization. We are exhaustively considering all options for meeting projected customer needs, including looking externally to market innovators to identify novel concepts, both on the non-traditional gas supply side and on the demand side from a wide array of competitive and innovative technology and energy companies.

While National Grid anticipates future changes to policies, regulations, or market conditions may reshape customer gas demand, the forecasts presented here represent the best available evidence-based projections of future demand under conditions as they exist today and will exist in the future absent changes brought about by new policies, regulations, or external factors. This Long-Term Plan proposes policy and regulatory actions to create the conditions necessary to achieve the Company's and New York's ambitious climate action commitments, but we must also be prepared to ensure safe and reliable service under existing policies and regulations.

1.3.2. Preserving reliable access to critical energy service will require ongoing maintenance of the gas network and near-term investments in strategic assets to maintain the gas network.

National Grid must ensure that our network can function safely and reliably as well as provide sufficient energy to our customers to meet their needs on the coldest days of the year in order to maintain service to existing customers and to provide service to new customers under the Company's obligation to serve such customers. Meeting these obligations requires continued investment in gas system infrastructure, even as we plan for a decarbonized future.

One important category of necessary ongoing investment is removal of Leak Prone Pipe ("LPP"). The Company is committed to minimizing leaks to preserve the safety of our system, avoid unnecessary GHG emissions, and control costs. While we evaluate NPAs to remove LPP segments, we have not to date secured the required level of customer participation necessary to implement such an NPA, underscoring the importance of identifying novel NPA approaches. We also continue to invest in our system to alleviate bottlenecks, expand service as requested by customers, and to maintain or upgrade existing infrastructure.

National Grid currently operates six compressed natural gas sites and two liquefied natural gas facilities. These components of our networks provide critical supply and pressure support and are needed to provide service to our existing customers under the most demanding circumstances, especially when temperatures fall below 15°F. These assets also provide enhanced reliability should we experience disruptions to our gas supplies delivered by the interstate pipeline system. Continued investment in these assets is necessary to ensure the continued provision of safe and reliable service.

Absent continued investment in the gas network, moratoria on new customer connections may be necessary to ensure safe and reliable service to existing gas customers. In the Moratorium Management Order, the Commission approved moratorium management procedures applicable to all gas Local Distribution Companies ("LDCs") to provide transparency, consistency, and equity to customers. The Commission emphasized that LDCs have an obligation to provide safe and reliable service to existing customers under the regulations, and moratoria should only be used as a "last step."[24]

National Grid is committed to serving our customers and communities reliably, as we have for more than 100 years. If the Company is faced with an inability to meet projected customer Design Day demand, a moratorium on new customer connections could be required in the future. The most immediate risk facing the Companies with respect to moratoria are the supply-demand gap projected in DNY in 2027/28 without approval, construction, and commissioning of the Iroquois Enhancement by Compression ("ExC") Project and the supply/demand gap due to growth that appears in Upstate NY by 2030/31. Under the Moratorium Management Order this would require notices of potential moratoria in Downstate NY in 2025 and Upstate NY in 2028. These dates will be revisited when new forecasts are issued or new information is incorporated into our analysis regarding supply-side and/or demand-side options.

1.3.3. New policies and regulations are necessary to put our shared GHG emissions reduction targets within reach.

National Grid has identified several key categories of regulatory and policy reforms that will be necessary to enable decarbonization of the gas system, regardless of the pathway to achieving 2050 targets. The policy and regulatory frameworks described briefly here and in greater detail in Section 8 are necessary to achieve the CLCPA's emissions reduction and environmental justice mandates and are consistent with the Climate Action Council's recommendations in the Scoping Plan.

1.3.3.1. Establishing frameworks for an orderly transition

- <u>Integrated Energy Planning:</u> Considering and incorporating critical interactions between the gas, electric, and customer energy systems into energy utility planning processes statewide

[24] Case 20-G-0131, *Case Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, "Order Adopting Moratorium Management Procedures" at 24 (issued and effective May 12, 2022) ("Moratorium Management Order").

can help advance decarbonization goals at the lowest achievable cost and with the greatest and most equitable benefits for customers.

- Policy and regulatory changes to encourage heat electrification: Existing statutory and regulatory requirements for the provision of service may present barriers to cost-effective electrification. Eliminating the obligation for gas utilities to connect new customers to the gas network and potentially modifying the obligation to serve existing customers should be considered, but any modifications must take care to ensure adequate alternatives are available at reasonable costs and avoid unreasonably disrupting customer choice.
- Regulatory frameworks to scale targeted electrification and NPAs: New policies to fairly and equitably target segments of the gas system for decommissioning through the adoption of electric heating technologies including air source heat pumps and Utility Thermal Energy Networks ("UTENs") can empower customers and protect customer choice while optimizing emissions reductions and costs. New, more effective means of incentivizing customers to electrify, including new approaches to funding, must be developed to reach the levels of electrification needed for either the CEV or AE scenarios, and reduce long term customer affordability risk by reducing gas system cost.

1.3.3.2. Ensuring long-term energy affordability

- Equitable depreciation: Addressing the pace at which gas utilities recover costs for new and existing assets can be a powerful tool for reducing future bill impacts and enhancing intergenerational equity as utilization of the gas network evolves.
- Cross-utility cost coordination: Coordination of statewide planning efforts, incentives and investments among gas and electric utilities is essential to ensure costs associated with meeting today's gas demand are not borne disproportionately by gas customers who are unable to electrify. While encouraging customers to electrify is essential for the gas transition, customers who leave the gas system must not leave behind the rate base associated with their gas service to be paid for by remaining gas customers. A multi-modality approach to the allocation of decarbonization costs should be considered.
- Optimizing New York Cap & Invest ("NYCI") for affordability: Ensuring costs associated with the NYCI program are phased in gradually, and tailoring cost impacts and revenue reinvestments to customer circumstances can enhance affordability while incentivizing cost-effective emissions reductions.

1.3.3.3. Scaling efficiency and electrification to equitably reduce customer gas demand

- Developing new sources of funding for DSM programs: While the current approach of customer-funded DSM programs worked well in the past, new sources of funding, including from sources other than utility customers, will be necessary to enable the levels of demand reduction required to achieve the CLCPA's targets.
- Enhancing program design and implementation to ensure equity and balance customer bill impact with emissions reductions: New frameworks for setting program targets, innovations on program delivery, and an ongoing focus on ensuring LMI customers and those in DACs can access DSM programs will enable greater emissions reductions and a more equitable transition.
- Improving portfolio planning to ensure the most cost-effective and achievable mix of demand-side tools for achieving emissions reductions: Building a new portfolio planning

process and supporting tool to evaluate the most affordable, equitable, and reliable mix of demand-side levers to achieve state climate goals.

1.3.3.4. Enabling procurement and integration of affordable clean alternative fuels

- Gas Utility Decarbonization Performance Standard: Programs to require gas utilities to reduce emissions from customer fuel consumption over time, including through the procurement of clean alternative fuels, will support decarbonization of hard-to-electrify buildings and industry, complement electrification, and ensure the market for RNG and clean hydrogen begins to scale up to meet demand for these fuels in the CEV and AE scenarios.
- Accurate GHG Accounting: Evidence-based GHG accounting frameworks rooted in the US and international best practices, including methods that consider lifecycle emissions impacts, must be embedded in all decarbonization policies to maximize emissions reductions, and avoid unintended consequences like GHG "leakage," where policies shift emissions to other sectors or jurisdictions instead of reducing them.
- Support for pilots and demonstrations: Enhanced support for Research, Development and Demonstration ("RD&D") for alternative fuels (i.e., hydrogen, RNG) is necessary to understand the value and role of alternative fuels in an orderly gas system transition and is essential for any CLCPA-compliant future.

1.4. Recommended Path Forward

While near term threats to reliability due to imbalances in supply and demand are real and require immediate attention, and the structural barriers to economy-wide decarbonization of the gas network are significant, this Long Term Plan demonstrates that the CLCPA's targets can be achieved and identifies no-regrets actions policymakers, stakeholders, and utilities can take together to enable an equitable energy transition that ensures the continued provision of the safe, reliable, and affordable energy services on which every New Yorker depends on.

Our analysis presented in this Long-Term Plan demonstrates that the Clean Energy Vision remains the best available approach to achieve New York's and National Grid's shared decarbonization goals. As we demonstrate in Section 7, the CEV scenario has a smaller impact on customer bills and lower net societal costs, while reducing over 1.1 billion tons of CO_2e through 2050.

While National Grid believes the Clean Energy Vision is the more feasible and lower-risk option, we acknowledge that some stakeholders see things differently. We do not expect to resolve these differences of opinion here, nor do we believe it is necessary to do so to move forward on the gas decarbonization transition. In fact, our analysis shows that both the Clean Energy Vision and the Accelerated Electrification scenario require largely the same suite of enabling policies, which can be pursued immediately even without agreement on how the gas system should be configured in 2050. Absent such innovative new policies and regulations, the future will look much more like the Reference Case, which fails to achieve our shared climate action and decarbonization goals. We may not all agree on what the future should look like in 2050, but we hope there is broad consensus that action is required now to put key enabling policies in place to achieve our shared decarbonization, equity, and affordability goals.

The central tenet of this Long-Term Plan is that the near-term actions necessary to enable achieving a CLCPA-compliant future – whether the future looks more like the Clean Energy Vision or the Accelerated Electrification scenario – are the same. Both the Clean Energy Vision and the Accelerated Electrification scenario require transformative levels of gas demand reduction, rapid increases in customer adoption of electric heating, significant volumes of low-carbon alternative fuels, and new frameworks for integrated energy planning and utility cost allocation to support equity and energy affordability. Importantly, the policies that would enable the Clean Energy Vision would not preclude the Accelerated Electrification scenario if they were appropriately designed to incentivize customers and market participants to choose the lowest-cost and most feasible clean energy options available to them according to an evidence-based, scientific assessment of avoided lifecycle emissions. The right frameworks should empower *customers* to choose which path New York takes toward CLCPA compliance.

Our overarching recommendation for building the regulatory and policy innovations necessary to achieve the CLCPA targets is to implement the process and framework put forward by the New York Climate Action Council in its Final Scoping Plan, which was released in December 2022.[25] The Scoping Plan calls for the Department of Public Service ("DPS") to lead the development of a "coordinated plan" for decarbonizing the gas system "through an orderly transition that is equitable, cost-effective, and maintains system safety and reliability," with support from New York State Energy Research and Development Authority ("NYSERDA"), Long Island Power Authority ("LIPA"), New York Power Authority ("NYPA"), and Department of Environmental Conservation ("DEC").[26] National Grid supports the Scoping Plan's recommendations to develop a coordinated plan for a strategic transition away from fossil natural gas. We agree that a "well-planned and strategic transition" with "coordination across multiple sectors," "integrated planning" of gas and electric systems, and due consideration of alternatives where "full electrification" may not be "the most cost-effective and technically feasible solution" are necessary to ensure an equitable transition that protects "reliability, safety, energy affordability, and resiliency."[27] We further agree that "it is important that the strategic transition to a decarbonized gas system in New York State does not impose undue cost burdens on customers who currently rely on this fuel for home heating, especially those who can least afford cost increases."[28]

We urge the Public Service Commission and DPS to build on the Long-Term Plans filed by National Grid and the other New York gas utilities to establish new workstreams within the open proceeding on Gas Planning Procedures to develop a coordinated statewide gas system transition plan pursuant to the Scoping Plan's recommendations in Chapter 18. We look forward to collaborating closely with stakeholders and DPS to implement the Scoping Plan's recommendations.

We believe the CEV scenario illustrates the attractive features of a gas system transition that balances affordability through a broad portfolio of clean energy resources while achieving deep decarbonization. We also believe it would be a mistaken attempt to engineer the future to match a preconceived scenario, especially considering that our analysis of the CEV and AE scenarios indicates that both scenarios require the same barriers to be overcome. We must take action together immediately to get on track for our shared 2050 objectives.

[25] NY Climate Action Council Final Scoping Plan
[26] Id., p. 360.
[27] Id., p. 350.
[28] Id.

2. Introduction

2.1. Report Purpose and Procedural History

Pursuant to the Commission's Order Adopting Gas System Planning Process issued May 12, 2022 ("Order"),[29] NY Local Distribution Companies ("LDCs") are required to submit a long-term gas plan on a three-year cycle to facilitate better understanding and engagement for all parties regarding the future of gas infrastructure in New York State. The Commission is concerned with the adverse impacts of recent moratoria and LDC planning on customer choice, affordability, and emissions. The Order instituted a new long-term gas planning process and non-pipeline alternative ("NPA") framework and imposed additional compliance obligations to advance the objectives of and next steps in the proceeding.

National Grid's (or the "Company's") long-term plan ("LTP") is a comprehensive, multi-year document that addresses various areas affecting LDC operations, including demand, supply, reliability infrastructure plans and alternatives, each under different scenarios (i.e., reference case, clean energy vision, and accelerated electrification scenarios), and puts forward a strategy for achieving the Climate Leadership and Community Protection Act's ("CLCPA's") requirements consistent with the recommendations of the Climate Action Council's ("CAC") Scoping Plan ("Scoping Plan"). The long-term planning process ensures that residents of New York can continue to meet their energy needs while achieving an equitable and affordable clean energy transition, and it promotes effective customer planning, reduces confusion, and avoids inequities or the appearance of inequities.

On May 31, 2024, National Grid filed its Initial Gas System Long Term Plan and to-date has (i) hosted eight technical conferences, (ii) replied to nearly four hundred information requests from PA Consulting and other stakeholders, and (iii) held numerous meetings with Staff, PA Consulting, and stakeholders to discuss all aspects of National Grid's gas business and its Initial LTP. National Grid is committed to ensuring that all interested stakeholders have the opportunity to engage with the Company on the future of gas infrastructure in New York State and that those engagements can be productive, informative, and aligned with the Planning Order, when done in a constructive and professional manner.

This Revised Gas System Long Term Plan primarily reflects required updates to the Company's scenario analyses utilizing demand forecasts that were finalized in June 2024, which occurred shortly after filing the Initial Gas System Long Term Plan on May 31, 2024. The Initial Gas System Long Term Plan was based on demand forecasts finalized in June 2023. The revised demand forecasts are reflected in the resource mix described in Sections 2.3, 8.1, and 8.2; Demand Forecast Results in Section 3.4; the Non-Pipe Alternatives analysis in Section 6; the Bill Impact Analysis in Section 7.3; the Benefit-Cost Analysis results in Section 7.4; the GHG emissions reductions in Section 7.5; and the revenue requirement analysis in Section 8.2.

Stakeholder feedback was provided in formal comments due on September 18, 2024 to which National Grid filed its Reply Comments on October 3, 2024 to address stakeholder feedback on National Grid's Initial Gas System Long Term Plan. Certain matters raised by stakeholders that the Company addressed in its Reply Comments may not be included in this Revised Gas System Long Term Plan due to the limited timeframe allowed for including new analyses and details. The Final Gas System Long Term Plan scheduled for filing on January 23, 2025 will more fully address such issues.

[29] 20-G-0131 et al., *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures.*

2.2. About National Grid and Our Customers

National Grid is one of the largest investor-owned energy companies in the US, serving gas and electric customers throughout New York and Massachusetts. Through its affiliates, the Company also owns and operates several electric generating plants and electric transmission projects.

2.2.1. Our Reliability and Safety Culture

National Grid has a strong focus on reliability and safety culture. The Company is committed to providing safe, reliable, and affordable energy to its customers, while ensuring the safety of its employees, contractors, and the communities it serves. National Grid has implemented a number of programs and initiatives to promote safety and reliability, including employee training, regular safety audits and inspections, training for emergency responders in our communities, and the use of advanced technology to monitor and maintain its energy infrastructure.

National Grid's reliability culture is centered around ensuring that its energy infrastructure is designed, operated, and maintained to the highest standards. The Company has implemented a number of measures to ensure that its systems are resilient and can withstand extreme weather events and other disruptions. National Grid also has a robust emergency response plan in place to quickly respond to any incidents that may occur.

National Grid's safety culture is focused on promoting a safe working environment for its employees and contractors, as well as keeping our communities safe. The Company has implemented safety programs and initiatives to ensure that its employees are trained to identify and mitigate potential safety hazards. National Grid also encourages its employees to report any safety concerns or incidents and has established a system for investigating and addressing safety issues. National Grid's strong focus on reliability and safety culture has helped to establish it as a leader in the energy industry.

2.2.2. Our New York LDCs

In Upstate NY, Niagara Mohawk Power Corporation d/b/a National Grid ("NMPC") provides gas service in portions of Jefferson, Oswego, Onondaga, Madison, Oneida, Herkimer, Fulton, Montgomery, Warren, Saratoga, Schenectady, Albany, Washington, Rensselaer, and Columbia counties. As of December 2023, NMPC serves approximately 630,000 gas customers via approximately 9,220 miles of gas mains.[30]

In Downstate NY, The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") operates in New York City in the counties of Staten Island, Brooklyn, and parts of Queens while KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") operates across Long Island in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. KEDNY and KEDLI provide service to approximately 1.3 million and 630,000 customers respectively, totaling over 1.9 million customers. As of December 2023, National Grid's Downstate NY gas business encompassed approximately 13,030 miles of gas mains.[31]

[30] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Gas Distribution Annual Data 2010 to present.
[31] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, Gas Distribution Annual Data 2010 to present.

National Grid serves residential customers, multi-family customers (multi-unit residential buildings that are centrally metered), and commercial and industrial customers in its New York gas service territory. These customers use gas for a wide range of purposes:

- Space Heating – using natural gas to heat air or water that is subsequently circulated throughout the building to maintain desired indoor temperature. Space heating accounts for most of the gas consumption activity for customers, particularly during cold peak days
- Water Heating – using natural gas to heat water for household needs (e.g., washing dishes, taking a shower)
- Cooking – using natural gas for cooking by utilizing gas stoves and ovens in homes or in business facilities (e.g., restaurants)
- Industrial Processes – using natural gas for production of goods and services (e.g., fuel for industrial furnaces)
- Other/Miscellaneous – using gas in other appliances (e.g., gas fireplaces, gas clothes dryers)

National Grid is at the heart of one of the greatest challenges facing our society – transforming our electric and natural gas networks with smarter, cleaner, and more resilient energy solutions to reduce greenhouse gas emissions, fight climate change, and create a fairer, more affordable clean energy future. National Grid has seen sustained growth in peak demand in New York due to economic development, as well as a concerted effort to move large commercial and industrial customers from heating oil to lower-emitting natural gas. On average, from 2013 to 2023, KEDNY's and KEDLI's combined peak day demand grew by approximately 31,000 Dth per year, even after accounting for the cumulative effect of past energy efficiency, demand response, and interruptible service programs to reduce load on peak days. This growth resulted, in part, from municipal programs (e.g., NYC Clean Heat) and incentives designed to promote the use of natural gas to displace more expensive, higher-emitting fuels.[32] Similarly, the net peak day gas demand for NMPC grew at an average rate of approximately 8,500 Dth per year over the period from 2013 to 2023 after the cumulative effects of the implementation of its DSM programs.

To support this growth in gas demand, and in recognition of the need to enhance resiliency following Superstorm Sandy, New York City was actively encouraging increased supply capacity in 2013 to enhance the reliability of the region's energy networks.[33] The Public Service Commission policy

[32] NYC Clean Heat promoted conversion to natural gas and was implemented under New York State S.1145-C and NYC Local Law 43-2010, see https://www.nyc.gov/office-of-the-mayor/news/212-12/mayor-bloomberg-more-100-million-financing-new-resources-help-buildings. On December 22, 2021, New York City enacted Local Law 154 that subjects newly constructed buildings to certain emissions limits that would prohibit the installation of natural gas and other fossil fuel-fired systems. This requirement applies to new buildings beginning January 1, 2024 for buildings less than seven stories or July 2, 2027 for buildings seven stories or more. The ordinance does not mandate the phase out of natural gas use in existing buildings. It allows oil-to-gas heating conversions in existing buildings, non-heating gas customer upgrades to heating, and conversion of non-firm customers to firm gas service. The code changes are expected to reduce total Downstate NY gas demand by 35 MDth/day, or 1.0% in Winter 2027/2028. By Winter 2035/2036, the code changes are expected to reduce total Downstate NY gas demand by 127 MDth/day, or 3.3%.

[33] NYC Special Initiative for Rebuilding and Resiliency, "A Stronger, More Resilient New York" (June 2013), at 127 ("The natural gas connections to New York City generally have sufficient capacity to provide the city's customers with gas, but on days when demand is high, all five city-gate connections are needed to prevent forced shutdowns. The City will continue to support ongoing projects by gas pipeline operators to install additional city-gate capacity linking New York City to new natural gas pipelines.")

clearly supported natural gas growth[34] and approved a number of programs and incentives designed to promote the increased use of natural gas.[35]

However, given the urgency of addressing climate change, gas growth is no longer a goal of the Company or the State of New York. National Grid has committed to manage its business with the goal of reducing billed gas usage, ceasing gas marketing activities, eliminating financial incentives for adding new customers, terminating any gas conversion and other incentive programs, and working with various stakeholders (e.g., electric utilities, trade organizations) to promote the adoption of geothermal and other alternative energy options as described in the Joint Proposal adopted as part of the 2023 KEDNY and KEDLI Rate Cases recently approved by the Commission.[36] Every day, National Grid works with stakeholders to promote the development and implementation of more sustainable, innovative, and affordable energy solutions.

2.2.2.1. Downstate NY & Upstate NY Gas System Commonalities and Differences

Our Downstate NY system is well-integrated, with high pressure transmission main feeding lower pressure systems and laterals that culminate in services to our customers. It is supplied by four major interstate pipeline systems: 1) Transcontinental Gas Pipeline ("Transco"); 2) Texas Eastern Transmission Gas Pipeline ("Tetco"); 3) Iroquois Gas Transmission System ("IGTS"); and 4) Tennessee Gas Pipeline Company ("TGP" or "Tennessee"). These pipelines interconnect with Downstate NY facilities at one or more locations located within the footprint of KEDNY, KEDLI, or Consolidated Edison Company of New York, Inc. ("Con Edison"), as further described in Section 2.2.2.2. Our Downstate NY system also receives pressure and supply support from two liquified natural gas ("LNG") plants (with liquefaction, storage, and regasification capabilities) and five compressed natural gas ("CNG") injection facilities.

The Downstate NY system serves approximately 1.8 million residential customers, 140,000 commercial customers, and 180 large customers on special contracts. There are approximately 2,200 non-firm customers with an estimated Design Day load of 160 MDth, whose service may be restricted when temperatures are very low, or system conditions are otherwise unsatisfactory to provide uninterrupted service.

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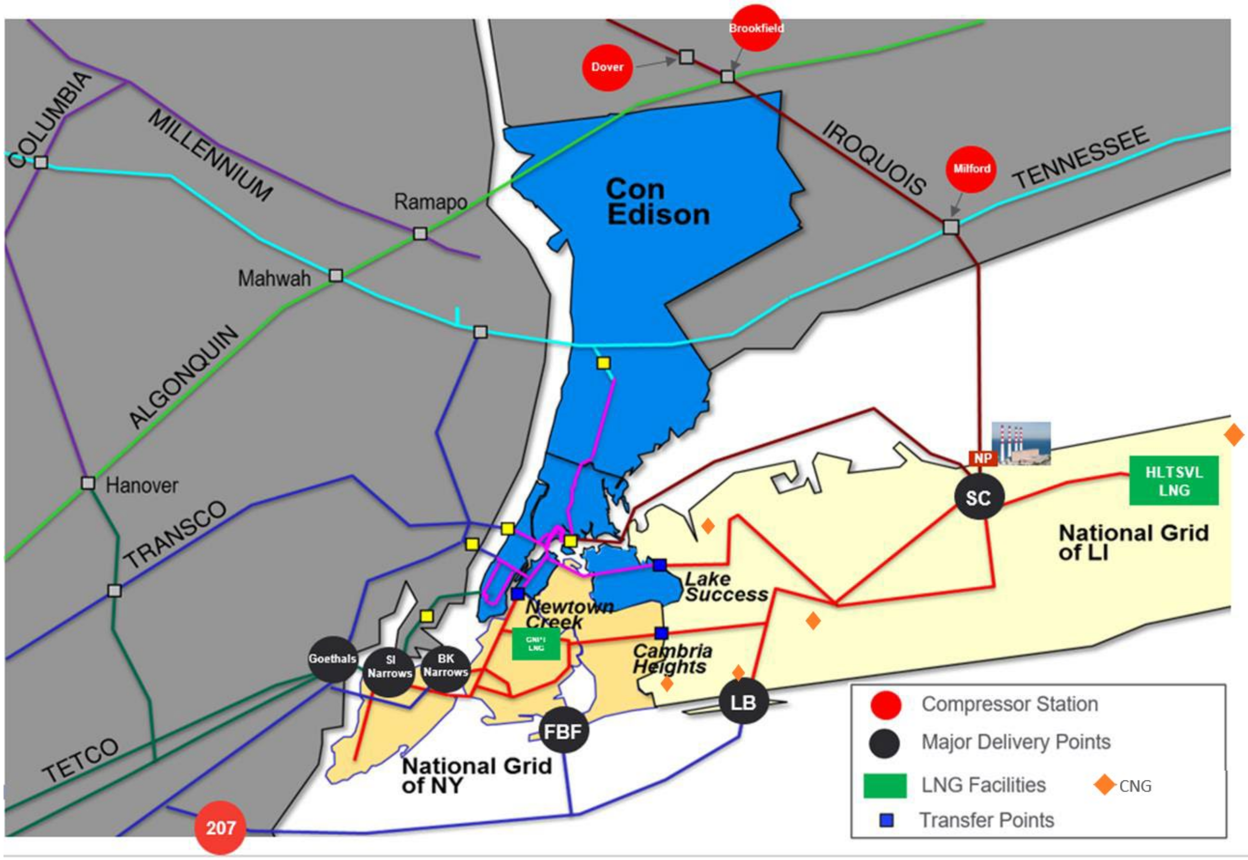
[34] Case 12-G-0297, *Proceeding on Motion of the Commission to Examine Policies Regarding Expansion of Natural Gas Service*, "Order Instituting Proceeding And Establishing Further Procedures" (issued and effective November 12, 2012) ("Natural gas is cleaner than other fossil fuels used for home heating and under current market conditions costs a third as much . . . Therefore, by this order we institute a proceeding to examine our policies concerning the use of natural gas and consider whether we should take steps to foster its use through expansion of the natural gas delivery system or otherwise."). This proceeding was closed in 2022.

[35] See, e.g., Case 16-G-0058 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, "Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans," (Issued and Effective December 16, 2016), which provided KEDNY and KEDLI an incentive to achieve growth on pages 59 and 107 of the Joint Proposal as well as a Neighborhood Expansion program for KEDLI on page 107 of the Joint Proposal.

[36] 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*; Case 23-G-0226, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*; and Case 23-G-0200, *Petition of The Brooklyn Union Gas Company d/b/a National Grid NY for a New York State Sales Tax Refund under 16 NYCRR Section 89.3 and Request for an Extension*, "Order Approving Terms Of Joint Proposal And Establishing Gas Rate Plans, With Minor Modification And Corrections," Joint Proposal's CLCPA-Related Provisions at p. 99 (Issued and Effective August 15, 2024) ("KEDNY-KEDLI Order").

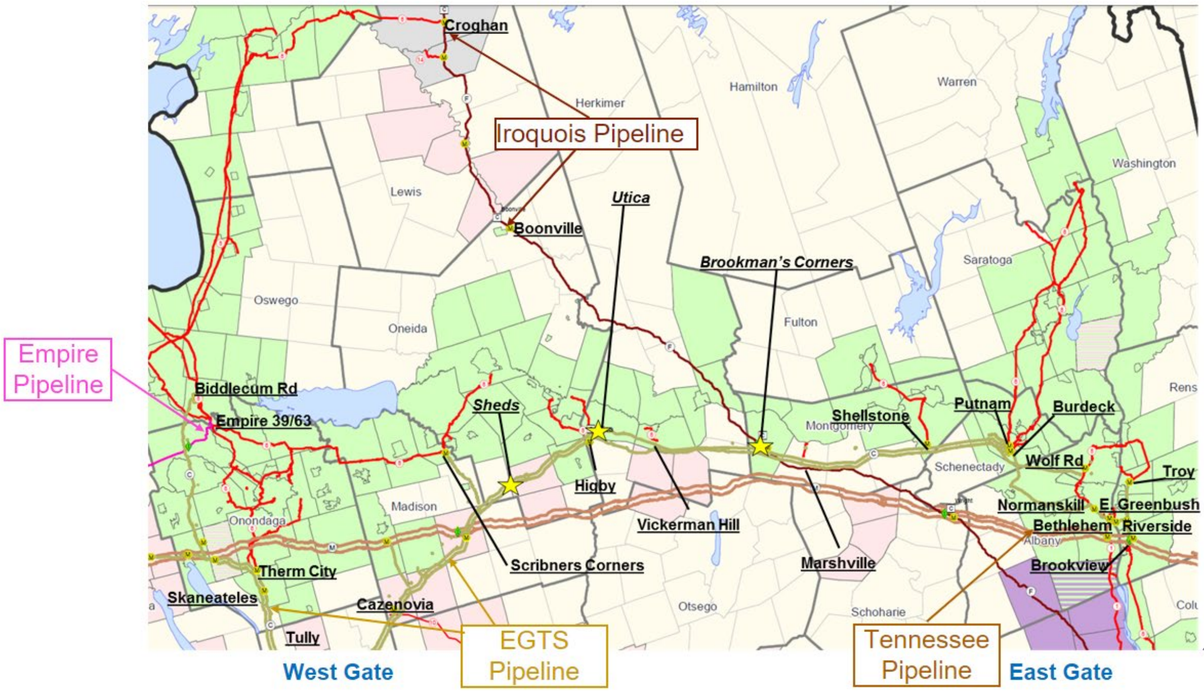
Figure 2-1: National Grid DNY Transmission Network



Our Upstate NY system is configured differently than our Downstate NY system due to geographic and logistical factors. The interstate pipelines run through our Upstate NY territory, so a Company-owned and operated fully integrated transmission system throughout the Upstate NY service territory akin to the Downstate NY system would be redundant. Instead, the Company leverages interstate pipeline facilities that provide gas at high pressure and builds the network it needs to transport gas to the rest of the Upstate NY system. Some areas are well-integrated and supplied by multiple pipeline interconnects, but many are served by a single interconnect. The majority of gas supplies are delivered by Eastern Gas Transmission & Storage ("EGTS" or "Eastern"). The Company also has interconnects with Empire Pipeline ("Empire"), IGTS, and TGP. The Company has one CNG facility located in Moreau, NY. The Upstate NY gas system is divided into an eastern division, often referred to as the East Gate, serving the Albany, Troy, and Schenectady areas, and a central division, often referred to as the West Gate, serving the Syracuse and Utica areas.[37] The Upstate NY gas system serves approximately 590,000 residential customers, 47,000 commercial customers, and 425 industrial or large customers on special contracts. There is not a substantial population of non-firm customers, however, there is a substantial population of firm, non-core customers for whom the Company ensures sufficient facilities exist on its distribution system to provide reliable service, but for whom the Company does not acquire gas capacity or supplies; these customers fall outside of the mandatory capacity release program offered by the Company and are considered non-core. The estimated Design Day load of these customers was 126 MDth in winter 2022/23.

[37] Because NMPC's electric system extends west of Syracuse, but the gas system does not, the Syracuse area is in the central division as opposed to the western division. However, EGTS is a gas-only transmission provider and refers to the Syracuse region as the West Gate.

Figure 2-2: National Grid Upstate NY Transmission System



Note: Gas Supply Points are owned by EGTS unless otherwise noted.

2.2.2.2. New York Facilities Agreement

KEDNY and KEDLI have a unique arrangement with Con Edison for the operation of the high-pressure gas transmission system known as the New York Facilities ("NYF") Agreement. The NYF Agreement denotes the systems of each company as severally constructed and owned systems while facilitating the exchange of gas between the companies. This arrangement maximizes supply diversity, minimizes capital requirements, and supports one another's daily operations, especially during planned and emergency work. The NYF system accommodates peak gas requirements and involves ten gate stations from multiple pipelines. Committees comprised of representatives from National Grid and Con Edison address design, supply, operations, and accounting concerns under the agreement. The NYF Agreement includes an annual long-term planning process considering peak demand, capital projects, pipeline interconnects, and supply procurement. The goal is to optimize system reliability at a reduced cost. Figure 2-1 above highlights National Grid's Downstate NY gas transmission network and the interstate pipelines that supply the NYF system.

2.2.3. The Electric LDCs that Serve Our Gas Customers

The majority of our KEDNY customers receive electric service from Con Edison. The majority of our KEDLI customers receive electric service from PSEG-LI. The majority of our Upstate NY gas customers receive electric service from National Grid.

2.2.4. The Communities We Serve

National Grid's Downstate NY Companies operate gas distribution networks in Nassau, Suffolk, Richmond, Queens, and Kings counties. National Grid's Upstate NY Company operates gas distribution networks serving the Albany and Syracuse regions, as well as smaller municipalities and rural areas in Central New York, the Mohawk Valley, and the North Country.

Many of National Grid's customers are located in Disadvantaged Communities ("DACs"). The Company has established internal processes to track and report on our clean energy investments in DACs in furtherance of the goals of the CLCPA. Serving DACs will require consideration of community needs in the development of our customer products and services, from inception through delivery and in all market sectors, including residential and small business programs.

The Companies' gas service territories cover DACs in multiple regions of the State. The KEDNY service territory includes three of the five boroughs of NYC. According to the New York State Energy Research and Development Authority ("NYSERDA"), 44% of census tracts in NYC and 59% of households either fall within a geographic Disadvantaged Community or are low-income. On Long Island, which corresponds with the KEDLI service territory, 14% of census tracks and 26% of households fall within this same definition. For the Upstate business, National Grid covers six of the eight regions of New York. Of these, Central NY has the highest percentage of census tracts in DACs (35%) and the highest percent of households that are low income and/or located in a DAC (47%). Of the regions of Upstate NY within NMPC's territory, the Capital Region has the lowest number of households in DACs or that of low income (35%). When categorizing customers based on geographic location alone, close to 100,000 of National Grid's residential and commercial customers are in DACs across KEDLI, and over 400,000 for each of KEDNY and NMPC.

National Grid is committed to serving customers in DACs in line with the CLCPA. The Companies aspire to center the voices of customers in DACs to inform programs, and to build trust through outreach and tailored incentive offerings, with the goal of equitable distribution of investment and benefits in energy efficiency ("EE") programs. The Companies' recent energy efficiency and building electrification proposal builds energy equity into program design and program delivery to support the Commission's statewide requirement that 35% (with a goal of 40%) of clean energy incentives go to DACs.

These efforts will be complemented by the work noted in the National Grid Energy Efficiency and Building Electrification ("BE") Programs Language Access Proposal Filing dated September 18, 2023 filed under Case 18-M-0084, which presents the Companies' plan to increase language accessibility of EE and BE programs, as well as the National Grid Diversity, Equity, and Inclusion Strategic Plan as filed on June 1, 2023 under Case 22-M-0314, which includes support for building equity within clean energy workforce development. The Companies will strive to describe the benefits of clean energy projects on several dimensions and with cultural awareness. The Companies will continue to develop tailored, culturally responsive, and in-language marketing campaigns for EE/BE programs and will explore ways of using existing IT platforms to target communications more precisely. The Companies intend to coordinate with NYSERDA and the Regional Clean Energy Hubs across the state, and with other NY State utilities in overlapping service territories to harmonize outreach efforts, drawing on the strengths of each organization. Existing partnerships with Community Based Organizations ("CBOs") will be leveraged in coordination with the Companies' Community Affairs team and Customer and Community Representatives, with new partnerships explored with organizations like chambers of commerce.

To build equity into program design, National Grid proposes to offer direct install programming to customers in DACs regardless of whether their building is a single-family residence, multifamily residence, or a commercial space. These offerings will be designed to help reduce customer energy consumption and improve customer trust and engagement with EE/BE programs. The proposed programs will bundle lower-cost measures, including but not limited to HVAC system improvements, HVAC controls, and domestic hot water controls. In National Grid's experience, direct install programs can significantly lower barriers to participation since program administrators guide customers through the entire customer journey and provide the labor and equipment required to complete the project scope. This aligns with principles from NYSERDA's DAC Barriers and

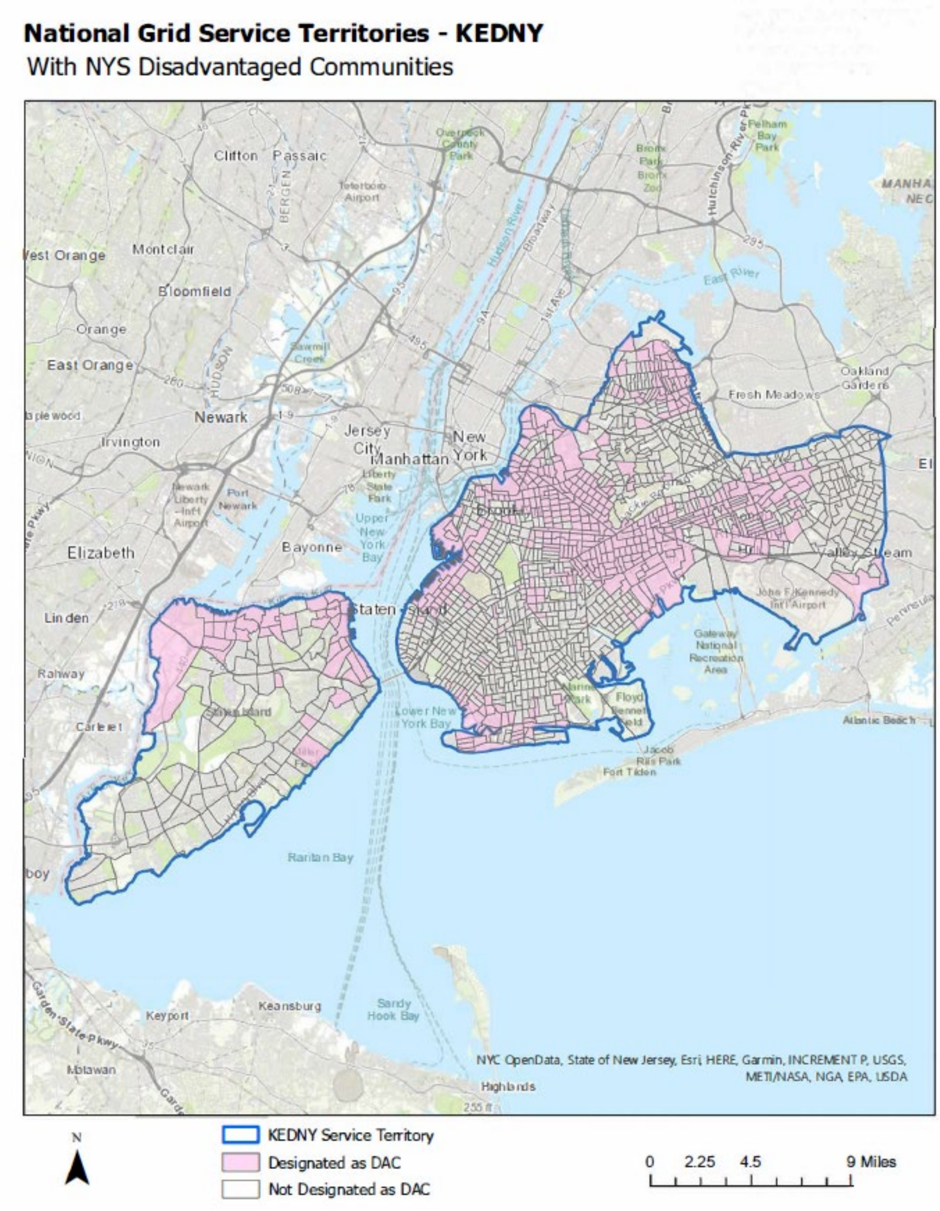
Opportunities Report, especially the principle of transitioning to program models that require little to no effort to participate.[38]

The Companies have also proposed an energy equity program evaluation initiative similar to other program evaluations, but with a focus on how well National Grid achieves energy equity benchmarks and how best to improve access for underserved communities. The evaluation portfolio will include efforts to examine how well the programs serve customers in DACs. Studies will assess program performance and participation with an equity lens and identify barriers to program access.[39]

[38] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Proposal of The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid for Market-Rate Energy Efficiency and Building Electrification Programs (filed Nov. 1, 2023) ("KEDNY-KEDLI EE/BE Proposal") at pp. 22-28 (discussing existing EE equity initiatives) and 40-45 (proposed equity initiatives for 2026-30); Case 18-M-0084, *supra*, Proposal of Niagara Mohawk Power Corporation d/b/a National Grid for Market-Rate Energy Efficiency and Building Electrification Programs (filed Nov. 1, 2023) ("National Grid UNY EE/BE Proposal") at pp. 39-43 (existing EE equity initiatives) and pp. 54-61 (proposed equity initiatives for 2026-30).

[39] Case 18-M-0084, *supra*, KEDNY KEDLI EE-BE Proposal (filed Nov. 1, 2023) at pp. 30, 34, and Appendix A Budget Tables; National Grid UNY EE/BE Proposal (filed Nov. 1, 2023) at pp. 45, 49 and Appendix A Budget Tables.

Figure 2-3: Disadvantaged Communities – New York City (KEDNY) Map



The blue lines indicate National Grid’s KEDNY service territory.

Figure 2-4: Disadvantaged Communities – Long Island & Far Rockaways (KEDLI) Map

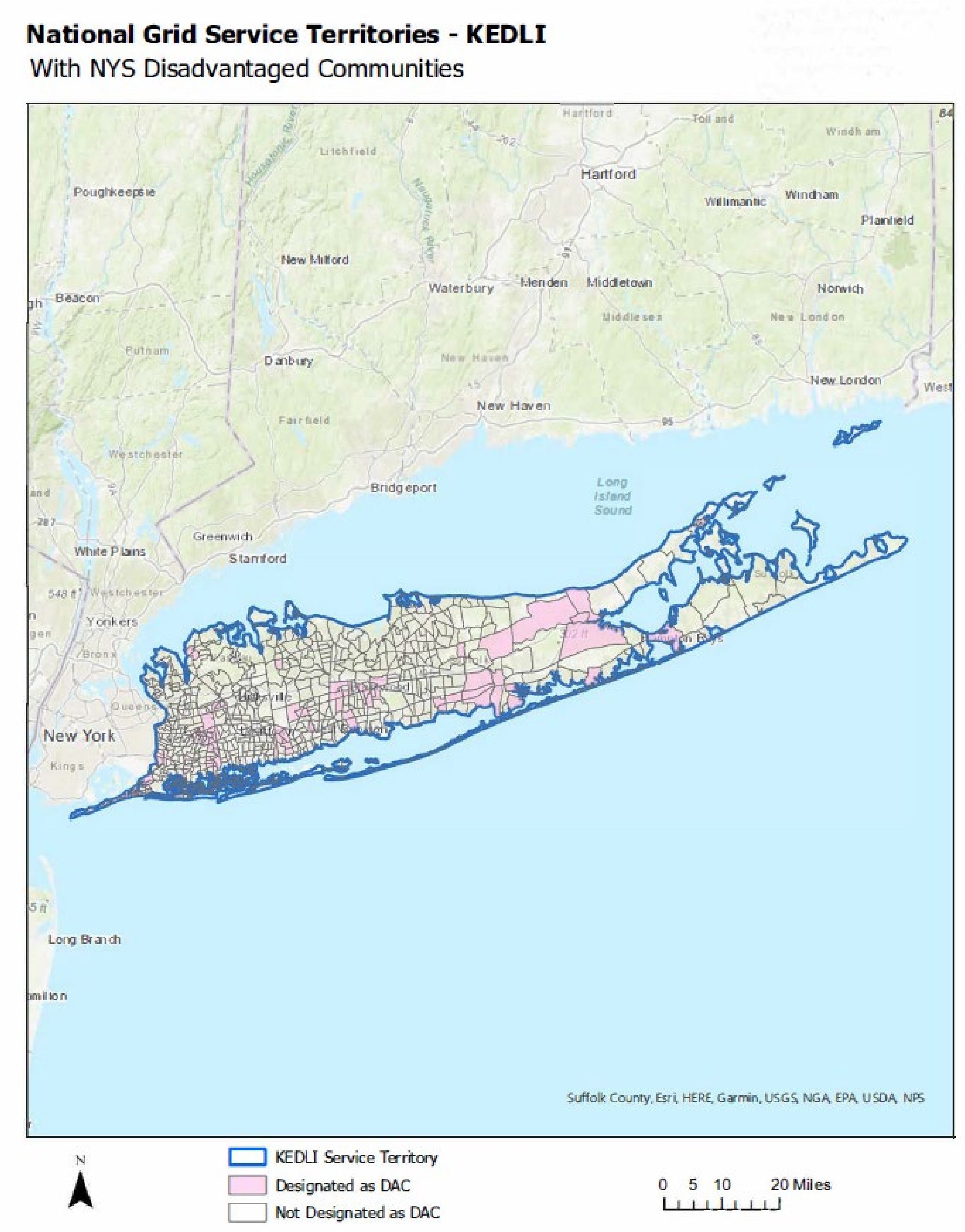
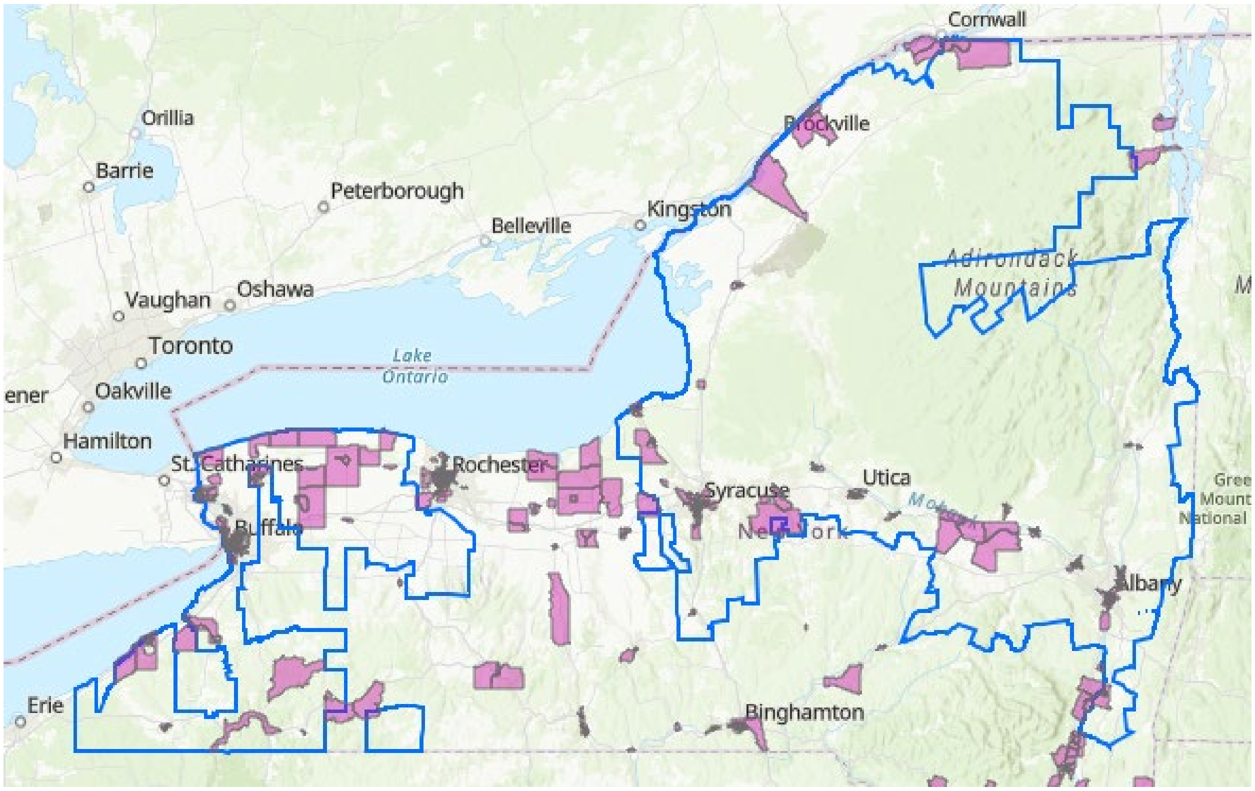


Figure 2-5: Disadvantaged Communities – Upstate NY NMPC Map



The blue lines indicate National Grid's NMPC service territory, including its Western NY territory that is electric only.

In addition to customers in geographically designated DACs, households with a total income of 60% or below the State Median Income are considered as part of the established DAC definition. Households that meet the low-income criteria are eligible for the Company's Energy Affordability Program which provides a bill discount to customers with the goal that a customer pays no more than 6% of their income on their energy bills. As of August 2024, there are 91,298 electric customers, 157,809 gas customers and 56,558 combination customers enrolled in the Company's Energy Affordability Program. Table 2-1 below displays a breakout by operating company. The Company is consistently working to increase participation in the Energy Affordability Program to provide benefits to the most customers. The Companies conduct file matches with the New York City Human Resources Administration ("NYC HRA") and the Office of Temporary and Disability Assistance ("OTDA") to enroll more eligible customers and supported legislation to create consistent statewide file matching. National Grid also conducts outreach and engagement through marketing campaigns and the Company's Consumer Advocates to increase awareness around the program.

Table 2-1: Customers Enrolled in the Energy Affordability Program

	Combination	Electric Only	Gas Only
NMPC	56,558	91,298	2,284
KEDNY			141,970
KEDLI			13,555

National Grid also estimates based on purchased income data that approximately 19% of its customers are potentially low income, meaning that they may fall within the low-income guidelines based on the Companies' data. It also estimates that approximately 12% of its customers are potentially moderate income, which is defined as households with incomes between 60% of State Median income and 80% of State or Area Median income whichever is higher, as shown in Table 2-2. Low-to-Moderate Income ("LMI") customers are also eligible for energy efficiency and building electrification programs offered either through National Grid or NYSERDA.

Table 2-2: Estimated Low-to-Moderate Income Customer Population

	Enrolled in EAP	Potentially Low Income	Potentially Moderate Income	Total
NMPC	10%	19%	8%	37%
KEDNY	12%	20%	17%	48%
KEDLI	2%	15%	13%	31%

2.2.5. We Operate in a Gas-Constrained Region

Both our Upstate NY and Downstate NY Companies are located in areas where incremental sources of gas are not readily available. There is minimal unsubscribed interstate gas pipeline capacity with deliverability to either of the Company's distributions systems. Significant growth in customer requirements in either area would necessitate additional facilities, such as an interstate pipeline expansion project or additional CNG/LNG facilities. In Downstate NY, the Department of Public Service ("DPS") Staff has noted that "the existing assets relied upon by Con Edison and National Grid have little to no headroom for Design Day growth and these utilities are already overly relying on CNG – an inherently unreliable source of gas during the cold winter months."[40] National Grid agrees that incremental CNG beyond what is currently in progress is not a viable option in Downstate NY. The Company endeavors to mitigate growth in the requirements of its customers by aggressively pursuing energy efficiency and demand response programs, encouraging prospective customers to consider electrification of their heating systems, launching a building weatherization program (i.e., insulation), and soliciting third-party NPAs to reduce the construction of additional gas infrastructure. Nevertheless, the Company continues to experience requests for new or incremental gas service and is currently required by law to provide such service if it can be done safely and reliably. Therefore, for both Upstate NY and Downstate NY, the Company currently forecasts continued growth under its Reference Case, which incorporates existing approved policies, regulations, and laws. The Company does not market gas service to existing or prospective customers.

2.2.6. New York State Economic Development

The clean energy transition presents both opportunities and challenges for economic development in New York State. Being a national leader in clean energy policy makes New York an attractive destination for manufacturers and other businesses in the clean energy economy, as well as for talented workers – and future workers – who want to be part of the transformation.

The Climate Action Council's Final Scoping Plan includes a "clean-tech-focused economic development plan" that encourages private sector investment and the attraction of clean energy related businesses to New York.[41] Indeed, that is beginning to happen. State, regional and local

[40] DPS letter to DEC, Feb 26, 2024, "DEC Application IDs: 3-1326-00211/00001 (Dover Compressor Station); 4-1922-00049/00004 (Athens Compressor Station)", page 8, available at https://dec.ny.gov/sites/default/files/2024-02/dpsresponseletter.pdf
[41] New York State Climate Action Council, New York State Climate Action Council Scoping Plan ("Scoping Plan), at Chapter 22.3, pp. 427-428 (2022). Available at https://climate.ny.gov/resources/scoping-plan/

economic development organizations, as well as National Grid's own economic development staff, are reporting an extremely high level of interest from national and international clean energy businesses that are evaluating locations for future investments. These include manufacturers in the PV/solar, offshore wind, green hydrogen, and battery storage sectors.

Additionally, the recent successful recruitment of Micron Technology, Wolfspeed, Edwards Vacuum and others, as well as existing energy-intensive companies that have long-called New York home, has bolstered New York's reputation as a good place to do business for companies in the semiconductor and other advanced manufacturing industries. Development of Artificial Intelligence and hyperscale data centers is also surging nationally, including in New York where the "Empire AI" initiative, a consortium designed to secure New York's position as a leader of artificial intelligence research, was recently announced by the State.

These projects all represent huge economic development opportunities in terms of job creation, capital investment and direct/indirect economic activity for the State and the communities in which they are sited. However, many of them are also very energy intensive, requiring both firm, reliable electricity and natural gas, with requirements that exceed the capabilities of most developable sites in the region, in terms of the existing energy delivery infrastructure, gas pipeline supply and/or electric system capacity. Successful attraction of these businesses, as well as preventing leakage of existing companies not only will require the continued availability of gas for their manufacturing processes, but also to fuel the electric generation that ultimately will be necessary to keep pace with their accompanying electric loads – which in aggregate will be extraordinary – at the same time that electric demand is also increasing to never before seen levels, and as summer peaking shifts to winter peaking.

In addition to having a limited inventory of existing "shovel ready" sites that can easily accommodate such large gas and electric loads, there is increasing concern in the business community – including developers, existing customers, and prospective customers – around the impacts the clean energy transition may have on the future availability, affordability, and reliability of gas service. The NYISO's recent reports of dwindling reliability margins are creating an additional layer of concern among economic developers, given the need for new generation to fuel future economic growth in New York. Uncertainty regarding the scope and pace of electrification is compounding these concerns, not only with respect to potential impacts on the electric system, but also direct impacts on businesses that may lack a technical and/or economic alternative to utilizing gas in their critical processes.

Just as the state has built (and earned) a strong reputation as a destination for the semiconductor manufacturing industry, the economic development community is concerned that these uncertainties will become a competitive disadvantage versus other states with transition plans (or no transition plan at all) that are perceived to be less risky from a business perspective, and where the utilities are continuing to invest not only in gas system resiliency and reliability but in the growth of their gas networks. The risks associated with operating an energy intensive business in New York – whether real or perceived – are being noted by the corporate real estate and site location consultants responsible for helping companies identify the best sites for their investments. This has the potential to undermine New York's recent success in attracting new jobs and investment to the state.

In addition to the potential dampening effect on business attraction, customer uncertainty around gas availability, affordability and reliability has the potential to disrupt the state's existing manufacturing base. The New York economy includes major manufacturers in the paper/paperboard, primary metals, chemicals, glass, food processing and other gas-intensive industries. Many of these operations will be difficult if not impossible to electrify in the near term with existing technology. As the clean energy transition and NYCI move forward, retaining these businesses will be a serious challenge for the State, potentially putting thousands of high-paying jobs at risk. Some may become financially distressed and shut down. Others, particularly those with similar manufacturing establishments in other states, may choose – or be required by their parent company – to shift their operations to other corporate locations where there are perhaps more options and more certainty around meeting their energy requirements. This “leakage” represents a zero-sum game in terms of the national and global efforts to reduce carbon emissions, and it represents a net loss for the economy and communities of New York State.

2.2.7. Our Long-Term Gas Capacity Reports Demonstrated our Strategy to Meet Growing Downstate NY Customer Requirements and informs our Long-Term Plan approach

National Grid’s continued investments in its gas infrastructure to ensure sufficient capacity on the Design Day is informed by the potentially devastating impact of a gas outage caused by a supply shortfall. DPS Staff recently articulated this in a letter[42] issued in February of this year, as follows:

“Should the gas system not have adequate supply and capacity to meet Design Day demand, the results can be catastrophic. To avoid potential unsafe operating conditions, the gas utility would need to curtail customers’ usage by shutting off parts of its system. If such curtailments extend to residential customers, those customers would be without their primary – and potentially only – source of heat on what would invariably be one of the coldest days of the year. Unlike the restoration of electric service, which can happen quite quickly after an interruption, an interruption of gas service to residential customers can take weeks and even months to restore in a safe manner. The reason for the lengthy time of restoration is because utility personnel must go from building-to-building to ensure all appliances are turned off prior to restarting gas service. Otherwise, restoration of service could result in gas spreading into a building, resulting in a significant fire hazard and risk to public health. For this reason, it is critically important to maintain gas system reliability at all times.”

The consequences of unplanned outages to the electrical grid are familiar: critical medical equipment can cease to function, the risk of heat stroke and other medical emergencies rises, food spoils in refrigerators, schools cannot operate, etc. However, outages on the gas system are exceedingly rare. A survey by the American Gas Association, reported by the Natural Gas Council, revealed in one recent year that Americans experienced 8.1 million power outages and fewer than 100,000 natural gas outages. This low frequency of occurrence – particularly the exceedingly low frequency of them occurring on the coldest days of the year – means that many people are unaware that the impacts and consequences are much more severe than with electrical blackouts.

Typical small gas outages – e.g., ones that occur when someone inadvertently damages a gas pipe while digging in their yard – are resolved quickly and without system-wide disruption; and they can occur on any day of the year, including mild or warm days, so the impact is limited. However, outages that occur as a result of imbalances on the gas system due to high demand for, and low supply of, natural gas, are a different matter. First, they would be likely to occur on the coldest days of the winter, when customers are using the most gas to heat their homes and businesses, and so would have a much higher impact on customers. Second, the process to restore gas service in these instances is much more complicated and challenging: the local gas distribution utility must first shut off the flow of gas to select areas of the system to ensure safety, then go to every single premise in that area to stop the flow of gas to every single piece of gas-burning equipment (including boilers, furnaces, stoves, and hot water heaters), and then, once normal gas system pressures have returned, enter every customer premise to safely restore the flow of gas. This process can take from days to weeks; and during that time, customers will be without gas, and so may not have the ability to effectively heat their homes and businesses. Since such an outage is more likely to occur on the coldest days of the winter, customers are at risk of being exposed to very extreme temperatures,

[42] *See* DPS letter to DEC at page 7-8.

elevating risks to health, life, and safety. In addition, property risk from frozen pipes bursting may occur following an extended cold weather outage, especially after temperatures rise enough to thaw out the broken pipes and enable water flow.

As noted above, unlike with the electric system, there is zero allowable contingency or reserve margin to guard against extreme weather or unexpected disruption to gas supply, gas infrastructure, or demand-side resource availability. Zero contingency means that the plans for balancing gas demand and supply have no supply contingency or reserve margin. In other words, the system is designed to balance supply and demand, assuming forecasted peak demand is not exceeded and that all available gas capacity resources will be available with no disruption.

In 2019, because of serious concerns about the potential for such an outage, National Grid announced that it would stop connecting new gas customers because of a forecast shortfall in the supply of natural gas needed to meet growing demand in Downstate NY. The response from residential customers, small businesses, developers, elected officials, customer advocates, and regulators[43] was overwhelmingly negative, as these stakeholders expressed concern about the economic development, affordability, and other impacts of denying customers viable options for satisfying their heating needs. As part of a settlement with the State of New York (the "Settlement"),[44] National Grid agreed to lift the service restrictions and implement various short-term measures to continue serving new customers. Acknowledging both the extent of the supply gap, and that new solutions were necessary to avoid future moratoria, the Settlement provided that National Grid would conduct a public process to identify projects and programs to maintain sufficient gas supplies in Downstate NY.

From 2020 through 2022, the Company issued four Natural Gas Long-Term Capacity Reports for its service territories in Brooklyn, Queens, Staten Island and Long Island. The reports provided detailed analysis of the natural gas capacity constraints in the region and the available options for meeting long-term demand. National Grid held a series of public meetings and received thousands of written comments.

This process identified a distributed infrastructure solution consisting of LNG Vaporization, CNG injection, and IGTS enhancements to existing infrastructure, and a roadmap for how additional DSM measures could be leveraged given necessary funding and policy treatment.

The Company has developed and commissioned the additional portable compressed natural gas capacity and has developed a plan and secured long-lead materials for the proposed LNG vaporization enhancements at its existing Greenpoint facility. The Company also continues to support the ExC project being pursued by IGTS.

2.3. Our Long-Term Plan Scenarios

This Long-Term Plan presents three scenarios – the Reference Case, the Clean Energy Vision, and the Accelerated Electrification scenario – to outline what can be achieved under existing conditions, and what conditions would be necessary to create a range of CLCPA-compliant outcomes in the future. These scenarios are not intended to be predictive. Undoubtedly the future state of New

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[43] Case 20-G-0131, *Case Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, "Order Adopting Moratorium Management Procedures" at 24 (issued and effective May 12, 2022) ("Moratorium Management Order").
[44] Case 19-G-0678, *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid*, "Order Adopting and Approving Settlement," Appendix A dated November 24, 2019 (issued and effective November 26, 2019).

York's energy systems will not perfectly align with any of the scenarios presented here. Instead, we aim to define the window of opportunity for achieving the CLCPA targets, identify "no-regrets" steps that can be taken in the near-term, and establish key indicators and signposts to guide policy and regulatory decisions in the future.

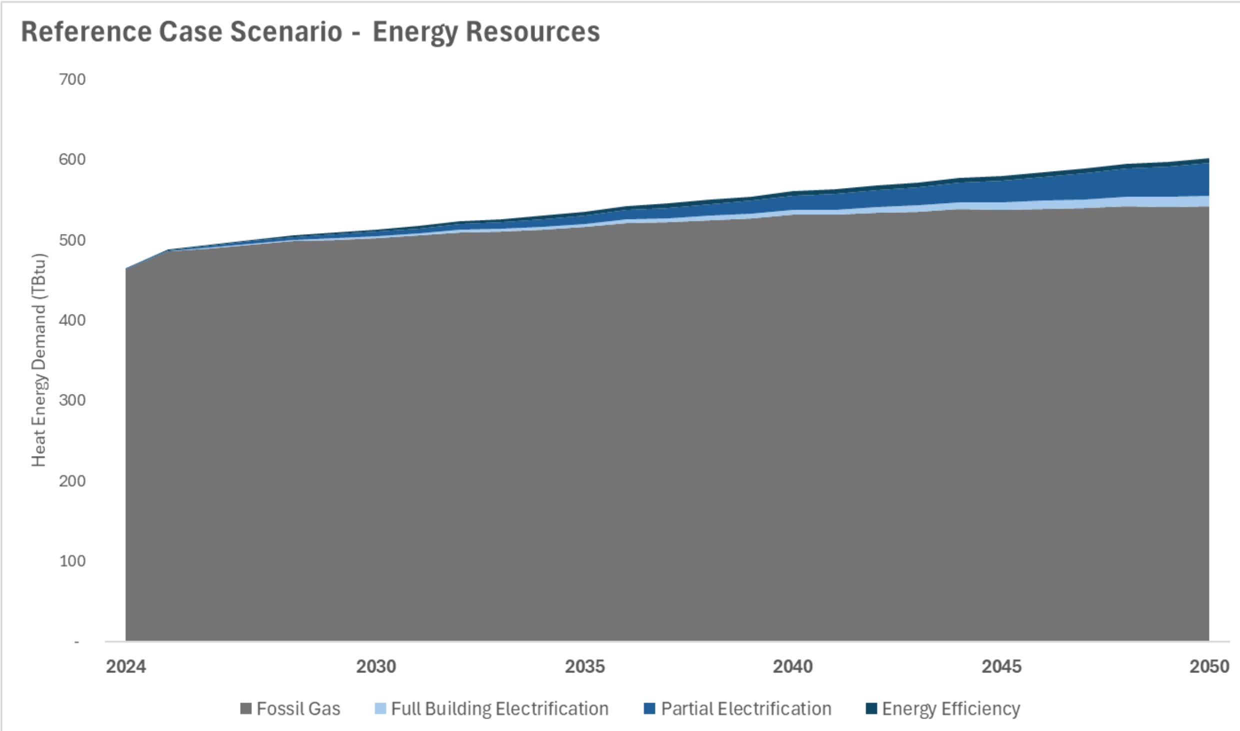
2.3.1. Reference Case Scenario

National Grid's Reference Case in the LTP is a representation of the Company's forecast of supply and demand that reflects National Grid's existing customer programs and outlook for key drivers that are external to National Grid. This includes a demographic and economic outlook, natural gas and electricity prices, and assumptions regarding the availability of end-use technologies.

The Reference Case reflects today's legal and policy framework, which incorporates important first steps at reducing GHG emissions, but does not allow for meaningful reductions in the use of fossil natural gas. The Reference Case assumes limited regulatory, technological, and market changes during the next two decades, but does include clean energy investments that the Commission has approved as well as existing legislation. In addition, capital investments are made based on a business-as-usual approach, which means the Company will continue to allocate funds to ensure the safe and reliable delivery of energy. The system growth in the Reference Case considers the current legislation and local laws that affect new gas service hookups. This approach aims to maintain the existing infrastructure and accommodate any necessary expansions under known regulatory and market conditions.

It is important to note that the Reference Case does not include the impact of CLCPA actions that have not yet been planned or implemented, and it assumes that none of the identified National Grid decarbonization actions in the CEV or AE scenarios have been implemented. The Reference Case is a baseline against which one can measure the GHG emissions reductions and associated costs that result from implementing the specific decarbonization actions that comprise each scenario.

Figure 2-6: Reference Case Scenario



2.3.2. Clean Energy Vision Scenario

The Clean Energy Vision ("CEV") scenario represents National Grid's preferred pathway for achieving the CLCPA's emissions reduction targets. It involves fully eliminating fossil fuels before 2050, rapidly expanding electrification and energy efficiency, leveraging existing gas infrastructure to lower costs, enhance equity, supporting overall energy system reliability and resilience, and putting the existing gas utility workforce at the center of the clean energy transition. The CEV represents a hybrid approach to decarbonization in which the majority of heating demand in 2050 is met through energy efficiency and electrification, while the gas network plays a complementary role delivering low-carbon alternative fuels. The costs in the CEV scenario exclude investments required by the customer behind the meter, decommissioning of the gas network, and incremental operating expenses (“OpEx”) for avoided capital expenditures (“CapEx”) necessary to maintain safe and reliable energy deliveries. The CEV scenario empowers customers with multiple options for clean energy.

National Grid’s CEV rests on four pillars of action:

- Pillar 1: Energy efficiency in buildings – National Grid will continue to provide programs for our customers to accelerate energy efficiency improvements to buildings, including deep retrofits and measures that reduce peak gas and electric demand; and support more rigorous building codes for new buildings.
- Pillar 2: 100% fossil-free gas network – National Grid will eliminate fossil fuels from our existing gas network no later than 2050 by delivering renewable natural gas and green hydrogen to our customers.

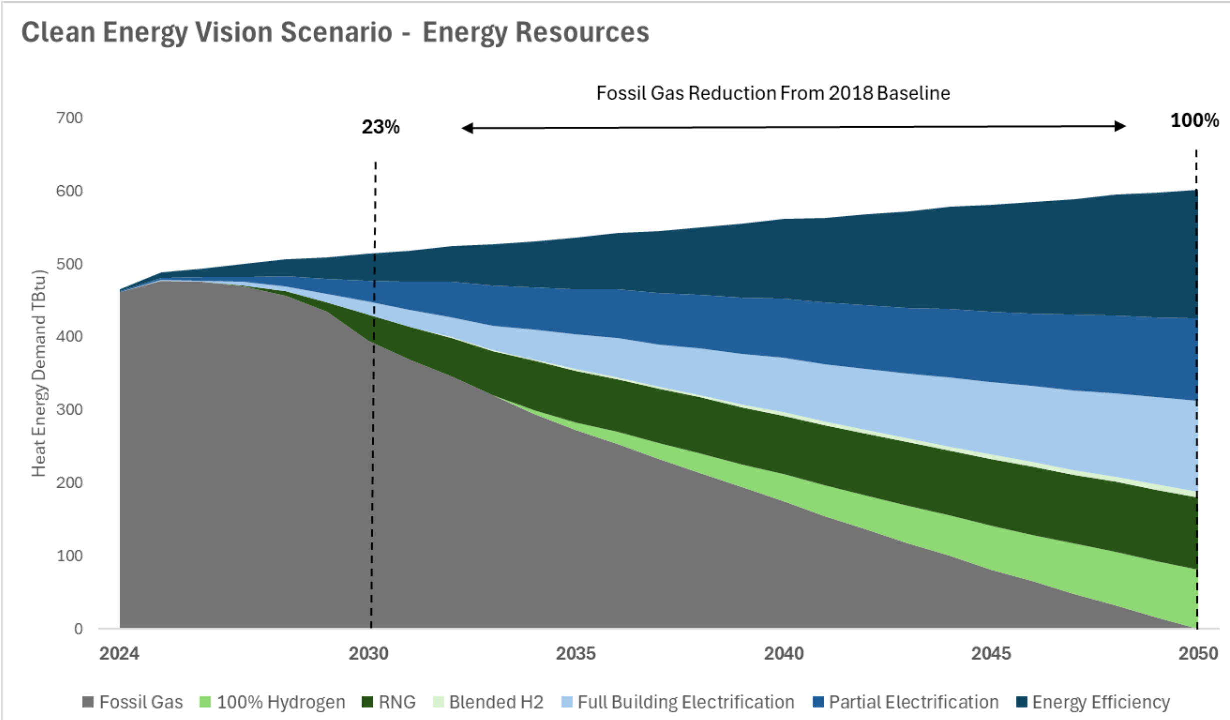
- Pillar 3: Hybrid electric-gas heating systems – National Grid will support our customers by providing them strategies and tools to capture and maximize the benefits of pairing electric heat pumps with their gas appliance.
- Pillar 4: Targeted electrification and networked geothermal – National Grid will support cost-effective targeted electrification on our gas network, including piloting new solutions like networked geothermal. The Company will support customers who heat with oil and propane with strategies and tools to convert to heat pumps.

The CEV is consistent with the Scoping Plan's findings, including:

- Recognition that electrification and energy efficiency will be essential to decarbonization of the buildings sector. The Scoping Plan's vision for 2050 is for 85% of residential and commercial buildings are electrified "with a diverse mix of energy efficient heat pump technologies, and thermal energy networks,"[45] and the value of using backup heat sources, particularly in cold areas or to mitigate potential electric capacity constraints.[46]
- Recognition that decarbonization will "entail a substantial reduction of fossil natural gas use and strategic downsizing and decarbonization of the gas system."[47]
- Recognition of the strategic role that clean alternative fuels may play "to meet customer needs for space heating or process use where electrification is not yet feasible or to decarbonize the gas system as it transitions."[48]
- Recognition that the pace of gas network transition will depend on the pace of customer adoption of alternative heating technologies, and that gas utilities retain an obligation to provide safe and reliable service.[49]

[45] Scoping Plan, p. 180.
[46] Id., p. 361.
[47] Id., p. 350.
[48] Id., p. 351.
[49] Id., p. 353.

Figure 2-7: Clean Energy Vision Scenario



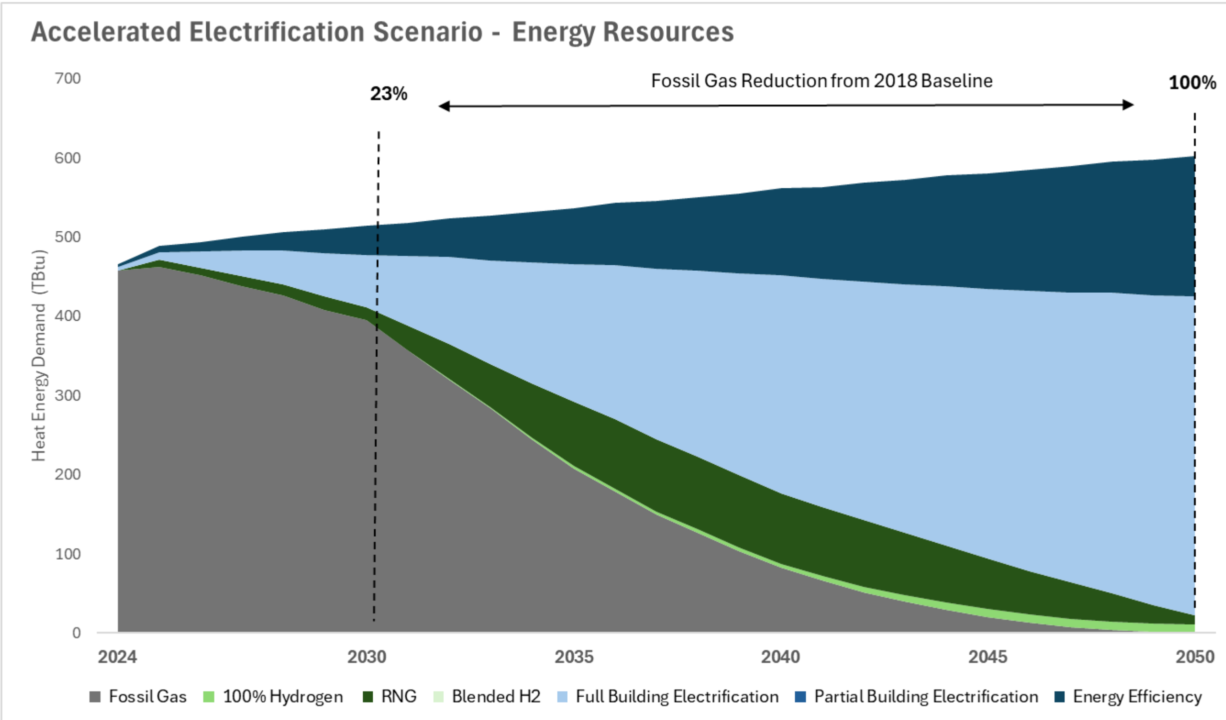
2.3.3. Accelerated Electrification Scenario

The Accelerated Electrification ("AE") Scenario is based on Scenario 3 of the Climate Action Council's Integration Analysis.[50] This scenario also uses significant volumes of low-carbon alternative fuels, but higher levels of electrification than the CEV. The AE scenario assumes a more limited role for RNG and hydrogen combustion than the CEV. The costs in this scenario exclude investments required by the customer behind the meter, decommissioning of the gas network, and incremental OpEx for avoided CapEx necessary to maintain safe and reliable energy deliveries.

The scenario parameters were adjusted based on geography to account for the different demand profiles and technology mixes that exist in various regions. The feasibility of low and zero-carbon replacements, as well as the influence of local policies such as NY City's Local Law 97, varied by region. Upstate regions, where heating oil is more prevalent, will have different energy profiles and decarbonization options. The use of networked geothermal will be limited to areas with suitable soil characteristics, close customer proximity, and affordable pipelaying. All of these factors were taken into consideration when forecasting demand for the regions analyzed in this LTP.

[50] https://climate.ny.gov/resources/scoping-plan/-/media/project/climate/files/Appendix-G.pdf

Figure 2-8: Accelerated Electrification Scenario



3. Demand Forecast

Demand forecasting is vital for National Grid to provide safe, reliable, and affordable service to its customers in New York. These forecasts inform rate-making decisions by projecting billed gas volumes and aid infrastructure planning by determining system sendout requirements.

Unplanned outages on extremely cold days can have severe consequences, requiring multiple visits to affected homes and businesses for shutoff and subsequent relighting when gas service is restored. Recovery from such events is labor-intensive and time-consuming, lasting days to weeks, or potentially longer in the event of a large-scale customer outage. Therefore, it is crucial to maintain regular operations during multi-day cold snaps, the coldest day, and peak usage hours. Local distribution companies address this by developing design planning criteria to meet demand on a "Design Day/Design Hour," ensuring they can serve demand during the peak hours of extremely cold days.

This section provides an overview of National Grid's forecasting methodology, outlines key assumptions for the three scenarios discussed in this filing, and presents forecast results for meter count, annual volume, and Design Day demand for each scenario.

3.1. Design Standards

Design standards are a pre-requisite to demand forecasting because they establish the most severe weather that the Company plans to. The design standards set forth the defined weather conditions and consequent sendout requirements that must be met by resource portfolios throughout the year.

The Company maintains the following design standards:
1. **Design Day Standard**: Used to establish the amount of system-wide throughput (i.e., interstate pipeline and vaporization capacity) that must be available to the system on the peak day.
2. **Design Year Standard**: The design-year standard identifies the amount of gas supply that will be required over the design year to provide continuous service to customers under all design weather conditions.

Through the interaction of these two standards, the Companies are able to ensure that sufficient pipeline, vaporization, and decompression capacity is available on the Design Day and that there is adequate gas supply, flowing and in storage (underground storage and supplemental resources), to provide reliable service throughout the design year.

National Grid models the Downstate NY gas supply and distribution requirements for KEDNY, KEDLI, and in conjunction with Consolidated Edison for the NY Facilities System based upon a Design Day average temperature of 0 degrees Fahrenheit ("°F") in Central Park (i.e., 65 Heating Degree Days). Upstate NY gas supply and distribution requirements are modeled based upon a Design Day average temperature of -10°F at Albany and Syracuse airports (i.e., 75 Heating Degree Days).

The Downstate NY design year and Design Day standards are listed in Table 3-1 below.

Table 3-1: Downstate NY (KEDNY and KEDLI) Design Year and Design Day Criteria

Element	Value
Design Year HDD	5,141
Design Day HDD	65

The Upstate NY Eastern District (Albany) design year and Design Day standards are listed in Table 3-2 below.

Table 3-2: Upstate NY NMPC-East Design Year and Design Day Criteria

Element	Value
Design Year HDD	7,284
Design Day HDD	75

The Upstate NY Central District (Syracuse-Watertown) design year and Design Day standards are listed in Table 3-3 below.

Table 3-3: Upstate NY NMPC-West Design Year and Design Day Criteria

Element	Value
Design Year HDD	7,400
Design Day HDD	75

3.2. Demand Forecasting Methods

3.2.1. Methodology Overview

National Grid's gas demand forecasts are used to anticipate the needs of the distribution systems each winter, enabling National Grid to take necessary steps to ensure it has both an adequate gas supply and sufficient capacity on its system to meet the projected demand under Design Day conditions. As part of the annual gas load forecast process, National Grid prepares the following for each distribution company:

- Retail Forecast: forecast customer usage at customer meter. This is a monthly forecast of gas consumption at the retail level. The retail forecast is used for rate-setting purposes and is a key component in the Companies' wholesale forecast.
- Wholesale Forecast: The amount of incoming gas needed to satisfy the retail forecast, as measured at the Companies' city gate stations. This forecast is adjusted upwards from the retail forecast to account for loss within the system, such as unmetered usage, line losses, and metering errors. This is a daily forecast of wholesale gas requirements.
- Design Day Forecast: The wholesale requirements for the Design Day. This is used to ensure that the Companies have the resources to meet customer demand on the coldest days.

The demand forecasts, for both the Reference Case as well as the alternative demand scenarios, rely on the same general forecasting process. National Grid's forecasting methodology is described in these five steps:

1. Unadjusted baseline retail forecast: Determining the monthly retail demand using econometric regression-based models.

2. Adjusted baseline retail forecast: Adjusting for exogenous factors not captured in step 1. These could include acceleration in energy efficiency programs and electrification of heat initiatives as well as the impact of state and local regulations. These assumptions differ by scenario and are described in Section 3.3.2.

3. Retail to wholesale adjustments: Converting the monthly retail demand forecast to a normalized forecast of daily wholesale demand.

4. Wholesale and Design Day forecast: Specifying the forecasted daily demand at the wholesale level under design weather conditions.

3.2.1.1. Step 1 – Unadjusted Baseline Retail Forecast

In step 1 of the forecasting process, the Companies create econometric forecasts for the meter counts and average use-per-customer of different customer rate groups within each service territory. These forecasts are based on the billing data, weather data, economic data, and commodity price data.

The Companies develop these econometric forecasts of the monthly meter count and use-per-customer for each rate group in KEDNY, KEDLI, and the two gas divisions of NMPC: Eastern (Albany area) and Central (Syracuse-Watertown area). Each rate group is a combination of data from rate code level data aggregated to create pools of customers of similar characteristics in terms of their natural gas consumption and applications (residential non-heating, residential heating, commercial, multi-family, non-firm demand response, industrial, other). The forecasts of meter count and use-per-customer are then multiplied together to create the volume forecast for each of these rate groups.

To ensure their reliability in forecasting, each of its econometric models is based on the following best practices:

- Basing its models on monthly data.
- Minimizing the use of time-series analysis.
- Deriving its volume forecast through the product of number of customers times use-per-customer.
- Parsimonious reliance on indicator variables.
- Relying on independent variables whose t-statistics are greater than 2.0 to the greatest extent possible.
- Testing and correction for autocorrelation and/or heteroscedasticity which might occur in the residuals of the various models.
- Selecting stable models using Chow tests and ex-post forecast analyses.

Each model then is reviewed through a quality control process before incorporation into its forecast. The resulting forecasts are then adjusted for any exogenous factors that cannot be captured in the econometric models.

3.2.1.2. Step 2 – Post-Model Adjustments

The Companies' historical billing data includes the impact of past DSM programs and local laws and legislation. The econometric forecasts built from this historical data reflects these past savings in the forecast horizon but do not reflect any acceleration in DSM initiatives, upcoming local laws/legislation expected in next few years, market saturation, or other exogenous factors. Therefore, in National Grid's Reference Case, the econometric forecasts are adjusted for funded DSM savings, enacted local laws and legislation, and market saturation limits. This becomes the main planning scenario for National Grid.

In this step, the Clean Energy Vision and Accelerated Electrification scenarios are also created with a different set of assumptions. Both scenarios reflect a Net-Zero future and have higher levels of energy efficiency and electrification compared to the Reference Case.

3.2.1.3. Step 3 – Retail to Wholesale Adjustments

As described above, the retail forecast represents the meter count and volume projections, allocated to the internal rate code level, on a monthly basis under normal weather conditions. The retail forecast is used for pricing purposes and is a key input to the Companies' wholesale forecast. The wholesale forecast is used for resource planning and represents the daily amount of incoming gas needed to satisfy the retail demand that is adjusted upward for unmetered usage, line losses, and metering errors.

In Step 3 of the forecasting process, the Companies convert the retail demand under normal weather conditions into daily forecasts of wholesale (city gate) demand. This conversion involves inflating the retail forecast by the most recent lost-and-unaccounted-for factor (LAUF) and adjusting it to reflect calendar months to account for the lag in billing data. The adjusted calendar-month forecast is then distributed to the daily level based on regression analyses, which analyze the relationship between daily heating degree days and daily wholesale sendout. By adjusting and aligning the historical retail data with the historical wholesale data, the Companies convert the retail forecasts into daily wholesale forecasts under normal weather conditions.

To establish the normal year's daily HDD data, the Companies calculated the average annual number of HDD for the most recent thirty-year period. The results are presented below in Table 3-4.

Table 3-4: Normal Year Criteria

Service Territory	Weather Station	Time Period	Value
Downstate NY	KNYC, Central Park, NY, NY	Jan. 2014 – Dec. 2023	4,406 HDD
NMPC-Eastern	KALB, Albany International Airport	Jan. 1990 – Dec. 2019	6,378 HDD
NMPC-Central	KSYR, Syracuse Hancock International Airport	Jan. 1990 – Dec. 2019	6,494 HDD

3.2.1.4. Step 4 – Forecast for Design Day and Year

In Step 4 of the forecasting process, the Companies translate normal weather wholesale forecast to the level expected under design weather conditions based on the observed differences in daily sendout under design vs. normal weather. These design weather forecasts include the Companies' Design Days so the forecasts will then govern the amount of daily, seasonal, and peaking supplies needed in the Companies' resource portfolios.

The forecasting process is an iterative one. After releasing the annual planning scenario, the Companies continuously monitor both their retail and wholesale forecasts through variance reports. These reports serve to provide assurance regarding the adequacy of resource and distribution system planning based on the forecasts and offer insights for modelling improvements in the next forecast cycle.

3.2.1.5. Consideration of Uncertainty

National Grid recognizes the importance of understanding forecast uncertainty. In addition to the Reference Case, which serves as the Companies' main planning scenario, and the two decarbonization scenarios discussed in this filing, the Company also generates scenarios that incorporate uncertainty related to the economic outlook, DSM achievements, and policy impact. Analyzing the uncertainty surrounding these factors helps account for the range of potential outcomes in the forecast, which is particularly crucial for Design Day analysis.

To address this uncertainty in the main planning scenario for Design Day, the Companies create a band of uncertainty around the Reference Case. This band is constructed based on past modeling errors and sensitivities in the post-modeling adjustment impacts. It represents uncertainty, where the Design Day forecast could deviate slightly higher or lower than the Companies' primary planning scenario. In the long term, the Companies refer to the Clean Energy Vision and Accelerated Electrification Scenario to demonstrate the impact of different decarbonization pathways. Section 3.4 provides an overview of the uncertainty bands around the Reference Case.

3.3. Forecast Assumptions & Inputs

3.3.1. Economic Outlook (Early 2024)

The econometric forecasts are based on Moody's historical and forecasted outlooks for the Upstate NY and Downstate NY service territories. Summaries of the Moody's' outlooks for early 2024 when these forecasts were developed are provided below.

3.3.1.1. Downstate NY

The Downstate New York economy has seen recent growth, but it is expected that some of this growth will not be sustained in the long run due to unfavorable population and demographic factors. In 2023, the gross domestic product (GDP) expanded by 3.1%, surpassing the previous expectation of 1.7%. However, the renewed strength is not expected to last, with growth expectations for 2024 in the 2% range and a further dip to 1.3% growth in 2025.

The massive banking sector has struggled due to reduced deal volumes in an elevated interest rate environment, leading to employers cutting back on payrolls. This will impact economic and job growth in the near-term. However, there is some relief as the Federal Reserve is expected to postpone further increases in its key Reserve rate. Rising tourism flows to New York City will benefit consumer-oriented industries, but as the number of annual visitors approaches pre-pandemic levels, there is limited room for further improvement. Diminished weekday commuter traffic due to work-from-home policies will also temper the benefits from this sector. However, Long Island's medical services sector, with its share of wealthy retirees and low uninsured rates, will provide some relief to the regional economy.

Despite the drop in residents due to high living costs, which is in line with general out-migration patterns for the Northeast region, the housing stock expanded 0.3% in 2023 with similar gains expected in 2024 and beyond. This is the result of a history of underbuilding in a very tight market where demand for housing outstrips the supply of available units. Growth in the multifamily housing stock outpaced the corresponding increases in single-family units by several fold in 2023 as a result, representing a significant component of energy usage downstate.

Following updates to the commodity price forecasts, favorable price differentials for natural gas indicate its cost advantage will remain intact, which will ensure it is the preferred choice compared to alternative energy sources for many consumers, even as softer economic conditions weigh on customer in other ways through the near-term.

3.3.1.2. Upstate NY

Following a few tough years in the aftermath of the pandemic, the Upstate New York economy is making solid gains again, although some of the strength is not expected to last beyond the near-term. Gross domestic product (GDP) expanded 2.5% in upstate New York in 2023, coming in above the 2.2% previously expected. Despite some setbacks in some parts of the upstate region, like Buffalo, the upstate economy is trending in the right direction more decisively this year. The positive momentum is expected to translate into even faster GDP growth in 2024, clocking in at 2.9% per annum according to Moody's projections before shifting to a lower growth state hovering around the 2% range, on average, in 2025 and beyond.

Although there is still some progress to be made before employment reaches its precession peak, total non-farm payroll employment growth exceeded expectations in 2023, with a 1.5% increase compared to prior expectations of decline. Employment growth will taper in line with overall economic growth in 2024 and 2025, with 1.3% and 0.5% growth expected in each year, respectively. Rapid growth in semiconductor and nanotechnology industries will be a key source of employment strength and will go a long way toward revitalizing local manufacturing and adding high-paying jobs.

Despite a drop in the number of households, the housing stock expanded 0.3% in 2023 with similar gains expected in 2024, and a further uptick to come in 2025. Like DNY, this is the result of demand for housing being higher than the supply of available units. The old age of the housing stock in the upstate region also presents significant opportunities for renovation and/or reconstruction.

Updated commodity price forecasts indicate that natural gas will maintain a cost advantage over other energy sources, making it a favorable choice for many consumers when compared to alternatives.

3.3.2. Reference Case DSM & Policy Assumptions

3.3.2.1. Adjustments for Reference Case

The Reference Case serves as the primary scenario used by the Companies for planning purposes, while the alternative scenarios portray various decarbonization pathways. The assumptions used in Step 2 of the forecasting methodology for the Reference Case, which involves the post-model adjustment process, are detailed below.

3.3.2.2. Factor in market saturation of customer growth

The Companies consider restrictions on residential and commercial growth from oil-to-gas conversions (for structures that are not currently gas customers) in the forecasts. The Companies estimate an upper limit on future oil-to-gas conversions and then cut off customer growth in the unadjusted retail forecast due to conversions at that saturation point.

The Companies also cap the number of residential non-heating to heating conversions based on a market saturation analysis. Customer buildings with and without existing residential heating accounts at the same address were identified and addresses with existing heating accounts are not considered candidates for conversions. This information sets a floor on the decline in residential non-heating meters, which in turn limits residential heating growth.

Finally, the Companies assumed there is a floor in the decline of KEDNY's Non-Firm Demand Response ("NFDR") customers (see section 4.5 for more details on these customers). These saturation adjustments, which help project realistic growth in the forecast horizon out to 2050, are also used in the Clean Energy Vision and the Accelerated Electrification scenarios.

3.3.2.3. Factor in Local Law 154 and the All-Electric Building Act

The Companies also consider the impact of enacted local laws and legislation. Local Law 154 ("LL 154") prohibits the installation of gas systems or equipment in newly constructed buildings in NYC less than seven stories tall starting in 2024, and in buildings greater than seven stories starting in 2027, with exceptions for certain building types. This law affects the KEDNY service territory and a small part of the KEDLI territory.

In May 2023, the New York State legislature passed the All-Electric Building ("AEB") Act, which prohibits the installation of gas systems or equipment in new construction up to seven stories starting in 2026, and in all new buildings from 2029 onwards, with exceptions for certain building types. Neither LL 154 nor the AEB Act restrict or prohibit oil-to-gas conversions in existing buildings or low-use heating upgrades.

Based on this information, the Companies estimated the percentage of new construction customers affected by LL 154 and the AEB Act in each service territory. Customer growth from new construction in the unadjusted retail forecast was then curtailed to reflect the impact of these laws.

3.3.2.4. Factor in Local Law 97

Local Law 97 ("LL 97") imposes greenhouse gas emission limits on large NYC buildings. Building owners must report their energy use and reduce emissions or face penalties for exceeding the limits. Emissions reduction can be achieved through any combination of energy efficiency, fuel switching, and decarbonization of fuels.

The Company created a forecast of average gas usage for each building type that resulted in compliance with the emission standards until 2050. By comparing this forecast with the average baseline usage for each building type, it determined the necessary reduction in gas usage for LL 97 compliance. These reductions were then subtracted from the unadjusted retail forecast for KEDNY and KEDLI.

3.3.2.5. Factor in increases in energy efficiency

In this step, the unadjusted retail forecast is modified to account for any acceleration in the rate of energy efficiency. Annual energy efficiency projections were created based on the Company's expected achievement of NE:NY goals through 2025. From 2026-2030, the annual savings are based on the Companies' proposal in the Energy Efficiency and Building Electrification filing and NYSERDA's Low- and Moderate-Income state programs. Since there were no approved programs or goals after 2030 when this forecast was created, the Companies assumed that annual energy efficiency savings would continue to grow slightly through 2040 and eventually saturate (meaning that annual incremental EE still occurs, but at a slower rate) later in the forecast horizon.

National Grid's historical sales data already includes the impact of actual energy efficiency savings from past programs. Therefore, explicit adjustments are only made to the unadjusted retail forecast if the projections indicate an acceleration in the rate of energy efficiency compared to historical savings.

3.3.2.6. Factor in increases in electrification-of-heat

The Companies also adjust the forecasts for the impact of electrification. Because the Companies are not the electric service provider in Downstate NY, the electric distribution companies in the KEDNY and KEDLI service territories – Consolidated Edison Company of New York, Inc. and the Long Island Power Authority ("LIPA") (administered by PSEG Long Island, a subsidiary of Public Service Enterprise Group ("PSEG LI")), provided outlooks on electrification. The outlooks were used as a foundation for the electrification assumptions utilized in this forecast. In Upstate NY, the heat pump forecasts are based on its NE:NY Clean Heat portfolio goals through 2025 and the Company's proposal in the Energy Efficiency and Building Electrification filing for 2026 to 2030.

The Companies' electrification forecasts for all scenarios are expressed as heat pump targets (i.e., the number of heat pump installations expected to replace gas service). The Reference case models three kinds of heat pump installations: full electrification, full electrification of space heating, and partial electrification of space heating.

The full electrification category is modeled as a loss of customers, assuming that all end-uses of gas are electrified. To prevent double counting of customer losses, the projections for full electrification are compared to the estimated impact of Local Law 154 and the All-Electric Building Act. Only if the customer losses exceed the impact of these laws, an adjustment is made to the forecast. This adjustment represents the net difference between the projected losses and the impact of the laws.

The second category of electrification, full electrification of space heating, assumes that customers install a heat pump that is sized to meet their entire heating requirements. In this case, there is no loss of customers, but the load associated with space heating is assumed to be completely curtailed by the heat pump.

Customers who opt for partial heat pumps are assumed to retain their existing gas furnace, which remains in service. The forecast assumes that these heat pumps operate when outside temperatures are above 30°F, and the gas system is used when temperatures drop to 30°F or lower. Partial heat pumps are not considered as a loss of metered customers in the forecast. Instead, they are classified as partial heating customers, and their gas usage is reduced by the amount typically used when temperatures are above 30°F. While individual customers may have different switchover temperatures above or below 30°F, the available data suggests that 30°F is a reasonable assumption for the average customer.

3.3.2.7. Factor in customer demand response

Lastly, the wholesale Design Day forecast is adjusted to reflect savings from the demand response programs/pilots that the Company has approved for residential, commercial, multifamily and industrial customers. These programs include Load Shedding, Load Shifting, and Bring Your Own Thermostat ("BYOT") programs in both Upstate NY and Downstate NY, all of which aim to curtail usage during peak hours.

3.3.3. Scenario Demand Forecasts

3.3.3.1. National Grid's Clean Energy Vision

The Companies also produced a variation on the Reference Case to reflect the Companies' Clean Energy Vision ("CEV"). The Clean Energy Vision scenarios for Upstate NY and Downstate NY represent accelerations in energy efficiency programs and electrification of heat. The results also include the thermal requirements of any customers using renewable natural gas and blended hydrogen for their energy requirements.

The Clean Energy Vision scenario emphasizes the use of low-carbon and renewable fuels, such as green hydrogen and renewable natural gas, in conjunction with electrification to meet the Climate Act's GHG emissions requirements. To mitigate peak electric demand, the CEV scenario relies on existing gas infrastructure to deliver low-carbon and carbon-neutral gases, while assuming a transition to partial building electrification, include (1) hybrid gas and electric space-heating systems, (2) electrification of non-heating loads (cooking, water heating, dryers, etc.) and (3) full space heating electrification while maintaining non-heating loads. Hybrid space-heating systems would combine an electric GSHP or ASHP with a gas-fired heating system that can meet heating needs during cold periods when heat pumps are less efficient.

Table 3-5: Clean Energy Vision Scenario Assumptions Based on Clean Energy Vision Pillars

Pillars of National Grid's Clean Energy Vision	Clean Energy Vision Scenario Assumptions
1. Energy Efficiency in Buildings — continuation of programs to help customers accelerate energy efficiency improvements to buildings, ranging from deep retrofits to the support of more rigorous building codes for new buildings.	The CEV scenario assumes that energy efficiency improvements will account for roughly 30% of required energy savings by 2050.
2. Fossil-Free Gas Network — elimination of fossil fuels from existing gas network by 2050 through the substitution of renewable natural gas and green hydrogen.	The CEV scenario assumes that gas deliveries will transition from fossil fuels to a mix of RNG and hydrogen, and that 11% of non-residential customers will transition to 100% hydrogen gas service by 2050. The CEV assumes that hydrogen blending in pipeline gas will reach 7% of total blend (by energy) by 2050.
3. Hybrid Electric-Gas Heating Systems and other Partial Building Electrification Scenarios — continuation of support for customers by providing strategies and tools to capture and maximize the benefits of pairing electric heat pumps with existing gas appliances	The CEV scenario assumes that by 2050, 44% of residential heating and commercial buildings will partially electrify their buildings through the following three scenarios: - 64% will convert to hybrid electric-gas space heating system and also electrify all non-space heating gas loads - 26% will convert to hybrid electric-gas space heating system, but maintain non-space heating gas loads - 10% will fully electrify their space heating equipment but maintain non-space heating gas loads
4. Targeted Electrification— should optimize the economics of avoided gas network investment and additional electric grid investment	The CEV scenario assumes that by 2050, 35% of residential heating housing units will convert to fully electric alternatives, whether it be GSHP, ASHP or Networked Geothermal for space-heating, as well as electric cooking, water heating, and other appliances.

3.3.3.2. Accelerated Electrification Scenario

We also produced a variation on the Reference Case demand forecast to reflect the Climate Action Council's Scenario 3, referred to here as the Accelerated Electrification scenario, which assumes significant energy efficiency improvements and the full electrification of natural gas-related requirements such as space heating, hot water, cooking, and clothes drying. The CAC's Scoping Plan provides more details regarding this scenario.[51]

Table 3-6: Accelerated Electrification Scenario Assumptions

Accelerated Electrification Scenario Assumptions
- Energy efficiency improvements will account for roughly 30% of required energy savings by 2050. - All remaining gas demand is served by RNG in 2050. No hydrogen blending in pipeline gas. - No customers transition to hybrid electric-gas heating systems or other partial building electrification scenarios - Approximately 95% of residential heating customers and 99% of commercial customers will fully electrify by 2050.

3.4. Demand Forecast Results

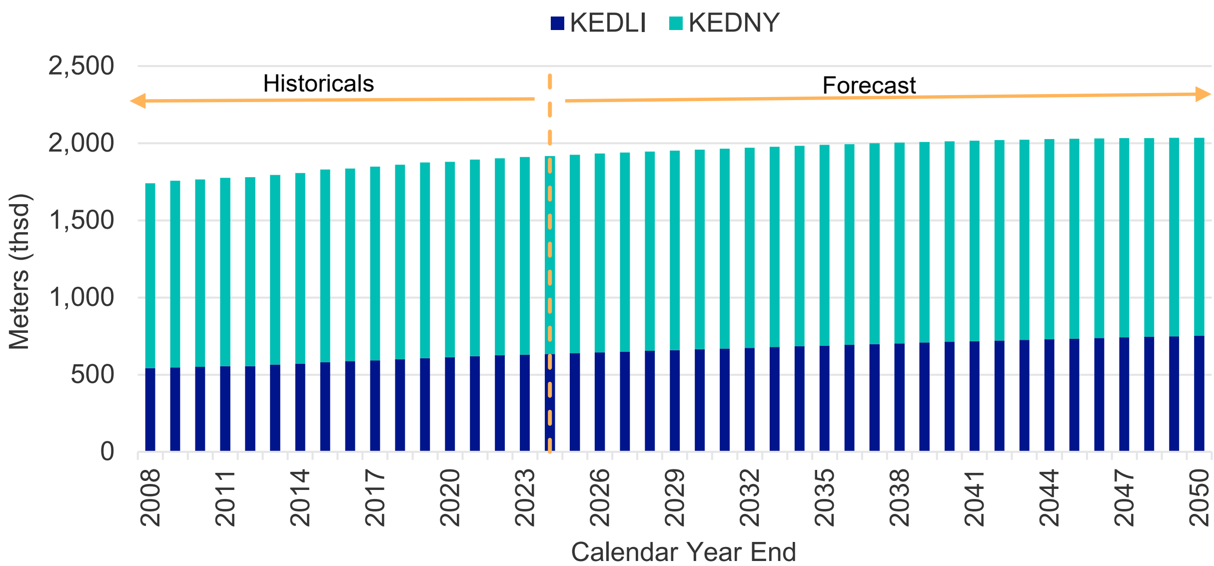
3.4.1. Downstate NY Reference Case Results

As described above in Section 3.2.1, the Companies produce the main planning scenario annually, referred to in this filing as the Reference Case. The Downstate NY forecasts were finalized in June 2024. These forecasts guide gas resource (supply and capacity) planning, distribution system planning, financial planning, and cost recovery. The Reference Cases reflect all known and quantifiable laws, programs, and measures that are currently in place at the time of the forecasts, all of which were presented in Section 3.3.2 above.

In the Companies' Reference Case for Downstate NY, its historical meter count rose from 1.740 million meters at the end of CY2008 to 1.910 million meters at the end of CY2023, growing at a rate of 11.341 meters per year or 0.62 percent per annum. The forecasted meter count then rises from 1.910 million meters at the end of CY2023 to 2.035 million meters at the end of CY2050, growing at a lower rate of 4,656 meters per year or 0.24 percent per annum (see Figure 3-1).

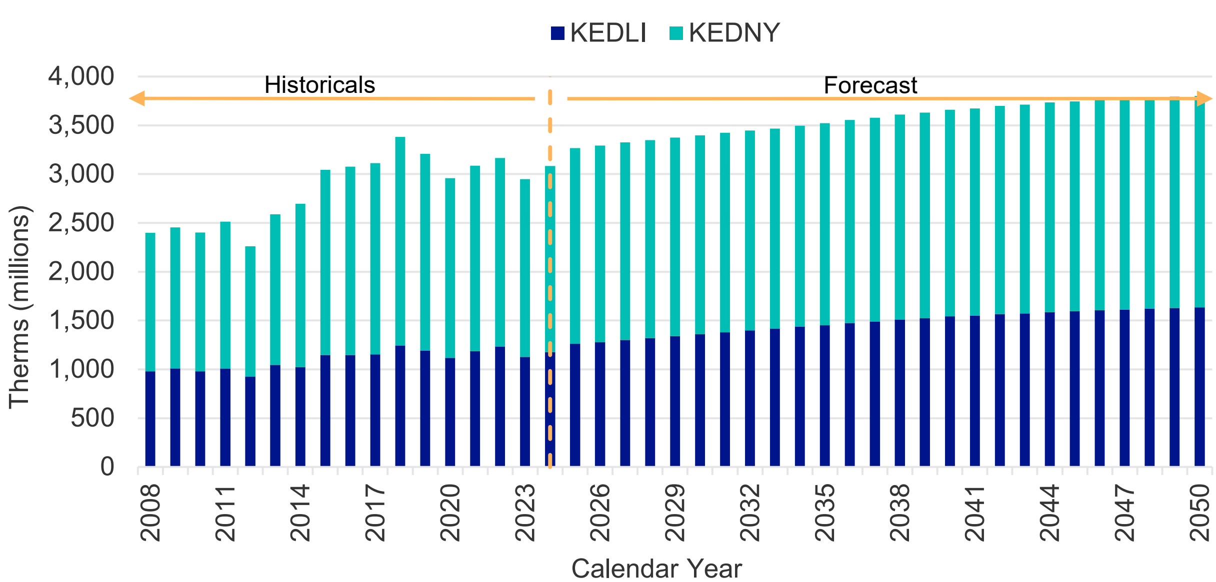
[51] See: NY CAC (December 2021). "Draft Scoping Plan Appendix G," sections 2.1 and 5.3.

Figure 3-1: Downstate NY Meter Count Data for Reference Case



In the Companies' Reference Case for Downstate NY, volumes reflect a similar trend to its meter count forecast. Historical retail volumes rose from 2,398 million therms in CY2008 to 2,950 million therms in CY2023, growing at a rate of 36.8 million therms per year or 1.39 percent per annum. The forecasted retail volumes then rise from 2,950 million therms in CY2023 to 3,801 million therms in CY2050, growing at a lower rate of 31.5 million therms per year or 0.94 percent per annum (see Figure 3-2).

Figure 3-2: Downstate NY Volume Data for Reference Case

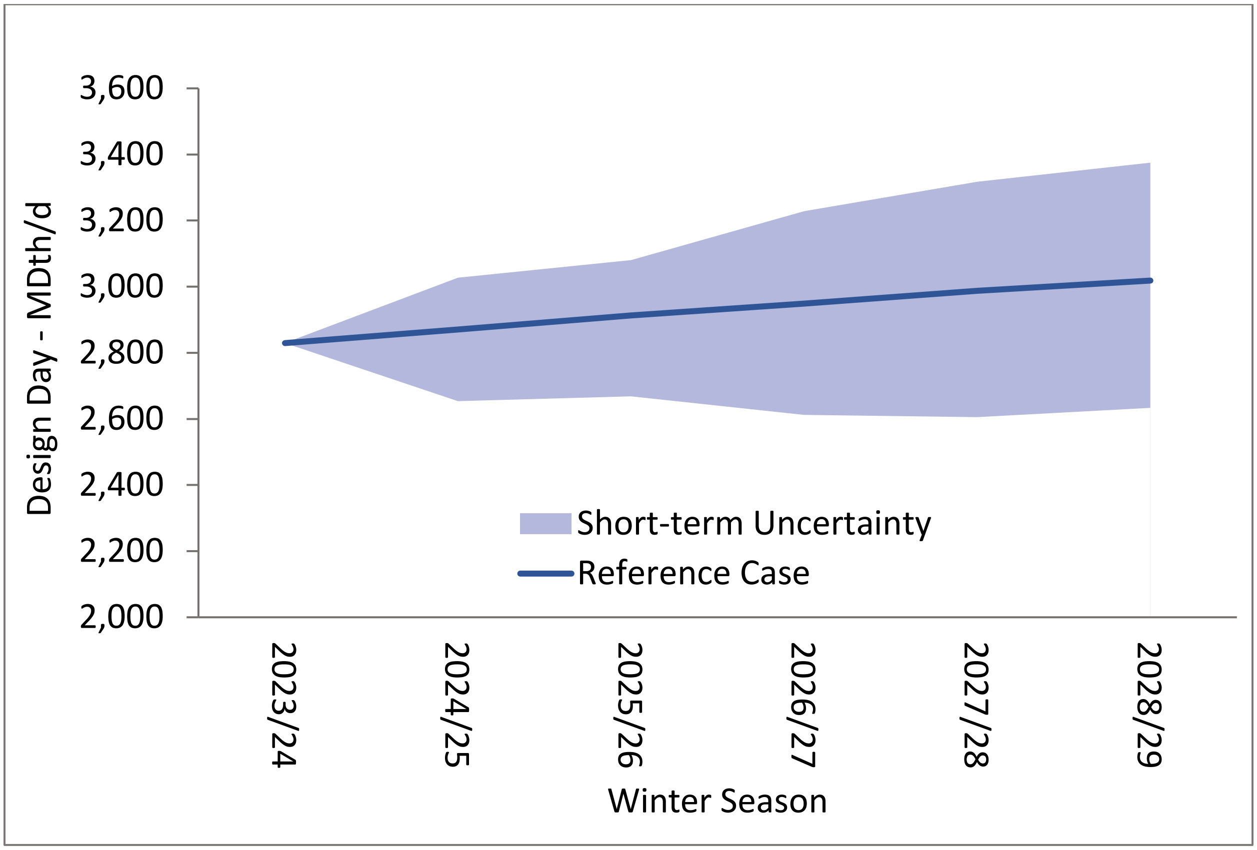


In Figure 1-1 in Section 1.3.1, the Companies presented the Reference Case's Design Day wholesale requirements for Downstate NY. Historical wholesale design volumes rose from 2,094 MDth/day in winter 2007/08 to 2,829 MDth/day in winter 2023/24, growing at a rate of 46.0 MDth/day per year or 1.90 percent per annum. The forecast wholesale Design Day volumes then rise from

2,829 MDth/day in winter 2023/24 to 3,551 MDth/day in winter 2049/50, growing at a lower rate of 27.7 MDth/day per year or 0.88 percent per annum.

Figure 3-3 illustrates the uncertainty bands surrounding the Downstate NY Design Day forecast, as discussed in Section 3.2.1.5. The bands take into account uncertainties related to variations in modelling, the economy, and demand-side management. By winter 2034/35, the uncertainty around the reference case is approximately plus or minus 12%. Note that this analysis assumes the same fundamental policies remain and does not take into account uncertainty around fundamental change in policies or programs, only sensitivities around existing ones. Longer-term uncertainty is reflected in the different policy-based scenarios.

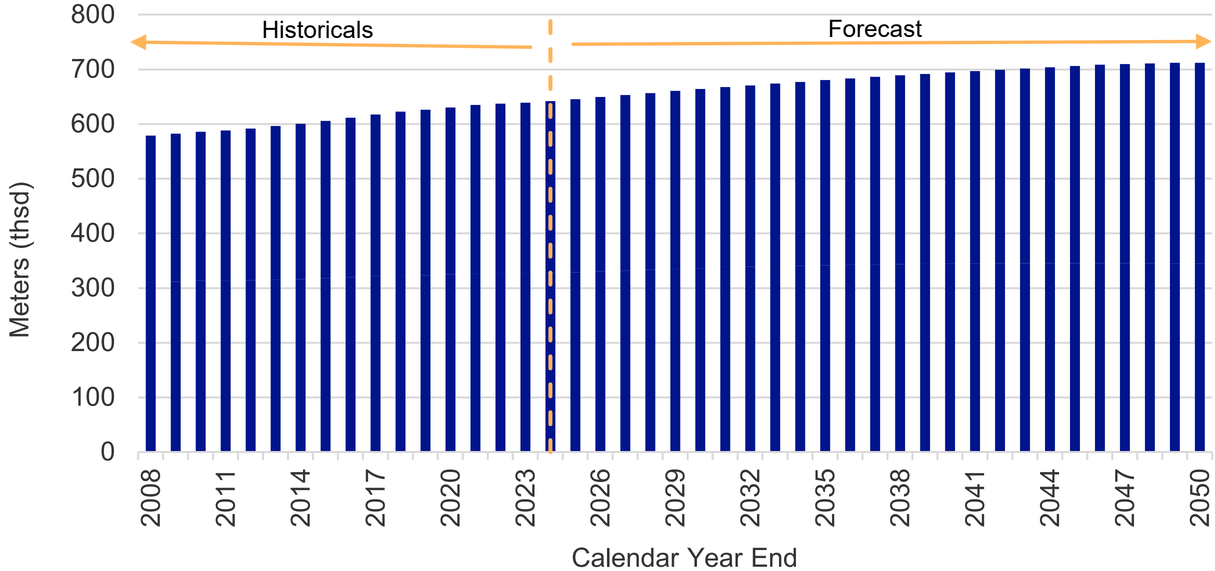
Figure 3-3: Downstate NY Design Day Uncertainty in the Reference Case



3.4.2. Upstate NY Reference Case Results

In the Reference Case for Upstate NY, also finalized in June 2024, the historical meter count rose from 578,682 meters at the end of CY2008 to 638,814 meters at the end of CY2023, growing at a rate of 4,009 meters per year or 0.66 percent per annum. The forecasted meter count then rises from 638,814 meters at the end of CY2023 to 712,042 meters at the end of CY2050, growing at a lower rate of 2,712 meters per year or 0.40 percent per annum (see Figure 3-4).

Figure 3-4: Upstate NY Meter Count Data for Reference Case



In the Reference Case for Upstate NY, volumes reflect a similar trend to the meter count forecast. Historical retail volumes rose from 1,312 million therms in CY2008 to 1,484 million therms in CY2023, growing at a rate of 11.5 million therms per year or 0.82 percent per annum. The forecasted retail volumes then rise from 1,484 million therms in CY2023 to 1,676 million therms in CY2050, growing at a lower rate of 7.1 million therms per year or 0.45 percent per annum (see Figure 3-5).

Figure 3-5: Upstate NY Volume Data for Reference Case

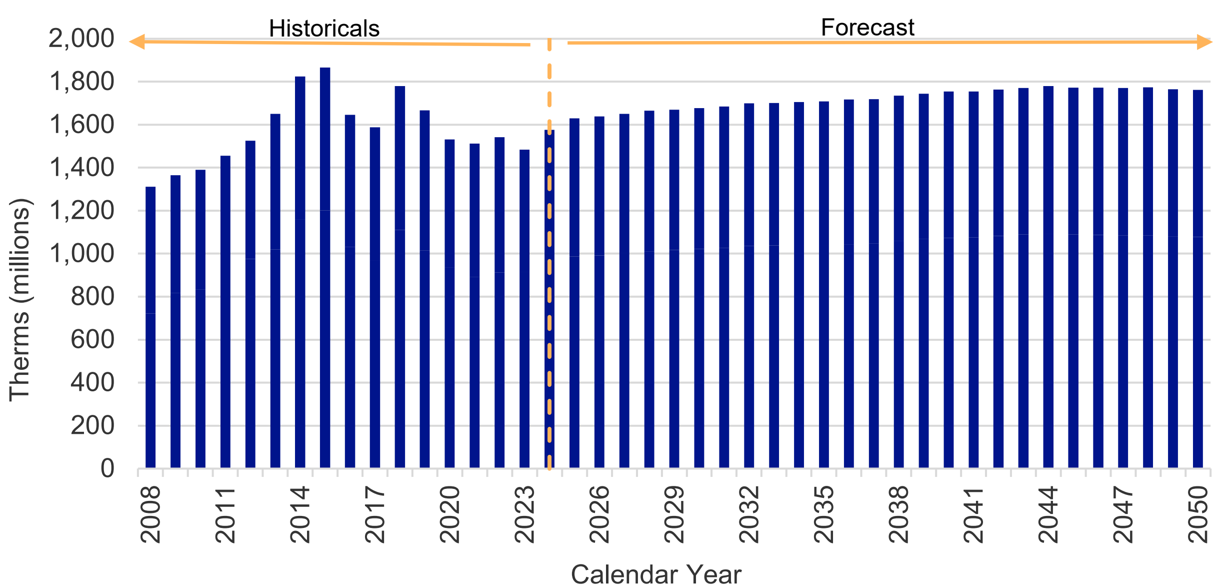
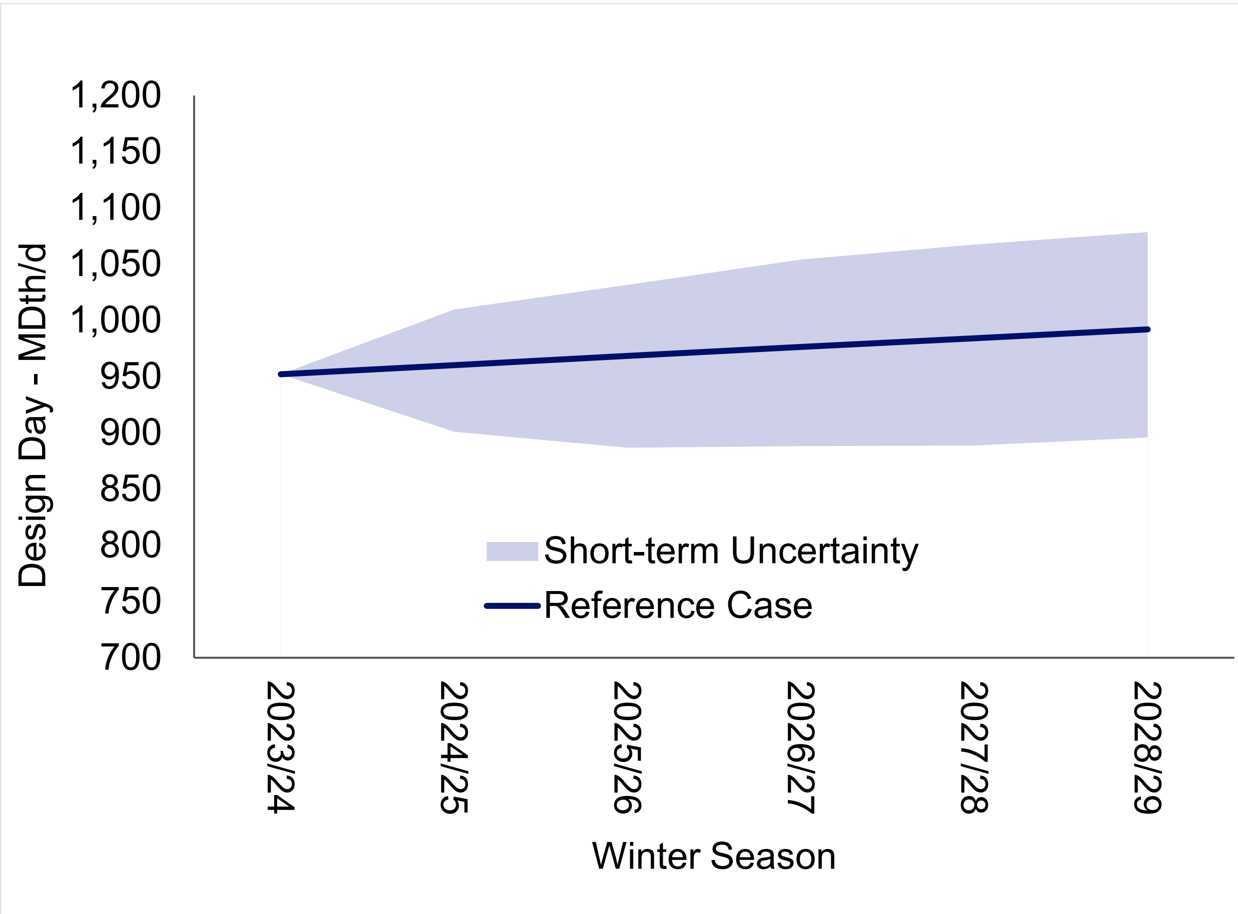


Figure 1-2 in Section 1.3.1, shows the Reference Case's Design Day wholesale requirements for UNY. Historical wholesale design volumes rose from 842,670 Dth in winter 2010/11 to 952,158 Dth in winter 2023/24, growing at a rate of 8,422 Dth per year or 0.94 percent per annum. The forecasted wholesale Design Day volumes then rise from 952,158 Dth/day in winter 2023/24 to

1,093,638 Dth/day in winter 2049/50, growing at a lower rate of 5,442 Dth/day per year or a compound annual rate of 0.53 percent per annum.

Figure 3-6 illustrates the uncertainty bands surrounding the Upstate NY Design Day forecast, as discussed in Section 3.2.1.5. These bands take into account uncertainties related to variations in modelling, the economy, and demand-side management. By winter 2033/34, the uncertainty surrounding the reference case spans a range of approximately plus 10% to minus 9%. Note that this analysis assumes the same fundamental policies remain and does not take into account uncertainty around fundamental change in policies or programs, only sensitivities around existing ones. Longer-term uncertainty is reflected in the different policy-based scenarios.

Figure 3-6: Upstate NY Design Day Uncertainty in the Reference Case



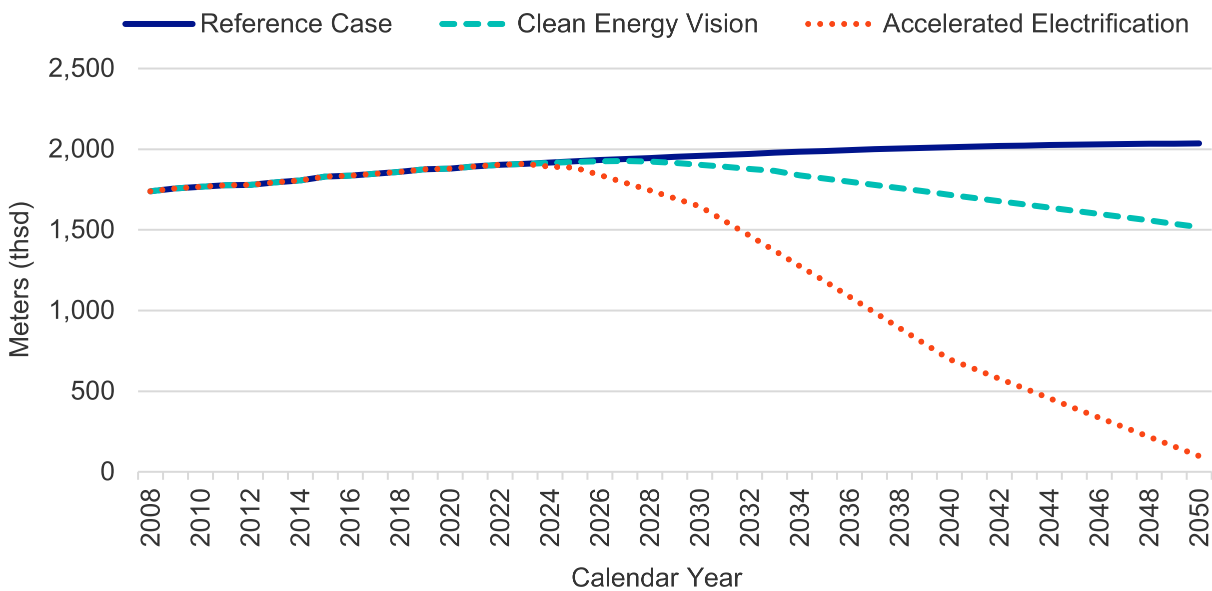
3.4.3. Comparison of Scenarios in Downstate NY

The charts below provide a comparison of the meter count, retail volume, and Design Day forecasts in Downstate NY for the Reference Case, the Clean Energy Vision, and Accelerated Electrification scenario.

In the Clean Energy Vision Forecast for Downstate NY, Figure 3-7 shows the projected meter count in 2050 for customers remaining on the gas system is 1.518 million meters. This is lower than the 2.035 million meters projected in the Reference Case. It represents an average decrease of 14,507 meters per year or a -0.85 percent annual decrease as some gas customers are assumed to fully electrify or switch to pure hydrogen usage.

Figure 3-7 shows that in the Accelerated Electrification Scenario, the projected meter count in 2050 for customers remaining on the gas system is 98,448 meters. This count is lower than both the Reference Case and Clean Energy Vision as most customers are assumed to disconnect from the gas distribution system. It represents an average decrease of 67,085 meters per year or a -10.40 percent annual decrease.

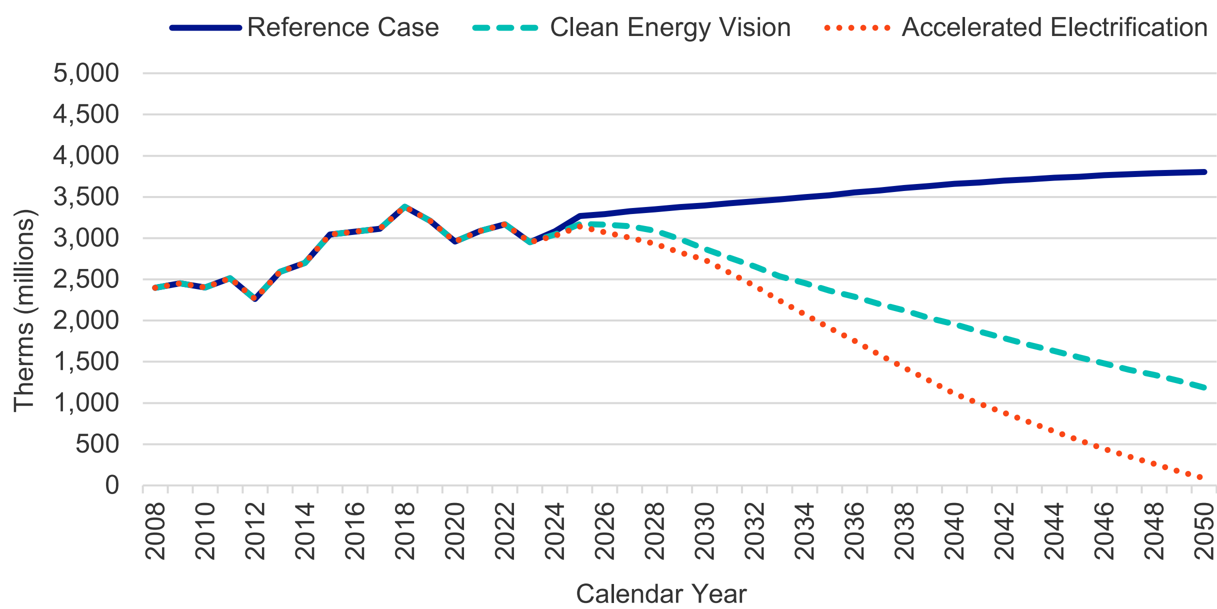
Figure 3-7: Downstate NY Meter Count Data by Scenario



In Figure 3-8, the projected volumes in the Clean Energy Vision scenario follow a similar trend to its meter count forecast. These volumes represent the demand from customers who remain on the gas system and exclude the demand from customers who switch to pure hydrogen usage. The forecast retail volume for customers remaining on the gas system in 2050 is 1,187 million therms, which is lower compared to the 3,801 million therms in the Reference Case. This represents an average decrease of 65.297 million therms per year or -3.31 percent per annum from 2023 to 2050. The difference between the Reference Case and the Clean Energy Vision is larger in terms of volume rather than meter count. This is because the Clean Energy Vision assumes a large number of customers remain on the gas system with hybrid heating systems, which curtails a portion their gas usage.

In the Accelerated Electrification scenario, the forecast retail volumes are 85.231 million therms in 2050, which represents a decrease of 106.118 million therms per year or -12.30 percent per annum from 2023 to 2050.

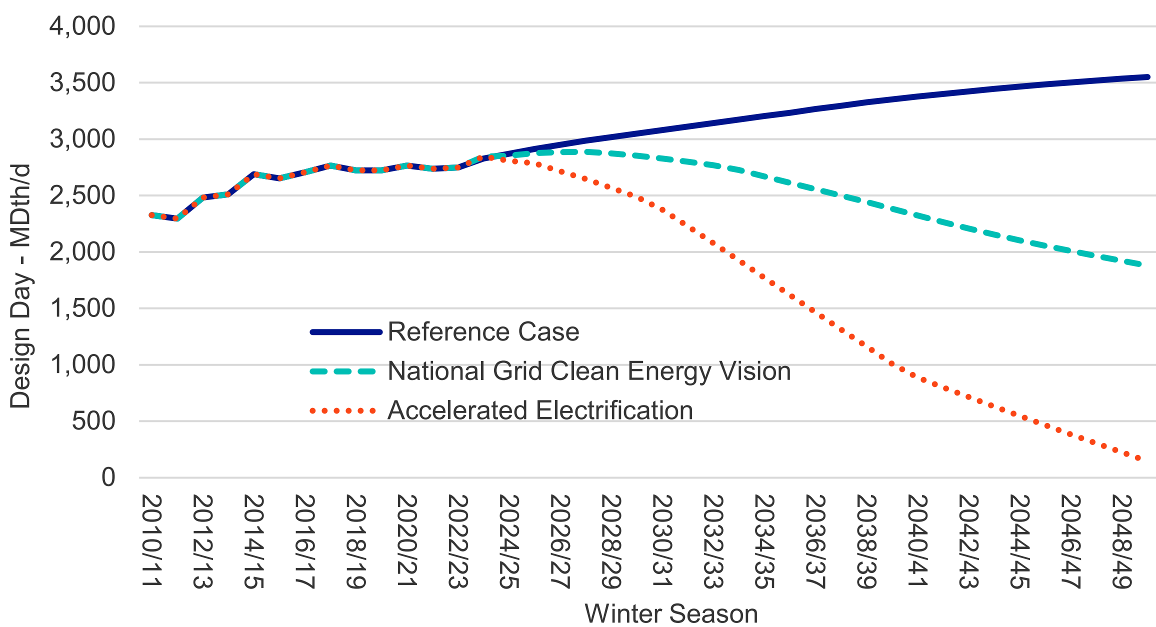
Figure 3-8: Downstate NY Volume Data by Scenario



The forecasted wholesale Design Day volumes for gas in the Downstate NY Clean Energy Vision decreases to 1,880 MDth/day by winter 2049/50 compared to the 3,551 MDth/day in the Reference Case. This represents an average decrease of 37.1 MDth/day per year or a compound annual rate of -1.58 percent per annum (see Figure 3-9).

The forecasted wholesale Design Day volumes for the Accelerated Electrification scenario for Downstate NY decreases to 143 MDth/day by winter 2049/50, which is lower than the Reference Case and Clean Energy Vision as most customers are assumed to disconnect from the gas system. This represents an average decrease of 103.9 MDth/day per year or a compound annual rate of -10.86 percent per annum (see Figure 3-9).

Figure 3-9: Downstate NY Design Day Volume Data by Scenario



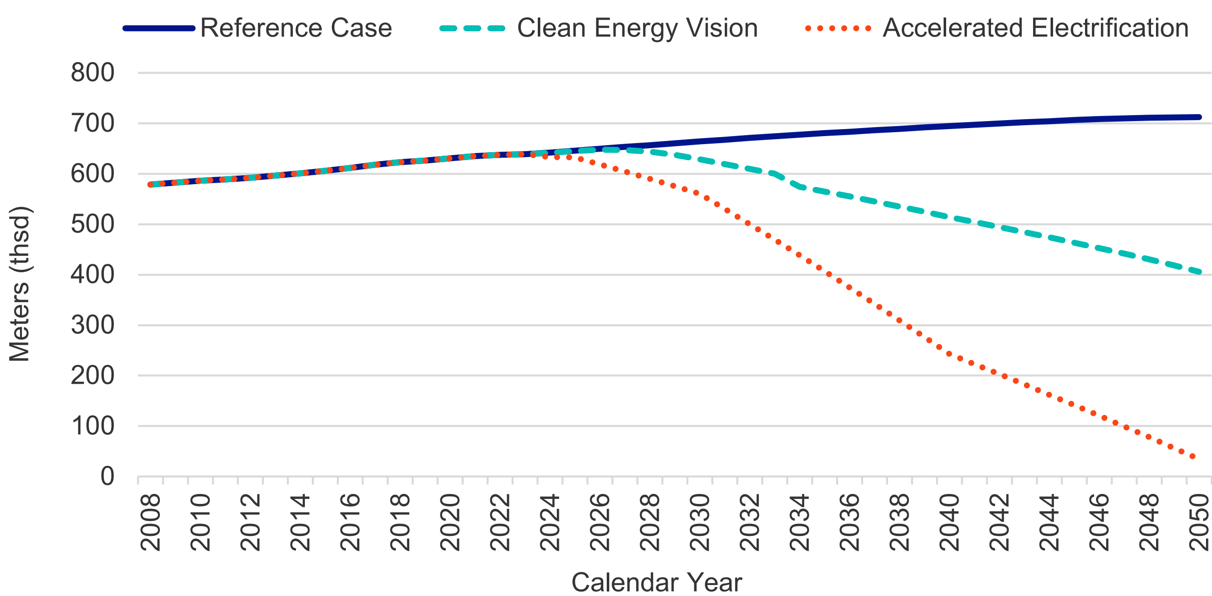
3.4.4. Comparison of Scenarios in Upstate NY

The charts below provide a comparison of the meter count, retail volume, and Design Day forecasts in Upstate NY for the Reference Case, the Clean Energy Vision, and the Accelerated Electrification scenario.

In the Companies' Clean Energy Vision Forecast for Upstate NY, Figure 3-10 shows the projected meter count in 2050 for customers remaining on the gas system is 405,969 meters. This is lower than the 712,041 meters projected in the Reference Case. It represents an average decrease of 8,624 meters per year or a -1.67 percent annual decrease as some gas customers are assumed to fully electrify or switch to pure hydrogen usage.

Figure 3-10 also shows that projected meter count in 2050 for customers remaining on the gas system is 34,832 meters in the Accelerated Electrification scenario. This count is lower than both the Reference Case and Clean Energy Vision, as most customers are assumed to disconnect from the gas distribution system. It represents an average decrease of 22,370 meters per year or a -10.21 percent annual decrease.

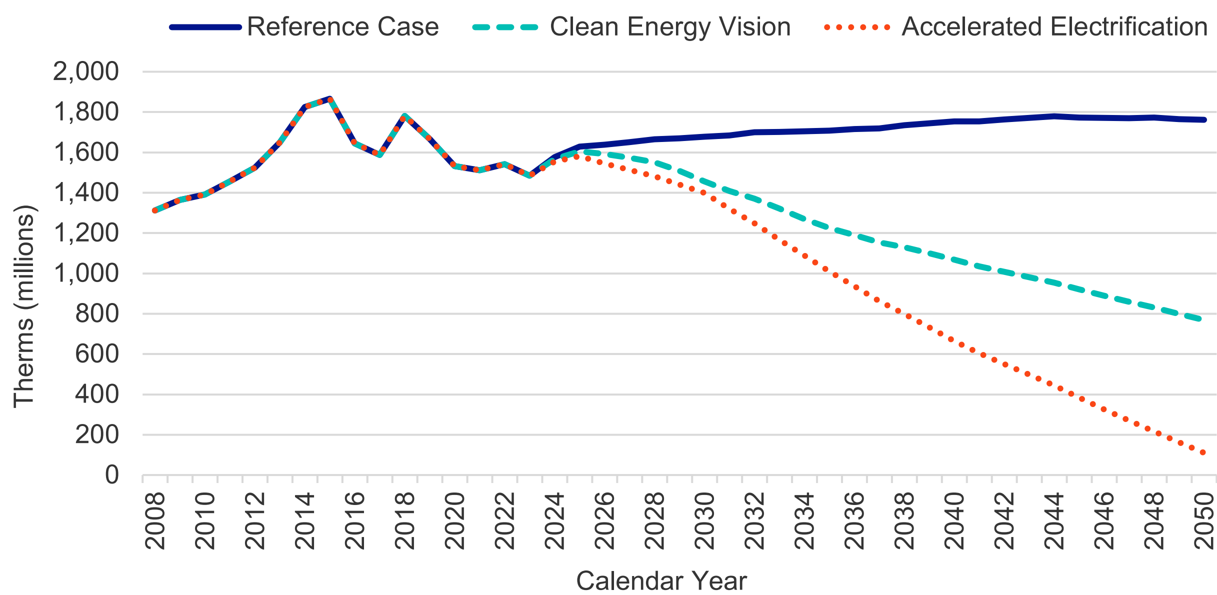
Figure 3-10: Upstate NY Meter Count Data by Scenario



In Figure 3-11, the projected volumes in the Clean Energy Vision scenario follow a similar trend to its meter count forecast. These volumes represent the demand from customers who remain on the gas system and exclude the demand from customers who switch to pure hydrogen usage. The forecast retail volume for customers remaining on the gas system in 2050 is 769.540 million therms in the Clean Energy Vision, which is lower compared to the 1,676 million therms in the Reference Case. This represents an average decrease of 26.465 million therms per year or -2.40 percent per annum from 2023 to 2050. The difference between the Reference Case and the Clean Energy Vision is larger in terms of volume rather than meter count for the same reason as in Downstate NY: hybrid heating customers.

In the Accelerated Electrification scenario, the forecast retail volumes are 110.170 million therms at the end of 2050, which represents a decrease of 50.886 million therms per year or a -9.18 percent per annum decrease from 2023 to 2050.

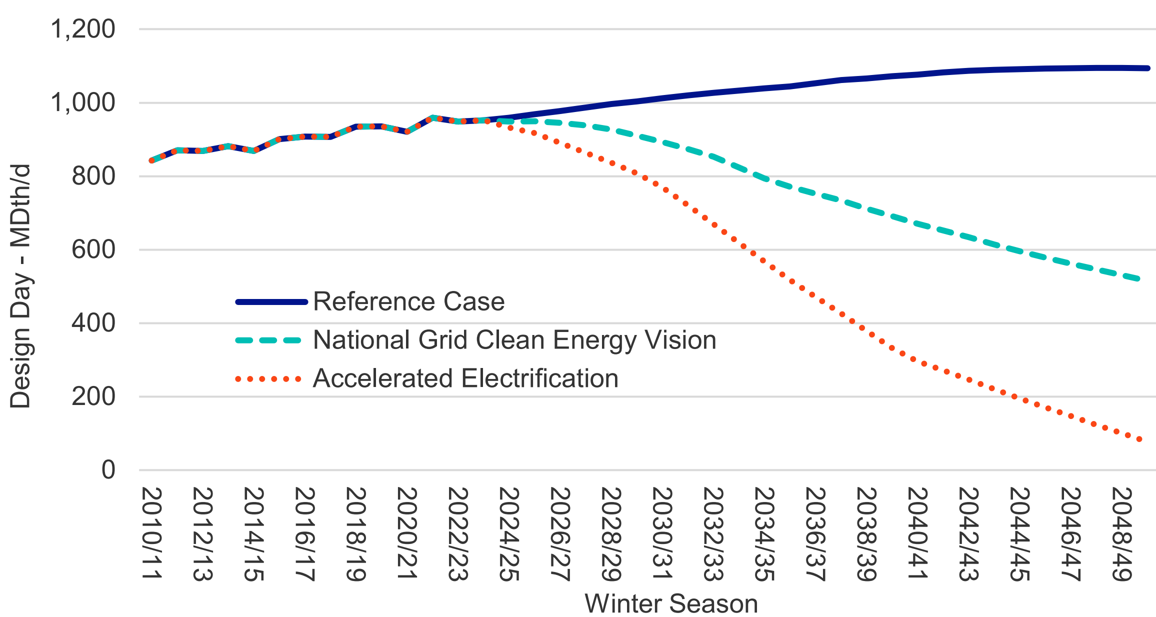
Figure 3-11: Upstate NY Volume Data by Scenario



The forecasted wholesale Design Day volumes for the Companies' Clean Energy Vision for Upstate NY decreases to 515 MDth/day by winter 2049/50 compared to the 1,094 MDth/day in the Reference Case as seen in Figure 3-12. This represents an average decrease of 16.8 MDth/day per year or a compound annual rate of -2.34 percent per annum.

The forecasted wholesale Design Day volumes for the Accelerated Electrification scenario for Downstate NY decreases to 77.3 MDth/day by winter 2049/50, which is lower than the Reference Case and Clean Energy Vision as most customers are assumed to leave the gas distribution system. This represents an average decrease of 33.6 MDth/day per year or a compound annual rate of -9.20 percent per annum (see Figure 3-12).

Figure 3-12: Upstate NY Design Day Volume Data by Scenario Reference Case



4. Supply Planning

The Companies' current planning horizon for supply and capacity purposes is ten years. Typically, in the spring of each year, the Companies develop plans to meet gas supply requirements for the annual period from November 1 of that year through October 31 of the following year. This planning process begins with an updated, ten-year demand forecast of customers' gas requirements that ultimately determines the level of incremental pipeline, storage, or peaking assets needed.

The primary firm demand (i.e., core customer load forecast) forms the basis for the Companies' gas supply portfolio. The primary firm demand is the demand from the Companies' core firm customers, regardless of whether they purchase gas commodity from the Companies or energy service companies ("ESCOs"). Pipeline and storage capacity, along with peaking assets, are used to satisfy the primary firm demand. An annual load duration curve or similar approach is utilized to structure capacity contracts to best meet the shape and frequency of the anticipated loads and to assure the Companies' ability to meet those loads. Currently, the Companies do not incorporate any reserve margin assumptions when developing their design weather forecasts and capacity requirement determinations.

The Companies' primary gas supply planning goals are to:

(1) Dispatch the gas supply portfolio assets under a least-cost strategy to reliably meet projected core primary firm demand;
(2) Maintain a diverse portfolio of gas supply, storage, and transportation capacity contracts with varying terms and pricing provisions; and
(3) Implement a formal hedging program to mitigate price volatility.

These goals are consistent with the Commission's "Statement of Policy Regarding Gas Purchasing Practices" issued in Case 97-G-0600 and updated by letter issued March 31, 2011. The Companies maintain a portfolio that meets customer requirements under design conditions while maintaining sufficient flexibility for mild winters.

The Companies monitor these goals with regular meetings (monthly supply plan, quarterly review, and annual RFP review). Pursuant to Recommendation IX-4 from the final audit report in the Commission's 2013 gas management audit (Case 13-G-0009), the Companies established a process for the quarterly review of gas supply procurement plans compared to actual purchases for a sample day(s) during the quarter. The review identifies variances in volumes and the use of storage and delivery pipelines caused by weather, market conditions, operational constraints, or other factors. Variances are reviewed for patterns and opportunities to improve the procurement process.

4.1. Supply Portfolio

The Companies file an annual Winter Supply Review ("WSR") each July[52] which includes a listing of all transportation and storage contracts in the portfolios. The most recent listing can be found in Section 11.1.

Section 11.1 also contains NY gas supply flow diagrams. Figure 11-1 illustrates the current Niagara Mohawk supply portfolio. The portfolio consists of capacity contracts with EGTS, TGP, and IGTS. Upstate NY has delivery point entitlement redundancy on two significant transportation contracts with EGTS (contracts 100001 and 700001). Each contract has deliverability to both the East Gate

[52] Case 24-M-0205, *Report on the New York State Electric & Gas Supply Readiness for 2024-2025 Winter*, National Grid's responses to the request for information from Department of Public Service Staff, filed on July 15, 2024, see Tables 4 and 5.

and the West Gate that, when added together, exceed the contract Maximum Daily Quantity ("MDQ"). Therefore, the Company has allocated the MDQ of each contract to the East Gate and West Gate in accordance with its Design Day customer requirements. The total amount the Company may transport to the EGTS East Gate and EGTS West Gate using all its EGTS transportation contracts is limited by the Maximum Daily Delivery Obligation ("MDDO") for each region.

Figure 11-2 contains the current Downstate NY flow diagrams. KEDNY's city gates include Tetco-Goethals (Staten Island), Transco-Narrows (Brooklyn) and Transco-Rockaway (Floyd Bennett Field, Brooklyn). KEDLI's city gates include Transco – Long Beach and Iroquois – S. Commack. Both KEDNY and KEDLI have contracts delivering to Con Edison's White Plains gate station – gas is then redelivered to KEDNY and KEDLI through the NYF System exchange points. The LNG plants at Greenpoint (KEDNY) and Holtsville (KEDLI) provide a combined total of 394,500 Dth/day on a peak day. There are five CNG injection sites on LI at Glenwood, Inwood, Barrett, Farmingdale, and Riverhead. The Farmingdale site shows "0" supply in the flow diagram as there was not an immediate need for that site in 2023-24 although it will be needed in future years.

4.1.1. Evolution of our Supply Portfolio

During the last ten years, both KEDNY and KEDLI experienced steady Design Day growth. To keep up with increasing requirements, KEDNY and KEDLI required incremental supply and capacity and worked with pipelines connecting to KEDNY and KEDLI city gates as needed. Contracting with gas suppliers for short term delivered supplies ("city gate peaking") to KEDNY and KEDLI city gates allowed the Companies to bridge the gap between pipeline expansion projects. The Companies also made other contract decisions in order to diversify the portfolio and reduce customer costs.

Heading into the 2013-14 winter season, Upstate NY was in a period of declining requirements due to lingering impacts from the 2008 financial crisis. The Albany area, largely served by EGTS, nevertheless had design hour constraints that needed to be addressed in advance of future customer requirements growth. Over the next 10 years, Upstate NY Design Day and design hour requirements slowly began to increase.

The supply portfolio termination/expiration/turnback decisions summarized below did not impede deliverability to the KEDNY, KEDLI and NMPC city gates, as these pipeline paths are all upstream of the pipeline capacity that delivers the Companies' city gates. Additions to supply portfolios were made to ensure adequate supplies to meet forecasted requirements.

Table 4-1: Supply Portfolio Additions, Terminations, and Expirations

Year	MDth	Downstate NY	MDth	Upstate NY
2014	-650.0	Petal Gas Storage capacity (terminated)		
2015	100.0	Transco Northeast Connector FT		
	-131.0	Union Pipeline FT (expired)		
2016	8.0	First CNG Site (KEDLI)	20.0	TGP Dracut to South Albany FT
2017	115.0	Transco NY Bay Expansion Project FT	-8.3	Transco Zone 2/3 to Leidy FT (terminated)
	82.0	Dominion (EGTS) New Market Project FT	30.0	Dominion (EGTS) New Market Project FT
	-25.0	Vector Pipeline FT (expired)	30.0	TGP Dracut to South Albany FT
2018	-580.7	Eminence Storage Service (terminated)	-14.0	TGP Zone 0 to Ellisburg (terminated)

	-130.0	TransCanada Pipeline FT (expired)	20.0	TGP Dracut to South Albany FT
	-150.8	Empire Pipeline FT (expired)		
2019	-734.4	Eminence Storage Service (terminated)	8.8	First CNG Site
	8.8	Second CNG Site KEDLI		
2020	-68.0	Transco Long Haul FT Zn 1-3 (turnback)	26.2	EGTS to East Gate FT
	-35.2	Third and Fourth CNG Site (KEDLI)		
2021	60.0	Pipeline FT acquired via permanent capacity release		
	192.0	Multiple FT contracts with Asset Mgmt Arrangements		
	58.0	Winter Only City Gate Peaking Supplies		
2023	17.6	Fifth CNG Site (KEDLI)		

4.2. Risks & Reliability Concerns

4.2.1. Winter Storm Elliott

From a gas supply perspective, Winter Storm Elliott ("WSE") had minimal impact to the Upstate NY gas system. While most pipelines that deliver to Upstate NY and Downstate NY had various restrictions in place due to the colder than expected weather, Upstate NY did not experience any significant supply loss. Since most of the Upstate NY supply portfolio receives pipeline gas supply via EGTS, this event did not adversely impact the Upstate NY gas system.

Unlike Upstate NY, the Downstate NY supply portfolio heavily relies on Transco, Tetco and Iroquois pipelines for the majority of its supplies. Supply losses occurred on all three pipelines due to various issues including:

- Weather forecast error resulting in extreme and rapid temperature drops coupled with wind, rain, and snow.
- Compressor "failure to start" and outages resulting in reduced pipeline pressures.
- Producer underperformance caused by equipment freeze-offs, resulting in failure to deliver supply to pipelines.

Because Downstate NY temperatures were not expected to fall below 10°F, standard preparations were made for forecasted temperatures in the 13°F to 25°F range:

- Cold weather messaging sent to non-firm customers.
- 2% Balancing Operational Flow Order ("OFO") issued to be in effect by 10am EST December 23, 2022.
- Non-firm demand response customers with 15°F and 20°F interruptible temperature triggers were directed to switch to alternate fuels by 10am EST on December 23, 2022.
- Incident Command Structure ("ICS") staffed and executed.
- LNG assets placed into service the night of December 23, 2022, in expectation of morning load peak.
- Over 200,000 Dth of pipeline underground storage was reserved as "upswing" to manage unexpected drops in temperature (as experienced).

National Grid was made aware of the first compressor outage at approximately 8am EST on December 24 and was notified of over ten more such outages over the next two days. On December 26, all pipeline compressors impacting KEDNY and KEDLI city gates were reported back online.

Due to the pipeline equipment and supply issues, National Grid took the following additional steps:

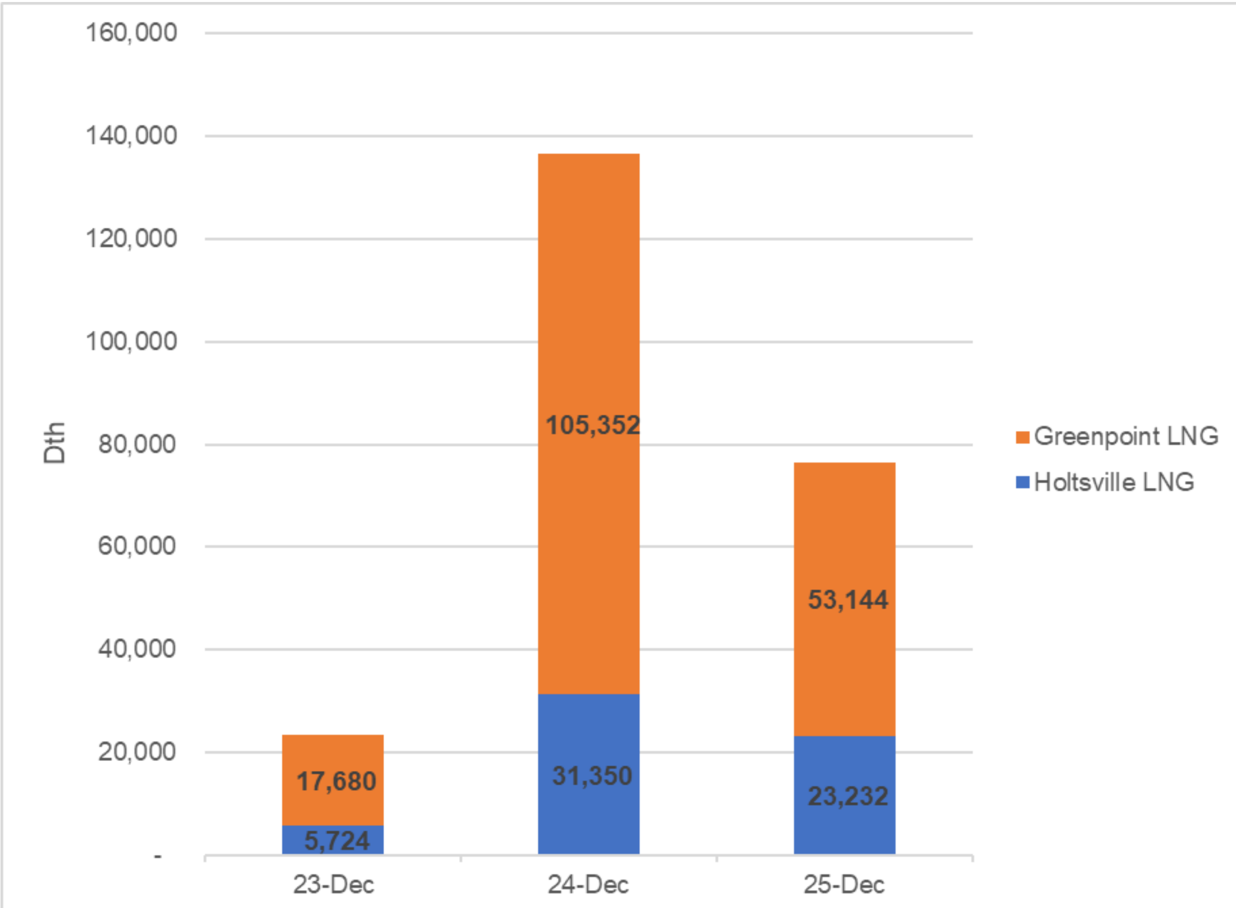
- Ramped up LNG vaporization at Greenpoint and Holtsville to supplement supply, support pressures, and backstop pipeline issues.
- Curtailed all gas-fired power generators beginning 12/24. National Grid communicated with dual-fuel customers to allow for a safe and timely transition from gas to alternate fuels. Some of these customers had already transitioned to alternate fuels for economic reasons before the events of 12/24. By 2pm EST on 12/26, all generators were allowed to resume burning gas.
- Declared an Emergency Demand Response ("DR") event for 12/24 evening period (6-10pm EST) and morning peak 12/25 (6-10am EST). This applied to incentive-based Commercial & Industrial Firm DR Program customers who would typically be asked to reduce gas consumption at forecasted temperatures of 10°F or less. This also applied to the residential and small commercial BYOT Program customers.
- Coordinated with Con Edison to issue a Voluntary Load Reduction ("VLR") notice to all customers. Intent of notice was to help mitigate supply related constraints by having our customers voluntarily reduce their gas load demand by way of lowering their thermostats to 65°F.
- Emergency Gas Outage Management Plan ("EGOMP") was reviewed but not executed as the prior steps were successful in dealing with the event. EGOMP is a program that identifies areas of the gas system that can be isolated in an extreme emergency condition. The intent is to decrease large volume gas usage during an emergency to maintain the reliability of the gas system. Field crews were mobilized and directed to the valves that would be used to isolate the pre-identified areas of the gas system that were most at risk for losing service. The valves were not closed because the system recovered due to all of the efforts mentioned above, equipment coming back online, and the weather moderating. Had EGOMP been implemented in the identified zones, tens of thousands of customers would have been impacted.

Supply cuts at KEDNY and KEDLI city gates occurred on Gas Days December 24-27, 2022 as follows:

- 12/24 93,220 Dth
- 12/25 86,008 Dth
- 12/26 58,928 Dth
- 12/27 2,872 Dth

Underground storage withdrawals helped to mitigate the impact of the pipeline flowing supply cuts. The use of on-system LNG assets at Greenpoint and Holtsville were critical in maintaining adequate system pressures as well as providing supply. The LNG output during this event is shown below.

Figure 4-1: LNG Output during Winter Storm Elliott (Dth/day)



The use of on-system LNG during this period reduced the flows at the city gates and allowed time for pipeline pressures to recover from the compressor outages. More importantly, the use of LNG prevented the loss of gas system pressures that would have jeopardized firm customers with loss of natural gas service. Loss of gas service could have resulted in loss of life due to customers not having heat during extremely cold conditions as well as property damage due to frozen water piping. Restoring service to these customers would have taken weeks or months due to the magnitude of the resulting restoration effort. Every impacted gas service would have been required to be shut off and secured prior to being able to safely reintroduce gas into the isolated system. Then, access to each premise would have been required to gas-in each service and perform a manual relight of every gas appliance.

Throughout the entire event, National Grid was in contact with all pipelines connecting to Upstate NY and Downstate NY city gates. In addition, meetings were conducted with Con Edison to coordinate plans for NYF System operations and share information as needed to maintain adequate supplies and system pressures between the LDCs. National Grid was also in frequent communication with NYPSC and other external stakeholders during the event.

While this particular event did not significantly impact Upstate NY, the Upstate NY supply portfolio could experience a similar set of effects should the conditions associated with the Downstate NY event materialize in Upstate NY. In fact, the lack of LNG in Upstate NY leaves the system even more vulnerable since Upstate NY does not have the same supply contingency and pressure support offered by the Downstate NY LNG facilities.

Lessons Learned & Next Steps

1. **Communications with Pipelines**
    a. LDCs should continue to communicate with pipelines during these events to determine cause of outages and/or supply losses and work to prevent re-occurrences if possible.
    b. In the case of Downstate NY, have joint meetings with each pipeline that include Con Edison rather than each LDC having 1:1 meetings with each pipeline. These joint meetings were helpful and productive during this event and saved valuable time by allowing for faster and more informed decision-making.
2. **Producer/Supplier "Underperformance"**
    a. Producer and supplier underperformance messages from pipelines is new terminology. Producers must be accountable for underperformance and the impact it has on pipeline operations.
    b. LDCs should communicate directly with gas suppliers who underperform during extreme cold events to determine the root cause and if supply losses can be avoided in the future under similar conditions.
3. **Better CNG Utilization During Pipeline Events**
    a. National Grid typically only dispatches CNG trucks to injection sites when temperatures are forecasted to be 10°F or less. Because of the distance between compression capacity and CNG injection sites for the Companies, CNG supply contracts typically require 24-48 hours' notice to mobilize and have trailers delivered. As temperatures were forecasted to be above 10°F, no CNG supply contracts were dispatched. By the time pipeline issues were realized, there was insufficient time to mobilize CNG.
    b. National Grid will continue to pursue opportunities to implement on-site CNG storage at other locations. This will require a thorough evaluation of process safety requirements at each location. If more sites can accommodate on-site storage, future CNG supply contracts can include this additional flexibility.
    c. Changing out the trailers takes up to eight hours per site, so each site is limited to two injection cycles of four hours plus two trailer replacement cycles of eight hours within a 24-hour period.
4. **LNG Usage During Pipeline Events**
    a. Existing LNG assets must continue to be a critical component of the Downstate NY supply portfolio. The ability to quickly dispatch up to 394,500 Dth/day into the Downstate NY gas systems cannot be equaled or duplicated by CNG.
    b. LNG assets need to be maintained during this transition period to cleaner energy solutions to ensure safe and reliable gas system operations.
    c. The proposed addition of Vaporizers 13/14 to the Greenpoint Energy Center would increase its peak daily output by 20%. That increase could be the difference between keeping customers on during extreme cold events and having to implement extreme measures by isolating and interrupting firm customers in an EGOMP scenario. As gas usage declines, pipeline asset retirement will increase the criticality of local supplies to meet the energy needs of the remaining gas customers.

Many of National Grid's lessons learned and recommended next steps are echoed in *FERC, NERC and Regional Staff Report dated October 2023*[53] surrounding the December 2022 events. The most notable recommendations in the report include:

[53] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022, available at https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022

- Congressional and state legislation or regulation is needed to establish reliability rules for natural gas infrastructure to ensure cold weather reliability.
- North American Energy Standards Board ("NAESB") should convene a meeting of gas and electric grid operators and gas distribution companies to identify any needed communications improvements and suggests an independent research group analyze whether additional gas infrastructure is needed to support grid reliability.

The Company is in the early stages of considering how we can incorporate contingency measures into our supply portfolio to backstop producer/supplier underperformance and interstate pipeline pressure concerns such as establishing a reserve margin to preserve reliable service while also ensuring affordability.

4.2.2. Non-Core Customer Concerns

Non-core customers are customers who procure their own supply, or purchase supply from a third-party marketer, but do not participate in the Company's mandatory capacity release programs. NMPC provides service to many firm non-core customers. The Company has extremely limited visibility into the supply arrangements for these customers and has taken several steps to ensure reliability for firm, core customers.

Since early 2015, the Company has not allowed any increases to the SC-8 D1 Election amounts due to interstate pipeline constraints. In the 2017 NMPC Rate Case, the Company proposed to eliminate SC-8 D1 service, but ultimately agreed to maintain the service without allowing increases.[54] Over the past several years, New York Public Service Commission Staff and Customers have been inquiring regarding increases to the SC-8 D1 Elections. In the NMPC Rate case filed May 28, 2024, the Company has put forth a proposal to clarify the grandfathering of existing SC-8 customers who have taken the D1 Election and to further clarify that no customers other than existing customers who satisfy the grandfathering requirements may secure D1 Elections. There continues to be a supply demand imbalance under the NMPC rate case forecast and the current gas load forecast. The Company does not want to accelerate or exacerbate the imbalance by expanding the SC-8 D1 service.

Further to this issue, in the 2020 NMPC Rate Case Joint Proposal, it was agreed, that new firm non-core daily balanced customers will not be permitted to commence service absent proof that the customer, or its supplier, has contracted for firm primary point upstream capacity to the Company's city gate delivery point or points in a quantity sufficient to serve customer's anticipated peak day requirements for at least one year with the explicit understanding that such firm primary point capacity must be renewed for as long as the customer wishes to remain a firm customer.[55] The Company was required to complete an audit of Direct Customers (i.e., customers who procure their own supplies) taking firm transportation service and ESCOs providing service to such customers to determine what, if any, portion of their load is not served with upstream, primary point pipeline capacity to the Company's city gate. The results of the audit confirmed that Direct Customers/ESCOs do not hold sufficient primary point capacity to meet their forecasted peak day requirements.

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[54] Case 17-G-0239 et al. *Proceeding on Motion of The Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service,* "Joint Proposal," (Filed January 19, 2018).

[55] Case 20-G-0381 et al. *Proceeding on Motion of The Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service,* "Joint Proposal," (Filed September 27, 2021).

4.2.3. Transco Emerging Supply Issue Related to Capacity Expansion

Transco recently placed their Regional Energy Access Expansion Project ("REA") fully into service this year. The Project was designed to increase transportation capacity by approximately 850,000 Dth/day by maximizing the use of Transco's existing infrastructure. The REA facilities are fully integrated with the greater Transco system. In January 2023, FERC issued a certificate authorizing REA. In July 2024, the U.S. Court of Appeals for the District of Columbia Circuit sided with opponents and ruled that FERC had erred in 2023 when it approved REA (Docket No. 23-1064). Vacating approval of REA would require Transco to shut down operation of any facilities related to the project. None of the National Grid companies are shippers on this project, however, according to Transco, the inability to operate the REA facilities would impact LDCs that hold non-REA capacity along the same pipeline path(s). In Transco's emergency petition to FERC, it provided a volume estimate of 170,000 dt/day of capacity from Transco's Station 515 that would be unavailable to the New York Facilities companies (KEDNY, KEDLI and Con Edison) as soon as early November 2024 Pending FERC's ruling on Transco's application for an emergency temporary certificate to continue to operate the REA facilities, or a successful appeal of the DC Circuit decision, Transco will be required to shut down the REA facilities until FERC addresses the Court's concerns in a new certificate order.

4.3. Renewable Natural Gas in our Current Portfolio

In March 2023, National Grid, in partnership with the New York City Department of Environmental Protection ("DEP"), commissioned the Newtown Creek biogas facility. In the first year of operation, April 2023 through March 2024, the Company's conditioning system injected 116,717 Dths of RNG into the local distribution network. The Company has experienced excellent operation in Year 2, surpassing the previous year's total in less than six months, with an additional 140,333 Dths injected. The Company forecasts annual production of approximately 250,000 Dth/year, thanks in large part to growing office attendance in lower Manhattan.

There is no regulatory framework that permits National Grid to procure RNG in a financially competitive way. Although supply is produced and injected into our distribution system through the production of renewable natural gas at Newtown Creek, the environmental attributes are being sold on the open market. National Grid recognizes the decarbonization benefits are largely tied to the attributes, and as a result, National Grid is not claiming Newtown Creek's production as RNG in our current portfolio. Until such time as legislative or policy changes are enacted that allow the Company to procure RNG at scale, options to expand or continue to purchase supply produced by RNG facilities behind National Grid city gates will be driven by third-party developers and landowners.

In addition to supplies generated by Newtown Creek, the Company is also awaiting the completion of an anaerobic digestion waste-to-energy facility on Long Island that will be owned and operated by American Organic Energy, LLC ("AOE"). Under the agreement with AOE, the Company will purchase a portion of the gas supply generated by the facility but will not purchase the environmental attributes.

The Company is also supporting development of RNG interconnections via a deferred future recovery mechanism in the KEDNY / KEDLI rate case[56] for the following projects:

- KEDNY Interconnection 1 – Jamaica Water Resource Recovery Facility
- KEDNY Interconnection 2 – Biogas Corporation Food Waste RNG

[56] See the recently filed KEDNY-KEDLI Order, Joint Proposal at Section 7.8 Biomethane Supply Interconnections.

- KEDLI Interconnection 1 – South Shore Water Reclamation Facility
- KEDLI Interconnection 2 – Enterprise Food Waste RNG

The Company is seeking additional support for development of RNG Interconnections in the NMPC rate case filed in May 2024. Those projects are listed below:

- NMPC Interconnection 1 – Ag-Grid RNG Project 1
- NMPC Interconnection 2 – Saratoga Wastewater Treatment Plant
- NMPC Interconnection 3 – Ideal Dairy Farm
- NMPC Interconnection 4 – Ag-Grid RNG Project 2

In total, AOE and the four approved DNY projects are expected to collectively inject approximately 5,350 Dth/day. The proposed RNG interconnections in NMPC would inject an estimated additional 2,200 Dth/day.

4.4. On-System Peaking Asset Reliance

National Grid's reliance on peaking assets is a critical component of its strategy to ensure reliable gas supply, particularly during peak demand periods. The decision to lean on these assets is driven by the need to balance the stability and availability of supply with cost-effectiveness and environmental considerations. LNG and CNG offer flexible and scalable solutions for meeting sudden spikes in demand, especially during winter months when gas consumption typically peaks. Additionally, LNG provides a reliable backup supply and reduces dependency on constrained pipelines. CNG, on the other hand, offers mobility and can address specific local demand pockets effectively, but as a result of system constraints, relies on use of long-distance trucking for the delivery of product to our service territories during peak conditions. National Grid is likely to continue its reliance on other peaking assets, such as demand response programs, albeit with a strategic shift from non-firm to firm DR in areas like Downstate NY. This shift is justified by the need for more reliable demand-side management, aligning with customer migration trends and regulatory frameworks. Furthermore, the use of peaking assets aligns with the broader industry move towards more flexible and responsive energy systems, capable of integrating renewable sources and adapting to changing consumption patterns. National Grid's reliance on these assets, therefore, reflects a pragmatic approach to modern energy challenges, balancing immediate needs with long-term sustainability and cost-efficiency.

4.4.1. LNG Plant Maintenance

National Grid continues to identify capital projects to preserve reliability and decrease supply risks at both the Greenpoint LNG Plant and the Holtsville LNG Plant.

The projects at the Greenpoint LNG Plant consist of the following:

- New Control System (Complete in FY30) and Control Building w/Maintenance Area (Complete in FY27)
- Tail Gas Compressor Refurbishment (Complete in FY29)
- Tank 1 Low Pressure (60 PSIG) LNG Send-Out Pump Refurbishment (Complete in FY29)
- High Pressure (350 PSIG) LNG Vaporizers 7 & 8 Refurbishment (Complete in FY30)
- Nitrogen System Refurbishment (Complete in FY27)
- Tank 2 Foundation Heaters Upgrade (Complete in FY28)
- Salt Water Pump House Upgrade (Complete in FY27)
- Hydrant & Deluge Piping Upgrade (Complete in FY27)
- Fire Protection Panel System Upgrade (Complete in FY29)

The projects at the Holtsville LNG Plant consist of the following:

- Holtsville Plant Modernization (Complete in FY28)
- Hydrant Piping Refurbishment (Complete in FY29)
- Liquefaction System Refurbishment (Complete in FY29)
- High Pressure (350 PSIG) LNG Send-Out Pump Upgrade (Complete in FY32)

The Holtsville Plant Modernization Project is intended to overhaul various tank related systems and include a detailed internal tank inspection of the LNG tank (which is approximately 50-years old). This project is necessary to ensure the continuation of service from this critical energy facility. The upgrades that must be performed include: LNG Tank Internal Weld Inspection, LNG Tank Stairs/Handrails, LNG Tank Secondary Emergency Egress, LNG Tank Tie-off Anchor Points, LNG Tank Foundation Heaters, Boiloff Compressor System, Power Center, Outer LNG Tank Stiffeners, LNG Tank & Nitrogen Breather Tank Grounding, LNG Tank Lighting, LNG Tank Pressure Protection, LNG Tank Liquid Isolation Valve, LNG Tank Internal Tank Valve, Nitrogen Breather Tank Bladder, and LNG Tank Instruments. These upgrades will increase reliability, mitigate safety concerns that the existing equipment presents and bring the LNG tank and associated systems into compliance with current codes and standards. Upgrading the facility also enables the facility to incorporate design practices for modern LNG tanks.

4.4.2. CNG Asset Reliance & Changes

Beginning with the winter of 2016/17, Downstate NY began utilizing CNG injection services at one location in Nassau County after it was determined that the amount of gas supply and pressures on the NYF system would be inadequate to serve customer requirements on a peak day. Since then, the Downstate NY companies have added CNG injection capability at four (4) other sites on LI to meet current and forecasted peak day requirements. Each CNG injection site (three in Nassau County and two in Suffolk County) is intended to only be operated during the morning and evening periods of peak days for a total of eight (8) hours of supply. One of the sites in Suffolk County is currently scheduled to be upgraded after the 2024/25 winter to increase the CNG injection capability from 1,100 Dth/hour to 2,200 Dth/hour to match the other four (4) sites on LI. The maximum daily CNG supply from all five (5) sites represents less than 1% of the total peak day supply portfolio but is critical because it accounts for approximately 7% of the peak hour supply. Supply related outages are most likely to occur when the system demands are at their peak conditions, but as discussed elsewhere, impacted customers will remain out until they are restored, not just until the system recovers.

Due to forecasted peak hour shortfalls in the Upstate NY East Gate and based on the success of CNG injection services in Downstate NY, the Company pursued a CNG injection site at Moreau, NY in our Upstate NY territory. The Moreau, NY facility has been accessible to the Company under a lease agreement since 2018 and the CNG injection services received at the facility consisted of a bundled agreement for CNG supply and rental of a decompression skid from the CNG supplier. In the fall of 2023, the Company successfully closed on a purchase of this same property and began to pursue expansion of the facility's injection capabilities. As part of this effort, the Company will own, operate, and maintain decompression equipment at the expanded facility. The planned expansion and its associated contracted supply will be operational for the 2024/2025 winter, and the Company will have the capability to inject up to 2,200 Dth/hour for four hours twice per day (just as the Downstate NY sites operate) at this location.

A second Upstate NY East Gate constraint at Troy, NY, was originally going to be addressed with an infrastructure project; unless and until that infrastructure project, a similar project or a reliable non-pipeline alternative can be available, a second CNG site in the vicinity of Troy is required. This new CNG site will be constructed with the same 2,200 Dth/hr decompression capability as the other sites but will also have enhanced capabilities so that it can also accept RNG and will be known as Energy Transfer Site #2 ("ETS2"). The ETS2 site is needed to meet Design Day demand in the 2027/28 winter, however it is currently scheduled to be operational for winter 2026/27. RNG enhancements and any lessons from ETS2 may be incorporated into other CNG sites as needed.

National Grid does not intend to further expand CNG decompression capacity in New York State beyond the five Downstate NY and two Upstate NY sites once all seven sites are in service at the 2,200 Dth/hr capacity level. This decision is based on concerns shared by National Grid and DPS Staff about over-reliance on CNG to meet Design Day conditions following Winter Storm Elliott (see 2.2.6). DPS Staff also noted that "Con Edison did not receive the full expected volume of CNG,"[57] indicating possible constraints on CNG delivery capacity at an industrial scale. To mitigate certain concerns regarding reliability of CNG, the Company has begun to implement on-site storage at various CNG interconnects on its system. On-site CNG storage will not however increase the design day capacity, as the capability of the injection site is limited by both the decompression equipment and number of truck bays at the site, as well as the volume of gas supply the companies secure to inject at the CNG location. In contracting for supply and the number of trailers that could reasonably inject into a CNG injection facility, the Companies must consider the time and process required to safely inject CNG supply, remove empty trailers and replenish the facility with full supply. The Companies therefore limit CNG injection to morning and evening peak periods. Although on-site CNG storage does not increase the design day capacity of CNG supply, the Companies have opted to pursue its use for the reliability enhancements it offers to system operation. Due to the supply constraints in the Companies' service territories, the Companies cannot rely on filling or refilling trailers with CNG during peak periods from its own gas system. The Companies and its CNG suppliers must therefore source CNG supplies from unconstrained supply areas, including the Marcellus region. This necessitates reliance on long distance trucking during peak winter conditions, which may include high winds, inclement weather, and road and/or bridge closures. Therefore, CNG that is not stored on-site cannot be reasonably expected to be dispatched on short notice.

4.5. Role of Non-Firm Demand Response Programs

The Company's Non-Firm Demand Response ("NFDR") programs in KEDNY and KEDLI, previously referred to as Temperature-Controlled ("TC") and Interruptible ("IT") and currently referred to as Tier 1 and Tier 2 due to tariff changes, are essential to managing Design Day resources, providing over 150 MDth/day of demand reduction. The Companies would need a like amount of firm supply and significant on-system reinforcements to convert these customers to firm service.

KEDNY and KEDLI also have individually negotiated peak shaving contracts with some cogeneration customers that provide 65 MDth/day to the supply portfolio from November through March. Cogeneration customers who are planning to run during peak shaving events will typically switch to an alternate fuel if they have not already done so for economic reasons. These customers can request to deliver replacement supplies (supplies in excess of peaking call volume) in order to remain on gas, but this can only be approved if gas system conditions allow for it. These supplies are dispatched according to the Downstate NY Interruptibility Matrix that is included in the currently effective Gas Transportation Operating Procedures ("GTOP") manual filed with NYPSC each year (or more frequently as needed). Other electric generators in KEDNY and KEDLI (with fully or 30-day interruptible service) can also be interrupted as needed to ensure the safe and reliable operation of the gas system. In special circumstances where the load reduction is not enough, the Companies can also curtail generators and require them to maintain their nominated gas supplies for use by firm customers. In this instance, the generators would be cashed out per KEDNY or KEDLI tariff curtailment provisions.

More information on the NFDR programs is available in section 5.1.5 of this plan.

[57] DPS letter to DEC, "DEC Application IDs: 3-1326-00211/00001 (Dover Compressor Station); 4-1922-00049/00004 (Athens Compressor Station)", page 9, Feb 26, 2024,

4.6. Affiliate Issues

KEDNY, KEDLI, and NMPC do not have any affiliate relationships with pipeline developers.

4.7. Potential Changes to the Supply Portfolio

In response to forecast growth, KEDNY and KEDLI signed a precedent agreement with Iroquois to deliver an additional 62,500 Dth of natural gas per day to the Downstate NY area. Iroquois has received the necessary authorization from the Federal Energy Regulatory Commission ("FERC") and now requires permits from both the New York State Department of Environmental Conservation ("NYSDEC") and the Connecticut Department of Energy & Environmental Protection ("CT DEEP") before the project may commence construction.

Additionally, a project was identified in 2020 to increase the vaporization capability of the Greenpoint Energy Center in Brooklyn, NY. This project was also conceived to address forecast growth in Downstate NY. The Greenpoint Vaporizer 13/14 Project consists of two new vaporizer units that will increase the peak day output of the facility from 291,200 Dth/day to 350,000 Dth/day. The new vaporizers:

(i) provide critical safety and reliability benefits for the gas network,
(ii) do not add any new gas supply to the system as the maximum on-site LNG storage quantity will not change,
(iii) will only operate on a handful of the coldest days of the year when they are needed to meet customers demand,
(iv) are more efficient than existing vaporization units,
(v) are more cost-effective than other options because the project leverages existing assets,
(vi) will be located within an existing National Grid facility with minimal construction impacts, and
(vii) can be easily decommissioned should customer demand decline in the future and/or can support the system through the energy transition if upstream assets are retired before customer demand declines sufficiently.

The Company is preparing to file an Air State Facility permit application for this project before the New York State Department of Environmental Conservation. The project will take approximately 36 months from permit approval to complete mobilization, construction, pre-commissioning, and final commissioning.

As noted above, for Upstate NY, the Company is currently siting ETS2 in the East Gate and near Troy, New York. The site will be capable of decompressing up to 2,200 Dth/Hr for a daily total of 17,600 Dth/Day when the site is run for a total of eight hours per day. More information about this project can be found in section 4.4.2 and in the most recent NMPC Rate Case filing.[58]

4.7.1. Extension of Existing Pipeline Contracts

As decision dates for contract extension/termination approach, the Company determines the need to maintain and or modify (to the extent possible) each contract as part of the resource portfolio. The Company uses several criteria to assess the need for transportation and storage contracts including, but not limited to, receipt point liquidity, reliability, complement to the existing portfolio, and economics.

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[58] Case 24-G-0323, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service,* GIOP Testimony, filed May 28, 2024.

Also, the Company considers options to replace long-haul capacity with shorter-haul capacities where opportunities are available in each portfolio. For example, as supplies from the Marcellus shale region became abundant and readily accessible, the Company did not renew expiring long-haul contracts with Union, TransCanada and Empire pipelines in the Downstate NY portfolio and similarly did not renew contracts with Transco and TGP pipelines for the Upstate NY portfolio. The option to reduce capacity paths is not one typically offered by the pipelines, so, when the opportunities occur, the Companies will seek to take full advantage of such de-contracting providing such options do not have an adverse effect on the reliability and economics of the portfolio.

4.8. Renewable Natural Gas

The EPA defines RNG as “a renewable energy source that, when used, can reduce methane emissions, and provide other environmental benefits. Derived from organic waste matter, RNG can be used as a substitute for natural gas The biogas used to produce RNG comes from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities also known as wastewater treatment plants, livestock farms, food production facilities, and organic waste management operations.”

RNG offers potential for a decarbonized energy alternative that can work within our country’s existing infrastructure. As a drop-in fuel, it is able to offset geological natural gas, leveraging carbon supplies at the surface in lieu of extracting sequestered supply.

The RNG market continues to grow rapidly. According to the RNG Coalition, the number of RNG projects active nationwide has increased significantly since 2015, with over 300 operational projects, 176 projects under construction and over 300 planned for construction. The result of these projects coming online is more than 218% growth in RNG production nationwide over the last 5 years.[59] Looking to the future, to quantify RNG potential nationally and within the State, National Grid used recent studies and publications from the American Gas Association and NYSERDA. Each of these studies offers a low and high potential scenario broken down by production technology.

4.8.1. RNG Potential Nationwide

In December 2019, the American Gas Foundation (“AGF”) published a study conducted by ICF assessing the supply and emissions reduction potential of renewable sources of natural gas.[60] The report uses publicly available data from the US Government to quantify raw resource potential by state by feedstock. ICF developed production potential estimates by incorporating a variety of constraints regarding accessibility to feedstocks, the time that it would take to deploy projects over the timeline of the study (out to 2040), the development of technology that would be required to achieve higher levels of RNG production, and consideration of likely project economics – with the assumption that the most economic projects will come online first.

ICF estimated low and high resource potential scenarios by considering constraints unique to each potential RNG feedstock, such as accessibility and production economics. Low resource potential only considers the most profitable projects, while high resource potential assumes conversion of all facilities ICF deemed financially viable. These projections are only a portion of the raw technical resource potential RNG has nationwide. As shown in Figure 4-2, ICF found that nearly 95% of US

[59] RNG Coalition: 300 RNG Facilities Now Operating in North America, available at https://www.rngcoalition.com/news/2023/8/1/rng-coalition-300-rng-facilities-now-operating-in-north-america
[60] American Gas Foundation, Renewable Sources of Natural Gas: Supply And Emissions Reduction Assessment, available at https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf

residential natural gas consumption is capable of being sourced from RNG in a high resource scenario by 2040.

Figure 4-2: Estimated Annual RNG Production, Low Resource Projections from the AGF Study, TBtu/year

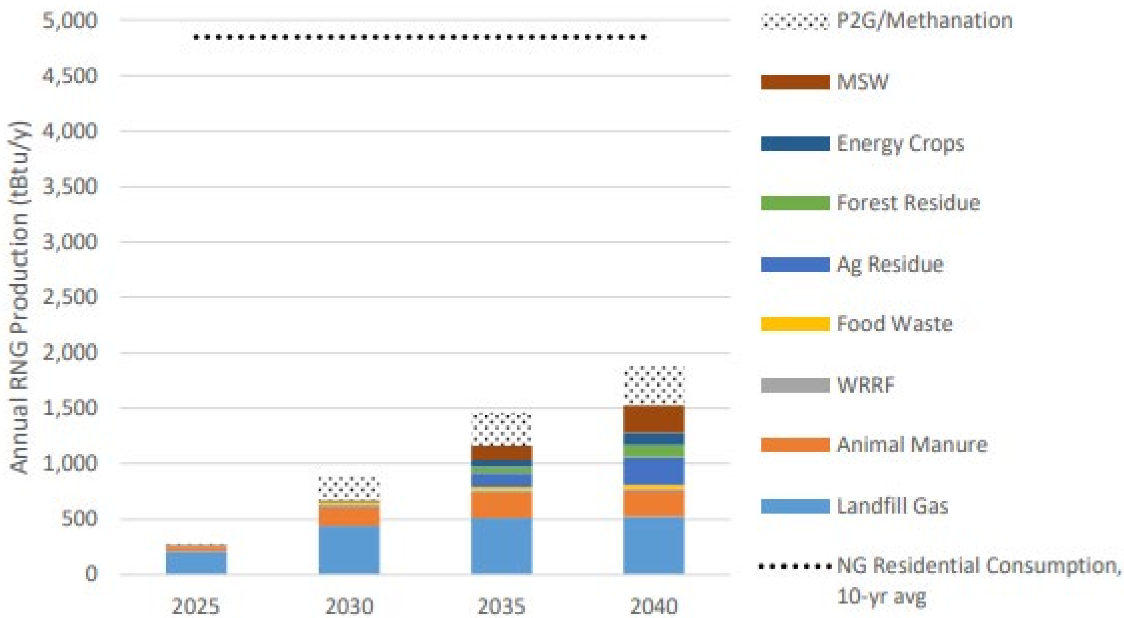
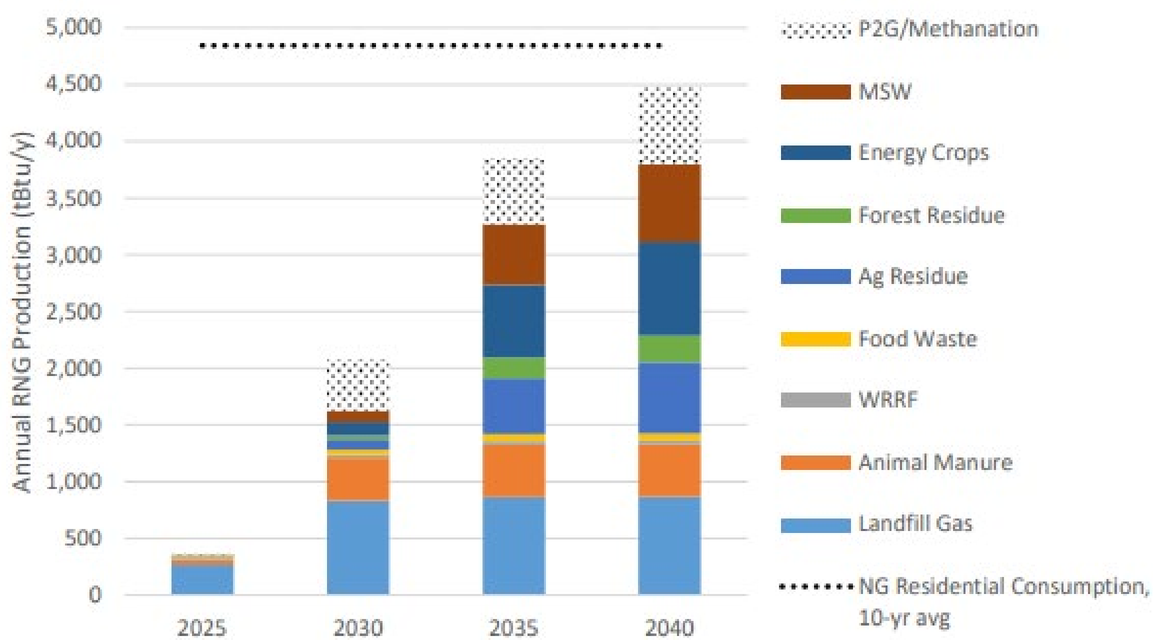


Figure 4-3: Estimated Annual RNG Production, High Resource Projections from the AGF Study, TBtu/year



4.8.2. RNG Potential Eastern U.S. and New York State

According to the 2019 AGF study, New York has the second highest potential for wastewater treatment plants ("WWTPs"), third highest potential food waste, and 8th highest potential for landfill gas. New York is also the 5th largest dairy producer in the country and largest producer of cottage cheese and yogurt. Furthermore, there are over 10 projects actively injecting, under construction or planning to interconnect to National Grid's pipeline by 2030.

An April 2022 study by NYSERDA[61] quantified the potential of Renewable Natural Gas in New York State. Conducted by ICF as well, the study determined a limited adoption scenario of 47 TBtu/year and an optimistic growth scenario of 147 TBtu/year by 2040.

In 2022, National Grid contracted Guidehouse Inc. to help support National Grid's New York Climate Leadership and Community Protection Act Study.[62] Guidehouse developed an Eastern US RNG supply potential, based on the AGF Study, the NYSERDA study, and an American Gas Association (AGA) study.[63] The results and estimated share for New York and National Grid's New York service territories are displayed in Table 4-2.

Table 4-2: Estimate of Annual RNG Production from Eastern U.S. States, and Potential RNG Supplies Available to New York

RNG Supply Cases Defined by AGF	Annual RNG Supply Potential Eastern U.S. in 2050 (TBtu/year)	Estimated Share of Eastern U.S. RNG Supply potential in 2050 (TBtu/year)	
		NY State	National Grid (NY only)
Low Supply Case	1,158	150	83
High Supply Case	2,199	285	158
Regional share of non-power, non-industrial natural gas sales in 2020		13.0%	7.2%

4.8.3. Barriers & Risks

The AGF report explores low resource, high resource, and technical resource scenarios. Assumptions were developed based on real world factors including viability and cost effectiveness. A few key barriers and risks for development of RNG are as follows:

1. **Combined Heat and Power**

   On a national level, combined heat and power ("CHP") is still the most common use of biogas. According to the CHP database maintained by the US Department of Energy, there are over 4,700 CHP projects in operation today. When establishing the low and high resource potential scenarios in the AGF report, full conversion of all projects meeting the low and/or high resource potential was assumed. For facilities that recently upgraded their CHP system, it's likely they'd wait until their assets are nearing the end of their useful life before they'd begin exploring RNG. It's believed that the environmental attributes offered to RNG projects via the EPA's Renewable Fuel Standard ("RFS"), voluntary markets and/or

[61] NYSERDA, Potential of Renewable Natural Gas in New York State, available at https://www.nyserda.ny.gov/-/media/Project/Nyserda/files/EDPPP/Energy-Prices/Energy-Statistics/RNGPotentialStudyforCAC10421.pdf
[62] Case 19-G-0309, et al., *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,* "National Grid New York Climate Leadership and Community Protection Act Study, Final Report," (Filed March 17, 2023).
[63] American Gas Association, Potential of Renewable Natural Gas in New York State, available at https://www.aga.org/wp-content/uploads/2022/02/aga-net-zero-emissions-opportunities-for-gas-utilities.pdf

California’s Low Carbon Fuel Standard (“LCFS”) could drive investment in RNG and conversion of CHPs systems but potentially not at the rate proposed in the AGF report.

2. **Interconnection Viability**

   In New York State, there are approximately 889 dairy farms in operation today, many of which are located in more remote rural areas of the State. By nature of their location, the nearest gas line may be too far to interconnect with or would not have sufficient summertime consumption to permit year-round injection. Despite best efforts, not every project can be viable given the existing gas infrastructure. As such, utilities and developers are starting to pivot. Centralized trucking facilities offer RNG developers the potential to truck RNG as compressed (renewable) natural gas. Similarly, developers are exploring hub and spoke type projects, where biogas and/or organic material is trucked from a variety of sources to a single site for processing and injection.

3. **Buildability of production facilities**

   RNG production from food waste, dairy manure, or a combination of both have significant capital costs. Developers need to build receiving stations, digesters, heating systems, gas conditioning systems, process control systems and RNG interconnection. Depending upon the site location, size of the system and complexity of the project, these costs can be upwards of $60M. Recently, the combination of the Renewable Fuel Standard D3/D5 credit and California’s Low Carbon Fuel Standard offered significant incentives to build these systems. With uncertainty about the future of the LCFS for RNG, developers need to balance the capital cost of the project against potentially diminished returns from credit sales.

4. **Competition for supply**

   While the AGF’s report estimated that nearly 95% of residential natural gas consumption is capable of being sourced from RNG, residential use is far from the only market looking to buy RNG. The RFS and LCFS programs are designed to utilize RNG to reduce emissions associated with the transportation market. Voluntary markets are also growing rapidly, with utilities competing against large corporations for the same supply. With a finite supply of RNG, competition between sectors and other gas utilities could lead to elevated commodity prices.

4.8.4. RNG Procurement

National Grid has a vast network of pipeline transportation capacity throughout the country, with transportation rights on pipelines originating in liquid basins as far as the Gulf Coast and Ontario to our service territories in the Eastern United States. Through market analysis, National Grid has identified RNG feedstocks that could interconnect directly with National Grid’s transportation capacity. National Grid also understands that certain feedstocks will not be located near these transportation networks, resulting in supplies that cannot be physically transported to its service territories. Therefore, National Grid is considering a procurement strategy that will allow for RNG projects that can be physically transported to its service territories as well as those that can only advance through an unbundled procurement arrangement.

National Grid’s CLCPA Study, cited above, found the high and low resource potentials for RNG in the eastern United States in 2050 to be 2,199 and 1,158 TBtu/year respectively. In order for National Grid to achieve its Clean Energy Vision, the procurement of approximately 98.5 TBtu/year of RNG will be necessary by 2050; this would represent approximately 5.9% of the average RNG potential in the eastern United States. In 2020, this same study reported National Grid’s regional share of non-power, non-industrial natural gas sales in New York to be 7.2%. Therefore, the share of RNG in the region National Grid would need to procure to achieve its Clean Energy Vision would be less than its current share of non-power, non-industrial natural gas sales in the region.

4.8.5. RNG Cost

RNG pricing for long-term scenarios is derived from a production cost-based approach. This approach utilizes technology cost assumptions to supply RNG. This is different from a policy or market-based approach using programs such as EPA's Renewable Fuel Standard Program or California's Low Carbon Fuel Standard Program that consider cost of credits to reduce emissions or regulatory compliance. A policy- or market-based approach may result in different forecasted prices depending on policy and market conditions, including the status of RNG policy in New York. The supply curve for RNG in the long-term plan scenarios rely on data from the US Department of Energy[64] ("USDOE"), and the 2019 AGF study referenced above for certain feedstocks that were not from USDOE (primarily landfills and wastewater treatment).

It should also be noted that there are additional sources for pricing low carbon fuels. S&P Global Platts, a provider of energy and commodity price assessments, recently began publishing RNG and Hydrogen premiums. Publications for RNG premiums began in May 2023 and Hydrogen premiums in April 2022.

Platts does not currently have a forward curve for RNG and Hydrogen. For this reason, the Company relied on the National Grid New York CLCPA study for the expected costs of these commodities. As indicated above, the Guidehouse study uses a production cost-based approach while Platts relies on policy drivers and market conditions. As these are nascent markets, it is expected that market developments, including enabling policies in New York, could stimulate RNG production and dramatically impact currently projected pricing.

Table 4-3: RNG Prices, by Analysis Year

Fuel Type	Units	2020	2030	2040	2050
RNG	**2020$/MMBtu**	**$43.53**	**$16.03**	**$14.16**	**$13.54**

The production cost-based approach starts in 2030 and beyond, and only sustainable biomass feedstocks have been considered. Sustainable biomass is defined as wastewater treatment facilities, food waste, livestock manure, agriculture, and forest residues. Given sustainability concerns, the analysis excludes purpose-grown energy crops and forests for bioenergy production. In each decade the majority of RNG production, approximately two-thirds, are from landfills and wastewater, and the remaining is livestock manure.

It is important to note that biomass resource availability in the northeast is relatively low compared to the other regions in the United States. Therefore, the company would import RNG from other states. In this analysis, the company has assumed that it can access RNG production east of the Mississippi River. This dividing line was established based on existing pipeline infrastructure that is currently utilized to deliver natural gas into the New York region.

4.9. Hydrogen

[64] USDOE, 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy. See: https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

Hydrogen, the most abundant chemical element on Earth, offers enormous potential as a source of clean energy and fossil-free heat. When hydrogen gas is burned to release its energy, the main byproduct is water vapor. Hydrogen produced using renewable feedstocks is known as green hydrogen. One of the most promising green hydrogen pathways is the process of electrolysis, using renewable electricity from wind and solar, which is carbon-free.

Hydrogen can help decarbonize multiple sectors, including heat, power generation, and transport. For heating, hydrogen can be blended with natural gas or RNG up to 20% by volume (7% by energy), run through our existing gas networks and used in customer appliances without significant upgrades to infrastructure or equipment. In areas with high levels of gas demand, pure hydrogen also has the potential to serve fossil-free heating and other energy needs in dedicated 100% hydrogen clusters.

Green hydrogen complements growing renewable electricity capacity due to its ability to be stored and its flexibility to be used across different sectors. Hydrogen can be made during periods when wind or solar resources are able to produce more electricity than the grid needs and then stored for later use, thereby maximizing the benefits of renewable energy resources. The gas network itself can also serve as a large storage reserve by carrying hydrogen.

4.9.1. Availability of Hydrogen

Hydrogen development to enable the energy transition is receiving strong government support and interest from industry. The US Department of Energy's Earthshot Initiative aims to reduce the cost of green hydrogen to be in line with today's costs for natural gas by 2030. The bipartisan Infrastructure Investment and Jobs Act passed by Congress in February 2022 allocated $8 billion to establish regional clean hydrogen hubs; $1 billion for Research, Development and Demonstration ("RD&D") to reduce costs of hydrogen produced from clean electricity; and another $500 million to support hydrogen equipment manufacturing and domestic supply chains. Pilot projects driven by the private sector are also proliferating across the US – covering production, storage, pipeline transmission and distribution, end uses, and use in power generation. Hydrogen to supply our customers could be sourced from a mix of renewable generation and electrolyzer capacity in the Northeast as well as imports from outside our region.

While the renewable resources required for green hydrogen production are unevenly distributed across New York, and hydrogen storage is limited to the northwestern region of the state where large underground salt caverns can be found, the location of hydrogen production can be determined based on where it makes the most economic sense and does not always need to be co-located with the renewable resources or storage facility. It is possible to co-locate electrolyzers with renewable electricity resources and transmit hydrogen via dedicated pipelines, or to transmit electricity from the generation resource and co-locate electrolyzers with storage facilities and demand centers.

4.9.2. The Role of Hydrogen

The use of green hydrogen produced locally or regionally is a key element of National Grid's Clean Energy Vision to decarbonize the gas networks. Hydrogen is also an important tool for decarbonizing industrial energy demand currently served by gas in of the Climate Action Council's Integration Analysis scenarios, including Scenario 3, which is the basis for the Accelerated Electrification scenario presented in this LTP.[65] Hydrogen is very flexible – the ability to produce, store, distribute and use hydrogen in multiple ways makes it the ideal energy carrier to deliver gas decarbonization in

[65] New York State Climate Action Council Scoping Plan, Appendix G: Integration Analysis Technical Supplement, p. 32.

a manner that is responsive to customer demand and market prices. Additionally, blending hydrogen into the gas network allows customers to use their current infrastructure and devices, making the transition to cleaner energy more accessible and affordable.

4.9.3. Hydrogen Blending

For heating, green hydrogen can be blended with natural gas or RNG up to 20% by volume and run through existing gas networks that have been upgraded through the Company's LPP removal program and used in existing customer appliances and systems without significant upgrades to infrastructure or customer equipment. With proper handling, hydrogen can be used to deliver zero carbon energy to a diverse set of customers with a risk profile that is equal to or lower than legacy natural gas distribution or utilization.

4.9.4. Hydrogen Cost Assumptions

The cost of hydrogen, which in the case of green hydrogen is produced by electrolysis, is primarily based on the cost of the renewable power used to produce it, the efficiency of the production process and the cost of the delivery to an injection point in the gas transmission or distribution system. Today, the US Department of Energy has established the "Hydrogen Shot" and has aligned all federal research and policy toward a cost target of $1 per kg. Accomplishment of this goal would result in a supply cost of $7.43 per Dth. Accordingly, the Inflation Reduction Act includes a Production Tax Credit ("PTC") with a value depending on the carbon intensity of the hydrogen produced. For the hydrogen with the lowest carbon intensity, as determined by the federal GREET model, that credit is up to $3.00 per kg or $22.28 per Dth. However, rules proposed by the IRS would require hydrogen production to be from new renewable power capacity with time matching between the source and production of hydrogen. The projected impact of the PTC on hydrogen costs is not included in this analysis.

The cost of hydrogen in the long-term scenarios is based on E3's work for the California Energy Commission. Production cost trajectories were developed in partnership with UC Irvine in 2019 and the report also includes data from NREL. The following table represents the cost for hydrogen.

Table 4-4: Hydrogen Pricing for Long-Term Plan Scenarios, by Analysis Year

Fuel Type	Units	2020	2030	2040	2050
Import: Hydrogen	**2020$/MMBtu**	**$28.95**	**$25.85**	**$20.71**	**$17.81**

All of the hydrogen is derived from electrolysis using renewable electricity (also referred to as "green hydrogen"), and an alkaline electrolysis cell ("AEC") was used to produce hydrogen due to its low cost and technological maturity. Several ways were considered to source clean electricity as input for the electrolyzers, and using off-grid wind resources from the Pennsylvania region was found to be the most cost-effective way to produce hydrogen. There was also an assumption that hydrogen would be stored underground and delivered into the region. The costs above are for delivered hydrogen which include production costs, new salt cavern underground storage outside of New York and new dedicated hydrogen pipelines. The analysis includes an upper limit of 20% hydrogen blend by volume (approximately 7% by energy content) in the existing pipeline without the need for pipeline and equipment upgrades.

4.9.5. Hydrogen Demonstration Projects

The Company may propose for Commission approval a series of hydrogen demonstration projects that will demonstrate the practicality and will evaluate the cost competitive features of one or more hydrogen concepts. Early projects may include onsite production of green hydrogen from solar or wind power, but such projects will rely on the third-party market for locally or regionally sourced green hydrogen supply. These third-party supply projects have the potential to produce substantial new capacity of about 74 tons per day (42 MDth/day) of green hydrogen in NY state under development by Plug Power (due in 2025) and another project by Linde at Niagara Falls.[66]

To enable these demonstration projects, and in general the blending of hydrogen into our gas networks, changes in policies and technology are necessary to support hydrogen production growth and blending:

- **Network readiness** – Investments are needed to establish and grow areas in our existing gas network that are capable of safely delivering hydrogen blended gas to our customers. This includes work to eliminate all remaining LPP in an area and confirming the blended hydrogen in the network will not result in any long-term reliability concerns due to the lower Btu value per cubic foot of hydrogen blended gas. Additional research, and demonstration projects, may be needed to enable hydrogen blending upstream from our distribution system – including gas transmission, pressure regulation and LNG assets – and deploying dedicated hydrogen clusters. If hydrogen is to be procured upstream of the Company's distribution system along pipeline transportation paths currently used to flow natural gas, those pipelines and other customers receiving supply along this same corridor must also be prepared to take blended hydrogen.
- **Procurement Authority** – Current regulations mandate that we purchase energy for our gas customers at the lowest possible cost. However, due to the limited market and higher cost of hydrogen compared to natural gas, it is necessary to make regulatory and legislative changes to mature the hydrogen market, reduce its overall commodity cost, and ensure proper recovery when purchasing hydrogen on behalf of our gas customers.
- **Supplier Development** – Other utilities, as well as commercial and industrial end-users, are also interested in using hydrogen for their customer and business needs. The limited supply of hydrogen production and growing competition for it can create a significant challenge in properly sourcing the hydrogen needed to enable demonstration projects and supply larger areas on the gas network with hydrogen blended gas.
- **Regulatory, Stakeholder & Community Approval** – In addition to regulatory limitations on the cost of hydrogen as stated above, regulatory approval will be needed on the gas quality change required when using hydrogen blended gas. Investment in increased stakeholder and community outreach is necessary to educate stakeholders about the safety and viability of hydrogen blending to decarbonize gas networks. Many stakeholders and community members may not be familiar with the benefits and risks of utilizing hydrogen as a part of a gas network decarbonization strategy. Therefore, it is essential to engage with them and provide accurate information to build trust and support for hydrogen blending.

4.10. Process to Identify Upstream Supply Projects

Prior to the start of each winter, using the most recent forecast of customer requirements, the Companies perform an initial evaluation of the existing supply portfolio in relation to the firm sendout forecast for the Design Day and design season. As part of this initial evaluation, the Companies review the possible strategies for meeting customer requirements using the existing supply portfolio in a variety of circumstances. Since 1996, the Company has been using the SENDOUT® model originally developed by New Energy Associates as its primary analytical tool in the portfolio design

[66] Hydrogen demonstration projects will require Commission approval. A copy of any such proposal in KEDLI or KEDNY's service territory will be filed in Cases 23-G-0226 and 23-G-0225 during the term of the rate plan in accordance with the KEDNY-KEDLI Order.

process. The SENDOUT® model is a linear-programming optimization software tool used to assist in evaluating, selecting, and explaining long-term portfolio strategies. Using the SENDOUT® model, the Companies' can:

1. Determine the least-cost portfolio that will meet forecasted customer demand, and
2. Test the portfolio's sensitivity to key inputs and assumptions, and its ability to meet the Companies' planning standards and contingencies for Design Day and design season.

Based on this analysis, preliminary decisions can be made on the adequacy of the supply portfolio and its ability to meet system requirements for the upcoming year and over the longer term. While the first look at determining the adequacy of the portfolio is focused on Design Day and design season, it has become necessary to determine the Companies' ability to meet peak hour customer requirements as the upstream pipelines serving the Companies' various distribution systems continue to become more constrained. As such, a hydraulic analysis is also performed for each portfolio that allocates peak hour customer load by city gate compared to the contractual peak hour entitlements available from the upstream pipeline, as well as any on-system resources. Based on the results, the Companies must determine:

1. Can incremental energy efficiency and/or demand side management solutions be applied?
2. Can incremental electrification programs be applied?
3. Is there additional supply and/or capacity available in the market that the Companies can contract for?

If this effort, which is essentially an NPA analysis, determines incremental EE, DSM, and electrification programs are inadequate to address increased customer requirements, the Companies will begin the process of identifying upstream supply projects.

4.11. Process to Identify On-System Capital Projects

Each year Gas System Strategic Planning ("GSSP") performs an analysis on the New York State gas systems to determine reinforcement projects and associated costs that need to be constructed over the following five years to support forecasted customer demand. Program costs are estimated for subsequent years six through ten, and any known large-scale projects are identified. Reinforcement projects are designed to maintain minimum design pressures throughout the gas system under peak-hour conditions and are traditionally constructed as they become necessary for the most efficient use of capital dollars. The 5-Year Plan is revised and issued annually so that it can be adjusted for changes to the Advanced Data Analytics ("ADA") sendout forecast, differences between actual load growth and estimated load growth (including electrification variances), reinforcement project deferrals, public works activity, main replacement and removal activity, Customer Gas Connections supported growth reinforcements, and updates/ improvements to the Synergi computer network analysis models.

In addition to reinforcement projects designed to support forecasted demand, GSSP also identifies system reliability projects. In general, these projects improve the overall reliability of the distribution system, often by providing additional system resiliency for unanticipated events or through improvements to system integration. These projects are aimed at improving overall system reliability and include, but are not limited to, eliminating farm-tap installations, eliminating distribution systems fed by a single district regulator (i.e., single-feed systems) and isolated low pressure ("LP") systems, eliminating non-standard pressure systems, and resiliency projects aimed at addressing areas of the system where greater than 5,000 customers would lose service if a critical pipeline facility becomes inoperable when the average daily temperature is 15ºF (5ºF in Upstate NY). The installation of Remote Control Valves ("RCV's") is also included in this program. In many cases, deferred reliability projects become reinforcement projects in future years. Certain larger-scale system reliability projects and supply-related projects are budgeted separately and are identified as special projects.

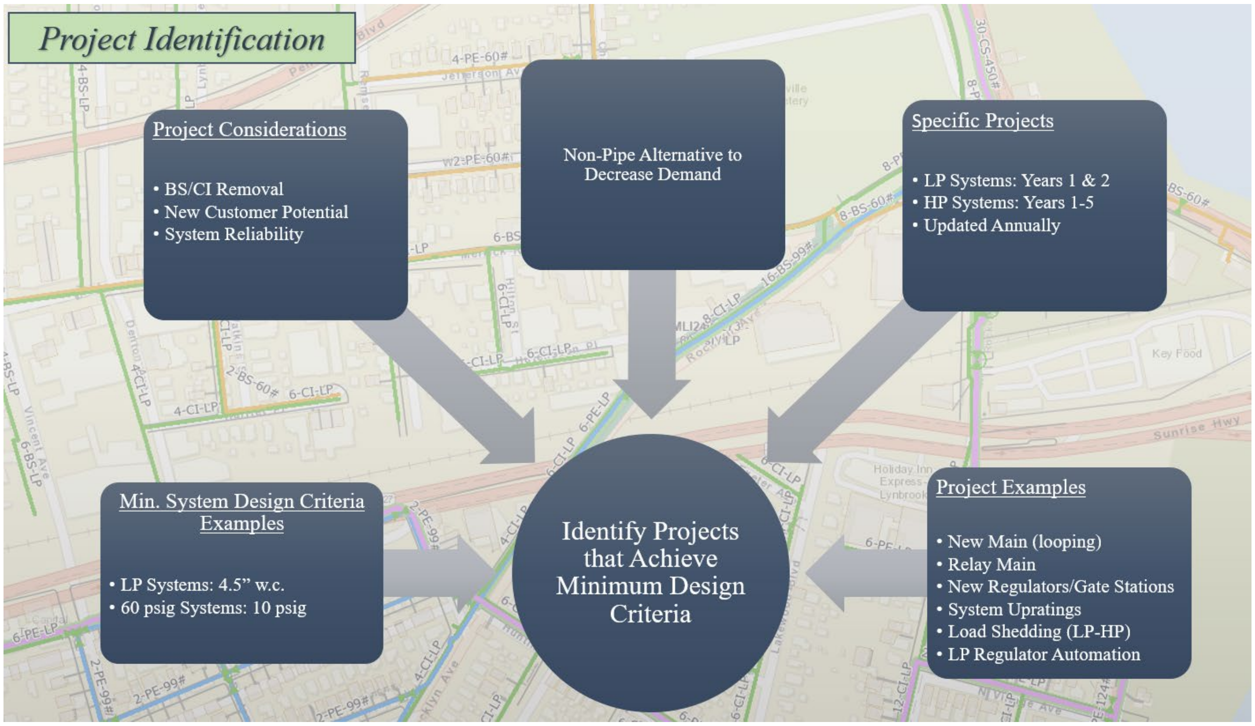
Once the Synergi models are loaded with the forecasted customer demand, specific distribution system reinforcement projects and regulator capacity projects that must be constructed to support each company's average annual system growth are identified. These projects are designed to maintain the minimum system design pressures. Once the scope of work is identified, potential NPAs for the identified projects will be evaluated. If an NPA cannot be implemented in time to maintain system reliability in a cost-effective manner, the project will move forward.

Distribution system reinforcement projects ensure that adequate minimum pressures are maintained on the Company's high and low-pressure distribution systems during periods of peak demand. These include, but are not limited to, installing new main, relaying existing main, installing new sources (e.g., district regulators, take stations), low pressure main load shedding, and system upratings. When reinforcements are required, the removal of leak-prone main is given priority. When reinforcing low-pressure systems, upgrading to elevated pressure is investigated where appropriate. Due to the sensitivity of low-pressure systems to the exact location where customer growth occurs, specific low-pressure system reinforcement projects are generally only identified for the first two years of the plan. The average low-pressure spending in the first two years of the Plan is used to estimate low-pressure reinforcement spending for the final three years of the Plan. In addition, an estimated spending level is determined for years six through ten of the Plan, along with the identification of any known large-scale projects.

Regulator capacity projects, which generally involve replacing undersized regulators, ensure that regulator stations on the distribution system can meet the load demands of the system. As system load grows, some of the older regulator stations are not able to meet the higher capacity requirements and, as a result, are not able to maintain required set points necessary to sustain adequate minimum distribution system pressures.

The figure below provides a visual example of the on-system project identification process.

Figure 4-4: On-System Project Identification Process



4.12. Leak-Prone Pipe Removal Process

The Leak Prone Pipe ("LPP") Removal Process for National Grid's inventory of LPP reduces leaks, greenhouse gas emissions, and the risks associated with LPP in the Companies' distribution systems. LPP is defined as all 12-inch and smaller diameter pipe that is (i) unprotected (i.e., non-cathodically protected) steel pipe (whether bare or coated); (ii) cast and wrought iron pipe; (iii) pre-1985 vintage Aldyl-A plastic pipe; and (iv) unprotected steel/wrought iron, copper, vintage HDPE and Aldyl-A plastic services ("associated services").

Gas Engineering identifies individual main segment candidates for removal through:

1) Field Requests (which are reviewed throughout the year)
2) Public Improvement Job Areas as requested by Field Operations and/or Public Works employees (which are also reviewed throughout the year)
3) Annual risk analysis performed using DNV's Synergi Pipeline integrity and risk management software
4) Annual Screenings by Main and Service Engineering
5) Lab Failure Analysis Reports, reviewed by Distribution Engineering for system issues.

All identified main segment candidates are evaluated and prioritized by Distribution Engineering. The analysis considers pipe material and diameter, leak repair history, surrounding structures and field conditions. All leaks due to equipment failure (valves, tees, etc.) on the actual main segment and services shall be included in the evaluation and prioritization process. Leaks resulting from damages to distribution mains and services are not systemic integrity issues and therefore are not to be included in the evaluation and prioritization process. Opportunities to take advantage of coordination with municipal projects and other National Grid programs and projects are also considered.

Every approved job is processed through GSSP for sizing (determining the appropriate replacement material and diameter) and Corrosion Engineering for determining if the removal will have any impact on existing cathodic protection systems. Each main segment identified for removal will be evaluated for NPA feasibility. If no NPA is feasible, reason(s) will be provided. The teams will also determine if abandonment or a system uprating is an appropriate option.

The benefit of performing this work includes mitigating open gas leaks, eliminating high risk services associated with existing LPP mains, reducing safety risks and the potential for incidents associated with LPP, and improved community and government relations. By replacing pipes with high leak rates such as cast iron and unprotected steel, the LPP Program has reduced GHG emissions by 18.5% avoiding 5,538,160 metric tons of CO_2e since 2008. The GHG emissions were calculated using GHGRP as referenced in the New York State Oil and Gas Sector Methane Emissions Inventory, Table 3.2.7.1 Distribution Pipelines and AR5 GWP20. Furthermore, removing leak prone pipe continues to significantly reduce greenhouse gas emissions. The rate of main removal is constrained by cost, workforce availability, municipal considerations, and other factors.

4.13. Right Sizing our Supply Portfolio

The Companies have always strived to maintain a diverse portfolio of assets that serve customers in a least-cost manner while also satisfying the operational requirements of the gas systems. During periods of demand growth that cannot be fully mitigated with demand side solutions, the Companies will attempt to add assets to the portfolio in a least-cost manner. Any additions to the portfolios must address:

a. Design Day requirements
b. Design hour requirements
c. Supply liquidity
d. Supply reliability

Acquiring available capacity in the marketplace that can satisfy all requirements is the preferred strategy. Any existing capacity that the Companies contract for must be deliverable to the city gates that have adequate take-away capacity. If on-system limitations exist, the Companies can investigate whether an on-system infrastructure project is also needed. If on-system projects alone cannot mitigate supply shortfalls, the Companies will then need to investigate upstream pipeline solutions. The Companies will discuss possible pipeline expansion projects with those that already deliver to our city gates.

As customer demand decreases, the Companies will de-contract assets as needed. Because of the diversity of each supply portfolio, the Companies can leverage the varying contract terms to de-contract when necessary. Contract terms include:

a. Fixed term with yearly renewal rights
b. Fixed term without renewal (i.e., Would require negotiation to set new contract term)
c. Evergreen (rollover) agreements that automatically renew for 1 year or more

The contracts could have notice dates of 1 year or more that can be exercised if the Companies were de-contracting. Each potential termination would need to be analyzed for cost and operational impacts (i.e., Which termination would provide the most savings to the customer? Will the operational integrity of the gas system be comprised by certain terminations?). To mitigate issues that would arise later if forecasted customer requirements were to increase, the Companies will need to determine if maintaining a slightly long supply/capacity position is necessary. The Companies would like to discuss this with NYPSC as the termination of contracts is irreversible. The Companies may also have the ability to reduce contract volumes rather than terminating in some cases if the pipelines are willing to accommodate these requests.

4.14. Supply-Demand Imbalance

4.14.1. Hydraulic Modeling Process

Throughout the Companies' service territories, DNV's Synergi Gas hydraulic modeling software is used to build gas system models to reflect Design Day conditions based on National Grid's corporate gas demand forecast. These models are updated on an annual basis by combining two components: the facility portion (pipes and appurtenances) and the demand portion (customer usage).

GSSP annually reviews and evaluates the operating condition of the gas network along with the accuracy of the network models used to simulate field operating conditions. Network models are used for critical short and long-term recommendations including decisions related to capital investments (e.g., reinforcement and reliability projects, new customer requirements) on the gas system, and decisions associated with system operations (e.g., System Operating Procedures, abnormal operating condition response). Accuracy of the network models is important to ensuring the safe, reliable, and cost-effective operation of the gas distribution system, as well as continued service to the customer base.

The primary basis for the annual review is a comparison and assessment of the gas system and network model under the high load conditions experienced during a cold day for the previous winter period. High send-out/demand conditions provide the best view into system constraints and/or model accuracy evidenced through available field pressure and flow data. System reliability and risk are assessed at an aggregate and site-specific level by comparing data discrepancies to established tolerance targets. Annual verification results are impacted by many factors including, in part, variation in temperature conditions within a region, multi-day and in-day weather conditions including temperature, wind, and cloud cover, line pack, system constraints (e.g., closed valves, water, debris, etc.), facility and customer data accuracy, and measurement equipment accuracy. Due to these factors, some variation between field data and model data is expected. In general, close correlation between field data and model data is achieved thereby validating the accuracy of the hydraulic models.

The Company uses Synergi's Customer Management Module ("CMM") to create a customer database containing data extracted from the customer system, which includes meter reads from the last 24 months. Once the data is loaded into CMM, each customer's base and heat load factors (gas usage factors) are calculated using CMM's Load Factor Generator based on the customer's gas consumption data and related weather condition data. The factors are determined through regression analysis using the average daily weather experienced during each consumption period. The customer is also assigned to a location on the respective gas piping system based on geographic data extracted from either the customer system or Geographical Information System ("GIS").

The hydraulic model is then adjusted at a zip code level to match the corporate forecast for Design Day conditions per year based on the scenario being analyzed. From there, the hydraulic models are analyzed for vulnerable areas and any on-system projects that may be required are identified.

This process takes into account any limitations at the Company's city gates (contractual, physical capacity, or other on-system constraints). A city gate is defined as the point of interconnection and physical transfer of gas between the upstream pipeline and the Company. The resulting flow at each city gate is based on the location of the customer demand and the dynamics of the Company's existing infrastructure that is used to deliver gas to customers. For some of the city gates, there is a risk that the resulting hourly and/or daily flows exceed one or more of these limitations. The forecasted city gate flows are evaluated for peak hourly demand in each year of the 5-year planning forecast. This process was most recently completed using the planning forecast (i.e., reference case) issued in June 2024.

4.14.2. Timing and Magnitude of the Gap

A "no infrastructure" scenario is infeasible for any portion of National Grid's Long-Term Plan. Under the Reference Case, existing gas capacity in Downstate NY only meets forecasted customer demand through 2026/2027. Without additional capacity from the Iroquois ExC Project and the Greenpoint Vaporizer 13/14 Project (further described in section 4.15), National Grid anticipates a supply gap for peak gas demand starting at 5 MDth/d in winter 2027/2028 and growing to 567 MDth/d in winter 2049/50. The gap does not include expiration of approximately 73,000 Dth/day of cogen and city gate peaking contracts after the 2024/25, 2025/26 and 2026/27 winters. National Grid is currently working on re-contracting or replacing these expiring contracts. The magnitude of the gap cannot be resolved with demand response measures and other NPAs in time. Similarly, a supply-demand gap of 0.06 MDth/d is projected to emerge in Upstate NY in 2030/31 due to growing demand in the East Gate region without additional infrastructure investments.[67] This gap reaches 83.4 MDth/d in winter 2049/50. This gap includes the expiration of 20,000 Dth/day of city gate peaking capacity which expires after winter 2026/27. The Company expects that all other contracts in the portfolio will be maintained or renewed. As stated in Section 1.3.2 without continued investment in the gas network, moratoria may be necessary to ensure safe and reliable service to existing gas customers. Under the CEV and AE scenarios, supply-demand gaps do not appear, which allows for theoretical no-infrastructure scenarios that rely on NPAs for ensuring continued safe and reliable service. However, as previously discussed, both scenarios require a suite of enabling policies to be feasible.

4.14.3. Reference Case- Incremental Infrastructure

4.14.3.1. Upstream Capacity & Supplies

Through joint coordination and analysis between the Gas Supply Planning and Gas System Strategic Planning teams, several projects were identified as best suited to mitigate the supply-demand gaps in the Reference Case.

For Upstate NY, one option is to utilize existing capacity on the Empire pipeline, which is currently available at a volume of up to 60 MDth/d. The second option is to secure existing capacity on the TGP pipeline, which would be available in November 2042 at a volume of 25 MDth/d. However, this project would require additional infrastructure on the Upstate NY system to facilitate the transportation of this supply from the city gate.

For Downstate NY, there are two projects out of several which were identified as best suited to mitigate the supply demand gaps. The first project is the Transco Rockaway expansion, which would increase supplies to the Floyd Bennett Field Supply Point and is needed in-service by 2031/2032. The second project is the Iroquois expansion, which will increase supplies from the South Commack Supply Point and is incremental to the ExC project which is discussed in section 4.15.2 below. This project is needed by 2043/2044.

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[67] Such infrastructure investments are described in Case 24-G-0323, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service, GIOP Testimony, filed May 28, 2024.

4.14.3.2. On-System Projects

For Upstate NY, there are two on-system projects included in the reference case. The first is the Energy Transfer Site #2, which is scheduled to be on-line for the winter of 2026/27 for RNG purposes and 2027/28 for design hour peaking service. The volume of ETS2 will be 17,600 Dth/d and it will be located in the East Gate region near the Troy Citygate. The second project, which is necessary to take the upstream capacity and supplies into the system, involves installing approximately 10 miles of 16 inch main on the East Gate. In the Company's rate case, the Company is seeking approval for an East Gate Reliability Assessment, which will be further discussed in the vulnerable areas section of this report.

For Downstate NY, under the Reference Case scenario, there is one on-system project required to support the Iroquois expansion upstream project needed in 2043/2044 (not required for ExC). This project would involve installing approximately 23 miles of 24 inch main in Nassau and Suffolk Counties and would install a new 450 psig to 350 psig regulator station. The project allows incremental supply from the Iroquois expansion project to support the vulnerable areas of the Downstate NY system and is required to be in-service by the 2043/2044 winter. On a smaller scale, a 350 psig to 15 psig regulator station is being installed in Queens to prevent contractual flows from Con Edison to KEDNY from exceeding the limits set forth in the NYF Agreement for the 2nd Ward of Queens. This project also addresses a distribution system constraint that poses a service reliability risk to local residents using the least disruptive and lowest cost option.

National Grid pursued an RFP to identify NPA proposals that could alleviate gas demand within the 2nd Ward of Queens. More than 100 companies were contacted as part of an initial RFI process, but only 12 expressed an interest in receiving the RFP. An additional 2 companies were added prior to RFP issuance. Of the 14 that received the RFP, 11 returned the Non-Disclosure Agreement ("NDA") that was required to receive the detailed request information. Only 1 bid was received, and it was a combination proposal from several of the bidders. The submitted bid would only have removed 984 Dths of Design Day usage, which was 17.6% of the 5,600 Dths of Design Day usage that was required by the RFP. Therefore, National Grid made the decision not to recommend an award for the bid.

Under the CEV and AE scenarios, there are no additional on-system projects required outside of localized system reinforcement projects or storm hardening efforts for either Upstate NY or Downstate NY.

4.14.4. Seasonal

Design year load duration curves represent the relationship between the load (demand) on the gas system and the duration of time during which that load occurs throughout the design year. The Gas Supply Planning team analyzes these curves to understand gas demand patterns and to help plan and design the gas infrastructure accordingly.

Interpreting the design year load duration curves involves analyzing the following aspects:

1. **Load Variation**: The curves show how the gas demand varies over time, indicating peak demand periods, low-demand periods, and overall load patterns. This information helps in understanding the system's capacity requirements and planning for infrastructure upgrades or expansions.
2. **Peak Demand**: The curves identify the highest levels of gas demand during the design year. This information is crucial for sizing storage facilities, ensuring supply reliability, and determining the maximum capacity needed to meet peak demand.

3. **Load Duration**: The curves provide insights into the duration and frequency of different load levels. This helps in assessing the system's ability to meet demand during extended periods of high or low load and aids in optimizing supply and distribution strategies.
4. **Seasonal Variations**: By analyzing the curves, seasonal variations in gas demand can be identified. This information is valuable for planning supply contracts, managing inventory, and optimizing resource allocation to meet the varying demand throughout the year.

Overall, design year load duration curves serve as a valuable tool to understand the demand patterns, plan infrastructure investments, optimize resource allocation, and ensure reliable and cost-effective gas supply to meet customer needs. Figure 11-3 and Figure 11-4 in the appendix show design year load duration curves under the Reference Case for 2023/2024, 2033/34, and 2049/50 for NMPC and Downstate NY.

4.15. Downstate NY Need for Iroquois ExC Project & Greenpoint Vaporizers 13 & 14

4.15.1. Background

The Company identified a need in 2015 for incremental resources to meet forecasted long-term Downstate NY customer requirements, specifically the forecasted Design Day increases over the 10-year planning horizon ending 2024/25. In its Natural Gas Long-Term Capacity Supplemental Report[68], published on May 8, 2020, the Company presented two options to resolve projected imbalances between supply and demand; Option A consisted of a portfolio of targeted distributed infrastructure and non-gas infrastructure options, while Option B consisted of a large-scale interstate pipeline expansion project. Soon thereafter, the state permit applications for Option B were denied, and National Grid has been executing on Option A since then. The Company refers to this portfolio as the Distributed Infrastructure Solution ("DIS"). The DIS consists of: (1) incremental DSM programs including EE, EH, and DR offerings; (2) incremental portable CNG capacity; (3) additional LNG vaporization capacity in Greenpoint, NY that allows the Company to maximize its existing LNG storage capacity; and (4) the Iroquois ExC project, which involves the construction of additional compression facilities to increase capacity on the IGTS.

Since the Natural Gas Long-Term Capacity Reports ("LTCRs") were published, the most recent of which was issued in August 2021, the Company has made substantial progress implementing the DIS. The fifth and final CNG injection site on LI was selected and was commissioned in June 2023. While the Company has had some success with enhanced DSM offerings such as our firm DR options and BYOT programs, our ability to implement incremental EE and EH programs has faced headwinds. As a result, the Company has not been able to realize the potential demand reductions envisioned in the LTCR series. While the Company made substantial progress planning and ordering long-lead materials for the Greenpoint Vaporizer 13/14 project, the Company has not moved forward with construction given the Order Denying Cost Recovery for the Vaporizers 13 & 14 Project.[69]. In its Order, the Commission stated the Company shall include a discussion of the potential future need for the Vaporizers 13/14 Project in its gas long-term plan. Regarding the Iroquois ExC Project, IGTS continues to work with NYS DEC and CT DEEP to secure necessary

[68] 19-G-0678, *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid*, "Natural Gas Long-Term Capacity Supplemental Report," (Filed May 8, 2020).
[69] Case 19-G-0309 et al., *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 and KeySpan Gas East Corp. d/b/a National Grid for Gas Service*, "Order Denying Cost Recovery For The Vaporizers 13 & 14 Project," (Issued and Effective March 16, 2023).

permits for construction of the facilities. Until such time as both agencies have issued all permits, IGTS cannot proceed with construction.

4.15.2. Iroquois ExC

Iroquois owns and operates an existing 414-mile interstate natural gas pipeline extending from the U.S.-Canadian border at Waddington, NY, through New York State and western Connecticut to its terminus in Commack, NY, and from Huntington to the Bronx, NY. As a pipeline transporting gas in interstate commerce, Iroquois is regulated by FERC and must apply for and receive approval from FERC for any modifications to their certificate to operate, including the offering of new service. The ExC Project is expected to include the addition of incremental compression and/or gas cooling at or adjacent to Iroquois' existing Athens, Dover, Brookfield, and Milford Compressor Stations for which FERC approval is needed. The ExC Project will provide an additional 125 MDth/day of supply which will be split evenly by National Grid and Con Edison. The Company participated in an open season for the Iroquois ExC Project in July 2019, when it executed a binding twenty (20) year precedent agreement for service with an originally intended in-service date of November 2023. As a result of the Company's participation, National Grid will receive 62.5 MDth/day of natural gas transportation capacity on the ExC Project once it commences service.

The project will enhance system reliability by delivering gas to the eastern most city-gate delivery point, where National Grid demand modeling indicates additional gas will be needed to satisfy ongoing customer needs.

On March 25, 2022, Iroquois received its certificate of public convenience and necessity from FERC for the ExC Project.[70] In addition to receipt of the necessary FERC permits, Iroquois has filed to obtain air permits from New York and Connecticut for modifications to its existing facilities. The delayed receipt of states' approvals could delay project completion beyond the currently projected 2027/2028 time frame.

4.15.3. Greenpoint Vaporizers 13 & 14

The Greenpoint Vaporizer 13/14 Project consists of two new low-pressure LNG vaporizers at the Greenpoint Energy Center to expand the plant's hourly and daily output. The Project does not increase the total amount of gas provided by the facility because there is no increase in storage capacity. The two additional vaporizers, designated as "Vaporizers 13 and 14", would bring the total number of vaporizers at this facility to eight. This will increase the maximum rate of storage vaporization at the facility to a total send-out of 350 MDth per day and improve overall plant and system reliability. The new vaporizer units will allow for more efficient extraction of LNG from the existing Greenpoint LNG storage during periods of peak demand. The new vaporizers:

i. provide critical safety and reliability benefits for the gas network;
ii. do not add any new gas supply to the system;
iii. will only operate on a handful of the coldest days of the year when they are needed to meet customers demand;
iv. are more efficient than existing vaporization units, operating with an improved energy efficiency of 95.8 percent;
v. are more cost-effective than other options because the project leverages existing assets;
vi. will be located within an existing National Grid facility with minimal construction impacts;
vii. can be easily decommissioned should customer demand decline in the future and/or can support the system through the energy transition if upstream assets are retired before customer demand declines sufficiently, and

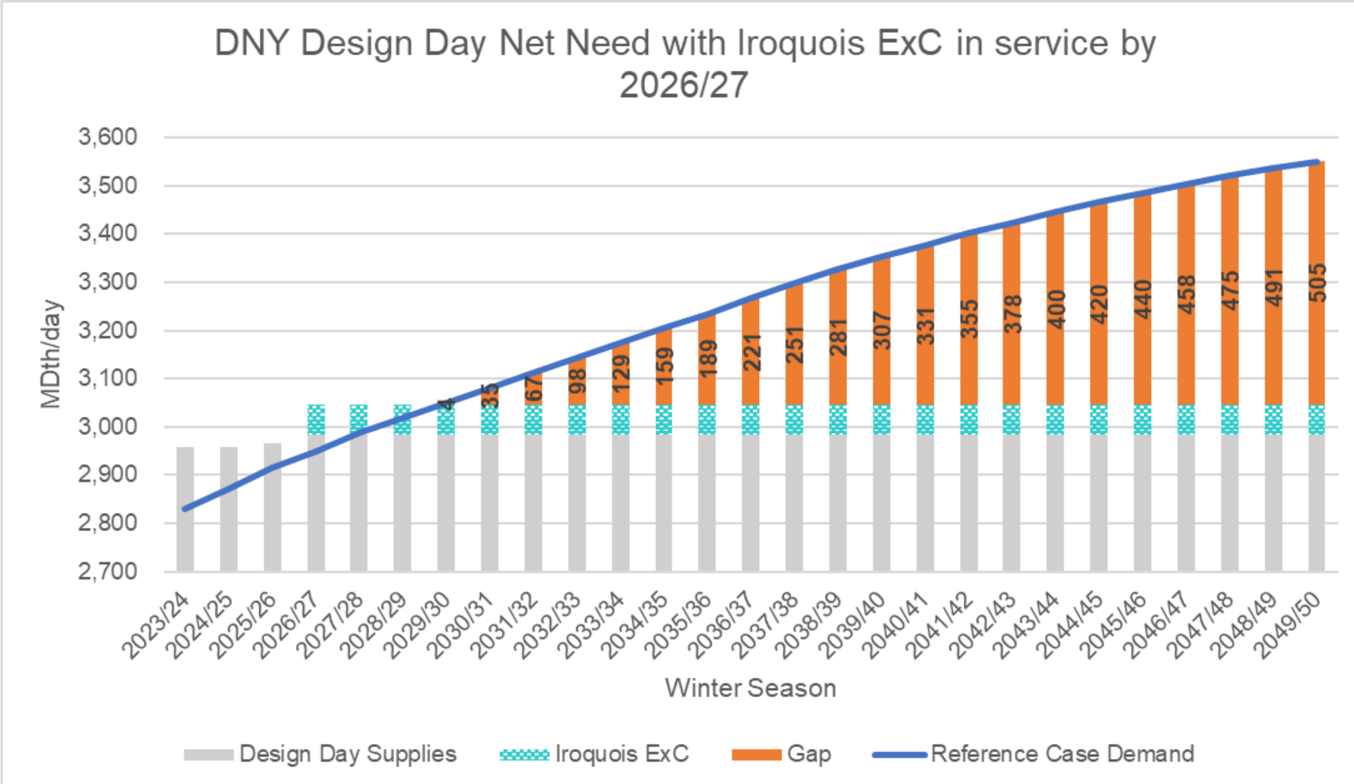
[70] Docket No. CP20-48-000, Order Issuing Certificate.

viii. will add redundancy to vaporizer operations connected to the low-pressure system ensuring reliable operations.

The need for the Greenpoint Vaporizer 13/14 Project has been presented and vetted in multiple proceedings since the project was first identified and initiated in 2020. Even if the Iroquois ExC Project comes online in time to provide service for the 2027/28 winter, a gap re-emerges in 2029/30, as shown in Figure 4-5. The Vaporizer 13/14 Project has a lead time of approximately three years from when permits are approved to complete mobilization, construction, pre-commissioning, and final commissioning. The implication is that this Project cannot be in service in time to avoid a moratorium on new gas connections in Brooklyn and Queens if the ExC Project is denied or delayed. Various alternative projects/programs were (and continue to be) considered for meeting peak demand in Downstate NY. The Long-Term Capacity Report, Supplemental Report, Second Supplemental Report, Third Supplemental Report and related materials, describe in detail the Companies' efforts to identify and assess various alternatives.[71] The results of the analyses confirm that the Greenpoint Vaporizer 13/14 Project remains the best available solution to address the projected supply-demand gap in the time required and is consistent with New York's Net Zero goals.

Figure 4-5: Downstate NY Design Day Net Need with Iroquois ExC

[71] Available under Case 19-G-0678, *Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid.*



The Greenpoint Vaporizer 13/14 Project not only provides safe and reliable service to new and existing customers, but also mitigates the risk of interstate pipeline curtailments and outages and enables the Companies to meet customers' near-term energy needs in Downstate NY throughout the winter season by enhancing the plant's ability to utilize its existing inventory to address a larger shortfall in supply than the plant can currently address. Because gas systems operate with effectively zero Design Day contingency and given the challenges to securing additional gas supplies from new sources, projects that can leverage existing infrastructure to support peak operations are critical to ensuring reliability and resiliency going forward. Indeed, the Commission, noting operational issues on interstate pipelines, has found that "National Grid and all gas utilities should consider single points of failure on the interstate gas system and have contingency plans in place to ensure such changes do not negatively impact the reliability of its system."[72] The Greenpoint Vaporizer 13/14 Project provides such contingency on non-Design Days.

For the current Greenpoint Vaporizer Project, National Grid has completed detailed engineering, procurement, and delivery of long lead materials, conducted environmental reviews and public meetings, and performed preliminary work that may precede the issuance of a permit. The Project has received NYC Department of Buildings ("DOB") permits and FDNY approvals for construction within New York City. For its previous Air State Facility Permit application before the NYSDEC, National Grid has performed a GHG assessment for the Greenpoint Vaporizer 13/14 Project, as is required by the CLCPA. National Grid's CLCPA GHG Assessment[73] demonstrates that the Project

[72] Case 19-G-0678, "Order Instituting Proceeding and to Show Cause," at 5.
[73] See, AKRF, "National Grid Greenpoint Energy Center – CLCPA GHG Assessment," dated October 20, 2021 (available at https://greenpointenergycenter.com/wp-content/uploads/2021/10/National-Grid-Greenpoint_DEC_CLCPA-GHG-Assessment_20211020_Final.pdf). Information related to the Project is available on National Grid's dedicated website: https://greenpointenergycenter.com.

would result in a decrease of the energy consumption and GHG emissions from the facility's vaporizers.

4.16. Moratorium Risk

A moratorium is a hold placed on elements of gas service due to supply or system limitations and may vary in duration based on service territory location and the nature of constraint.

4.16.1. Vulnerable Locations & Timing

In Upstate NY, the risk pertains to city gates owned and operated by EGTS and TGP. On EGTS, each city gate has a contractual MDDO at that point, or group of points, each with a corresponding maximum hourly limit of 5% of the MDDO. EGTS city gates serving NMPC are grouped into the West Gate and East Gate. EGTS has posted on their Electronic Bulletin Board ("EBB") a copy of the Company's MDDOs. This can also be found in the appendix of this document.

On the West Gate, the vulnerable city gates are Tully, Biddlecum Road, and Shellstone (aka Amsterdam). At Tully and Shellstone, the Company plans to explore a strategy for various locationally-targeted DSM techniques (e.g., electrification, energy efficiency, demand response) as the primary mitigation approach to the gate overrun risk. The Biddlecum Road gate serves several large customers (i.e., SC-8), so in addition to exploring overall DSM potential, the Company is evaluating the options associated with these large customers and will pursue those options capable of reducing flows at Biddlecum Road. The Company is also investigating available interstate pipeline capacity to the Company's West Gate.

On the East Gate, the vulnerable gate stations are Burdeck Street (aka Schenectady), Wolf Road, and the gates east of the Hudson River including Brookview, Fort Orange, East Greenbush, and Troy. In the Company's Rate Case proposal, the Company is requesting cost recovery for an East Gate Reliability Assessment to evaluate all possible solutions that address both overall East Gate constraints and individual gate overruns. Part of this assessment will address and evaluate the impacts of targeted electrification to eliminate the need for incremental gas supply, DSM and NPA options, and subsequently review potential on-system projects and pipeline enhancements. Renewable natural gas can also help improve the design hour supply requirement, as incremental supply, and help achieve gas decarbonization goals during off-peak periods. The proposed ETS2 will have RNG capability to support RNG projects where direct connection is not cost effective. ETS2 will also support risk mitigation at Wolf Road and the city gates east of the Hudson River, primarily at the Troy gate station. ETS2 is expected to be operational for RNG deliveries beginning winter 2026/27 and for peaking service beginning winter 2027/28. At the South Albany TGP city gate (aka Bethlehem), the Company currently has limited capability to take in additional gas through this meter without incremental infrastructure.

There are two other proposals that the Company is proposing in the NMPC Rate Case which may affect the projected model flows. The first is to lower the interruptible service class (i.e., SC-6) annual threshold from 2,500,000 therms to 1,000,000 therms.[74] This proposal may attract existing firm customers to this service class and would therefore reduce Design Day and design hour demand on the system. The second proposal is for daily balancing customers and would require the marketers/direct customers with daily balanced customers in their pools to secure Primary Point Capacity to the city gates. The Company is also seeking to implement a Daily Balanced Pool Alert where the Company would be monitoring the total Maximum Peak Day Quantity ("MPDQ")

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[74] Case 24-G-0323, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service,* Gas Rate Design Panel Testimony, filed on May 28, 2024.

compared to the actual pool nominations of each marketer/direct customer. If approved, this would have potential impacts on Design Day flows as it would allow the Company to curtail flows to customers and marketers that are unable to deliver sufficient gas supplies to the city gate during extreme cold weather. The Company is currently exploring how to reflect this proposal in its hydraulic models.

Under the Reference Case, the NYF hydraulic model for Downstate NY shows that without incremental supply or demand destruction, demand will exceed supply, and accordingly, the Brooklyn and Queens areas of the service territory would be at risk of a moratorium in 2027 due to hydraulic constraints. If the Iroquois ExC project is in-service for the 2027/28 winter and updated demand forecasts are in line or lower than the June 2024 forecast, a moratorium may be delayed. The Greenpoint Vaporizers 13 & 14 will need to be ready for testing during the 2028/2029 winter for full use in the 2029/2030 winter to meet demand beyond what the ExC project can support.

4.16.2. Customer Rights

The New York State Customer Bill of Rights provides guidance to customers of natural gas local distribution companies in New York on rights that apply in the event a moratorium on new service is declared. On June 27, 2022, pursuant to Ordering Clause 2 of the Commission's Order, the Joint LDCs submitted a draft New York State Customer Bill of Rights to be issued upon declaration of a natural gas service moratorium.[75] The Customer Bill of Rights is subject to Commission review and approval. National Grid will incorporate the final version of the Customer Bill of Rights in its communications plan once adopted by the Commission.

4.16.3. Communications Plan

National Grid created the moratorium communications plan to comply with the Commission's Gas Planning Order (Case 20-G-0131) and prepare for the possibility of a future natural gas moratorium.[76] The plan provides a roadmap for stakeholder engagement, outreach, notifications and communications to customers and local officials, and the distribution of information regarding energy efficiency and alternative forms of energy available within the LDC's service territory.[77] The communications plan complements the notice of natural gas moratorium and the Customer Bill of Rights approved by the Commission. The plan is updated annually.

The communications plan is guided by the following key principles:

- **Period of Awareness:** The timing of the notice of moratorium is critical. LDCs must provide adequate notice to customers and stakeholders and help them prepare for the future.
- **Customer Empowerment:** Customers need the ability to make decisions regarding their service and available energy options.
- **Targeted Communications:** Frequent communications should be sent to customers most impacted by the moratorium.
- **Transparency:** Communications should be simple and clearly explain timing and expectations.
- **Maximize Reach:** Communications should be made through blended channels (digital and nondigital) and in multiple languages to facilitate ease of access and ensure they are received by a broad range of customers and stakeholders.

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[75] See Moratorium Management Order.
[76] Id.
[77] Id. at 30.

- **Enable Contact Center Representatives:** National Grid will ensure that customer representatives are prepared to answer questions and help customers through a combination of trainings and written materials.

The chart below summarizes, at a high level, the customer-specific outreach efforts that may be conducted in connection with a moratorium at the following time periods: (1) at the time the moratorium is declared; (2) during the moratorium period; and (3) at the conclusion of the moratorium.

Table 4-5: Moratorium Communications Plan

Target Audience				
General Population	**Green Lights**	**High Potentials/Trade Partners**	**Inquirers**	**Denied Customers**
90 Days Before				
• Public Meetings/ Webinars • Utility Customer Bill of Rights & Alternative energy options list published[78] • Digital channels – web site, social media • On Bill Messages • Hotline • Handouts	• Look at applications with no contact • Include language in BAU connections comms	• Letter • Email every 30 days[79]	• Initial letter and email at declaration, every 60 days[80]	• N/A
60 Days Before				
• Review/Updates to listed channels as warranted	• Revisit applications with no contact every 30 days • Include language in BAU connection comms	• Email		• N/A
30 Days Before				
• Review/Updates to listed channels as warranted	• Revisit applications with no contact every 30 days • Include language in BAU connection comms	• Letter • Email • Webinars	• Final push: certified letter and email 2 weeks before moratorium start	• N/A
Day 1 of Moratorium Implementation				
• Updates to Digital channels – web site, social media • Bill messages • Hotline • Handouts	• Single point of contact assigned • BAU communications as part of regular	• Email/letter every 60-90 days • Call to largest companies every 60-90 days	• Letter & email at start of moratorium • Letter & email check in every 6 months[80]	• Email & call every 60-90 days[80]**Error! Bookmark not defined.**

[78] These will be linked to in the bulk of communications until a moratorium is lifted.
[79] We will request feedback on frequency of communications and adjust accordingly.
[80] We will cease communications once no further interest is expressed.

Target Audience				
General Population	**Green Lights**	**High Potentials/Trade Partners**	**Inquirers**	**Denied Customers**
	connections process			
Throughout Moratorium				
• List of services/options accessible through all channels • Review/updates to listed channels as warranted at least every 30 days	• Single point of contact assigned • BAU communications as part of regular connections process	• Email/letter every 60-90 days • Call to largest companies every 60-90 days	• Letter & email at start of moratorium • Letter & email check in every 6 months[80]	• Appeals process • Single point of contact assigned • Email & call every 60-90 days[80]
When the Moratorium is Lifted				
• If partial lift, public meetings • Digital channels – web site, social media • Customer email • Bill Messages • Hotline • Handouts		• Email • Letter – potentially certified • Calls to key associations	• Email	• Trackable Letter to all paused[81] • Email • Call[82]

5. Demand-Side Management Programs

5.1. Overview and Impact of Our Current Demand-Side Management Programs

The Company has a long history of encouraging and enabling our customers to reduce the amount of energy they consume, whether that energy is in the form of natural gas, electricity, or delivered fuels such as propane, fuel oil, and gasoline. As explained in the Executive Summary, it does so primarily via a portfolio of programs that we offer to our customers that are collectively referred to as demand-side management ("DSM"), since they enable the reduction of annual and/or peak energy demand. When it comes to the enablement of reductions in demand for natural gas, the Company's DSM portfolio includes energy efficiency, electrification of heat, gas demand response, and non-pipeline alternatives. More information on each is provided below.

The DSM portfolio has already contributed meaningfully to the achievement of New York's ambitious climate and energy goals: as detailed in the Executive Summary, since 2016, the Company's gas energy efficiency and heat pump programs have resulted in lifetime GHG emissions reductions of approximately 8.7 million metric tons of CO_2e,[83] which is equivalent to removing almost 2.1 million

[81] We will send a trackable letter regardless of email status.
[82] If we are unable to reach the customer, we will send a certified letter. If we still cannot access the customer, we will send a door hanger. If no response, we will send a letter via FedEx.
[83] Lifetime GHG emission reduction figures obtained from the NYSERDA Clean Energy Dashboard. Note that these figures do not include (a) GHG reductions from the Company's electric energy efficiency programs, the inclusion of which would cause GHG emissions reductions to rise to 22.1 million tons CO_2e and (b) GHG emissions associated with the Company's other clean energy programs such as those that enable the installation of electric vehicle charging infrastructure in its upstate NY territory.

gasoline-powered cars from the road for one year; removing 23 natural-gas fired power plants from service for one year; eliminating the annual GHG emissions from over 1.1 million average residential home; or the GHG emissions avoided by approximately 2,300 wind turbines running for a year.[84] In addition, the DSM portfolio reduces the demand for natural gas during the coldest days of the winter, thereby decreasing the amount of gas infrastructure required to be constructed or upgraded in order to serve peak demand. Lastly, the portfolio lowers costs for customers by reducing the amount of natural gas the Company must purchase to serve demand and by lowering energy costs for customers who adopt and participate in DSM programs; by lowering these costs, it enables a managed and affordable clean energy transition.

The Company has proven itself to be a leader and innovator when it comes to reducing demand for natural gas. In particular, its gas demand response programs are without peer in terms of scope and scale across the state and the country. Not only have the programs consistently garnered praise from the Public Service Commission, but the Company continues to innovate by piloting new methods to encourage customers to actively reduce their consumption of natural gas during peak periods.[85] Additionally, the Company was the first utility in the state to launch weatherization programs in Downstate NY in late 2021, and the Company plans to continue investing in weatherization programs for all customer sectors.

The Company recognizes, however, that despite its successes to date in proposing, launching, and scaling DSM, much work remains to be done to assist our customers to continue to reduce natural gas consumption to the levels necessary to meet the state's ambitious climate goals. As such, we remain committed to innovating new programs and solutions, to scaling our existing programs within the funding and resources available to us, and to engaging as many of our customers as possible.

5.1.1. Energy Efficiency (EE)

Energy efficiency programs are a core element of the National Grid's DSM portfolio. Through the installation of energy efficient equipment, advanced building controls, and upgrades to building envelopes (aka "weatherization"), the Company's programs reduce annual gas consumption, lower customer bills, reduce carbon emissions, improve occupant comfort and building performance, and provide benefits to the distribution system by reducing peak demand. As part of its Clean Energy Vision, National Grid recognizes that a reduction in gas consumption will be required to achieve New York's and National Grid's 2050 targets, and energy efficiency is a tool in achieving that reduction.

National Grid offers energy efficiency programs to customers in the 1-4 family, multifamily, small business, commercial & industrial segments, and to customers who receive both firm and non-firm service. Since the beginning of 2016, the programs have achieved almost 13.6 million Dth of annual energy savings by engaging nearly 315,000 participants. Aside from a downturn due to the impacts of the COVID-19 pandemic, the Company's programs in Downstate NY have seen growth in performance year over year; however, the Company has faced challenges in achieving similar growth in its Upstate NY territory.

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[84] Equivalencies computed using the EPA's Greenhouse Gas Equivalences Calculator. If the Company's achievements via its electric energy efficiency programs are included, the figures rise to 5.3 million cars, 59 power plants; 2.9 million homes, or 5,800 wind turbines.
[85] National Grid won the inaugural "Utility Industry Innovation in Gas" award from NARUC when the programs were first deployed in 2017, see https://pubs.naruc.org/pub/BC20B023-9C76-FA0B-A863-256E3B0E18BC

Figure 5-1: Downstate NY Annual Energy Savings

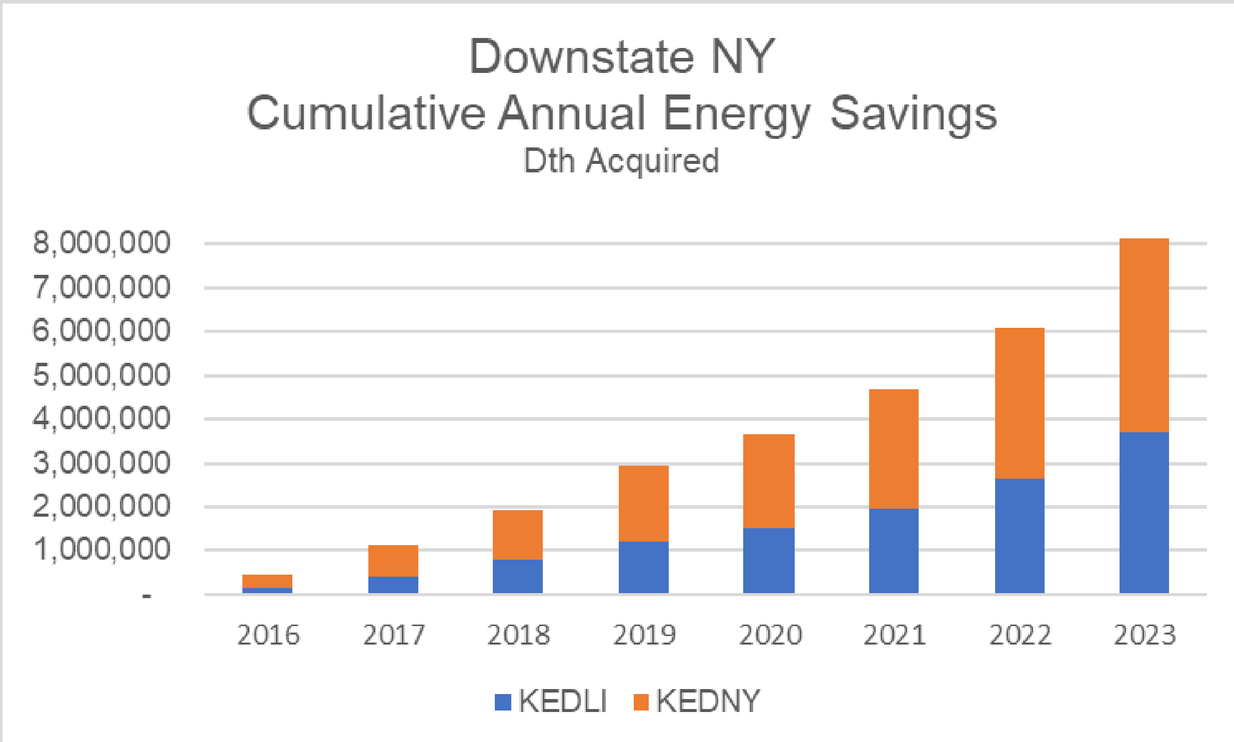
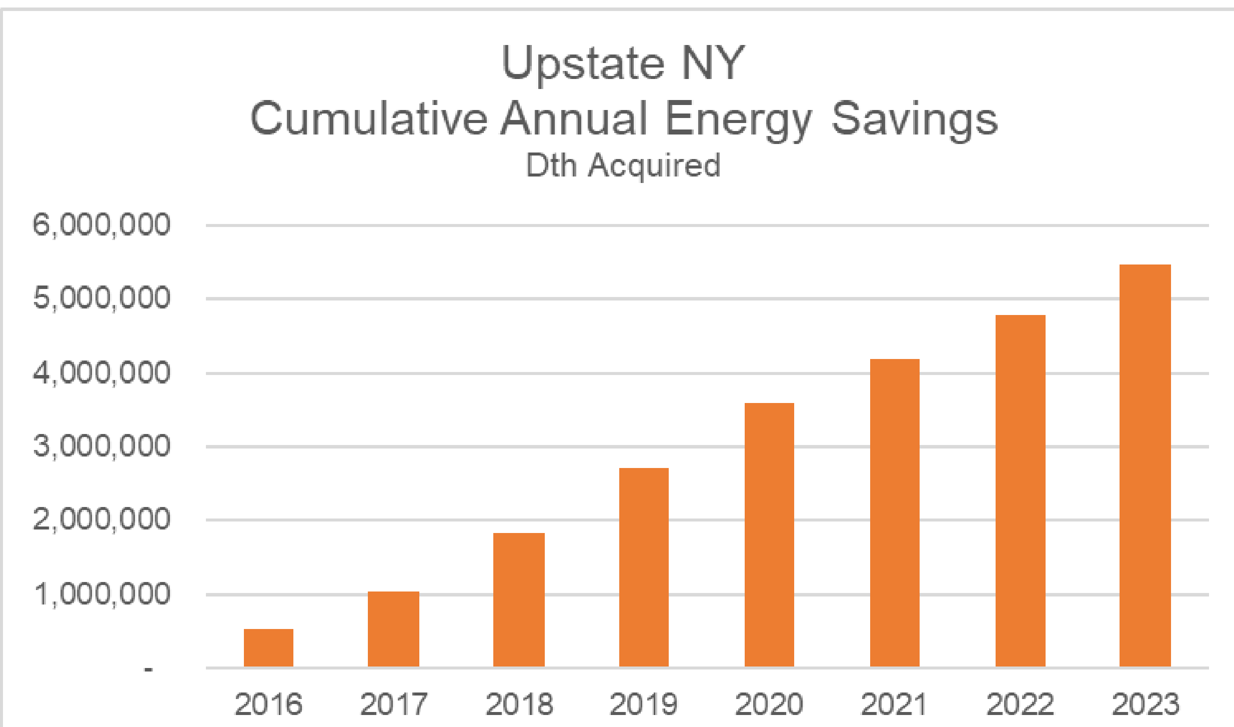


Figure 5-2: Upstate NY Annual Energy Savings



The following EE programs are offered to the Company's market rate customers in both downstate and Upstate NY:[86] Market rate customers are all non-LMI (Low to Moderate Income) customers.

- *Commercial and Industrial* ("*C&I") Program*: Provides technical services along with incentives for prescriptive, custom, and direct install (water saving measures), Kitchen Point of Sale, Kitchen Prescriptive, Midstream Heating and Water Heating incentives. It encourages and provides incentives for the installation of a wide range of efficient gas measures, including but not limited to building systems, manufacturing processes, and a variety of prescriptive and custom measures.
- *Multifamily Program*: Incentive programs designed to increase the installation of energy efficiency measures in existing multifamily buildings within National Grid's service territory by working with property owners, managers, trade allies, and tenants to encourage installation of gas energy saving measures.
- *Residential Program*: Educates customers and HVAC/plumbing contractors and vendors regarding the benefits of high-efficiency gas space and water heating equipment, along with associated controls. This incentive program aims to increase customer acceptance of these products and to encourage consumers to purchase high efficiency equipment and other gas saving measures when they shop.[87]
- *Residential Engagement Program*: A behavioral initiative that encourages residential customers to change their energy usage behavior to conserve energy. Behavioral initiatives seek to identify the motivational factors which cause residential customers to actively employ personal energy saving actions and/or participate in energy efficiency programs.[88]

Further, in Downstate NY, the Company offers programs that provide incentives for weatherization of both residential and non-residential customers.

- *Non-Residential Weatherization Program*: Comprised of measures that improve energy efficiency through building envelope improvements including air sealing, insulation, and window replacements.
- *Residential Weatherization Program*: Educates customers, program partners and vendors regarding the benefits of building envelope improvements such as air sealing and insulation.

National Grid was the first gas utility in New York State to offer such weatherization programs, and has made significant strides in scaling them, particularly for residential customers, since they launched in late 2021. The Company intends to expand these programs into its upstate NY territory in 2025.

In support of the principle that no customer should be left behind in the energy transition, the Company has worked to improve the energy equity of its energy efficiency portfolio by providing significant support to low-to-moderate income customers, small businesses, and customers in Disadvantaged Communities. That support includes the following efforts:

- *Low-to-moderate income incentives.* The Company continues to devote 20% of incremental energy efficiency funding to income-eligible customers, with 40% of that program spending allocated to affordable multi-family buildings. In collaboration with the NY Utilities and

[86] More comprehensive information on these programs can be found in the Company's System Energy Efficiency Plans ("SEEPs") and Clean Energy Dashboards, both filed in Case 18-M-0084.
[87] The PSC's July 2023 NE:NY Order prohibits incentives for residential gas fired heating equipment between 2026-2030, and so this program will be discontinued in late 2025.
[88] This program was discontinued in DNY in Q4 2023 and will continue for UNY customers in 2025, pursuant to the required constraints required for programs starting in 2026 under Case 18-M-0084 et al., *In the Matter of a Comprehensive Energy Efficiency Initiative*, "Order Directing Energy Efficiency and Building Electrification Proposals" (Issued and Effective July 20, 2023).

NYSERDA, the Company launched the Statewide Low- to Moderate-Income (LMI) Portfolio. This statewide portfolio is intended to create a more holistic and coordinated approach to deliver energy efficiency to LMI customers and communities across the entire state. The two major programs in this portfolio include:

- *Affordable Multifamily Energy Efficiency Program ("AMEEP").* The new Statewide existing affordable multifamily program, AMEEP, provides a consistent framework across the State such that all existing affordable multifamily building owners, developers, and their representatives have access to financial incentives to plan and make energy efficiency upgrades to their buildings. A key focus of AMEEP is to encourage comprehensive upgrades to achieve deeper savings, while taking advantage of opportunities to reduce administrative costs.

- *Residential 1-4 Family Program.* The members of the NY Joint Utilities, including National Grid have worked to improve overall energy affordability for low-and moderate-income households living in 1-4 family homes by providing no-cost energy audits, no-cost or subsidized energy efficiency upgrades and energy education for both renters and homeowners through the EmPower+ program and KEDLI Home Energy Affordability Team ("HEAT") program. Customers participating in EmPower+ may also be eligible for and for low-cost financing of energy upgrades through the Green Jobs – Green New York Program.

- *Language access.* The Company has translated selected EE program flyers into Spanish. It has also developed and filed with the Public Service Commission a comprehensive EE/BE Language Access plan which identifies numerous near-term and potential future steps to increase language accessibility.[89]
- *Contractor training and workforce equity enhancement.* The Company is working with NYSERDA to support minority and/or women-owned business enterprise ("MWBE") contractors in preparing for the opportunities within weatherization projects across the state. KEDNY, KEDLI, and NMPC provided funding to the Building Performance Institute ("BPI"), which trains eligible contractors and individuals to become BPI-certified installers of energy efficiency measures and services. This initiative will offer 225 training sessions throughout National Grid's New York service territories over the next 2 years and will offset the cost of training and certification throughout National Grid's New York service territories over the next 2 years and will offset the cost of training and certification.
- *Enhanced Incentives.* The Company has been offering enhanced incentives to hospitals, schools, universities, government agencies, houses of worship, and non-profit organizations in Disadvantaged Communities in KEDNY since June 2023. The Company intends to use the learnings from this initiative to create a strategy by 2026 to engage more customers to take advantage of the enhanced incentives.
- *NMPC Small Business Services ("SBS") Pilot Program.* Having identified a lack of capital as a barrier to small business customers undertaking EE projects, the Company developed this pilot sub-initiative within the SBS Program to cover a greater percentage (up to 100%) of the cost of energy efficiency upgrades for small businesses in its upstate NY electric territory within disadvantaged communities (DAC's). Prior to 2023, the enhanced incentives were funded by National Grid shareholders rather than by ratepayers.
- *Weatherization Health & Safety Pilot.* Recognizing that housing condition can be a significant barrier to weatherization, in 2022, National Grid implemented a shareholder-funded Weatherization Health and Safety pilot in KEDNY and KEDLI serving primarily LMI customers. The pilot was used to remediate health and safety issues present in customers'

[89] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, "Energy Efficiency and Building Electrification Programs Language Access Review Filing," (Filed September 18, 2023).

homes that would have made it difficult if not impossible to proceed forward with weatherization and other energy efficiency measures. The pilot proved successful, with 100% of customer-offered remediation services choosing to move forward with their EE and/or weatherization projects. The recent KEDNY-KEDLI Order includes a continuation of the pilot at a funding level of $2M per year.

5.1.2. Building Electrification

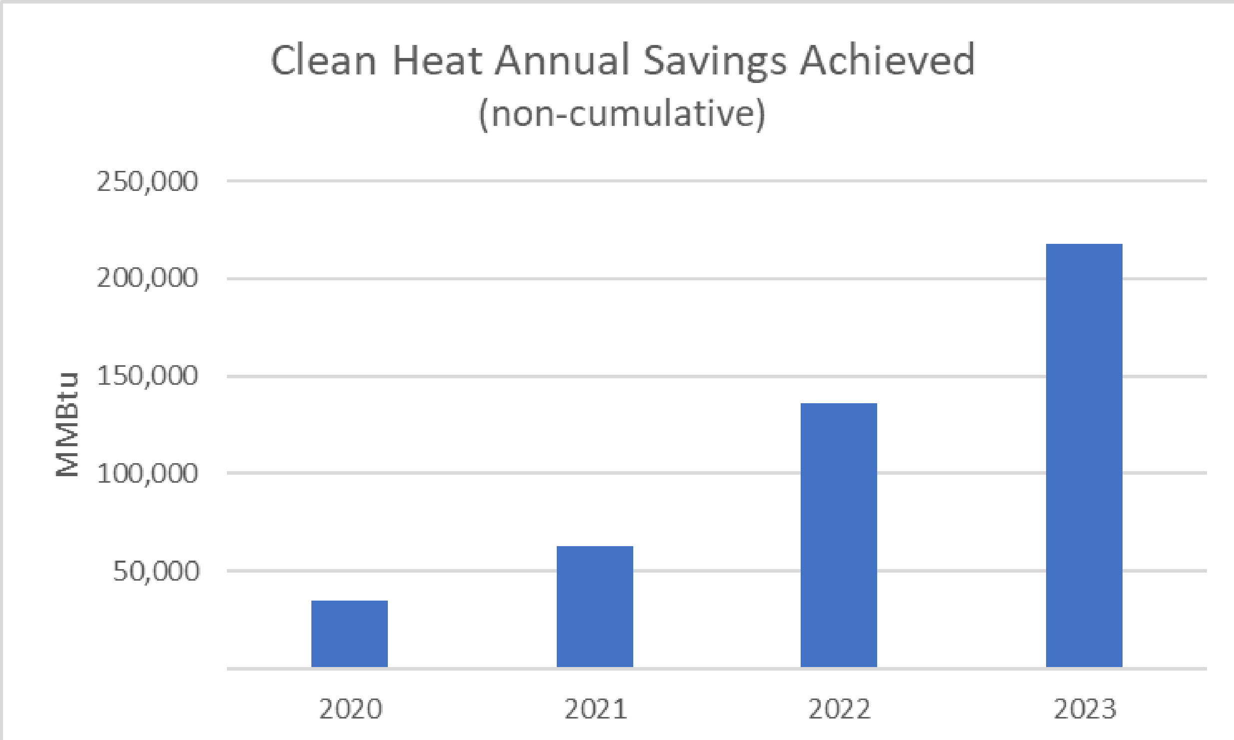
The electrification of heat via the installation of electric heat pumps is not only a key element of achieving the state's climate goals but is also another core pillar of the Company's DSM portfolio. When they supplement or replace gas-fired heating systems, heat pumps reduce GHG emissions and annual gas consumption; in certain configurations they can also reduce peak gas demand. As with energy efficiency, electrification of heat is a core part of National Grid's Clean Energy Vision, and it will enable the reductions in gas consumption that will be required to achieve New York's and National Grid's 2050 targets.

The 2020 New Efficiency: New York Order required a common statewide heat pump framework as well as the establishment of a joint NYSERDA and Electric Utility Management Committee, known as the Clean Heat Joint Management Committee (JMC). As previous co-chair and active participant in the JMC, National Grid has taken an active role in working collaboratively with all JMC members to continuously improve the statewide Clean Heat program.

The Clean Heat program's primary purposes are to increase customer awareness of, and access to, high-efficiency electric space heating and water heating equipment. The Company has an incentive-based heat pump offerings for customers in the 1-4 family, multifamily, small business, and commercial & industrial segments. The offerings are available to customers regardless of the type of fuel used in their existing heating system, whether propane, fuel oil, electric resistance, natural gas, or other sources. Since its launch in 2020, these offerings have led to the installation of over 13,500 heat pumps and achieved over 450,000 MMBtu in annual energy savings.

In Upstate NY, the Company administers Clean Heat, an incentive program, within its electric service territory. The program requires participating contractors to follow best practices related to sizing, selecting, and installing heat pumps in cold climates. It also promotes consumer education, in part by requiring that participating contractors provide guidance to customers on how to operate and maintain their systems. Year-over-year, the Clean Heat program has seen an average savings growth of 85%.

Figure 5-3: NY Heat Pump Program Performance



Providers continue to review the program's progress and adjust to improve performance as appropriate. Aligned with National Grid's Clean Energy Vision, the Company will support cost-effective targeted electrification on its gas network, including piloting new solutions such as networked geothermal. The Company will also support customers who heat with oil and propane with strategies and tools to convert to heat pumps.

In Downstate NY, the Company does not administer heat pump programs; rather, such efforts are led by the local electric utilities, Con Edison and PSEG-LI. However, in alignment with its Clean Energy Vision and the state's heat pump goals, the Company continues to be supportive of the electric utilities' programs. In particular, all customers who contact the Company's call centers to request new or upgraded gas connections receive information regarding heat pumps and referrals to the electric utilities' programs.[90]

One important fact to note is that, when supplementing an existing gas-fired heating system, all heat pumps systems can reduce a customer's consumption of natural gas over the course of an entire year. However, when installed in a hybrid configuration – i.e., one in which the customer's backup fuel system is left in place – heat pump systems do not typically result in a reduction in peak demand, since customers almost always elect to utilize the backup system on the coldest days of the winter. Therefore, while all heat pump systems can reduce or avoid natural gas consumption (and its associated emissions), only heat pump systems where the backup natural gas heating system is fully removed (i.e., "full electrification") result in reductions in peak gas demand (with the potential to reduce or avoid necessary distribution infrastructure). The pace of full electrification is

[90] The Company has surpassed all the targets for the number of referrals to be made annually that were set under its last rate case. Case 19-G-0309 et al., *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*, Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements (Issued and Effective August 12, 2021).

increasing, particularly as National Grid and the other utilities in the state remove incentives for partial-load heat pump systems. However, customers may still elect, for a variety of reasons, to maintain hybrid systems; and as such we must be careful about assuming that heat pumps necessarily equal reductions in peak gas demand.

5.1.3. Firm Gas Demand Response (DR)

The Company's firm gas demand response ("DR") programs, which are the largest and most comprehensive such programs in the country, play a critical role in reducing peak gas usage in the Company's New York service areas by incentivizing or encouraging customers to reduce or curtail gas usage during the coldest days of the winter. By doing so, they enable the Company to provide safe and reliable service on the coldest days of the winter, support system resiliency under emergency conditions, lower customer bills by reducing gas commodity costs, provide incentives to customers that can offset gas bills or be reinvested in energy efficiency projects, and help avoid increases in peak demand that might result in the need to upgrade existing gas infrastructure or construct additional infrastructure.

National Grid first began exploring the potential of gas DR through an innovative pilot program launched in its Downstate NY service territories in 2017; it was one of the first instances in the country of applying demand response program principles to firm service gas customers. The Company then built upon that pilot's success by launching a portfolio of gas DR programs in the winter of 2019-2020 and expanded those programs to the Upstate NY service territories in the winter of 2022-2023.

The following programs make up the Company's Gas DR portfolio:

- *Load Shedding Demand Response*: A program for large commercial, industrial, and multi-family firm service customers capable of reducing peak day gas load over a 4- or 8-hour period on event days.
- *Load Shifting Demand Response*: A program for large commercial, industrial, and multi-family firm service customers capable of reducing peak hour gas load over a 4-hour period on event days.
- *BYOT*: A residential and small commercial customer-focused program which utilizes Wi-Fi connected thermostats to remotely lower temperature set points and shift peak hour gas loads on event days.
- *Behavioral Demand Response*: A non-incentivized program that uses email and mobile app messaging to notify customers of impending cold weather and suggests methods to lower gas consumption during peak hours.[91]

The programs have seen considerable year-over-year increases in customer adoption. At the start of the 2024/25 winter season, combined program enrollments across the Company's Upstate and Downstate NY service territories totaled over 550 medium-to-large commercial, industrial, and multifamily accounts and over 39,000 Wi-Fi connected thermostats.

[91] The Company is only running a BDR program in the Downstate NY service territory and currently involves a limited number of customers. More detail on the BDR program can be found in Section 5.2.3.

Figure 5-4: Downstate NY Gas Demand Response Program Enrollment - Load Shedding

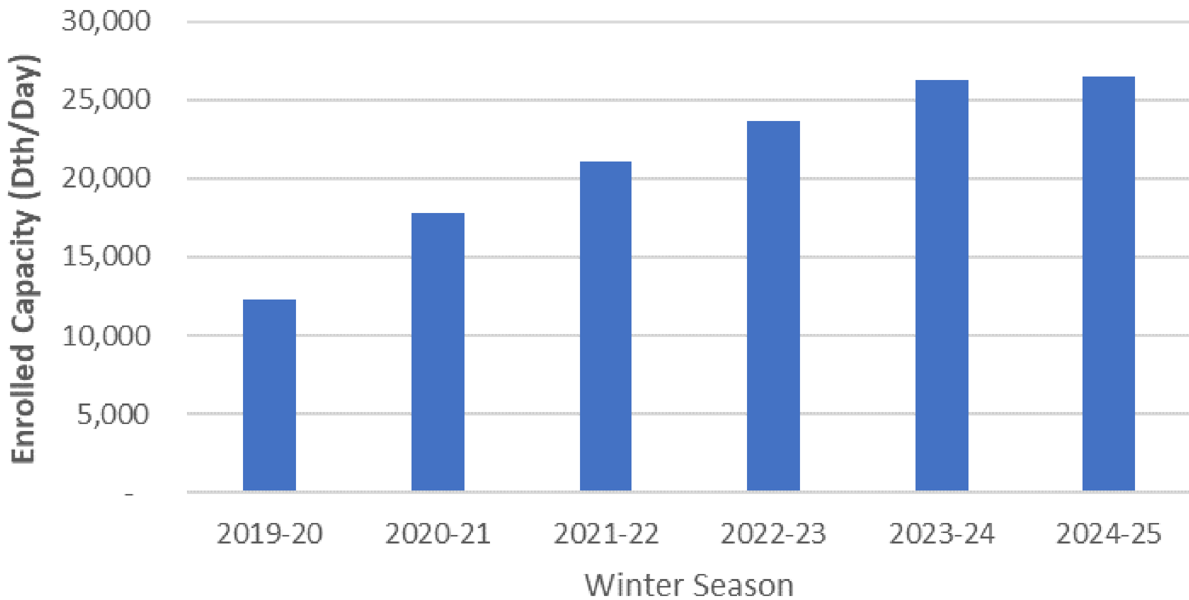
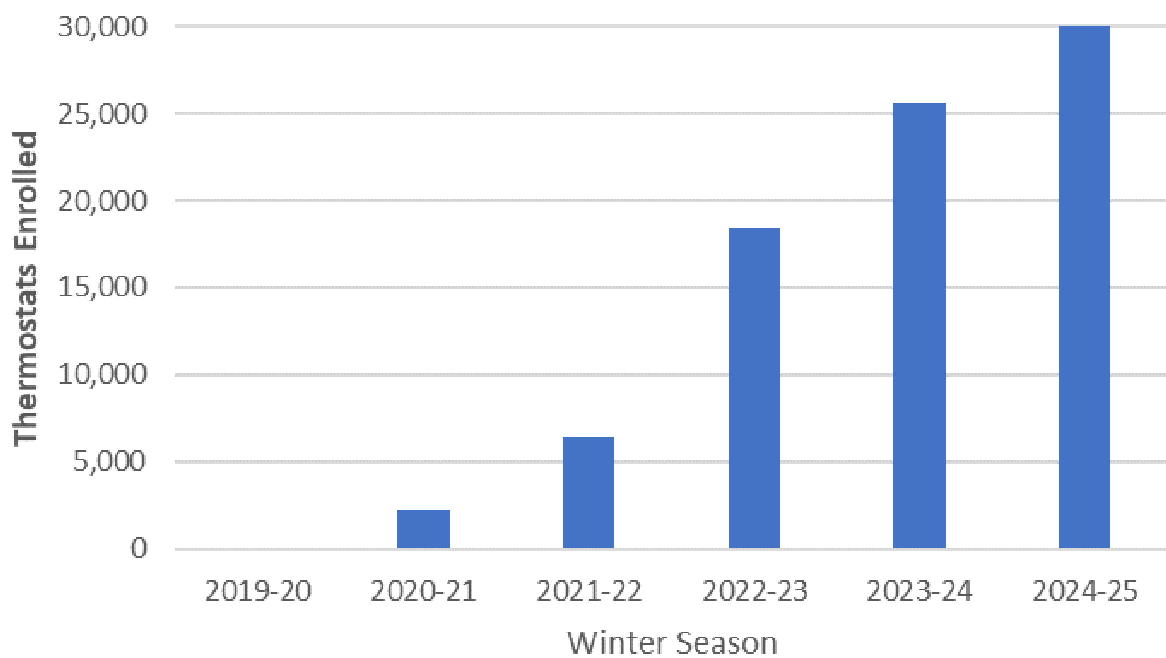


Figure 5-5: Downstate NY Gas Demand Response Program Enrollment - BYOT



The Company's gas DR programs have been successful not only in attracting many customers to enroll, but also in proving the reliability of those customers' demand reductions. As a novel program concept, gas DR has faced questions about the reliability of customer reductions, particularly at times of rare, extreme weather events. While the Company has been limited to evaluating Gas DR only under the conditions experienced over the last few years, the programs have thus far delivered consistently.

Of note, with regard to reliability and resiliency, is that demand response is a flexible resource that, unique among the DSM solution types, can also be called upon to reduce peak load during system emergencies. A recent example occurred during Winter Storm Elliott in December 2022, when National Grid requested gas DR customers to provide emergency load reductions. Gas DR program participants and enrolled thermostats responded within one hour's notice during the Christmas Eve and Christmas Day holiday, delivering over 11,500 Dth over two 4-hour periods, which is roughly equivalent to the supply provided by a 10-trailer CNG station.

5.1.4. Non-Pipeline Alternatives (NPAs)

The term "non-pipeline alternative" or "NPA" refers to any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of the natural gas distribution system. As part of its Clean Energy Vision, National Grid recognizes that a reduction in the throughput of gas, and a corresponding reduction in the amount of pipeline infrastructure, will be required to achieve New York's and National Grid's 2050 targets. Therefore, National Grid will aggressively explore, advocate for, and, when feasible, implement NPAs.

While changes to the Company's approach to NPAs are discussed in section 5.2.4, under the Company's current process, all gas capital projects undertaken by the Company that meet the threshold criteria or requirements outlined in the sections below will be screened for NPA feasibility (i.e. assessed to determine whether the project can feasibly be addressed with an NPA without impairing system safety, reliability, and/or causing National Grid to fail to satisfy existing regulatory requirements). This feasibility review is based on a technical review of the gas system and does not involve engaging with customers. If the project cannot feasibly be replaced with an NPA, the presence of customer interest would not result in NPA deployment. NPA opportunities that are considered to be feasible and that are not eliminated from consideration due to other criteria (e.g. Screening and Suitability Criteria) are passed on to the Customer group within the Company, which then coordinates contacting the customers to assess their interest in adopting the NPA in lieu of gas service.

There are three primary categories of infrastructure projects undertaken by National Grid that will create opportunities for NPAs.

New Connection NPAs: A customer seeking to connect to the gas system (such as a new property development or a residential home seeking to switch to natural gas in lieu of a delivered fuel such as propane) instead elects to electrify all or a portion of the facility, thereby avoiding or reducing the potential increase in gas consumption.

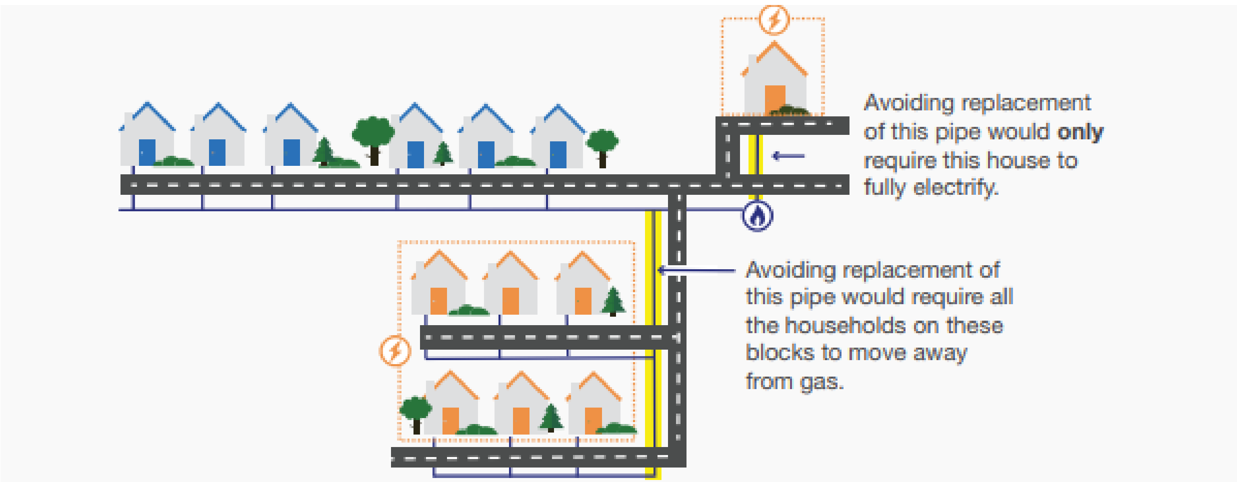
<u>Threshold Criteria or Requirements</u>:
For all new connections that require the installation of more than 500 feet of pipeline and that serve more than 5 customers, the Company proactively reaches out to the customers, or representative of the customers, who made the connection request to assess their interest in an NPA.

Due to the fact that New Connection NPAs are focusing on capital projects that would be additions to the current system, there is not a need to perform a technical review to determine the impact of not completing the capital project. Therefore, all capital projects are considered to be feasible from a technical standpoint.

To date, the Company has assessed 72 new connection requests that met the threshold criteria and this has resulted in one NPA that is actively under discussion, in which a developer may utilize NPA incentives to subsidize the cost of installing ground-source heat pump systems at a residential development of over 100 homes on Long Island, thereby avoiding the construction of over 12,000 feet of gas main.

Leak-prone pipe (LPP) NPAs: Customers along a segment of leak-prone pipe are contacted and presented with an opportunity to convert to a non-gas alternative in exchange for an incremental incentive based on the avoided cost of the LPP. If some or all of the customers on the segment choose to fully electrify, thereby avoiding the replacement of all or a portion of the segment and enabling it to be removed, the NPA can proceed. Because of the Company's statutory obligation to continue to provide service to existing customers, National Grid cannot force customers to disconnect from the system and electrify; as such, replacement of the segment can only be avoided or reduced if a contiguous block of customers on the segment of leak-prone pipe agree to give up their gas service, and only if those customers are located at the end of the segment of pipe or at a location on the pipe where it could be taken out of service (e.g. the center of a pipe that is not a single feed). [92]

Figure 5-6: Non-Pipeline Alternatives: Leak-prone pipe removal[93]



<u>Threshold Criteria or Requirements</u>:
The Company currently screens all LPP removal projects for NPA feasibility. The vast majority of LPP replacement projects are either too small or planned to be placed into service too quickly for them to be assessed for NPA feasibility using the Screening and Suitability Criteria. Therefore, National Grid has specific LPP evaluation criteria that are maintained as part of ENG04030, the Design Work Method for Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement, which is maintained by the Distribution Engineering group. These criteria are listed below:

- The main should not be a critical main
- The main must not be the primary feed in the area as defined by Strategy Development-System Planning

[92] In other words, if customers A, B, C, and D are on a segment of pipe that is due to be replaced, and customers B, C, and D elect to take the NPA incentive and proceed forward with full electrification of their homes, but customer A – who is located at the very end of the segment of pipe – elects not to fully electrify, then, due to the Company's obligation to serve, the replacement of the pipe must move forward and the NPA cannot proceed.
[93] Image credit: "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization" (whitepaper jointly published by National Grid and RMI, May 2022)

- Retirement of the main must not negatively impact the overall performance of the distribution system as required by Strategy Development-System Planning
- The main for consideration must qualify as Leak Prone Pipe
- Project must be in the work plan. If it is not in the work plan, after evaluation, it should be added to the work plan
- The pipe segment should be a stand-alone project (not part of another project)
- Main must be retired (cut & cap)
- Preferred pipe segment should be on a dead-end block (street) with no back feed

To date, the Company has performed outreach on 5 LPP segments per Operating Company per year. The Company conducts outreach to the customers who would be affected by deployment of the NPA to understand their willingness to give up their gas service and to receive an NPA incentive to do so. The process for outreach includes mailings, email contact, and phone calls, with multiple calls occurring, if necessary, to establish contact. This outreach has primarily been completed by employees of the Company but that will be changing, along with the rate at which LPP projects are evaluated, beginning in 2025, as the Company has been authorized to retain an Implementation Contractor to support its NPA outreach efforts. This will be discussed in greater detail in section 5.2.4.

The Company is currently in active NPA discussions with a community center located in a Disadvantaged Community in Brooklyn that is served by a segment of leak-prone pipe. The net avoided cost of upgrading almost 900 feet of leak-prone pipe would be offered to the customer to be put toward electrification. If successful, the Company will report on that project in a future update.

Additionally, the Company recently completed 3 LPP NPAs in Saratoga County, each of which serves one customer. These LPPs involved customers that were served by transmission services, which, as the name implies, connects a customer directly to a transmission line. These transmission services were required to be upgraded and the 19 customers served by these services were contacted about their interest in pursuing an NPA in lieu of continuing their gas service. Out of the 19, 5 expressed interest in learning more. Ultimately, 1 customer did not provide consent to move forward with the conversion work and 1 customer was determined not to be feasible based on legal and operational concerns with the site. The remaining 3 customers were fully electrified with a geothermal system serving as the primary source of heating and cooling. The design of the customer homes required extensive customization, including integrating both Ground Source Heat Pump (GSHP) and Air Source Heat Pump (ASHP) systems to deliver heating and cooling as required throughout the property. The Company worked with these customers for more than two years to ensure that they were satisfied with the final state of the installation. The gas services were disconnected at the homes in May 2024 and 586’ of gas service piping was able to be retired.

Reliability & Reinforcement (“R&R”): By reducing customer demand for natural gas in a specific geographic area of the distribution system, an infrastructure project (whether new, or an upgrade to existing equipment) that would address reliability or system reinforcement can be deferred or avoided. Because these projects require overall demand reductions rather than retirement of a specific segment of pipe, proposed solutions can include electrification (either partial or full) as well as energy efficiency, weatherization, demand reducing software, battery solutions, etc.

<u>Threshold Criteria and Requirements</u>: All reliability and reinforcement projects must be screened for NPA feasibility. Those that are not screened out due to critical reliability will be evaluated using the Screening and Suitability criteria, which were filed with the Public Service Commission in August 2022[94]. Per the Screening and Suitability Criteria, capital projects associated with immediate system

[94] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, “National Grid’s Proposals for Non-Pipe Alternative Screening and Suitability Criteria,” (Filed August 10, 2022).

needs related to safety, reliability, and service obligation, and those where construction is expected to commence and be completed within 24 months, would be excluded.

The Company has issued several RFPs for NPAs that seek to address R&R projects, but have seen limited success, largely due to a low number of bids by third-party vendors.[95] However, the most recent RFP issued by the Company for an R&R NPA, released in October 2023, and seeking to address three relatively small areas of constraint in both the KEDNY and KEDLI service territories, did receive one bid that is under active consideration by the Company.

All NPAs are typically required to be cost-effective (i.e., the net benefits of the NPA solution, including the avoided cost of the alternative infrastructure solution, must be greater than the net costs of the solution). This cost-effectiveness is evaluated using a Societal Cost Test, which incorporates costs and benefits that accrue to all residents of New York (and potentially outside the borders of New York), not merely those that are customers of National Grid.

It is important to note that NPAs still face substantial barriers to scaling, including the following:

- As shown in the image above, for leak-prone pipe NPAs, 100% of customers on a segment (or on specific portion of that segment) must agree to participate for the NPA to proceed.
- Relatedly, the Company's experience in conducting NPA-related outreach to customers has shown that customer sentiment may present a barrier to full electrification – including a preference for natural gas heating and/or cooking, the presence of undepreciated gas appliances, worries about higher energy bills due to electrification, and low levels of trust in the reliability of the electric system on very cold days. This is indicated by the fact that some customers will refuse to electrify even if the entire cost is covered via the combination of the NPA incentive and existing energy efficiency incentives.
- Another important barrier is the cost-effectiveness threshold. Typically, in order to approve a non-pipe alternative, DPS Staff will require that the net benefits of the NPA (which includes a variety of factors such as the avoided costs of the gas infrastructure, lower cost of carbon from greenhouse gas emissions reductions, etc.) be higher than the net costs of the NPA (which includes factors such as incentives paid to customers, vendor fees, required electric distribution system upgrades, etc.). NPAs are not guaranteed to pass the cost-effectiveness threshold, and National Grid has indeed received some vendor proposals whose relatively high cost meant that the potential NPA would not pass the threshold.
- The market for third-party NPA providers currently appears to be still in development, as has been demonstrated by the limited response rate to the Company's efforts to engage potential providers via RFPs and other activities. The Companies continue to collaborate with peer utilities, DPS staff, and other stakeholders to seek input and on ways to overcome these barriers. In general, that collaboration and the experience of utilities in other states and countries has should that certain conditions can increase the likelihood of NPA viability, including prioritizing opportunities that involve a low number of participating customers (i.e. less than 5) and those that involve greater than 100ft of pipeline to be avoided or other conditions that create a high value of avoided capital investment (such as an urban environment).

Over the past year, National Grid partnered with environmental think-tank RMI (formerly known as Rocky Mountain Institute) to better understand the emerging landscape of targeted electrification, NPAs, and gas-networking "rightsizing" in order to inform utility planning and policy underway in our

[96] As evidence, the Company maintains a list of approximately 200 vendors that could be potential participants in NPAs. An RFI was issued last year to 63 of those vendors, only 9 of whom responded; the subsequent RFP, issued in November 2023 to 10 vendors, received only one bid.

territories.[96] The paper examines nine case studies in the US and Europe to draw out potential insights for further exploration of the opportunities for NPAs, as well as potential policy changes that could further enable their development.

5.1.5. Non-Firm Demand Response (NFDR)

In order to further ensure safe and reliable peak day service, the Company offers non-firm, interruptible service to commercial and industrial customers that are capable of consuming at least 2.5 million therms annually. Collectively, this group of customers is sometimes referred to as "non-firm demand response."[97] In exchange for reducing peak demand by switching to an alternate fuel source when called upon to do so by the Company (i.e., during a non-firm "event"), non-firm accounts are charged a reduced transportation rate compared to relative service classes. In Downstate NY, non-firm event activations are triggered by the weather conditions: Tier 1 accounts, which currently receive a 55% delivery rate discount, are activated when temperatures drop below 15°F, and Tier 2 accounts, which receive a 65% delivery rate discount, are activated when temperatures drop below 20°F.[98] In Upstate NY, the event triggers are contract-based and vary by customer.

Non-firm demand response is distinguished from firm demand response in several ways. Non-firm customers are enrolled in a distinct and separate service class, whereas firm customers are enrolled in the standard service class for their customer type but elect to enroll in the firm response program. Non-firm and firm demand response events are called at different temperature thresholds, and non-firm customers can be assessed penalties for non-compliance with events and affidavits. Nevertheless, many customers enrolled in the firm DR Load Shedding program were, at one time, on non-firm rates, and as such there is significant overlap between the customer pools of both types. Lastly, firm DR includes customer types that are not eligible to be on non-firm rates, namely residential customers, who can enroll in the firm DR BYOT program.

Non-firm accounts provide considerable amounts of peak day reductions, as demonstrated by the rightmost column of the table below. However, those accounts do retain the ability to request to transfer from non-firm to firm rates, which would increase their peak gas demand, as they would no longer be switching to an alternate fuel source. Because significant transfers from non-firm to firm service would greatly disrupt peak day reliability, the Company closely monitors those transfers. It is making efforts to inform customers about the features of the non-firm rates (including eligibility for energy efficiency incentives, ability to choose a gas supplier, and the rate discounts mentioned above) so that they are fully informed before electing to transfer. The Company also conducted a survey in early 2023 to better understand customer motivations for transferring to firm rates.

Table 5-1: Impact of Non-Firm Demand Response[99]

Company	Accounts	Cumulative Design Day Impact (Dth/Day)
KEDNY	1917	126,988
KEDLI	165	12,909

[96] RMI, National Grid, "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization," available at https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf
[97] Historically, these service classes have also been referred to as "interruptible", "temperature-controlled", and/or "TC".
[98] In the recently filed KEDNY-KEDLI Order, these discounts were increased to 55% and 65%, respectively.
[99] Data in table is as of June 2024.

5.2. Planned Enhancements to our DSM Programs

National Grid recognizes that, despite the many accomplishments of our DSM programs that are enumerated above, much work remains to be done to achieve the goals of the Clean Energy Vision and the CLCPA. Continuous improvement will be required to meet those goals and is with that in mind that the Company envisions the following enhancements to its DSM programs.

5.2.1. Energy Efficiency (EE)

In response to the Public Service Commission's July 2023 order directing all members of the NY Joint Utilities to propose changes and enhancements to their energy efficiency and building electrification portfolios,[100] National Grid submitted its Energy Efficiency and Building Electrification ("EE/BE") proposals in November 2023.[101] In broad strokes, those proposals put forth plans for how National Grid's programs will evolve to align, in the 2026-30 period covered by the Order, with the strategic framework defined by the Commission. Those evolutions include some dramatic changes to the Company's energy efficiency programs, particularly to its portfolio of gas energy efficiency programs. Some of that evolution is already in process – in particular, a shift toward weatherization as the primary program offering in the Company's gas energy efficiency portfolios.

The Commission's July 2023 NE:NY Order defined "strategic" measures and programs as those that:

- Permanently reduce and/or eliminate natural gas usage on an annual basis, which would not occur absent the program's intervention.
- Permanently reduce and/or eliminate natural gas usage on a peak-hour or peak-day basis, in areas of current or anticipated near-term supply constraints.
- Improve the building envelope resulting in near-term reduction in fossil fuel usage that will also serve to mitigate future winter peaking on the electric grid in the event the buildings heating system is electrified; or,
- Permanently reduce and/or eliminate on-site combustion of fossil fuel usage on an annual basis, through the installation of efficient space heating or hot water electrification, which would not occur absent the program's intervention.

In contrast, the Order defined "non-strategic" measures and programs as those that:

- Jeopardize the advancement of strategic measures.
- Increase the use of fossil fuels.
- Have an effective useful life (EUL) of 6 years or less; or,
- Do not promote conservation behaviors and result in use of more energy through increased operation of a measures or are naturally occurring from market conditions.

In 2026-2030, all utilities and NYSERDA must spend at least 85% on strategic measures and no more than 15% on neutral measures of their EE/BE budgets. Between now and 2026, programs and measures that are non-strategic will begin to be phased out and strategic offerings introduced or expanded. Offerings that fall within the non-strategic category include customer engagement

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[100] Cases 18-M-0084 et al., *In the Matter of a Comprehensive Energy Efficiency Initiative, "*Order Directing Energy Efficiency and Building Electrification Proposals," (Issued and effective July 20, 2023). (July 2023 NE:NY Order")

[101] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, "Proposal of Niagara Mohawk Power Corporation d/b/a National Grid for Market-Rate Energy Efficiency and Building Electrification Programs, Proposal of the Brooklyn Union Gas Company d/b/a National Grid NY and the KeySpan Gas East Corporation d/b/a National Grid for Market-Rate Energy Efficiency and Building Electrification Programs, and Proposal of National grid for Low-to-Moderate Income Energy Efficiency and Building Electrification Programs," (Filed November 1, 2023).

programs and incentives for gas-fired commercial cooking equipment, fireplaces, space heating equipment, and domestic hot water equipment. Roughly 75% of total annual gas energy efficiency savings are currently derived from such offerings.

In the July 2023 NE:NY Order, the Commission elected to pursue a “budget bounding” approach that establishes an upper limit on ratepayer funded EE and BE programs, as “the scale of the EE/BE efforts required to comply with the CLCPA objectives cannot be funded through ratepayer collections alone.” Since the budget bounding approach sets annual budgets at levels allocated to National Grid in prior years, and because strategic measures cost much more per unit of annual savings achieved than non-strategic measures, the net effect will be a large decrease in the amount of annual gas energy efficiency savings that the Company is able to achieve.[102] The Company’s transition to strategic measures is already underway and we foresee challenges with existing EE programs meeting NE:NY annual savings targets within authorized budgets through 2025 while shifting portfolios fully by January 2026.

Despite that challenge, there are many benefits to transitioning to and scaling strategic offerings for gas customers, particularly weatherization. Weatherization provides year-round energy savings, has a long effective useful life (“EUL”), helps mitigate peak demand on the gas system, improves occupants’ comfort, and enhances building readiness for potential future electrification. Moreover, the bundled and comprehensive offerings proposed by the Company across all sectors will achieve cost efficiencies and allow customers to undertake larger, more substantial projects. Tailored offerings will be introduced for customers in Disadvantaged Communities, including direct-install measures that are accessible for customers not yet able to undertake weatherization projects. Direct install measures are designed to be easily accessible and implemented without the need for extensive research, planning or upfront costs. Such offerings typically involve trained professionals or contractors who visit properties to install energy-efficient equipment or implement energy-saving measures, resulting in overcoming the barriers of participation for such communities in a cost-effective manner.

The July 2023 NE:NY Order also mandated that certain programs – namely almost all low-and-moderate income programs – should transition from being administered by National Grid to being administered by the NY State Energy Research and Development Authority (NYSERDA).[103] This will decrease the number of DSM levers that are within the Company’s direct control, highlighting the fact that National Grid is not the sole actor within its territories in working toward achievement of the state’s climate goals, and that collaboration will be necessary to ensure that those goals are met while providing customers with as seamless an experience as possible.

5.2.2. Building Electrification

[102] In the July 2023 NE:NY Order, the Commission also identified federal funding such as the Inflation Reduction Act and the proposed NY Cap-and-Invest program as potential additional funding sources outside of gas and electric customer funding for EE and BE programs; the Company supports that approach and will pursue that funding where possible so as to mitigate impacts on ratepayers and scale its DSM programs. As of this writing, the Company continues to explore these opportunities, but has not yet secured funding from these sources for its EE and BE programs.

[103] The LMI programs to be transferred to NYSERDA administration include 1-4 family LMI programs statewide, and the Affordable Multifamily Energy Efficiency Program (AMEEP) in the Company’s upstate New York territory; AMEEP in downstate NY will continue to be administered by National Grid. NYSERA will continue to lead, as it has before, efforts regarding workforce development, technical assistance, customer awareness and education, new carbon-neutral and net-zero construction, and codes and standards, among others. For more information, see pp. 55-72 of the July 2023 NE:NY Order.

As part of the EE/BE Proposal described above, National Grid has proposed a number of changes and improvements to its electrification offerings in its Upstate NY service territory during the 2026-30 time period.

For residential customers, National Grid has proposed to continue its participation in the statewide Clean Heat program, which is funded and administered by electric utilities to support the electrification of space and water heating through customer adoption of heat pumps and other energy efficient electrification technologies.

The Company plans to explore a variety of enhancements and new offerings that may be added to the statewide program in 2026-2030. Alongside the addition in 2024 of air-to-water heat pumps to the list of technologies eligible for Clean Heat incentives, areas of future exploration include but are not limited to:

- Offering incentives for electric panel and wiring upgrades for customers in Disadvantaged Communities when electrical work is required as part of a heat pump installation.
- Creation of an incentive category for partial-to-full-load heat pump conversions
- Establishment of a new incentive category for dual-fuel (e.g., electric and gas) hybrid heat pump technologies
- Addition of new incentive categories for resiliency improvements such as hot water buffer tanks, batteries, and thermal energy storage that support heat pump systems.

National Grid is committed to ensuring, per the directive issued by the Commission in the Order Directing Energy Efficiency and Building Electrification Proposals, that customer funds do not support electrification projects that risk high energy use and exacerbating winter peak demand, while continuing to build market momentum for efficient beneficial electrification. For many customers, the cost of weatherizing their homes and installing a heat pump system at the same time can be challenging to manage. To address this, the Company is evaluating cost-effective ways to help customers weatherize their homes first, to increase the efficiency of heat pump systems incentivized through Clean Heat.

For many reasons, it is beneficial to weatherize a customer's home before installing a heat pump system. To address barriers and enable these benefits, the Company intends to explore new Clean Heat and weatherization offerings and cross-program coordination for 2026-2030 that emphasizes customers weatherizing their homes before they install heat pumps.

The Company is also exploring other funding streams to provide additional electrification incentives to potential residential Clean Heat participants, such as Non-Pipe Alternative (NPA) and other targeted electrification regulatory frameworks that may be necessary to enable future gas and electric integrated system planning to support an orderly clean energy transition. These funds could be added to Clean Heat incentives for customers located in specific areas of the gas network where the Company seeks to address a gas system need. The goal of any adder incentives would be to make it financially viable and preferable for customers to convert end uses, including space and water heating, from gas to electricity.

The Commission, in the July 2023 NE:NY Order, directed all utilities to address larger more complex applications, such as those seen in the multifamily segment, through a different programmatic design process and incentive structure, ideally embedded within other programs targeting these sectors. In response, National Grid intends to begin incorporating Clean Heat offerings for multifamily, commercial, and industrial customers into the energy efficiency programs for those customer segments rather than a standalone Clean Heat program and will add other electrification measures that the Company deems suitable for those segments. Air-source and ground-source heat pumps will be incentivized, along with other accompanying measures such as controls. The

Company will support the larger and more complex electrification projects for customers in those segments by allowing these customers to directly engage with the Company's program and technical assistance.

The Company is proposing several pathways for large heat pump systems including supporting customers in Thermal Energy Networks ("TENs"), Industrial Heat Pump ("IHP") offerings, and other custom offerings to support customers in the future. Thermal Energy Networks hold significant potential to help the State move forward with its ambitious electrification goals. As interest in and support for them develops, the Company could explore options to provide incentives to customers for equipment purchases allowing them to connect to TENs while observing PSC protocols and DPS guidance governing layered/overlapping incentives and cross-subsidization. Industrial Heat Pumps are currently limited in commercial availability in North America. However, NYSERDA plans to pilot adoption of IHP technology in conjunction with ACEEE and other NYS stakeholders by identifying potential end-users that may have interest in or be a good candidate for IHPs (such as FlexTech participants). This effort aims to overcome barriers to the use of high temperature output IHPs and attract manufacturers to enter the North America market. Early IHP opportunities in New York State include pulp and paper producers, primary metals, chemical plants, meat packing, dairy and other food products industries.

Other large heat pump technologies, best suited for promoting electrification in large commercial (hospitals, universities, municipalities, and schools) and industrial segments, are market ready for adoption to displace fossil fuels for space heating, cooling, process loads, and domestic hot water. Large heat pumps include heat pump chillers / heat recovery chillers, air-to-water heat pumps, and dedicated outside air heat pumps. All large heat pumps are to serve as the primary source of space heat and may use limited natural gas either for resilience purposes or under certain minimum conditions where large heat pumps lose performance and efficiency.

5.2.3. Firm Demand Response (DR)

The Company continues to explore new ways of encouraging customer participation in its firm gas demand response programs, both through incremental improvements to existing programs and through novel program designs. Recent program improvements include expanded customer marketing and engagement, adjustments to performance calculations, and curtailment case studies and recommendations for prospective customers.

One noteworthy recent program enhancement is the Incentive Match offering, which provides a 20% bonus to gas DR participants who choose to direct incentives earned by participating in events during the prior winter season toward energy efficiency projects. By doing so, the Company rewards customers who actively participate in its DR programs while increasing the amount of achieved energy efficiency.

The Company is also actively exploring two novel programs in its DNY territory: the Neighborhood Device Behavioral DR Program and a Gas DR Hybrid Electrification pilot.[104] The first leverages remote metering technology capable of reading hourly customer data from existing meters, provides that data to customers, and notifies them of DR events via a mobile application. This should allow the Company to evaluate program reductions more accurately in areas where advanced metering infrastructure ("AMI") is not available. The Hybrid Electrification Pilot, which was spurred on by a $1M award from the Department of Energy, seeks to identify the potential of hybrid heat pump

[104] More information on the BDR and DR Hybrid Electrification pilots can be found, respectively in the KEDNY/KEDLI 2022-23 Annual Report in Case 20-G-0086 and the Company's filing in Case 23-00775. (Note that the Neighborhood Device Behavioral DR Program was formerly referred to as the Behavioral DR Pole-Mounted Device Program.)

systems in both single-family homes and multifamily buildings to provide gas demand reductions during periods of peak system demand.

5.2.4. Non-Pipeline Alternatives

As described in previous sections, National Grid is continuing to expand its NPA efforts, integrating the review into all capital projects and working closely with peer utilities to determine best practices to support customer adoption. This has been recently formalized and approved by the Commission in the Joint Proposal adopted as part of the 2023 KEDNY and KEDLI Rate Cases, which describes the changes that National Grid will undertake in its NYC and Long Island service territories. Similar efforts have been proposed as part of the ongoing NMPC rate case, with a goal of promoting equity and standardization across National Grid's NY service territory, creating a sense of predictability for vendors that operate and therefore could potentially deploy NPAs throughout the state.

The changes that will be made to NPAs going forward are broken down into sections below:

Procedural/Outreach Changes

- The Company will file an LPP NPA implementation plan within 120 days of the KEDNY-KEDLI Order, which translates to December 13, 2024. This implementation plan will be subject to a 60-day stakeholder review and comment period, after which the Companies will file a revised implementation plan that incorporates stakeholder feedback. This implementation plan will provide detail on all of the process steps involved in analyzing LPP NPAs, along with references to other internal process/documents (e.g., ENG04030) so that a complete picture will be available to stakeholders.
- As stated earlier in this plan, the Company will retain an implementation contractor with the necessary planning, engineering, and marketing expertise needed to execute the Companies' commitments to NPAs. This implementation contractor will review existing processes and make recommendations to improve customer response. Outreach to customers on NPAs will be completed by the implementation contractor in coordination with internal employees.
- Through the use of this contractor, National Grid will be contacting customers as soon as possible once an NPA opportunity is identified (i.e., the project is NPA feasible and is not eliminated due to a critical system need), which will maximize the amount of lead time that a customer has to become familiar with the NPA opportunity and to make an informed decision.
- National Grid is beginning to develop its capabilities around Integrated Energy Planning (IEP). This will provide insight into the areas of the system where electrification-based NPAs will be able to be deployed with the lowest probability of needing to build out the electrical infrastructure. National Grid intends to include other available information into this review of its service territory. This may include customer propensity, demographic data (e.g., whether or not an area is in a DAC), information on building stock, and other contextual information. National Grid will work closely with stakeholders to leverage their knowledge of customers and regions so that this dataset can be as informative as possible.
- The Company will continue to engage with others (e.g., peer utilities) that are investigating and deploying NPAs to attempt to replicate successful methodologies to target customers willing to participate in NPAs.
- Specifically, the Company will undertake efforts to engage with the New York City Housing Authority for a potential large scale NPA.
- The Company will, during the term of the rate plans, increase their efforts to inform customers of NPA project opportunities and increase customer education and outreach.

- The Company will ensure that upcoming NPA project opportunities throughout the service territory are available on the Companies' website and in promotional materials in a timely fashion.
- The Company will, for each NPA opportunity, make note of the effectiveness of customer outreach efforts, customer feedback and disposition of gas alternatives as part of participation in an NPA project (e.g., what incentives are persuasive or not persuasive, why customers are willing or unwilling to eliminate their gas service, etc.). The Companies will report on these efforts and the success of the program in their annual NPA Opportunities and Programmatic Success reports (as described more fully below), and the Companies will identify the types of stakeholders (e.g., governmental entities, developers, community groups, etc.) included in the Companies' outreach and marketing as part of its reporting.
- The Company proposed in its NMPC rate case to hire a consultant who specializes in the SCT to develop a BCA handbook to use to calculate the BCA scores for all NPAs. If approved, the Company would ensure that the handbook would be applicable to all NPAs across its service territory.

New Connections NPAs

Threshold Criteria or Requirements:
The Company will perform an assessment of customer interest in NPAs for all gas service requests that involve a main extension of more than 100 feet (which shall include footage from smaller main extensions that reasonably can be grouped together). Additionally, the Company will develop an NPA proposal focused on new gas service line installation and replacements or relocations under the NPA Framework.

Connection requests that require less than 100 feet of main line and/or less than 100 feet of service line fall under the existing allocation available to customers and must be completed by the Company. However, customers who are requesting a connection will be required to complete an attestation stating that they are aware of non-fossil alternatives, along with incentives available to adopt them, and that they still wish to receive gas service.

By no later than March 31, 2025 (i.e., end of Rate Year One), the Company will convene a stakeholder engagement meeting to discuss progress related to the Companies' efforts to develop NPAs focused on gas service line replacement, including (to the extent applicable) a description of which strategies have been successful, which strategies have not, and what the Companies plan to modify going forward. The Companies will report on those efforts and the success of the programs in their annual NPA Opportunities and Programmatic Success reports.

LPP NPAs

Threshold Criteria or Requirements:
The Company will continue to review every LPP segment for NPA feasibility to identify instances where planned LPP replacement projects could be avoided by deploying NPAs, including thermal energy networks or individual ground or air-source heat pumps to serve affected customers.
The Company will, in accordance with the mandates of the CLCPA, prioritize potential projects to transition LPP to NPAs in DACs.

In its NMPC Rate Case, National Grid has proposed increasing the value of avoided cost in DACs by 20% from a BCA perspective to help to improve NPA adoption within DACs. It will also work closely with its Implementation Contractor and local community groups to improve receptivity within these areas. If this approach is approved, the Company will work with Department of Public Service Staff to determine if this should be incorporated into its BCA approach across NY.

NPA adoption in disadvantaged communities (DACs) faces a number of specific hurdles, including a relatively high propensity of renters, leading to a split incentive challenge, potential for language barriers, and greater affordability issues, which may be exacerbated by low-income customers being located in high density areas, therefore reducing the avoided LPP and associated avoided cost per customer.

In addition to prioritizing outreach to customers located in DACs, the Company will adjust its method for prioritizing LPP NPAs for outreach so that it will begin with LPP segments that have the lowest risk scores, meaning that there is a relatively longer period of time before replacement would be required. The Company will also target LPP projects that represent the greatest amount of footage, which would provide a higher avoided cost to support NPA incentives. LPP segments are reviewed on an ongoing basis and the review for NPA feasibility occurs as new segment information is obtained.

By no later than March 31, 2026 (i.e., the end of Rate Year Two), the Company will convene a stakeholder engagement meeting to discuss progress related to the Companies' efforts to implement the LPP NPA, including (to the extent applicable) a description of which strategies have been successful, which strategies have not, and what the Companies plan to modify going forward.

R&R NPAs

<u>Threshold Criteria and Requirements:</u>
All capital projects must be reviewed for NPA feasibility. Additionally, the Company will explore ways that NPA incentives could be offered to reduce gas system firm demand, including through targeted incentives for energy efficiency, demand response, and electrification.
The Company will focus and prioritize these efforts on the most constrained portions of its service areas and include a prioritization list as part of their annual NPA Opportunities and Programmatic Success reports.

Reporting

In a move that will improve transparency around the NPA process, the Company will, beginning in Rate Year Two, file an annual report with the Commission no later than July 31 setting forth in detail NPA Opportunities and Programmatic Success. To date, the Company has included information on NPA activities in other reporting (i.e., its semi-annual Gas Usage Reduction reports for NMPC and its quarterly Capacity Demand Metric reports for KEDNY/KEDLI). Establishing a single, recurring report for all NPA activities will provide a forum to share more detail, including any proposed process changes, and will make the information readily available to stakeholders.

This report will include:

a. Efforts to pursue NPAs in connection with LPP replacement, system reinforcements, service line installations and replacements, and customer connections.
b. Retention of an implementation contractor, describing how the contractor has impacted the Companies' efforts, and the costs associated with retaining the contractor.
c. Identify and provide justification, including but not limited to supporting documentation, for all instances in which the Companies provided analyses that concluded that an NPA was not feasible or beneficial for customers from a cost perspective or would not lead to reduced GHG emissions.
d. Identify prioritized portions of its service areas due to system constraints. The results will also include a list of all alternatives recommended to customers and will include all available electrification measures and other non-fossil alternatives.
e. Example marketing materials used during NPA outreach

5.2.5 Utility Thermal Energy Networks (UTENs)

Thermal Energy Networks ("TENs") refer to a system where a working fluid, often a water and glycol mixture, is circulated to exchange heat energy with multiple, independent customer premises. A Utility Thermal Energy Network ("UTEN") is a TEN where some or all of the components of the TEN are owned by a utility.[105] The working fluid in a TEN or UTEN is delivered to customer equipment, frequently water-source or ground-source heat pumps ("GHPs"), that condition space within the premises. The fact that multiple customers are connected to a single network means that it is possible to actively exchange energy between customers (e.g., a customer that has waste heat from a process load can have that heat removed by cooling the space and that same heat energy can be used to heat adjacent premises that require it). Any mismatch between the load profiles of the connected customers can be managed through the addition of thermal resources (e.g., geothermal boreholes, wastewater treatment plants, process loads, solar thermal) to ensure that the whole system remains within its design conditions.

The U.S. Department of Energy released an analysis in November 2023[106] highlighting that GHPs, when deployed at mass scale, could decarbonize buildings while also reducing the need for new electric grid upgrades. UTENs have a number of unique characteristics that will enable wider use and adoption of GHPs in building electrification of space heating and cooling.

Unique Characteristics of UTENs include:

- The impact of integrating multiple unique customers means that fewer thermal resources may be required when compared to customers installing non-networked geothermal systems.
- The fact that there will be distribution piping to connect multiple customers means that thermal resources can be in the optimal location, rather than constrained by property boundaries, as would be the case with customers installing individual geothermal systems.
- Since, by definition, a UTEN is owned by a utility, it is possible that boreholes could be installed within the right-of-way, which would help to address space constraints for a given parcel. This could be especially important in dense environments where geothermal is often not feasible.
- A UTEN, like other utility capital investments, would most likely be recovered via rates over the EUL of the assets. This may provide cost savings relative to personal financing but also, and perhaps more importantly, means that customers do not need to secure financing for the installation of a geothermal system. This is critical to ensure equity of access for all customers.
- The presence of a UTEN at the time of a customer making a purchasing decision would make it easier for customers to select a heat pump that utilizes a working fluid for additional thermal energy, which is more efficient in terms of annual energy used and which creates a lower demand on the electric grid compared to the installation of air-source heat pumps and other electrification options.

The Company is excited about the prospect of these benefits and is actively developing pilot projects, which are described more later, to identify the best way to incorporate them into future systems. The Company believes that there are certain parts of its service territories where UTENs may be better suited, specifically those areas that have diverse customer loads and that feature medium to high customer density.

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[105] As further described and authorized in the Utility Thermal Energy Network and Jobs Act, which was enacted into law on July 5, 2022. *See* Laws of 2022, Chapter 375.

[106] Oak Ridge National Laboratory, "Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps For Building Heating and Cooling Electrification in the United States," November 2023.

UTENs in Low Density Areas
Areas of low customer density will require extensive infrastructure to interconnect buildings and it is not evident that this cost and additional infrastructure would be justified by performance gains relative to non-networked systems. There may be non-performance considerations (e.g., removing financial hurdles) that should be evaluated but there may be alternative options to support electrification that do not rely exclusively on UTENs. There is also active energy exchange throughout the length of a thermal energy network system (i.e., BTUs that are removed from or added to the working fluid by the ground surrounding the pipe). This is the same principle that allows for geoexchange to occur in boreholes. The distribution lines, which run horizontally below the surface, are subject to greater temperature fluctuations than the boreholes, which go down from the surface. This could result in reduced system performance in low density installations because BTUs would be lost during the fluid traveling the greater distance between customers. Low density environments are also often to more likely be residential, meaning that there would be fewer large energy users and/or diverse loads that would help to balance the needs of the system. Non-networked systems that serve each building individually may be able to achieve similar levels of performance.

UTENs in Medium and High-Density Areas
In addition, medium and high-density areas will benefit from the ability to integrate non-borehole thermal resources (e.g., waste heat from process loads or wastewater treatment plants), as the Company has proposed in its Syracuse pilots, or to place newly-installed thermal resources in optimal locations, as the Company has proposed in its Troy pilot. Systems in these areas will have less pumping energy relative to low density installations due to the shorter length of pipe between customers. They would also develop a more significant benefit for the electric grid in terms of reduced peak demand, both because there would be a larger number of customers who would be converting in a more efficient way and because the electrical grid in areas of high density is often already constrained and expensive to reinforce. A number of areas of high density have requirements in place to support customers transitioning to electrification, which could improve the rate of customers connecting to the UTEN relative to areas where adoption would be organic.

However, medium and high-density areas do present some complicating factors. Construction costs, including land/easement acquisition, can be quite expensive. In dense metropolitan areas, other underground infrastructure may make it difficult to identify areas where boreholes could be drilled without disrupting existing infrastructure. The same density that allows for active energy exchange also means that there are more customers that would need to connect to the UTEN. As described in the NPA sections of this report, securing 100% customer adoption of an alternative can be challenging, especially in instances where the customer count is high. This may mean that customers would convert to a UTEN over time, which could result in underutilization during some portion of the network's useful life. This is not inherently different from a gas system expansion but merits consideration due to the relatively high capital cost of UTENs.

There are also certain types of buildings and certain mechanical systems that may be better suited for UTENs. Buildings that have a forced air distribution system sized for both heating and cooling are typically less expensive to convert than those who are currently using water or steam distribution. Advancements in technology and adoption of new installation approaches (e.g., using refrigerant lines to distribute energy from the distribution loop to head units throughout the building) are making UTENs easier to install in a wider variety of buildings. Buildings that were designed around a specific mechanical system (e.g. single-pipe steam systems in NYC) or those that are constructed in such a way that modification is difficult (e.g. those without conduits or chases where new lines could be installed, those with historical/landmark designations that limit changes to the façade) will be difficult to electrify regardless of whether or not they are connecting to a UTEN, though a UTEN will have the benefit of having less equipment that needs to be located on site or on the facade of the building.

Components of UTENs
There are three primary categories of components for a UTEN: the thermal resources, the distribution infrastructure (piping and pumping), and the customer equipment and conversion costs.

- *Customer Equipment and Conversion Costs:* The cost of converting a building to heat pumps is likely to be a similar order of magnitude regardless of whether the heat pumps are connected to a UTEN or not. For this reason, as the market for heat pumps continues to grow, both in terms of vendors and installers, the costs for both UTEN and non-UTEN electrification will decrease.
    - The costs of customer conversion will differ if there is a simultaneous goal of having customers disconnect from the gas system rather than adopting a hybrid arrangement.
    - Utilities should continue to support workforce development efforts and should ensure that they are creating and updating platforms that help customers to identify qualified vendors.

- *Distribution Infrastructure:* one of the appealing aspects of UTENs is that they leverage the same pipe materials and installation techniques as the current natural gas system. Therefore, in a single-pipe system (i.e., a distribution loop where all customers are connected in series to a single pipe), the footage of pipe would be similar whether the line is carrying gas or conditioned fluid for a UTEN. The pipe diameter is likely to vary, but that is usually not a significant portion of the project cost. Additionally, the pipe will likely be installed at a greater depth than natural gas piping to avoid temperature fluctuations (e.g., 6' below grade rather than 3'). This will increase the cost, specifically for jobs where open trenching is the preferred method of installation. In a two-pipe system, which is what the Company installed at its first UTEN system in Riverhead, NY in 2017, there would be twice as much footage required due to the need to have supply and return lines.
  All of these factors mean that the distribution infrastructure is likely to be similar in terms of magnitude of cost as installing or replacing natural gas infrastructure.

- *Thermal Resources:* thermal resources are the part of UTENs that are the least analogous to other electrification scenarios. They are the most diverse (e.g., geoexchange, WWTPs, solar thermal, process loads) and have the least straightforward set of benefits against which to be measured. The presence of thermal resources reduces the need for electric infrastructure and the amount of energy purchased by UTEN customers to meet their needs relative to installation of ASHP systems (i.e. an NWA), serves as a storage resource, may reduce operating costs and/or penalties for the producer, may create a non-energy benefit for users (e.g. additional rooftop space for buildings that no longer need cooling towers, potential for improved property value), and may allow for gas infrastructure to be retired.

Appropriately valuing these resources, including accounting for any discrepancy in timing of when customers connect to the UTEN, will be complicated. The Company will take a SCT BCA approach and expects to continue discussions with DPS Staff and peer utilities to determine an appropriate rate design and BCA framework for UTENs.

This will be complemented by National Grid's Integrated Energy Planning efforts, which will help to identify locations where UTENs could be minimally disruptive.
Thermal resources will be an area of focus in terms of reducing the costs of UTENs. This may occur due to additional vendors (e.g., borehole drillers) entering the market or it may occur due to developing a standard structure of interconnecting multiple types of thermal resources into the system. Utilities should work closely with DPS Staff to develop operational metrics that would allow the private sector to efficiently identify, develop, and interconnect thermal resources. The utilities will be responsible for balancing these resources, optimizing for cost and performance, in much the same way that the electrical grid is managed today.

Pilot Proposals
National Grid has three pilot proposals that are under review as part of the regulatory process initiated by the Utility Thermal Energy Networks and Jobs Act, which was signed into law by Governor Hochul on July 5, 2022. The three pilot proposals are:

1) Troy Pilot Proposal
The Troy pilot will involve connecting the distribution loop, which will be owned by the utility, to a geothermal well field, which will be located in a municipal park and owned by the Troy Local Development Corporation. National Grid will pay a thermal fee to the Troy LDC, which will based on the cost of the geothermal well field. This system is expected to connect nine buildings in the downtown center, with a total connected size of 730 tons. This system should produce a reduction of 1,782 tons of GHG emissions annually.

2) Syracuse Pilot Proposal
The Syracuse pilot will involve connecting the distribution loop, which will be owned by the utility, to the outfall of the Metropolitan Syracuse Wastewater Treatment Plant. National Grid will pay a thermal fee to the municipality, though the basis for how this fee will be established is not currently known. The energy that would be utilized by the UTEN is not currently valued but would become valuable based on the interconnection to customers who would seek to condition their spaces. This system will connect a variety of new construction buildings in the Inner Harbor, with a total connected size of 2,250 tons. This system should produce a reduction of 2,798 tons of GHG emissions annually.

3) Brooklyn Pilot Proposal
The Brooklyn pilot will involve installing a geothermal well field under the parking lot of the NYCHA buildings. These businesses, including a restaurant and a grocery store, all produce waste heat, which is intended to complement the thermal energy that will be accessible through the well field. A distribution loop will be installed that will interconnect the commercial businesses and three nearby multifamily buildings that are owned by the New York City Housing Authority (NYCHA). This will help both NYCHA and National Grid to understand how these sort of high-density housing buildings may be able to be transitioned to decarbonized mechanical systems in the future. This system will have a connected size of 560 tons and should produce a reduction of 448 tons of GHG emissions annually.

These pilots, if approved, will explore various technical, financial, and operational aspects of UTENs and thermal energy resources, as well as how best to leverage the technology to support customers. All three pilots are located in DACs, which will provide important learnings around how to support the residents of DACs during the energy transition.

5.3. Long-Term Demand Side Management Planning

As described in Section 5.1 above, National Grid administers a portfolio of innovative demand side management (DSM) programs that have provided, and will continue to provide, significant benefits in the form of reductions in annual gas consumption, peak gas demand, and greenhouse gas emissions. However, despite diligent efforts to develop and scale that portfolio by National Grid, and despite the efforts of other state utilities and NYSERDA, the levels of energy efficiency and electrification currently projected to be delivered through these programs is less than what is necessary to achieve both the Company’s Clean Energy Vision and New York State’s climate goals. Given the existence of that gap, National Grid is committed to identifying the best mix of current and new DSM tools to close this gap. To that end, we have identified the following actions as first steps to accelerate the uptake of DSM in New York:

1. Evaluate impacts from potential changes to gas service requirements and innovative rate design strategies;
2. Identify new regulatory frameworks or modifications to existing frameworks needed to scale targeted electrification and NPAs in alignment with a statewide integrated gas and electric system planning process;
3. Optimize statewide EE/BE gas and electric rate funded programs to work alongside other levers in the most cost-effective and reliable way;
4. Expand coordination with other program administrators in our territory, regulators, and policy makers in order to proactively quantify and model how new policies and programs can work with gas rate payer funded programs in a synchronized manner.

These and other recommendations are covered in more detail in Section 8.3.

5.3.1. Evaluating Impacts from Changes in Gas Service Requirements and Utility Rates

"Gas service requirement changes" encompass alterations to all activities in the process associated with connecting gas customers to, or disconnecting gas customers from, the network. In New York, National Grid is currently bound by a variety of service requirements, notably including the obligation to serve existing customers; the obligation to connect customers to the gas system who wish to do so; and the obligation to provide a no-cost extension of up to 100 feet of distribution service to any customer looking to connect (aka the "100 foot rule"). Changes to these requirements have been introduced within two bills that are currently under consideration by the NY state legislature, namely the NY HEAT Act and Affordable Gas Transition Act; those changes could impact the pace of DSM adoption. In addition to modification of those requirements, other gas service changes need to be evaluated as well, such as requirements to achieve certain levels of energy efficiency or heat one's home or business with a hybrid gas-electric heating system prior to connecting to the gas network.

"Rate design" encompasses the planning, development, and implementation of customer rates. Of note in this context is that as the number of customers connected to the gas system decreases over time, the revenue requirements associated with the operation and maintenance of that system will shift to a smaller customer base, thereby increasing per-customer bill impacts. Additionally, as heat pump adoption increases, the strain on the electric system will increase, leading to a need to operate that system more efficiently. Electric and gas rate design holds the potential to address both issues while also ensuring that rates remain transparent, fair, and affordable for both gas and electric customers.

It is not yet clear how, and to what degree, changes to gas service requirements and to rate design could impact DSM adoption and related tools. Nevertheless, because they are primary influences on customer decisions as to whether to participate in DSM programs, it is important to consider them first. The Company recommends conducting further data analysis and modeling to better understand the impacts of those potential changes, which in turn will allow for improved decision making and design of those levers.

5.3.2. Optimizing Statewide Energy Efficiency and Building Electrification Ratepayer-Funded Programs

The energy efficiency and building electrification programs administered by National Grid, other utilities in the state, and NYSERDA are the most mature tools for achieving DSM today. As discussed in Section 5.1, National Grid's 2026-2030 energy efficiency program proposals, filed with the PSC in November 2023, align with the Public Service Commission's Strategic Framework, which aims to enable deeper and longer-lasting savings measures. However, the levels of funding currently being contemplated in the ongoing New Efficiency: New York proceeding will not alone be sufficient to propel the levels of customer participation necessary to achieve the state's climate goals. (It should be noted, however, that the Commission asserts in the July 2023 NE:NY Order that "the scale of the EE/BE efforts required to comply with the CLCPA objectives cannot be funded through ratepayer collections alone" and goes on to point to federal funding or economy-wide Cap-and-invest funding as additional sources of funding.)

Given that limitation, National Grid is seeking ways to optimize the existing portfolio of statewide incentive programs via other means. This involves, first, a better data-driven understanding of how those programs can work in tandem with the other levers that are less mature – e.g., the potential gas service requirement and rate design changes described in Section 5.3.1 above. Modeling may help identify if some of the potential changes may prove more cost-effective and equitable for customers than increases in program budgets. Furthermore, National Grid is committed to exploring additional sources of funding for DSM program offerings.

Moreover, work can be done to ensure that the Clean Heat program, which is administered by electric utilities that are subject to the Commission's regulatory oversight, is well coordinated with gas utilities. Such coordination would enable gas utilities to:

- Obtain timely, accurate data regarding the amounts of electrification forecasted to occur in the gas utilities' territories, thereby improving gas system planning;
- Obtain up-to-date data on already-achieved electrification, thereby enabling them to better plan for stacking complementary incentives to drive further adoption of electrification in targeted areas;
- Stay better informed of and involved in decisions regarding changes to the statewide Clean Heat program guidelines that could impact their ability to contribute to achieving climate goals.

5.3.3. Expanding statewide coordination for synchronized planning of DSM policies and programs

Under the new paradigm of proactive and synchronized planning of DSM policies and programs, improved collaboration, alignment, trust, and transparency between all stakeholders will be critical. This will enable us to avoid double-counting of GHG savings between levers, steer clear of inequities or other burdens to customers due to uncoordinated levers, and ensure we are all working together toward an affordable, streamlined, and customer-centric energy transition. To that end, National Grid recommends expanding coordination with other program administrators in our territory, regulators, and policy makers to proactively quantify and model how new policies and program ideas can work in tandem alongside ratepayer-funded programs to achieve our collective climate goals.

In the near term, National Grid is exploring multiple pathways to access additional funding streams in support of delivering benefits to customers at the lowest possible bill impact. At the federal level, this includes coordinated efforts with stakeholders to explore potential direction of funds under the American Rescue Plan Act of 2021 toward support of energy efficiency efforts. In addition, National Grid is currently evaluating federal funding possibilities through the Infrastructure Investment and Jobs Act ("IIJA") and will pursue funding opportunities that align with the efficiency programs where practicable. National Grid is also considering how to leverage federal funding for affordable housing and projects in Gateway Cities to support energy efficiency, as well as how to work with schools or others within the education sector who may receive federal funding directly yet may need support to identify and implement projects.

6. The Role of the Greenpoint LNG Plant

6.1. Greenpoint LNG Facility Background

The Greenpoint LNG plant provides critical gas supply on the coldest days of the winter, serving primarily as a “peak-shaving” facility capable of meeting short periods of infrequent but significant peaks of demand. The LNG facility occupies 50 acres, including approximately 1/4 mile of waterfront along the Newtown Creek, within the Greenpoint Energy Center (“GEC”). The plant has two single containment LNG storage tanks with a total storage capacity of 1.6 billion standard cubic feet (“BCF”).

Figure 6-1: Greenpoint Energy Center

6.2. Supply and Reliability Benefits Provided by Greenpoint LNG

The Greenpoint LNG Plant has numerous benefits as it relates to both supply and reliability, which can be broken down into three categories:

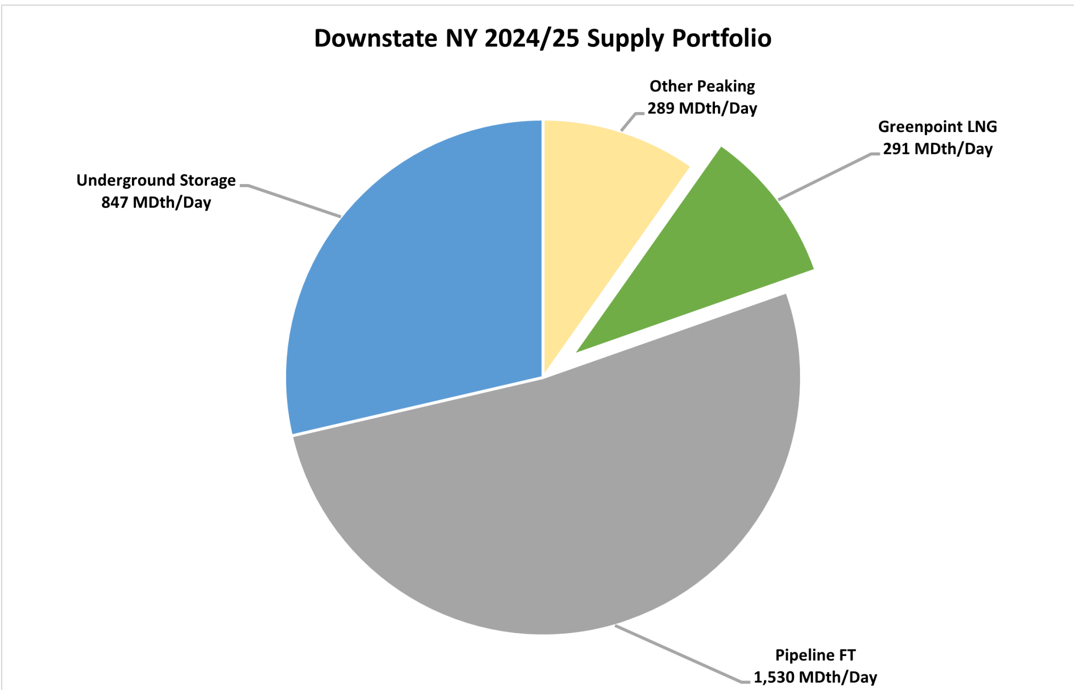
a. Supply Resource and Strategic Asset
b. Reliability Asset
c. Transmission and Distribution System Resource

6.2.1. Supply Source and Strategic Asset

The facility serves as a linchpin in ensuring a steady, reliable, and scalable supply of natural gas. The Greenpoint LNG plant can receive gas during off-peak periods (typically between April and November), cool it into liquid that occupies 600 times less volume (liquefaction process), and store it in the two LNG storage tanks, resulting in a space-efficient localized supply source. This LNG can be vaporized and sent into the gas system during periods of peak demand or when needed, mitigating risk associated with upstream supply issues (e.g., Winter Storm Elliott in December 2022) and overall supply constraints. The facility's flexibility to vaporize only the volumes needed (up to a maximum of 291,200 Dth/day) also allows the Company to balance supply and demand with a high degree of precision as well as preserve the LNG inventory (approximately 1.6 BCF when full) for use throughout the winter period as needed.

The following figure illustrates the contribution of the Greenpoint LNG Plant to the Downstate NY Design Day supply portfolio. For the 2024/25 winter, 10% of forecasted Design Day customer requirements would be served by vaporized LNG from the Greenpoint facility.

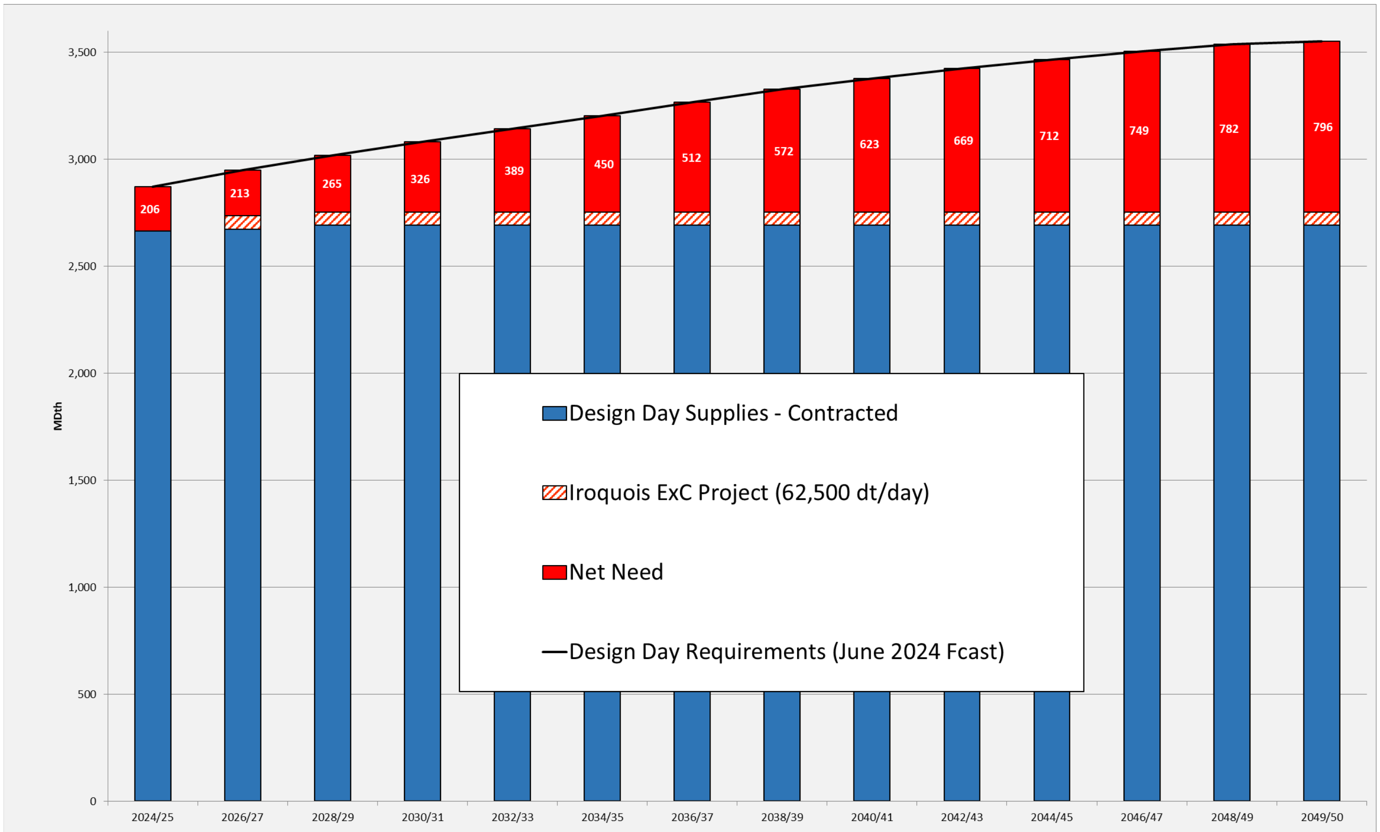
Figure 6-2: Greenpoint LNG's Role in the 2024/25 Supply Portfolio



When storing LNG, there is a small unavoidable percentage of natural gas that evaporates during storage (boil-off) from the top of the tanks. The facility's boil-off system efficiently captures this vapor and injects it into the gas system for customer use rather than flaring it, which would contribute to lost and unaccounted for gas volumes as well as additional emissions.

As shown in Figure 6-3 below, the Company projects an immediate supply-demand imbalance without the Greenpoint LNG facility in service. The imbalance is projected to grow substantially over time under the adjusted baseline forecast, necessitating supply side or demand side solutions above and beyond existing Greenpoint LNG vaporization capacity.

Figure 6-3: Downstate NY Net Need 2024-2050 without Greenpoint LNG



6.2.2. Reliability Asset

The LNG facility represents a highly reliable and resilient asset, contributing significantly to operational and supply security. Its unique ability to store LNG on-system allows the Company to ensure that our customers have reliable supply during Design Days and design hours. It also serves as a crucial resource should supplies being delivered from upstream pipelines be interrupted. The capability of the Greenpoint LNG plant to mitigate the risks associated with upstream supply disruptions or fluctuating demand cannot be duplicated by the other assets in the supply portfolio or by any available DSM solution. This asset supports the equivalent of approximately 291,200 customers based on the average usage of a residential heating customer on a Design Day, and loss of this asset would result in customer outages of approximately the same magnitude on a Design Day. Unlike the restoration of electric service, which can happen quickly after an interruption, an interruption of gas service to residential customers takes significantly longer to restore in a safe manner as discussed below.

6.2.2.1. Loss of Reliability Impacts

The Greenpoint LNG plant is a critical asset that helps to diversify the supply portfolio, increase reliability, and reduce the likelihood of an outage. The loss of the sufficient and reliable supply provided by the Greenpoint LNG plant needed to meet Design Day demand could have devastating consequences. If the gas system was unable to meet Design Day demand, National Grid would need to curtail customers' usage by shutting off parts of its system to avoid unsafe operating conditions. In the event of a supply loss as large as the Greenpoint LNG plant, curtailments would extend to residential customers, and those customers would be without their primary and potentially only source of heat on what would likely be one of the coldest days of the year. A customer outage of this magnitude would be unprecedented in the natural gas industry and would require a massive restoration effort that would likely take months to restore gas service to the impacted customers. The magnitude of the restoration effort would exceed the capacity of Company employees and contractor resources throughout Downstate NY, Upstate NY and MA, and would require significant Mutual Aid support from other companies through the Northeast Gas Association, the American Gas Association, and other qualified gas contractors from outside the region. The lengthy time of restoration is due to the manual effort required by Pipeline Operator Qualified personnel to go from building-to-building to ensure all gas services are shut off and secured prior to being able to safety reintroduce gas into the isolated system. Personnel must physically obtain access to every building and relight every appliance. Strict adherence to this restoration process is critical to maintain customer and pipeline safety and eliminate the potential for uncontrolled gas release into a building, which could result in a significant fire hazard and risk to public health. For this reason, it is imperative to always maintain gas system reliability and avoid customer outages, which is currently achieved by utilizing the Greenpoint LNG plant.

6.2.3. Transmission and Distribution System Resource

For over a century, the Greenpoint LNG Plant has been integral to gas service to customers in Brooklyn and Queens, and the gas system has in many ways been built around this location. Strategically positioned to serve customer needs efficiently, the Greenpoint LNG Plant is well-placed to meet customer demand and provide seamless access to major pressure systems across Brooklyn and Queens, including the 350 psig, 60 psig, and 15 psig systems. The facility's strategic location and operational capabilities make it an indispensable source of supply and pressure support for customers in KEDNY, and through the NYF system. It can provide indirect reliability support to Con Edison and KEDLI as well. It serves as a critical preventive measure for system interruptions and a reliable source of peak supply, enhancing the ability to deliver consistent, reliable, uninterrupted service to customers.

6.3. Costs to Operate, Maintain, and Improve the LNG Plant

6.3.1. Operations and Maintenance

The table below shows the operations and maintenance cost for the Greenpoint LNG Liquefier and Vaporizer in FY24.

Table 6-1: FY2024 Greenpoint LNG Plant O&M Costs[107]

	Operation	Maintenance	Total
Liquefier	**$316,972**	**$143,818**	**$460,790**
Vaporizer	**$250,800**	**$104,543**	**$355,343**
Total O&M Costs			**$816,133**

6.3.2. Reasonable Life Expectancy of LNG Plant

The life of the plant is dependent upon the care and maintenance of its components. The most important components are the LNG Storage Tanks. When the tanks were originally constructed, they were equipped with sample coupons that were submerged within the LNG. These coupons were made of the same 9% nickel steel material from which the tanks were made. Over the years, sample

[107] Data pulled from National Grid SAP Finance 4111 Reports

coupons have been removed and examined in a laboratory to test for signs of corrosion or other material related failures. To date, none have been found and the coupon material has retained its initial properties from when it was first installed. Furthermore, the limiting factors in cryogenic tank life are related to thermal cycling and fill cycling, both of which are typical for import terminals which are cycled every few weeks. Utility peak shaving plants like the Greenpoint LNG plant have not gone through thermal cycling or fill cycling (e.g., empty tank, let it warm up, then cool down and fill again). The American Gas Association paper "Evaluation of LNG Facilities for Aging"[108] stated that "the largest component, the LNG tank, provided it is maintained and monitored, will remain fit for service essentially forever." Therefore, with proper maintenance and monitoring, including internal tank inspections, there are many decades of tank life remaining. Normal care and maintenance of the carbon steel outer tanks and the foundation heaters are essential activities to ensure continued safe and reliable operation of the LNG Plant. The life span for equipment such as pumps, compressors, valves, vaporizers, and foundation heaters are dependent upon the amount of use they receive as well as the amount of care and maintenance. For example, the boiloff compressors in some plants last from 20 – 30 years whereas Greenpoint's original boiloff compressor has lasted over 50 years, mainly due to its infrequent use following the installation of additional jet compressors. Vaporizers last approximately 20 – 30 years depending on use and the choice of materials from which they are made.

6.3.3. LNG Improvement Projects and Costs

The Company's primary responsibility is to safely deliver uninterrupted gas to our customers, which is done by continuously monitoring and modernizing our infrastructure in the most cost-effective way to minimize risk, provide reliability, and maximize the life of our assets. Capital investments are a key component of good asset management practice. Capital investments in the Greenpoint LNG plant help maintain and improve the performance of the LNG facility, ensuring that the plant remains productive over the long-term. By investing in new equipment, technology, and infrastructure, the facility will continue to operate safely and reliably.

National Grid continues to identify capital projects to preserve reliability and mitigate risks associated with supply, and over the next 4 years (FY25-FY28), National Grid is proposing to invest $364M in capital improvements for the Greenpoint LNG Plant.

Table 6-2: Greenpoint LNG Plant Capital Plan

(In millions)	FY25	FY26	FY27	FY28	Total
Greenpoint LNG Plant Capex Budget	**$107**	**$112**	**$57**	**$86**	**$364**

6.4. Social Impacts of the LNG Plant

6.4.1. Enhancing Energy Affordability

The Greenpoint LNG facility plays a pivotal role in enhancing the affordability of energy. This facility acts as a strategic resource, enabling the procurement of gas supplies at more favorable prices during off-peak periods, notably in the summer when demand is typically lower. By leveraging the storage capabilities and the inherent flexibility of an LNG facility, energy can be strategically released during times of high demand. Since LNG vaporization is usually limited to near-Design Days, the overall bill impacts to customer commodity costs are minimal as the LNG storage price, or WACOG ("Weighted Average Cost of Gas"), is comparable to underground pipeline storage and compares favorably to market-priced supplies. Other Design Day peaking supplies, such as CNG,

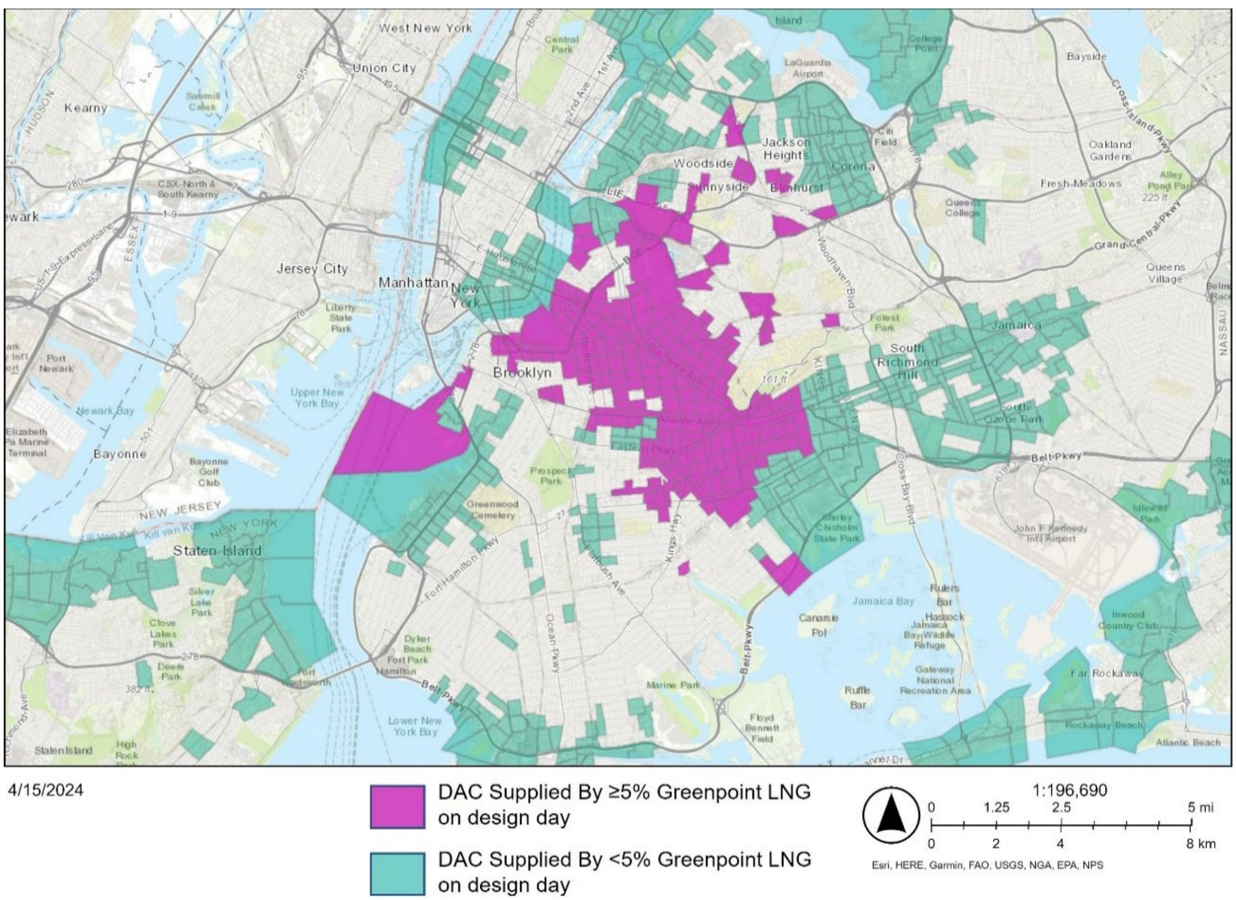
[108] Hoffmann & Feige, "Evaluation of LNG Facilities for Aging" April 25, 2007

and city gate delivered supplies are subject to market volatility. If the Company were to attempt to replace the 291,200 Dth/day of Design Day supply with year-round pipeline capacity, the fixed costs of such a contract addition would exceed $100M/year, significantly increasing customer costs. For comparison, Kinder Morgan's TGP East 300 expansion project delivering 115,000 dt/day into Con Edison's territory was completed in 2023. That project rate of $0.98/dt for 115,000 dt/day of year-round capacity will result in over $41M of annual fixed demand charges.

6.4.2. Disadvantaged Communities

The following map depicts Disadvantaged Communities in the New York City area that are in and adjacent to the KEDNY service territory. From this map, it is evident that DACs are not limited to the KEDNY service territory and that addressing their concerns should be a citywide effort. Of the DACs shown, those that are dependent on the Greenpoint LNG plant to meet their Design Day demand have been shaded pink. Teal shaded DACs, some of which are outside of National Grid's service territory, do not directly depend on the output of the Greenpoint LNG plant for their gas service. Through the New York Facilities System, Greenpoint improves the service reliability for the areas in teal by improving reliability to the areas in pink. There are over 192,000 individual customer accounts within the pink DACs who depend on the Greenpoint LNG plant on a Design Day.

Figure 6-4: Disadvantaged Communities supplied by Greenpoint LNG Plant



The Greenpoint LNG plant air emissions are shown in the table below. Decommissioning the Greenpoint LNG plant would reduce localized pollutants in the surrounding Disadvantaged Communities.

Table 6-3: Greenpoint LNG Plant Air Emissions Data

Year	Methane (pounds)	VOC (short tons)	Nox (short tons)	CO (short tons)	CO_2 (short tons)	PM2.5 (short tons)	HAPS (short tons)	SO_2 (short tons)
2019	18	1.38	5.56	3.72	471.52	0.08	0	0
2020	9	0.23	2.76	0.78	230.44	0.04	0	0
2021	16	0.39	4.51	1.30	430.85	0.07	0	0
2022	20	0.30	3.59	1.13	530.96	0.06	0	0
2023	13	0.42	3.58	1.33	336.58	0.05	0	0
5 Year Average	15.2	0.54	4.00	1.65	400.07	0.06	0.00	0.00
Emissions calculated using fuel consumption and EPA emission factors								

6.5. Alternatives to Continued Reliance on the LNG Plant

Per the terms of the KEDNY-KEDLI Order, the Companies are required to "provide a specific Non-Pipeline Alternative or portfolio of NPAs, that could serve as alternatives, as compared to the costs of continued operation of the Greenpoint LNG Plant."[109] The sections below provide some context regarding the definition and use-cases of NPAs, conceptual supply-side and demand-side alternatives, some context regarding existing demand-side programs, a thorough description of the many substantial challenges and limitations to scaling demand-side programs to the degree necessary to serve as an alternative to the Greenpoint LNG Plant, and a specific hypothetical heat pump alternative.

6.5.1. Supply-Side Alternatives

Supply-side NPAs consist of alternate methods of ensuring reliable energy supplies to our customers and/or enhancing our service flexibility, such as utilization of alternative LNG technologies and CNG.

6.5.1.1. LNG Trailer Trucks

A supply side NPA that was considered to replace the 291,200 Dth/day that the Greenpoint LNG plant provides is LNG trailer trucks. This method, mirroring our Compressed Natural Gas injection sites, would allow for vaporizing LNG and injecting the vapor directly into the distribution system during peak demand periods. However, this alternative faces substantial regulatory hurdles, most notably New York City's stringent transportation regulations, which prohibit LNG transport in cargo tanks within city limits. Furthermore, the LNG transportation market would be challenged to support this from a tractor and trailer standpoint. The number of LNG trailers required to replace Greenpoint LNG volumes, as well as the around-the-clock operation, would fall outside of the Company's safety and reliability tolerances given our existing reliance on CNG trailers. Implementing this alternative would not be possible due to these constraints.

6.5.1.2. CNG Injection Stations

[109] KEDNY-KEDLI Order, Joint Proposal at Section 5.2.c.

Compared to LNG, CNG energy storage is comparatively limited due to its lower compressibility ratio (1/100 for CNG compared to 1/600 for LNG). In addition, LNG tanks can utilize vertical space in a way that CNG trailers cannot. These limitations necessitate a significantly larger footprint for CNG across our operational territory to match the energy storage and delivery capabilities provided by the Greenpoint LNG facility. The capacity of a CNG truck is shown in Table 6-5 below. Achieving the CNG energy storage equivalent to our LNG storage capacity of 1.6 Bcf requires approximately 4,000 trailer trucks, posing substantial logistical and environmental challenges.

A shift from LNG towards CNG would lead to increased CO2 emissions due to the number of trucks required for CNG transportation. For example, the roundtrip distance for a single CNG truck is approximately 400 miles from its origin, and 794 CNG trucks are required to match the 291,200 Dth/day capacity of the Greenpoint LNG plant. The cumulative transportation mileage would be over 300,000 miles of travel and would equate to CO2 emissions of 593 short tons for the transportation alone.

Converting the current Greenpoint LNG facility to a single CNG operation poses significant challenges. A minimum of 51 acres would be required for CNG decompression operations. Additional land is needed to efficiently and safely stage and operate 794 trucks within a 24-hour period. In addition, the existing LNG site cannot be retired, decommissioned, and demolished until the new CNG facility is constructed and operational. This would take several years to complete and precludes using the land the LNG plant is on for CNG operations.

As shown in Table 6-6, to match the vaporization capacity of the Greenpoint LNG facility there would need to be the equivalent of 17 CNG sites constructed. Since this would require more land than is available in Greenpoint, an extensive analysis would be required in order to inject CNG at the most needed points in the gas system. Not only would it be extremely difficult to find the land required for these CNG sites within the congested Brooklyn/Queens area, but that property would need to be located in a place where the proper gas infrastructure exists to move the CNG supplies to the demand on the system. As stated above, 794 CNG trucks would be required to supply the nominal daily sendout of 291,200 Dth/day. This would result in the need for all CNG trucking associated with this Greenpoint LNG alternative to be traveling through not just the neighborhood of Greenpoint, but potentially through multiple Disadvantaged Communities along the routes to multiple sites. This would not only be a logistical challenge and greatly increase traffic on both major roads and in these neighborhoods, but it would also place an unnecessary risk to the reliability of the system.

The Greenpoint LNG plant is often utilized on the coldest of days. The Company has determined that relying on such a large number of trucks and sites for CNG operations is not a feasible or viable option, especially if there are unsafe weather conditions. Additionally, the skilled workforce required to operate these trucks and CNG sites would be significantly higher than what is currently required to operate the Greenpoint LNG plant and is not currently available.

Table 6-4: Greenpoint LNG Capacity

Greenpoint LNG Storage and Vaporization Capacities		
Total LNG Storage Capacity	**1,680,000**	**Dth**
Vaporization Capacity	**291,200**	**Dth/day**

Table 6-5: CNG Storage and Sendout Capacity

CNG Storage and Sendout Capacities[110]		
Total Daily Sendout	17,600	Dth/day
Storage Capacity – 24 trucks	8,800	Dth
CNG Truck Capacity (not including heel)	367	Dth/truck
Total CNG Trucks per day	48	trucks/day

Table 6-6: CNG/LNG Comparison

CNG/LNG Comparison		
Number of CNG sites to meet vaporization capacity	17	Sites
Number of CNG trucks to meet daily vaporization capacity	794	trucks/day
Minimum required land area	51	Acres
Annual cost to operate CNG sites[111]	$ 1,700,000	per year
Cost to construct one CNG Injection Site[112]	$ 50,000,000	
Total Project Cost of CNG injection sites to replace Greenpoint LNG	$ 850,000,000	

6.5.2. Demand-Side Alternatives

6.5.2.1. Current Demand-Side Management Programs

Demand-side NPAs are not a solution or a technology in and of themselves, but rather a mechanism that makes use of one or more demand-side management solutions, namely energy efficiency, electrification of heat, and gas demand response. Those DSM solutions, which reduce the consumption of natural gas during peak times, are not brand new, but rather are already being implemented by National Grid and other state utilities and adopted by customers, reducing the consumption of natural gas during peak times. Therefore, when considering DSM solutions as potential alternatives to the Greenpoint LNG Plant, it is important to begin by considering the structure, history, current status, and future plans of those solutions in DNY.

First, in Downstate NY, heat pump programs are run by the local electric distribution companies, Con Edison, and PSEG-LI, rather than by National Grid. This means that, although National Grid does support heating electrification, primarily by referring customers who request new and upgraded gas service to the EDCs' heat pumps programs, the Companies do not control the primary levers that might accelerate the pace of electrification in DNY.

In addition, as discussed more extensively in Section 5.1, National Grid has been running energy efficiency and demand response programs for decades, and those programs have already served to dramatically reduce annual and peak gas consumption. Not only have those programs achieved real and substantial reductions in peak demand that have enabled the Companies to ensure the ability to provide safe and reliable service, but they have avoided the need to replace, repair, or construct additional gas infrastructure.

Lastly, the Companies' forecasts incorporate factors that are reasonably expected to occur, and because it is reasonable to assume that: (a) the Companies will continue to operate their energy efficiency and demand response programs into the future; and (b) the electric distribution utilities in DNY will continue to operate their heat pump programs into the future, those forecasts assume that,

[110] CNG injection sites are capable of a daily sendout of 17,600 Dth.
[111] Cost estimate based annual on O&M expenditure of Barrett CNG.
[112] Cost estimate based on Moreau CNG injection site.

as a result of those programs, demand will be lower in the future than it otherwise would be. Since the determination of the need for peaking supply options, such as the Greenpoint LNG Plant, is based upon its forecasts of future customer demand, it already incorporates the peak demand reductions provided by the DSM programs. Therefore, when considering whether DSM can serve as an alternative to the Greenpoint LNG Plant, the amounts of DSM that are already incorporated into the Companies' forecasts cannot contribute toward that hypothetical alternative; rather, the DSM that would need to be achieved would have to be incremental to the amounts already predicted by the forecasts to be achieved in future.

6.5.2.2. Impact of the NE:NY Interim Review

As described in Section 5.2.1 above, in the Interim Review that is currently taking place as part of statewide New Efficiency: New York proceeding, the July 2023 NE:NY Order directed the utilities to follow certain guidelines when submitting proposals for their energy efficiency and heat pump programs for the period between 2026 and 2030. Among those guidelines were: (a) a direction to offer only measures categorized as "Strategic" or "Neutral"; and (b) provisional annual budgets for each utility.

The criteria used to define whether measures qualify as Strategic or Neutral will have the effect of removing gas utilities' ability to incentivize high efficiency heating equipment (i.e., enabling customers to replace old inefficient boilers and furnaces with ones that operate much more efficiently), since such measures are categorized as Non-Strategic. The criteria will instead encourage utilities to pivot toward weatherization and building envelope measures (e.g., insulation, windows, air sealing), since those measures are categorized as Strategic. Because weatherization generally necessitates deep retrofits of customers' homes and businesses, weatherization measures are generally much more expensive to implement, on a per-unit-of-energy-saved basis, than measures that do not fit the Strategic/Neutral criteria. Put simply, because of the direction toward Strategic measures, each dollar spent on energy efficiency will result in lower annual and peak savings than it previously did.

When those higher per-unit costs are coupled with the provisional budgets established by the Commission's Order, the Companies will not be able to achieve the amounts of peak and annual savings reduction at the pace at which it has been achieving in recent years. However, the Companies will remain steadfastly focused on maximizing energy savings through our programs.

6.5.2.3. Electrification of Heat / Heat Pumps: Challenges and Limitations

The electrification of heat via the installation of ground-source and air-source heat pumps can yield substantial greenhouse gas emissions reductions, and the Companies believe that it is not only an essential component of the clean energy transition, but a prime method by which NY State will meet its clean energy goals. The Companies, in their UNY territories, will continue to operate and scale their heat pump programs under the statewide Clean Heat umbrella (more information on which can be found in section 5.1.2 above), and continue to support electrification in DNY by referring customers who request new and upgraded gas connections to Con Edison's and PSEG-LI's heat pump programs.

However, the Companies do not believe that the electrification of heat – either on its own, or in concert with other demand-side solutions – can serve as a viable replacement for the peak supply provided by the Greenpoint LNG Plant due to the following substantial challenges and limitations:

- *Only full displacement heat pump systems reduce peak demand, and customers are often reluctant to install such systems.* Although heat pump system configurations where the backup fossil fuel heating system is retained – sometimes called either "partial" or "hybrid" systems – can do much to reduce fossil fuel consumption during moderately cold weather, they do not necessarily reduce fuel consumption on very cold days, since customers (even those with integrated controls systems) often switch to their backup systems when the temperature drops precipitously. Only heat pump systems that fully displace a customer's backup gas heating system – what are sometimes referred to "full load heat pumps" or "non-hybrid heat pump systems" – reliably reduce peak gas demand. Con Edison has taken steps to address this by eliminating incentives for partial or hybrid heat pump systems and focusing instead on encouraging customers to decommission their gas heating equipment or disconnect from the gas system. This change in incentives may have an impact, albeit potentially a limited one, on persuading customers to adopt full displacement systems rather than hybrid heat pump systems. However, customers are often wary of abandoning their backup systems for a variety of reasons, such as efficiency losses during very cold temperatures (which can lead to high spikes in electric bills), improper sizing of heat pump systems, concerns about electric system outages, a preference for the comfort provided by their backup system, and/or a lack of faith in the ability of heat pumps to provide reliable heating at very cold temperatures.

- *The additional incentives required to encourage enough customers to adopt full displacement heat pumps will result in substantial cost increases for all ratepayers*. By the Companies' rough estimate, electrifying the 291,200 single-family homes necessary to replace the Greenpoint LNG Plant would cost almost $9.46 billion in incentives (not on a net present value basis). This dwarfs the amounts of program funding currently made available to Con Edison by the Commission, or even the amounts proposed by Con Edison as part of the Expanded Portfolio plan put forward in their January 2024 New Efficiency: New York Energy Efficiency and Building Electrification proposal.[113] Even if that $9.46 billion in funding were approved by the Public Service Commission, and even if potentially defrayed by non-ratepayers sources such as federal funding or Cap-and-Invest funds, it would result in substantial impacts to electric ratepayers throughout New York City.
- *Turnover of existing gas heating equipment is not fast enough to result in very rapid switching to full-displacement heat pump systems*. Only a small portion of all heating equipment typically reaches the end of useful life in a given year – by the Companies' estimate, approximately 4-8% each year.[114] Given that turnover rate, the amount of potential annual full-displacement heat pump conversions is small. One can imagine incentive structures that would encourage customers to consider early replacement – such as covering a very high percentage of the cost of a new full displacement heat pump system, or by subsidizing a customers' electric bills after they make the switch – but such an effort would have uncertain results and be exceedingly expensive, imposing huge costs on all ratepayers.
- *Switching to full displacement heat pumps can result in higher energy costs for customers*. Due to the relative costs of electricity and natural gas in Brooklyn and Queens, customers who fully electrify can face an increase in their total annual energy costs.[115] This may further dissuade customers, particularly LMI customers, from switching to heat pumps. This hurdle might be overcome via higher upfront incentive payments or even by subsidizing customers'

[113]Con Edison's Expanded Portfolio Plan includes approximately $1.2 billion for electrification for the 2026-30 period covered by the proposal. Note that that funding amount would support electrification throughout Con Edison's territory, not just the portion in Brooklyn and Queens that is served by the Greenpoint LNG Plant. See Case 18-M-0084, "Consolidated Edison Company of New York, Inc. Non-Low-and-Moderate Income Energy Efficiency and Building Electrification Portfolio Proposal Filing", p. 14, filed on January 12, 2024.
[114] "End of useful life", in this instance, refers to the point at which a heating system fails completely and/or when maintenance and repair costs are high enough to warrant a replacement of the full system or of its major components.
[115] For supporting evidence, see "New York Building Electrification and Decarbonization Costs", Rosen Consulting Group, June 2022, available at https://www.nyserda.ny.gov/-/media/Project/Climate/Files/2022-Comments/NY-Building-Electrification-Cost-Full-Report-June2022. ("Ongoing energy costs following electrification are more likely to increase for homes currently using gas", p. 2).

electricity bills, but such payments would have uncertain efficacy and would be exceedingly expensive to other ratepayers. In addition, many homes and buildings require weatherization before installation of a heat pump heating system in order to properly size the system and ensure functionality in cold weather. This can substantially increase the cost of converting to a full displacement heat pump system.

- *Challenges to contractor resourcing may continue.* It is uncertain whether the dramatic increase in the number of heat pump installations required to replace the Greenpoint LNG Plant could be met with a corresponding increase in the contractor workforce necessary to install and maintain them.
- *Cost increases from required electric distribution system upgrades to serve the additional peak load from heat pumps would increase costs for electric ratepayers.* When used for heating, heat pumps can cause dramatic increases in peak load, especially due to drops in heat pump efficiency, especially for air-source heat pumps, in extraordinarily cold temperatures.[116] As a result, dramatic increases in heat pump adoption will lead to correspondingly dramatic increases in winter peak load and thereby to large increases in the costs to build and maintain the infrastructure needed to serve that load. An exact cost for the infrastructure necessary to serve that additional peak load in the areas served by the Greenpoint LNG Plant is very challenging to estimate and would require detailed capital analysis by Con Edison.
- *Building the necessary electric distribution system infrastructure to serve the additional load in time will be logistically very challenging.* The ability to build the necessary infrastructure at the accelerated pace required to serve the increased load from heat pumps would need to be determined by Con Edison and other relevant stakeholders and could require significant adjustments to their capital planning. The Companies are rapidly seeking to scale their integrated energy planning capabilities, which will ideally enable better collaboration between the EDCs and the Companies in the downstate region and hopefully help facilitate that planning. Nevertheless, better planning will only do so much to mitigate the challenges of building the necessary electric distribution system infrastructure in time.
- *National Grid has limited ability to influence heat pump adoption in Downstate NY, since heat pump programs are administered by the electric rather than gas utilities.* As noted above, the Companies do not operate heat pump programs in Downstate NY; rather, the local EDCs, Con Edison, and PSEG-LI, currently have the regulatory authority to administer those programs and offer incentives to their customers. As such, the Companies have limited ability to directly influence the adoption of heat pumps by customers. The Companies encourage newly connecting customers to consider electric alternatives and refer them to their respective electric utility and encourage customers to explore electrification options as part of certain gas energy efficiency program marketing materials, consistent with terms of rate case Joint Proposals.
- *The number of heat pumps necessary would need to be incremental to the amounts embedded in the Companies' forecasts.* As noted in section 6.5.2.1 above, the Companies' forecasts, upon which the continued need for the peak supply provided by the Greenpoint LNG Plant are based, already incorporate expected peak demand reductions from heat pumps that are installed as a result of Con Edison's heat pump programs. Therefore, if heat pumps were to serve as a viable replacement for the peak supply provided by the Greenpoint LNG Plant – either on their own, or in concert with other demand-side solutions – the amount of heat pump installations required would need to be incremental in number to the numbers already assumed by the Companies' forecasts to occur in future.

[116] This is not to say the heat pumps do not work at all in cold temperatures – indeed, advances in technology have enabled cold-climate heat pumps to produce heat even at temperatures far below freezing. However, data shows that the high efficiency performance of heat pumps in cool to cold temperatures tends to drop significantly at temperatures far below freezing, such as those that would be experienced on a design day.

6.5.2.4. Energy Efficiency: Challenges and Limitations

Energy efficiency has been, and will continue to be, an essential component of the clean energy transition and a prime method by which the state will meet its clean energy goals. As detailed further in section 5.1.1, the Companies have dramatically scaled the amount of energy efficiency savings provided by customers, and its programs have consistently been ranked highly by the ACEEE ("American Council for an Energy-Efficient Economy"). And although it is typically thought of as a means of reducing energy consumption throughout the year, energy efficiency also has the impact of reducing peak gas demand. Customers who weatherize their homes, for example, will likely reduce the amount of energy (whether gas or electricity) required to heat those homes on very cold days.

However, as with heat pumps, there are substantial limitations to the ability of energy efficiency to scale to the extent, and at the pace, needed to reduce peak demand enough to replace the Greenpoint LNG Plant, either on its own or in concert with other demand-side solutions. Those include:

- *Weatherization and other deep energy efficiency retrofits are relatively expensive.* As noted above, the Commission has issued guidance that all utilities should shift their portfolios away from measures classified as "Non-Strategic" (such as gas furnace and boiler replacements) and toward measures classified as "Strategic" (including weatherization). Although the Companies agree that weatherization is a vital tool in reducing annual and peak demand and helps make homes electrification-ready, it is much more expensive on a per-unit of energy saved basis than other energy efficiency measures. This is due to several factors, including the high cost of some of the materials involved (namely insulation) and the intensive nature of the work (which can often involve time-consuming work in attics and crawl spaces). Building envelope incentive programs are also more costly to administer because the upgrades and energy savings must be planned and calculated specific to each home or building.
- *Customer willingness to install deep retrofits may not be high enough to enable dramatically increased levels of participation*. Although customers reap multiple benefits from weatherization (lower energy costs, greater comfort, the ability to install heat pump systems that are smaller in size), it can also be a daunting undertaking due to the high upfront cost (see above) as well as to the intensive nature of the work, which may, depending on the physical structure and condition of the facility/home, involve a fair amount of disruption to residents and tenants. Given these barriers, customer appetite to participate may not be high enough to enable energy efficiency to serve as a viable alternative.
- *Energy efficiency results in relatively lower amounts of peak reductions per project/installation than heat pumps*. Whereas the installation of a non-hybrid heat pump system can eliminate a customer's peak gas consumption, energy efficiency only reduces a portion of an existing customer's peak gas consumption. For example, a typical single-family home utilizes on average 1 Dth/day on a Design Day: switching to full displacement heat pumps eliminates that peak gas demand, but weatherization only reduces peak demand by a portion of that amount. As a result, the potential for energy efficiency to provide peak gas reductions, as compared to the installation of non-hybrid heat pump systems that replace gas heating equipment, is relatively small.
- *Challenges to contractor resourcing may continue.* As the Companies experienced when launching their weatherization programs in Downstate NY, growing the contractor base for weatherization took time and concerted effort. It is uncertain whether the dramatic increase in the amount of weatherization required to replace the Greenpoint LNG Plant partially or fully could be met with a corresponding scaling of the contractor workforce necessary to install that weatherization.
- *The amount of energy efficiency necessary would need to be incremental to the amounts embedded in the Companies' forecasts*. As noted in section 6.5.2.1 above, the Companies' forecasts, upon which the continued need for the peak supply provided by the Greenpoint

LNG Plant are based, already incorporate expected peak demand reductions from energy efficiency achieved via the Companies' NE:NY programs. Therefore, if energy efficiency was to serve as a viable replacement for the peak supply provided by the Greenpoint LNG Plant – either on its own, or in concert with other demand-side solutions – the energy efficiency that would need to be achieved would need to be incremental to the amounts already assumed by the Companies' forecasts to occur in future.

6.5.2.5. Gas Demand Response: Challenges and Limitations

As described in Section 5.1.3 above, the Companies' gas demand response programs are peerless in the United States and have become an important resource to ensuring safe and reliable service during extremely cold, high demand periods. However, as with heat pumps and energy efficiency, gas DR faces substantial limitations that prevent it from being a feasible alternative to the Greenpoint LNG Plant, either on its own or in concert with other demand-side solutions. They include:

- Gas demand response has limited technical and market potential. The prime source of peak reductions from the Companies' portfolio of gas DR programs derives from its Load Shedding program, which incentivizes customers to cease use of gas partially or completely during dispatch events, with most customers responding by switching to backup fuel source (typically fuel oil). However, the pool of customers who have the equipment and the capability to do so is limited. The Companies' experience in the market shows that they have, to date, enrolled the majority of the large customers in Brooklyn and Queens who will be willing to participate, and that the remaining potential enrollees are smaller in size, which limits potential growth. Although the other programs in the gas DR portfolio – namely Load Shifting and its residential program, BYOT – still have growth potential, the peak reduction potential of each customer who enrolls in those programs is much smaller than the typical customer enrolled in the Load Shedding program. As a result, the technical potential of gas DR is small relative to the size of the Greenpoint facility.
- While gas DR programs provide reliability benefits and are capable of being dispatched on short notice, program rules limit the duration of Gas DR events. The Load Shedding program can be dispatched for up to 8 hours per gas day, while the Load Shifting and BYOT programs are limited to 4 hours per gas day. The flexibility provided by the Greenpoint LNG Plant, which can vaporize gas for 24 hours over 5 straight days, cannot be fully replaced by the Gas DR programs as currently constructed.
- The amount of demand response necessary would need to be incremental to the amounts embedded in the Companies' forecasts. As noted in section 6.5.2.1 above, the Companies' forecasts, upon which the continued need for the peak supply provided by the Greenpoint LNG Plant are based, already incorporated expected peak demand reductions from gas demand response.[117] Therefore, if demand response were to serve as a viable replacement for the peak supply provided by the Greenpoint LNG Plant – either on its own, or in concert with other demand-side solutions – the amounts of demand response capacity that would need to be achieved would have to be incremental to the amounts already assumed by the Companies' forecasts to occur in future.

6.5.2.6. Renewable Natural Gas and Clean Hydrogen Blending

RNG and hydrogen blending present a promising supply-side alternative to traditional LNG facilities, potentially mitigating their environmental impact and reliance on fossil-derived natural gas. The integration of RNG and hydrogen into the natural gas network could significantly reduce the demand

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[117] The amounts of gas DR embedded in the Companies' forecasts have grown over the past several years as continued experience with gas DR has increased their faith in its reliability as a peak demand reduction resource.

for LNG by providing a greener, sustainable alternative that aligns with global decarbonization goals. This approach not only contributes to reducing the environmental impact of heating and power generation but also enhances energy security by diversifying the gas supply with domestically produced renewable sources. Moreover, as technologies and infrastructures evolve, the level of hydrogen blending could increase, offering a pathway to a more sustainable and low-carbon energy future. This strategy, however, requires careful consideration of technical, economic, and regulatory factors to ensure safety, efficiency, and compatibility with existing systems while fostering the transition towards greener energy solutions.

The Company has begun the process of injecting RNG into the system, marking an important step towards integrating more sustainable energy sources. While the current scale of RNG and hydrogen (H_2) production does not yet suffice to replace the need for LNG facilities, the potential for future expansion holds promise. This transition towards RNG and hydrogen blending not only aligns with the Company's environmental goals by reducing carbon emissions but also enhances energy security through the diversification of energy sources. As the Company continues to explore and expand its procurement strategies for these greener alternatives, the long-term vision includes a substantial reduction in the need for traditional LNG, paving the way for a more sustainable and low-carbon energy infrastructure.

6.5.2.7. Alternative Supply and On-System Infrastructure

An additional alternative that could potentially be used to offset the 291,200 Dth/day provided by the Greenpoint LNG facility is additional pipeline supply, but current supply point constraints make this challenging. On-system infrastructure may also be required to move supplies to the necessary locations. The only existing supply point with the potential to deliver sufficient supplies on the Design Day is the Floyd Bennett Field supply point and it would require a substantial Transco expansion project to bring the necessary supply volumes to this point. The Greenpoint lateral, which is the gas main connecting the GEC to the gas network in Brooklyn/Queens, is significantly undersized to meet Design Day system demands if the Greenpoint LNG vaporizers are not in-service. The additional infrastructure required to meet customer demand could be up to 2 miles of 30-inch transmission main to address the incremental flow requirements to the GEC that a lack of any vaporization capability would cause.

6.6. Hypothetical Alternative: Full Building Electrification + Weatherization as a Substitute for the Greenpoint LNG Plant

Below, National Grid presents a hypothetical case under which demand-side management – namely a combination of energy efficiency and the full-displacement electrification of customers – serves as an alternative to, or replacement for, the Greenpoint LNG Plant by the year 2035.[118] Although infeasible, assuming this is achieved, this would then allow for the process of fully decommissioning the Greenpoint LNG Plant by 2044. We describe the assumptions necessary to be made to support the case and provide an estimate of the cost to implement the hypothetical alternative. *It is vital to note that this scenario is purely hypothetical. Given the substantial limitations and challenges of achieving this scenario, the Companies believe that this scenario is not feasible. Moreover, even if it were feasible, it would not be advisable to pursue since the magnitude of the resulting costs would impose a substantial cost burden on ratepayers.*

While the case examines replacing the Design Day supply provided by the Greenpoint LNG Plant as discussed in section 6.2.1, from an operational perspective the Greenpoint LNG Plant provides a

[118] Given the limited technical potential of gas demand response described above, which means that the amounts it could feasibly provide that are incremental to the amounts already included in the Companies' forecasts, the Companies chose to exclude it from this scenario.

level of gas system reliability that simply cannot be replaced by reducing demand to an equivalent level, which was discussed in section 6.2.2.

As seen in Table 6-7 below, the Companies estimate that approximately 291,200 single-family homes would need to be fully electrified in order to reduce Design Day demand to a level equivalent to the supply provided by the Greenpoint LNG Plant based on the approximation that a residential heating customer uses one dekatherm of gas on a Design Day. Multifamily buildings have not been included in this analysis, since those facilities are variable in their usage and since the Companies do not collect data on the number of units in multifamily customer buildings. However, it safe to assume that the peak usage of each multifamily unit is lower than that of a single-family home, and that therefore including those in this analysis would mean that the number of total housing units that would need to be fully electrified would be much higher. Given the much higher cost of fully electrifying multifamily buildings, including them in this scenario is likely to increase the total cost by a substantial amount.

Table 6-7 below demonstrates that, using an estimated 7% annual heating equipment turnover rate, and if all customers whose equipment reaches end of life fully electrify their homes, the hypothetical number of customers who could be fully electrified annually is about 36,120. This is about 12 times the number of customers fully electrified by Con Edison in 2023. It is important to note that, absent a new legislative mandate that requires customers in existing buildings to fully electrify, it is highly unlikely that every single customer will choose to do so, even if the entire cost of their projects is incentivized by utility or state programs for the reasons described in section 6.5.2.2.

Table 6-7: Full Building Electrification Customer Count

Full Building Electrification Customer Count			
(a)	Total Number of Residential Heating Customers in National Grid's service territory in Brooklyn & Queens (rounded)	516,000	
(b)	Estimated annual heating equipment turnover rate	7%	
I	Maximum Number of Potential Residential Customer Full Electrifications per year (rounded)	36,120	(a) x (b)
(d)	Number of Full Residential Heat Pump Conversions incentivized by Con Edison's Clean Heat program in National Grid's service territory in Brooklyn and Queens, 2023	3,060	
(e)	**Approximated increase in Annual Achievement Rate of Con Edison's Clean Heat program in National Grid's service territory in Brooklyn and Queens to electrify every customer whose heating equipment turns over each year**	**1I**(c) ÷ (d)	
(f)	Design Day Demand Reductions Required to Replace the Supply provided by Greenpoint LNG (Dth/day)	291,200	
(g)	Approximate Average Design Day gas demand per Single-Family Residential customer (Dth/day)	1.0	
(h)	**Number of Single-Family Residential Heating Customers that would need to fully electrify to reduce demand to a level necessary to replace the supply provided by the Greenpoint LNG plant**	**291,200**	(f) ÷ (g)

Table 6-8 below provides an estimate of project costs for full electrification of customers. It presumes that all customers will replace their space heating system, water heating system, and stoves with equipment that operates solely on electricity. It presents several project types; (1) Full electrification; (2) Full electrification with weatherization; (3) Full electrification with weatherization, and subsidization of increased electrical costs (for customers in Disadvantaged Communities); and (4) Full electrification with weatherization, subsidization of increased electrical costs, and mitigation of health and safety barriers to weatherization (for customers in Disadvantaged Communities).

Table 6-8: Energy Efficiency and Electrification Project Cost Estimates[119]

Energy Efficiency & Electrification Project Cost Estimates			
(a)	Average Cost: Residential Heat Pump Project	$14,693	Based on CAC IA – Annex 1
(b)	Average Cost: Heat Pump Water Heater	$3,267	Based on CAC IA – AnnI1
(c)	Average Cost: Induction Cooktop	$407	Based on CAC IA – Annex 1
(d)	Average Cost: Electric Clothes Drying	$770	Based on CAC IA – Iex 1
(e)	**Total Estimated Cost per Non-DAC Customer, without Weatherization**	$19,137	(a) + (b) + (c) + (d)
(f)	Average Cost: Residential Weatherization Project	$8,750	Program Evaluation Study
(g)	**Total Estimated Cost per Non-DAC Customer, with Weatherization**	**$27,887**	(e) + (f)
(h)	Estimated annual increase in total customer energy bills due to conversion to electrification	$970	Based on Avg Utility Rates
(i)	Average effective useful life of heat pump systems, years	15	
(j)	Estimated increase in total customer energy bills over lifetime of heat pump systems	$14,543	(h) × (i)
(k)	**Total Estimated Costs per DAC customer, without Health and Safety barrier removal**	**$42,430**	**(g) + (j)**
(l)	Average cost, health & safety barrier removal project	$3,011	Average of lower cost projects from 1-4 Family H&S Equity Plan Pilot
(m)	**Total Estimated Costs per DAC customer, with Health and Safety barrier removal**	**$45,441**	**(k) + (l)**

Table 6-9 below provides a very broad estimate of the costs to fully electrify, by the end 2035, the number of customers necessary to reduce Design Day demand to levels equivalent to the amount of Design Day supply provided by the Greenpoint LNG Plant. It assumes that Con Edison increases its annual number of heat pump installations with decommissioning at annual rate of 47%, thereby increasing from the current amount of 3,060 to the theoretical maximum of 36,121 by 2029. It also assumes that 50% of all customers not located in DACs perform weatherization alongside electrification, that all customers in DACs weatherize, and that 50% of those customers require the removal of health and safety barriers in order to proceed forward with weatherization. It utilizes those assumptions, along with the per-project cost estimates in Table 6-8 above, to arrive at a total estimated all-in cost of $9.46 billion over a 12-year time span.

[119] (1) Assumes that for a customer that is not in a DAC, the upfront costs would need to be covered by the incentive. Does not include any costs required outside of material and labor for the project (i.e., necessary electrical upgrades) and the customer understands and accepts their utility bills increasing post-installation. (2) Assumes that for a customer within a DAC, barriers to the project must be removed, all up front project costs would need to be covered by the incentive plus the costs to offset the resulting higher utility costs associated with electric heating in KEDNY. (3) Cost estimates are for an average residential heating customer. Based on CAC IA - Annex 1 Data from previously completed CLCPA Study. (4) Assuming adequate levels of workforce, supply chain processing speeds, electrical grid capacity, etc. (5) Given the significant size and scale of this hypothetical NPA, the installation of solar and storage systems may be needed for safe and reliable service for some or all of these customers. Solar and storage on the electric side could be considered analogous to Greenpoint on the natural gas side. For the purposes of this exercise, solar and storage costs were not included.

Table 6-9: Full Building Electrification Comparison

Full Building Electrification Comparison								
	A	B	C	D	E	F	G	H
Year	Annual # of Customers	Cumulative # of Customers	Percent of Max	% Non-DAC with Wx	% of DAC with H&S	Non-DAC Est. Annual Cost ($M):	DAC Est. Annual Cost ($M):	Estimated Total Annual Costs ($M):
2024	3,060	3,060	8%	50%	50%	$40	$59	$99
2025	4,506	7,566	12%	50%	50%	$58	$87	$146
2026	6,635	14,200	18%	50%	50%	$86	$128	$216
2027	9,769	23,970	27%	50%	50%	$126	$189	$317
2028	14,385	38,355	40%	50%	50%	$186	$278	$467
2029	36,121	74,475	100%	50%	50%	$467	$698	$1,174
2030	36,121	110,596	100%	50%	50%	$467	$698	$1,174
2031	36,121	146,717	100%	50%	50%	$467	$698	$1,174
2032	36,121	182,838	100%	50%	50%	$467	$698	$1,174
2033	36,121	218,958	100%	50%	50%	$467	$698	$1,174
2034	36,121	255,079	100%	50%	50%	$467	$698	$1,174
2035	36,121	291,200	100%	50%	50%	$467	$698	$1,174
Total Cost of Full Building Electrification DSM to replace Greenpoint LNG ($M)								**$9,463**

Notes:

1) Assumes current number of residential electrification projects and an increase significantly year over year until reaching the maximum number of annual residential customer electrifications (7% of Residential Customers). This maximum is considered based on natural replacement cycles.

2) Final Disadvantaged Community (DAC) Criteria for the New York City Region is 44% DAC

3) Wx = Weatherization, Column D represents assumed percent of projects for Non-DAC customers that require weatherization as part of their project. It's assumed that all projects within a DAC will benefit from weatherization improvements prior to electrification.

4) F = [A*55%*(Non-DAC)+A*55%*(1-D)*(Non-DAC+Wx)] / 1,000,000

5) G = [A*45%*(DAC+Wx)+A*45%*(1-E)*(DAC+Wx+H&S)] / 1,000,000

6) H = F + G

The resulting figure of $9.46 billion is not presented on an NPV basis. Additionally, it does not consider the necessary costs of upgrading or installing new electrical distribution infrastructure on Con Edison's electrical distribution system in order to accommodate the increased load from electrification.

For a point of useful comparison, the Public Service Commission has set an annual budget of $1 billion for all energy efficiency and building electrification programs across the entire state for the years 2026-2030 within its recent July 2023 NE:NY Order. Therefore, achieving this scenario would mean that the Public Service Commission would need to more than double that annual funding for those programs, and that it would need to allocate the entirety of that funding exclusively for programs in Brooklyn and Queens. Moreover, any building electrification or energy efficiency that would need to be installed to reduce demand to the degree necessary to reduce Design Day demand to a level equivalent to the supply provided by the Greenpoint LNG Plant would need to be incremental to the amounts already forecasted to be installed under Con Edison's building electrification programs and National Grid's weatherization programs.

Table 6-10 provides additional details around assumptions made in developing this hypothetical scenario.

Table 6-10: Full Building Electrification Hypothetical Scenario Assumptions

Assumptions	Notes
Natural gas heating equipment turns over at 7% per year	Available data suggests turnover rates in the range of 4 to 8% per year.
Every customer replaces their gas heating equipment that reaches the end of its useful life with full load electric heat pump systems with decommissioning. They also replace all other gas appliances, namely gas stoves and water heaters, with electric alternatives, namely induction cooktops and heat pump water heaters.	Even if all customers pay no cost for the significant upgrades included within this scenario, there will likely be a portion of customers who would be eligible that simply do not chose to participate. Therefore, for this assumption to be true, it would require a legislative mandate disallowing existing customers from replacing existing gas heating systems with anything other than electric systems. Although New York Local Law 147 requires full electrification for specific types of new construction projects, it does not do so for existing buildings, and thus this would be an entirely new legislative mandate that has not been proposed to date.
Customers in DACs receive additional incentives to cover the cost of remediation of health and safety barriers to weatherization.	National Grid's experience with its weatherization projects in Downstate NY has shown that health and safety remediation (e.g., of asbestos, mold, and other hazards) is often necessary to complete weatherization, particularly in Disadvantaged Communities where housing stock can be older and/or more poorly maintained and updated. However, there is little reliable data on how often such remediation is required or how extensive the necessary remediation efforts are. Per-project health and safety remediation costs can range from hundreds of dollars to upwards of $90,000.
Number of projects per year must increase over 47% year over year to ramp up to total maximum number of projects by 2029	Although not impossible, it is unknown whether this level of acceleration is feasible. Con Edison's current heat pump program experienced a 23% decrease in number of full load heat pump projects with decommissioning between 2022 and 2023.
In order to ensure backup reliability, each electrifying customer is provided incentives that cover the full costs of solar and battery storage.	One of the highest concerns of customers who do not want to electrify is system reliability and concern of service outages. To overcome that obstacle, the installation of an interruptible backup power supply, namely battery storage supplied by on-site solar, may be required. Although feasible in single-family homes, there are numerous technical challenges involved

	with ensuring that each customer would have reliable service and electrical capacity to meet need at any given time.
Contractor base matures quickly enough to serve the increased number of energy efficiency, weatherization, heat pump and solar and storage system installations.	This assumption is tenuous. As detailed in numerous publications in the general press, sourcing the workforce necessary to meet national and state heat pump and energy efficiency goals has proven challenging in recent years. It is uncertain whether that workforce will scale even further, and quickly enough, to support the number and pace of heat pump and weatherization installations necessary to achieve this scenario.
Manufacturers and distributors are able to supply enough heat pumps and materials to meet scenario installation targets.	This assumption is not unreasonable, but the COVID-19 pandemic has nevertheless had significant long-lasting negative impacts on availability of materials for projects that could persist into the future.
The EDC is approved for the funding necessary to accelerate the pace of construction of new and upgraded electric distribution infrastructure necessary to meet the increased peak load from the substantially increased number of heat pump installations contemplated by this scenario.	Although utilities, regulators, and stakeholders are well aware of the impending dramatic increases in peak load associated with electrification and of the necessary infrastructure upgrades needed to accommodate it, this scenario contemplates an increase in peak load that is beyond what has been contemplated to date. It cannot be said with any reasonable degree of certainty that the EDC would receive approval of the necessary funding.
The EDC is able to keep pace with the construction of new and upgraded infrastructure necessary to accommodate load added by heat pumps.	The scale and scope of the infrastructure buildout would be significant, and it is unclear whether Con Edison would be able to build that infrastructure in the timeframe necessary to enable this scenario.

6.6.1. BCA Analysis of Hypothetical Greenpoint LNG Alternative

In accordance with the State of New York Public Service Commission Order Adopting Gas System Planning Process and consistent with the Climate Leadership and Community Protection Act (CLCPA), National Grid has developed and applied a benefit-cost analysis (BCA) to the hypothetical alternative of Full Building Electrification + Weatherization as a Substitute for the Greenpoint LNG Plant, adopting the methodology established in the BCA Framework Order.

This BCA follows the same framework used throughout the LTP, as described in Section 7.4.1. This BCA compares the benefits accrued to customers, the electric and gas systems, and society through time to the estimated costs of electric and gas system investments, program costs, customer-side investments, and other societal costs captured by the existing BCA framework. As with the broader LTP, this analysis utilizes the Societal Cost Test (SCT) as the primary BCA method, which takes the holistic perspective of society. The SCT incorporates costs and benefits related to both gas and electric systems, as well as the societal value of greenhouse gas emissions, including carbon dioxide, nitrous oxide, and methane.

The BCA for this hypothetical alternative includes as a benefit the avoided gas infrastructure revenue requirement associated with avoiding investments in the GEC site otherwise planned through 2050, net an assumed $75 million cost in 2035 to decommission the site. Note that this BCA does not include the cost of site remediation, which may cost an additional $100-$300 million over several years. This BCA also includes as benefits the avoided gas supply costs and avoided GHG emissions associated with electrification of gas load. The costs include gas and non-gas utility administrative spending, as well as customer incremental technology costs from energy efficiency and electrification. Increases in electric consumption and demand from electrification are also considered a cost in this test. Utility customer incentives are considered a transfer payment and are excluded from this test. Non-energy benefits, such as comfort and reductions in bill arrearages, were not considered due to their difficulty in valuation. Finally, this analysis also did not quantify potential changes in the reliability or resiliency of energy service.

The BCA for this hypothetical alternative, relative to the Reference Case scenario, is shown in Table 6-11, where monetary values are shown in 2025 dollars. The SCT benefit-to-cost ratio is 0.41, with a net present value cost of $12B. This indicates that the considerable benefits from avoided gas system investments and GHG savings that could be attained by decommissioning the LNG Plant starting in 2035 are significantly less than the added costs to customers to electrify and to the electric grid to accommodate the additional electric demand during winter peak periods.

Table 6-11: Societal Cost Test for KEDNY of Decommissioning Greenpoint LNG Plant Beginning in 2035

Benefit or Cost Category	Full Building Electrification + Weatherization as a Substitute for GEC ($M)
Avoided Gas Supply	$1,872
Avoided Gas Infrastructure Revenue Requirement	-$196
Avoided GHG Emissions from Gas Combustion	$6,997
Total PV Benefits	**$8,673**
Added Future of Heat Infrastructure Revenue Requirement	-$165
Increased Electricity Consumption	$2,408
Increased Electric Capacity	$14,178
Increased GHG Emission from Electricity	$209
Incremental Participant Cost	$4,197
Electric Utility Admin	$83
Total PV Costs	**$20,910**
NPV	**-$12,237**
SCT Ratio	**0.41**

6.6.2. Bill Impacts of Hypothetical Greenpoint LNG Alternative

In this analysis, the Company conducted an assessment to evaluate the potential impact of our customers' bills resulting from the decommissioning of the Greenpoint LNG plant. This assessment specifically considers the hypothetical scenario of adopting an alternative approach centered around heat pumps, assuming that all relevant assumptions are met. *It is important to note that this is a hypothetical scenario, and the Company does not believe decommissioning the Greenpoint LNG plant through this alternative approach is feasible due to the substantial limitations and challenges.*

Table 6-12 below presents the total average monthly bill impact estimates if the Greenpoint LNG plant were decommissioned in 2035 for residential, commercial, and multi-family service classifications (“SC”) using the representative costs and customer usage profiles in the Reference Case excluding the 291,200 residential customers that would hypothetically be converting to heat pumps.

Table 6-12: Average Monthly Total Bill Estimate for Hypothetical Heat Pump Scenario

	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$168	$738	$504	$1,623
2030	$283	$1,125	$742	$2,304
2035	$468	$1,360	$898	$2,730
2040	$563	$1,591	$1,051	$3,152
2045	$636	$1,821	$1,204	$3,560
2050	$677	$1,948	$1,284	$3,752

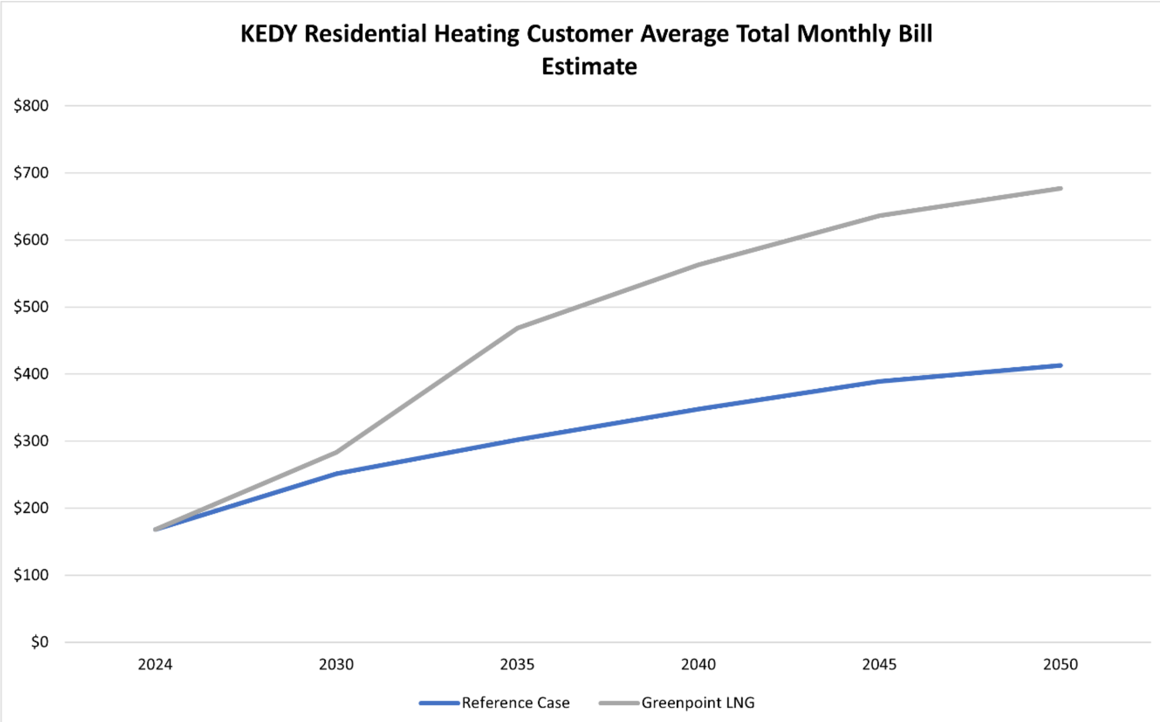
The actual usage of customers regardless of service class can and will vary. The bill impacts shown above indicate an increase in customer costs in all service classes if the Greenpoint LNG plant were to be decommissioned.

Table 6-13 and Figure 6-5 below show the increase in residential heating customer's total average monthly bill in our reference case scenario compared to the percent increase projected if Greenpoint LNG were to be retired.

Table 6-13: KEDNY Residential Heating Customer Average Total Monthly Bills Estimate

Year	Reference Case	Greenpoint LNG	% Increase
2024	$168	$168	0%
2030	$251	$283	13%
2035	$302	$468	55%
2040	$348	$563	62%
2045	$389	$636	63%
2050	$413	$677	64%

Figure 6-5: KEDNY Residential Heating Customer Average Total Monthly Bills Estimate



Compared to the Reference Case, residential bills in KEDNY will see a bill increase of 63% by 2050 without the continued use of the Greenpoint LNG Plant. These increases in customer costs are likely unsustainable for many customers, especially those within the DACs that we serve. It is also important to note that this bill impact analysis does not reflect the expected massive unquantified bill increases for electric utility customers to support the new incentives and infrastructure upgrades.

6.7. Key Risks

6.7.1. Continued Operation of Greenpoint LNG Plant and Potential Failures

The LNG plant is divided into several systems, with each system playing an integral part in the facility's operations. The LNG plant's systems are interdependent, so a failure in one system can have a cascading effect on other systems. Redundant designs, comprehensive maintenance programs, and continued capital investments can help ensure the plant functioning properly.

Equipment failure impacts the overall system, but redundancy is planned in the system's design. For example, installed at the plant are spare LNG pumps, boiloff compressors, and vaporizers. Investment in new and replacement equipment is required to ensure continued reliability.

- Vaporizers are critical to the operation of the facility and are normally operated on short notice as conditions can change rapidly during peak winter season. For this reason, the plant is outfitted with an "installed spare" for high pressure vaporization to enable the operation of spare equipment without the need to disassemble and reassemble complex equipment such as LNG pumps and vaporizers in a short time frame. The Vaporizer 13 & 14 project would establish a low pressure installed spare.
- Should the liquefaction system experience a failure that requires a long period of time to repair, the plant has been equipped with an LNG truck unloading station to allow LNG from

other National Grid plants to be transported to the Greenpoint LNG plant and unloaded. Any trucking through New York City would require special permission from the City which could only occur in a depleted LNG tank inventory system emergency. It is important to note as previously mentioned in section 6.5.1.1, LNG trucking faces substantial regulatory hurdles due to New York City's stringent transportation regulations, which prohibit LNG transport in cargo tanks within city limits.

- Electric power is derived from separate Con Edison circuits with a dedicated substation in addition to the plant’s three emergency generators.

The following capital projects highlight the importance of ensuring reliability service for the Greenpoint LNG plant.

Tank 2 Foundation Heaters Upgrade:

- Assessment and analysis found the existing foundation heater system is not providing sufficient heat beneath the LNG tank. The lack of heat beneath the tank foundation will increase the risk of frost heave. This risk of can unsettle the foundation and damage the LNG storage tank. The project will install a new heating system to ensure sufficient heat is provided.

High Pressure (350 PSIG) LNG Vaporizers 7 & 8 Refurbishment:

- Vaporizers 7 & 8, installed in the 1980s, are showing signs of age through a recent assessment. An evaluation of the existing vaporizers is required to ensure continued reliable service.

6.7.2. Potential Failures of Alternatives

As discussed in section 6.5.1.2, replacing the Greenpoint LNG facility with a CNG equivalent would require significant infrastructure improvements. To achieve the same daily sendout rate (291,200 Dth/day) of Greenpoint LNG, there would need to be significant infrastructure installed and land acquired for this equipment throughout the Brooklyn/Queens area in order to install 17 CNG Injection Stations. This would equate to a minimum of 51 acres of land with an estimated construction cost of $850,000,000[120]. In addition, nearly 800 trucks would be required to mobilize during a potential winter cold weather event. National Grid already requires over 200 CNG trailers to be delivered to KEDLI on a forecasted Design Day, which we believe is the largest, most complex CNG operation in the country. This CNG option is not feasible. The Company is uncertain about the trucking, compression, and supply providers to meet this level of demand for CNG deliveries. Even if CNG suppliers were able to deliver the quantities of trailers required at these additional sites, transporting that quantity of CNG and the number of trucks on the roads during peak winter conditions (e.g., ice, snow, high winds, bridge and road closures) would unnecessarily increase the risks associated with delivering gas to our customers on the most critical days. A trucked LNG solution would be associated with the same risks.

Regarding the RNG/H_2 alternative discussed in section 6.5.2, a similar comprehensive build-out of upstream infrastructure is necessary. This expansion includes the development of facilities for the production, processing, and transport of RNG from organic waste sources, as well as the establishment of electrolysis plants for hydrogen production, which requires substantial investments in renewable energy sources like wind or solar power. Moreover, the creation of a robust distribution network capable of blending and delivering RNG and hydrogen to the existing natural gas grid is critical.

[120] Cost estimate based on Moreau CNG Injection site.

The realization of this infrastructure is heavily influenced by market dynamics, including supply and demand fluctuations, technological advancements, policy incentives, and the overall economic viability of renewable and clean energy sources. As the market for RNG and hydrogen matures, it will necessitate regulatory support, financial incentives, and a concerted effort from both the public and private sectors to overcome the initial high costs and technical challenges associated with renewable energy infrastructure.

Furthermore, scaling up RNG and hydrogen production to levels that can significantly offset the demand for LNG also hinges on the development of end-use technologies compatible with higher blends of hydrogen and the establishment of safety standards and regulations governing the production, storage, and distribution of these gases. As these elements align with the growing imperative for cleaner energy solutions, the transition away from LNG dependency towards a more sustainable energy future becomes increasingly feasible. However, present conditions do not allow for serious consideration of RNG and hydrogen as alternatives to the GEC.

As detailed thoroughly in Sections 6.5.2 and 6.6, the barriers to scaling demand-side solutions to the level equivalent to the peak supply provided by the Greenpoint LNG Plant in the timeframe necessary are real and substantial. Such scaling would be monumentally expensive and would be contingent on overcoming a variety of barriers and obstacles such as the challenge of gaining customer acceptance to meet the required rate of heat pump adoption established in the hypothetical electrification alternative in section 6.6, the likelihood of which is low. Furthermore, a demand-side solution would not provide the reliability benefits provided by the Greenpoint LNG Plant, the challenges of which are discussed in Section 6.5.2.3.

6.7.3. Risk of Moratorium

The loss of the Greenpoint LNG plant without a replacement would require an immediate need to declare a moratorium on new gas connections in Brooklyn and Queens, if not all of Downstate NY. However, it is critical to recognize that our *existing* customers are relying on the GEC; a moratorium would substantially reduce *growth*, but it would not impact current Design Day demand. Therefore, a moratorium would not replace the LNG depended upon by our Downstate NY customers.

Using the June 2023 requirements forecast, the supply shortfall without the Greenpoint LNG volumes on a Design Day would be significant and insurmountable in the short-term. Figure 6-3 plots the current supply portfolio (less Greenpoint LNG), including the addition of the Iroquois ExC Project volume of 62,500 Dth/day, against forecasted requirements out to 2050. Note that the Iroquois ExC Project is not in service and the timing of when the project may be put into service is uncertain.

6.7.4. Risk of Curtailment of Firm Gas Customers

Without the Greenpoint LNG plant, the risk of curtailment of firm customers would be extremely high if actual weather was at or near Design Day conditions. The equivalent of up to 291,200 residential heating customers would need to be curtailed if the Greenpoint LNG plant were non-operational. In this instance, if firm customers were not proactively curtailed, pressures would drop below safe, minimum levels causing both widespread and dispersed customer outages. This could cause health implications due to loss of heating, hot water, and cooking, up to and including loss of life as well as significant damage to property (e.g., burst pipes). Should the Company experience a pipeline disruption event like Winter Storm Elliott (see section 4.2.1), curtailment of firm customer load would be required at warmer than Design Day conditions. Without the on-system flexibility of Greenpoint LNG, the Company would be forced to overtake from pipelines in order to mitigate unplanned supply disruptions. Pipelines, in turn, could exercise rights in their tariffs to issue operational flow orders ("OFOs") and/or implement flow control measures to prevent the pipelines from failing. Any such actions by pipelines would necessitate firm customer curtailment, either planned or unplanned.

6.7.5. Health Risks if Greenpoint LNG Plant were Non-Operational

Health and safety are directly linked to reliability when it comes to the gas system, and the Greenpoint LNG facility plays a critical role in providing that reliability in our supply portfolio. Supply delivered to the distribution system must be available to serve customers every day of the year. Reliability becomes particularly important during times of high stress on the gas supply and transportation system. These occurrences usually happen during times of extremely low temperatures as demand on the gas supply system is directly and strongly correlated to heating needs in most markets. Reliability is an important contributor to the safety of the served population because the risk of injury and loss of life is higher during extreme cold weather events than during times of normal operation. One specific example of the Greenpoint LNG plant providing this critical source of reliability was during 2022’s Winter Storm Elliott, as discussed in section 4.2.1. The use of Greenpoint LNG prevented loss of necessary gas system pressures that would have caused potentially unsafe operating conditions resulting in loss of service customers and helped speed the recovery of the overall system back to normal conditions.

6.8. Conclusion

The Greenpoint LNG plant currently provides substantial Design Day supplies, critical reliability, and necessary transmission and distribution system support throughout Brooklyn and Queens. Should the Greenpoint LNG plant be removed from service, an immediate moratorium would be required in conjunction with curtailment of firm customers as we approach design weather conditions, posing severe health and safety risks.

While the hypothetical heat pump analysis assessed the cost of a demand-side alternative to the supply benefits provided by the Greenpoint LNG plant, the reliability and system benefits cannot be duplicated by this hypothetical alternative. The Greenpoint LNG plant is, and will continue to be, a pivotal asset that allows the Company to provide safe, reliable, and affordable gas service to our customers.

After exploring both supply-side and demand-side NPAs it is evident that these alternatives are substantially more expensive, do not provide the critical reliability benefits of Greenpoint LNG, and are essentially infeasible. Our analysis shows typical residential heating customer monthly bills would increase by more than 60% if a heat pump alternative were implemented. With a SCT ratio of 0.41, the estimated benefits of the heat pump alternative are vastly outweighed by the estimated costs, and this does not account for the reliability and system benefits provided by the facility.

National Grid believes it is in the interest of our customers to continue to invest in the Greenpoint LNG facility to ensure adequacy of the resource portfolio, to maintain safe and reliable service to our customers, and to minimize bill impacts. As we proceed through the energy transition, we will continue to evaluate the need for all assets, including Greenpoint LNG, as we see enduring changes in customer usage patterns.

7. Scenario Analysis

7.1. Summary of Approach

This section presents the findings of three distinct analyses comparing the Reference Case, CEV, and AE scenarios: an analysis of customer bill impacts, benefit-cost analysis (BCA), and GHG emissions analysis. None of these analyses paint a complete picture of the impacts of these scenarios, and important factors remain outside the scope of this work. For example, impacts on other sectors of the economy, including induced economic effects and emissions leakage, and the impact on equity and justice are not considered here due to complexity and the difficulty in assigning dollar-values.

Our goal is not to adjudicate between the CEV and AE scenarios or to use these findings to “pick a winner,” as the scenarios are not intended to be directly implemented. The CEV and the AE scenarios are not proposals per se, but are idealized hypotheticals intended to illustrate the boundary cases for a feasible gas transition. The analyses presented in this section are intended to provide insights into the tradeoffs and commonalities between the scenarios to inform development of a statewide gas transition plan focused on resolving the barriers to affordable, equitable, and durable gas decarbonization rather than implementing a singular pathway.

7.2. Key Findings

The bill impact, BCA, and GHG emissions analyses highlight important advantages of the CEV, and show areas of commonality between the CEV and AE as well as key tradeoffs. Key findings include:

- The CEV and AE scenarios both achieve substantial emissions reductions – 1.1 billion and 1.2 billion metric tons of CO_2e respectively by 2050.
- Achieving those emissions reductions is costly for society as a whole and for gas customers in both scenarios.
- The costs of both scenarios outweigh the benefits according to the most comprehensive available benefit-cost test.
- Net costs are higher for the AE, totaling over $89.2 billion compared to about $82.5 billion for the CEV.
- The incremental net societal cost per ton of emissions reduction is the same for both the CEV and AE scenarios, at $75/ton.
- Gas customer bill impacts are substantially lower for the CEV, but the CEV is considerably more costly for gas customers than the Reference Case.
- AE bill impacts are incrementally higher than the CEV through about 2040, and then increase exponentially as customers exit the gas network leaving very few remaining gas customers in 2050 to share the costs of the gas network.
- We do not anticipate bill impacts of the magnitude forecasted in either scenario will be acceptable to customers, regulators, or policymakers. This analysis should inform targeted policy and regulatory initiatives to manage affordability and equity risk of the energy transition.

Taken together, these results affirm the core value proposition of the CEV, which is that leveraging existing gas infrastructure to deliver clean alternative fuels to customers with difficult to electrify heating needs while also rapidly expanding electrification and energy efficiency can achieve emissions reductions comparable to a high-electrification pathway at lower societal costs and with lower bill increases for remaining gas customers. Further, these results show that lowering societal costs and bill impacts for remaining gas customers is imperative no matter what path the gas transition takes.

7.3. Bill Impact Analysis

We conducted a comprehensive gas system customer bill impact analysis for each scenario through 2050 for select service classifications in KEDNY, KEDLI, and NMPC. This analysis is based on forecasted revenue requirements and meter counts for each scenario, including forecasted annual values for rate base, taxes, post-tax return on rate base, depreciation, O&M, DSM program costs, and purchased fuel (accounting for fuel costs and fixed costs). It does not include increases in electric bills due to full or partial electrification or other direct costs of electrification,[121] which are captured in the BCA presented in Section 7.4. Similarly, the bill impact analysis does not include costs associated with UTENs or 100% hydrogen distribution infrastructure or the bills paid by customers using those technologies.[122] UTENs and 100% hydrogen costs are also captured in the BCA.

This analysis is illustrative, not predictive. It should not be interpreted as a forecast of future customer bills. It is intended to inform the development of policies and regulations to enable a gas system decarbonization transition that will be affordable and equitable.

7.3.1. Findings

We find that while both the CEV and AE scenarios are highly effective at reducing GHG emissions, both scenarios result in significantly higher gas bills for customers who remain on the gas network. Our overarching finding is that new approaches to manage bill impacts for remaining gas customers will be essential for any successful gas decarbonization transition pathway.

Bill impacts are significantly lower for the CEV scenario relative to the AE scenario, although both scenarios are costly. Both scenarios face the same essential challenges, including increased commodity costs from replacing fossil natural gas with clean alternative fuels, the need to continue investing in the gas network to provide safe and reliable service for remaining customers even though the gas distribution network is significantly downsized by 2050, and a significantly smaller 2050 customer base.

Table 7-1 and Figure 7-1 below show the average monthly bill increase by scenario for the average National Grid residential gas customer through 2050 relative to 2024.[123] Overall customer bills, including both the delivery and commodity portions are forecasted to increase in all three scenarios as shown in Table 7-2, Table 7-3, Figure 7-2, and Figure 7-3.

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[121] Gas bill increases associated with increased customer charges to fund electrification programs are reflected in the bill impact analysis, but all other customer electrification costs are not reflected in the bill impact analysis but are instead captured in the BCA.

[122] UTENs and 100% hydrogen costs are excluded from the bill impact because the per-customer cost of these technologies is significantly higher than that of customers of the legacy gas network. The average annual capital expenditure per customer from when UTEN and H_2 investments begin in 2033 through 2050 is an order of magnitude greater than the per-customer capital expenditures on the legacy gas network over the same period. Average annual capex per customer is estimated to be over $26,000 for 100% H_2 (which is a component of the CEV only); over $46,000 for UTENs (the penetration and cost of which is identical for the CEV and AE); and just over $2,000 for the legacy gas system as it transforms to become fossil-free under the CEV and AE. Apportioning the costs of costly UTENs and 100% H_2 would unfairly and inequitably increase costs for remaining gas customers. Alternative methods of recovering costs for UTENs and 100% H_2 as well as policies and regulations to lower their costs will be necessary for these technologies to be deployed at scale. UTENs and 100% hydrogen costs were inadvertently included in the revenue requirement for the CEV scenario in the Initial LTP, and 100% hydrogen costs were inadvertently included in the AE scenario. This Revised LTP corrects the errors, excluding these costs from the bill impact. These costs are reflected in the BCA in both the Initial and Revised LTPs.

[123] Bill impacts for residential customers for each operating company and additional service classifications can be found in Appendix 11.5. Note that CEV and AE bill impacts for commercial and industrial customers in NMPC assumes an adjusted reallocation of the revenue requirement in 2050 when compared to 2024 due to commercial and industrial customers leaving the gas system.

Table 7-1: Average Monthly Residential Bill – Average of NMPC, KEDNY, KEDLI

Avg. Monthly Residential Bill - Avg. of NMPC, KEDNY, & KEDLI						
	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$136		$136		$136	
2030	$204	49%	$252	85%	$279	105%
2035	$236	73%	$298	119%	$425	212%
2040	$263	93%	$355	160%	$718	427%
2045	$294	116%	$393	188%	$1,224	798%
2050	$302	121%	$442	224%	$4,691	3340%

Figure 7-1: Average Monthly Residential Bill

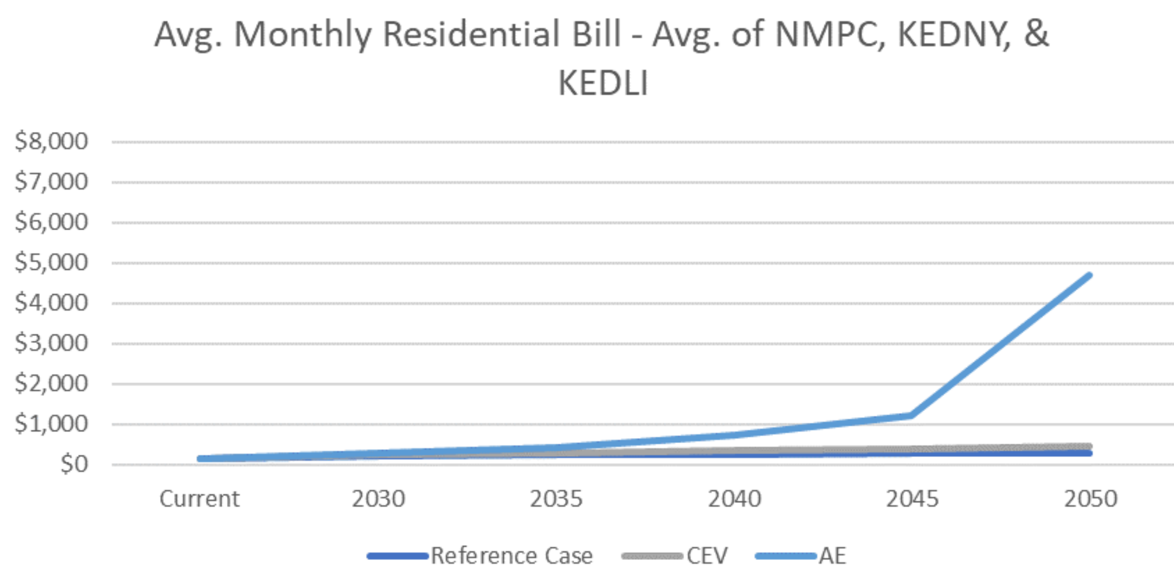


Table 7-2: Average Monthly Residential Bill (Delivery Only)

Avg. Monthly Residential Bill (Delivery Only) - Avg. of NMPC, KEDNY, & KEDLI						
	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$103		$103		$103	
2030	$162	56%	$205	98%	$235	127%
2035	$192	86%	$249	141%	$356	245%
2040	$218	110%	$304	194%	$631	510%
2045	$248	140%	$339	228%	$1,120	982%
2050	$257	148%	$368	256%	$4,460	4211%

Figure 7-2: Average Monthly Residential Bill (Delivery Only)

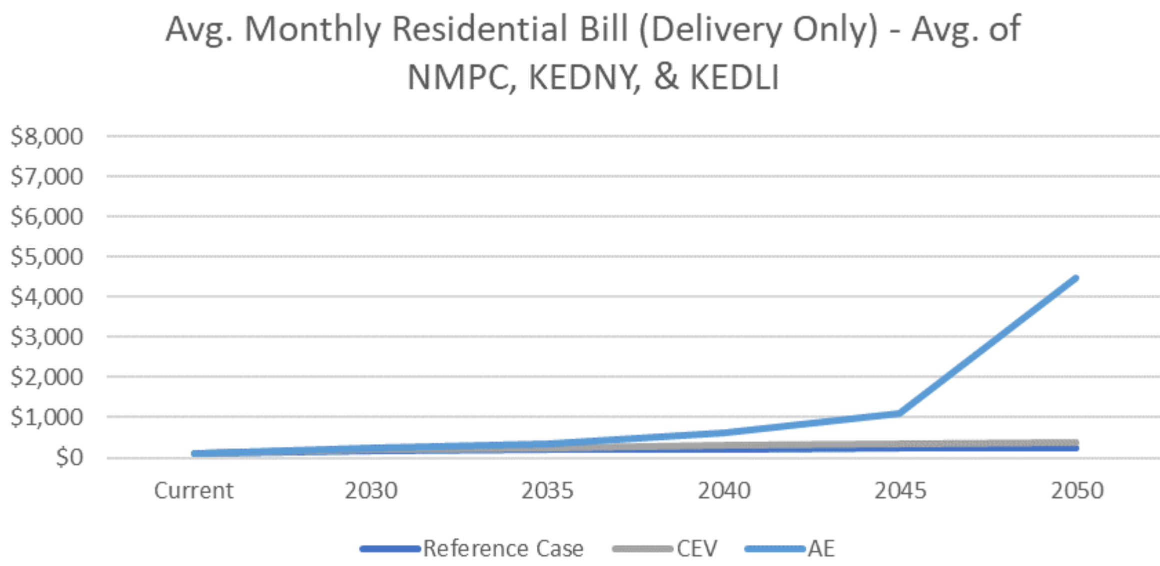
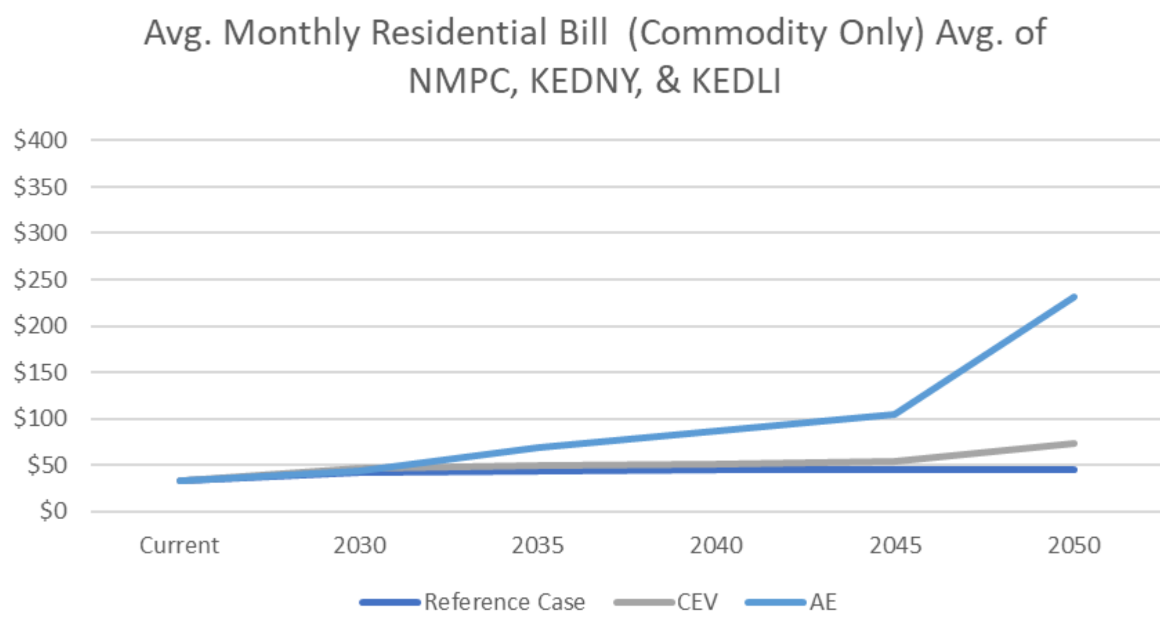


Table 7-3: Average Monthly Residential Bill (Commodity Only)

Avg. Monthly Residential Bill (Commodity Only) - Avg. of NMPC, KEDNY, & KEDLI						
	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$33		$33		$33	
2030	$42	27%	$47	42%	$44	33%
2035	$44	33%	$49	50%	$68	108%
2040	$45	36%	$51	54%	$87	164%
2045	$46	39%	$54	63%	$104	217%
2050	$45	37%	$74	125%	$231	602%

Figure 7-3: Average Monthly Residential Bill (Commodity Only)



7.3.2. Discussion

Under the Reference Case residential bills roughly double in 2050, driven primarily by a 148% increase in delivery costs and a relatively modest 37% increase in commodity costs. Reference Case delivery cost increases are attributable to investments necessary to ensure safety, reliability, and to meet future demand under the Adjusted Baseline Forecast.

Under the CEV scenario, 2050 bills are about 46% higher than 2050 bills under the Reference Case. CEV commodity costs in 2050 are 64% higher than 2050 Reference Case due to the replacement of fossil natural gas with higher cost RNG and clean hydrogen, while CEV 2050 delivery costs are about 43% higher than 2050 Reference Case..

Bill increases are an order of magnitude greater under the AE scenario. Customer bills are more than 16 times higher under the AE in 2050 than the Reference Case, with the average residential customer paying $4,691 per month. Delivery costs are more than 17 times higher under the AE scenario than the Reference Case in 2050, while commodity costs are about 5 times higher. Compared to the CEV, AE bills are over 11 times higher overall in 2050, with delivery costs around 12 times more and commodity costs more than triple.

The CEV is more affordable for remaining gas customers in 2050 primarily because there are approximately 1 times more customers sharing gas network costs. Under the CEV National Grid would have approximately 1.368 million residential customers in 2050, a 33% reduction compared to the Reference Case even as those customers would use 73% less gas than under the Reference Case in 2050 and 72% less than in 2024. In contrast, just 107,000 residential customers would remain in 2050 under the AE, roughly 95% less than under the Reference Case or compared to 2024. At the same time, the total revenue requirement for the AE scenario in 2050, not including the cost of fuel, is just 29% lower than for the CEV. More customers on the gas network in 2050 results in a lower per-customer revenue requirement for the CEV, resulting in lower bills relative to the AE.

The accumulated decline in customer count combined with relatively flat overall revenue requirement combine to cause AE scenario bills to increase exponentially in later years due to rapidly rising revenue requirement per customer, as shown in Figure 7-4 and Figure 7-5 below. Although customer decline occurs at a relatively consistent rate over time, as shown in Figure 7-6, each incremental departing customer has a larger effect on the year-over-year percentage decline in customer base, shaping the exponential increase in customer bills.

Figure 7-4: Revenue Requirement Per Customer

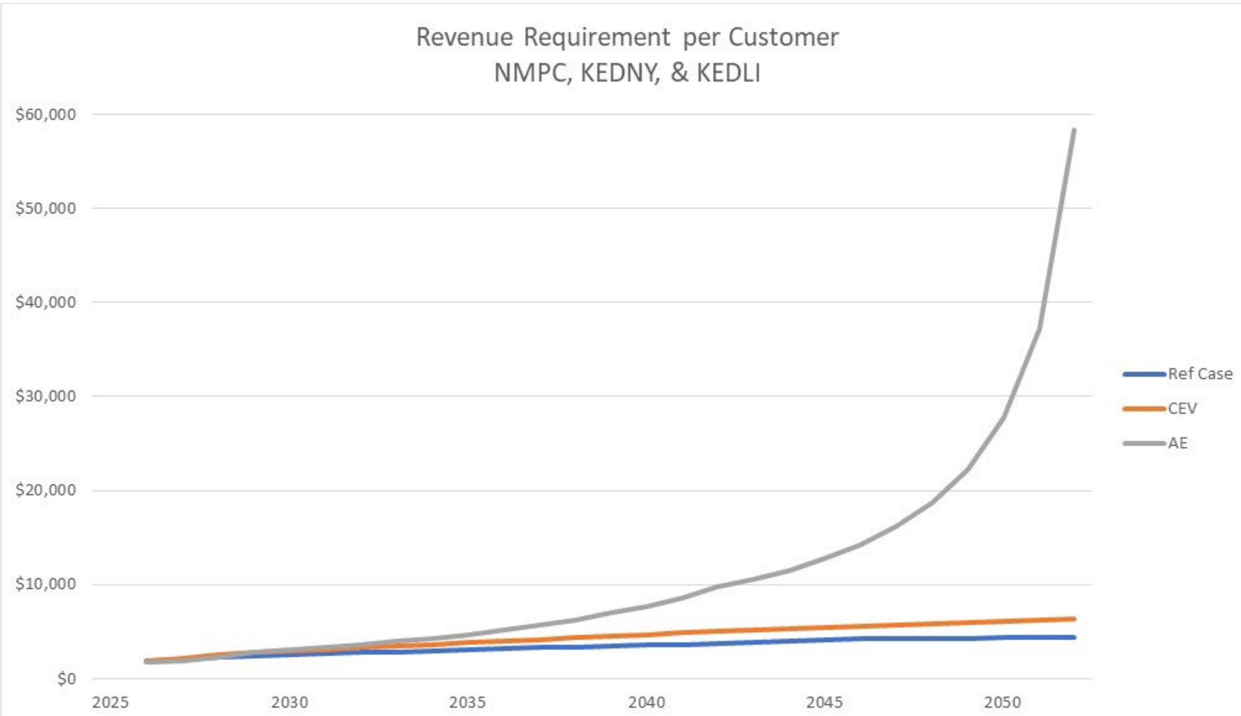


Figure 7-5: Residential Customer Allocated Revenue Requirement

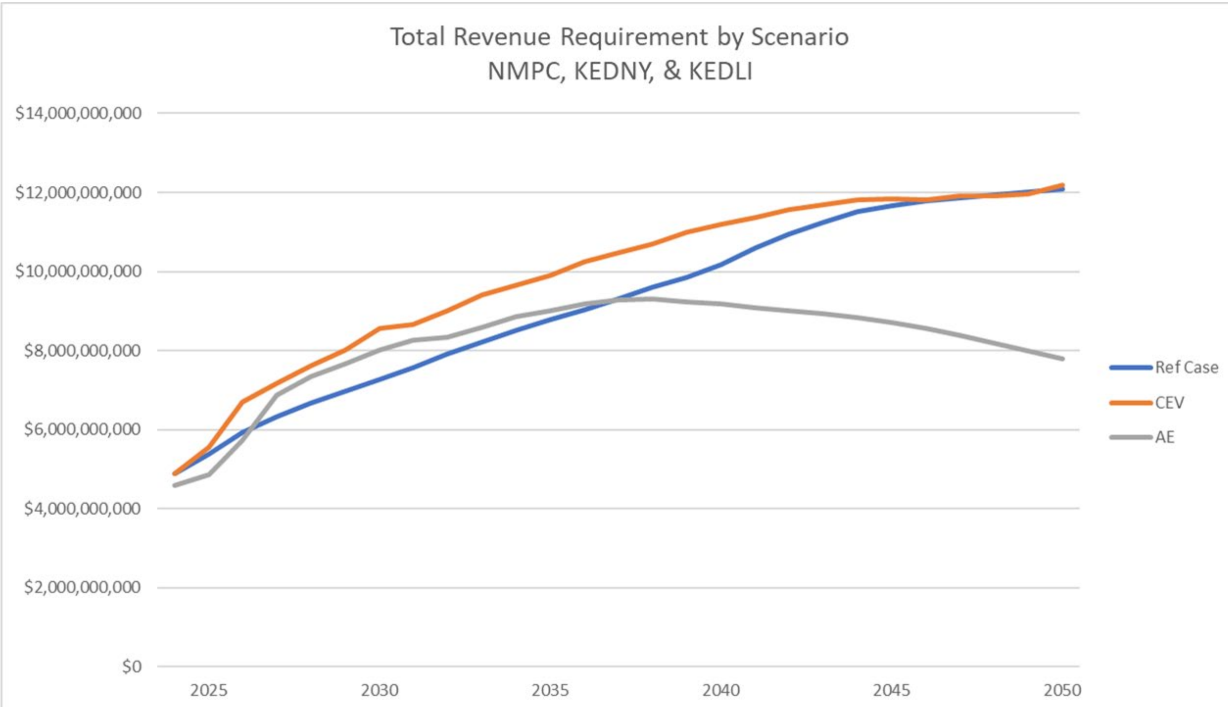


Figure 7-6: Total Customer Count by Scenario

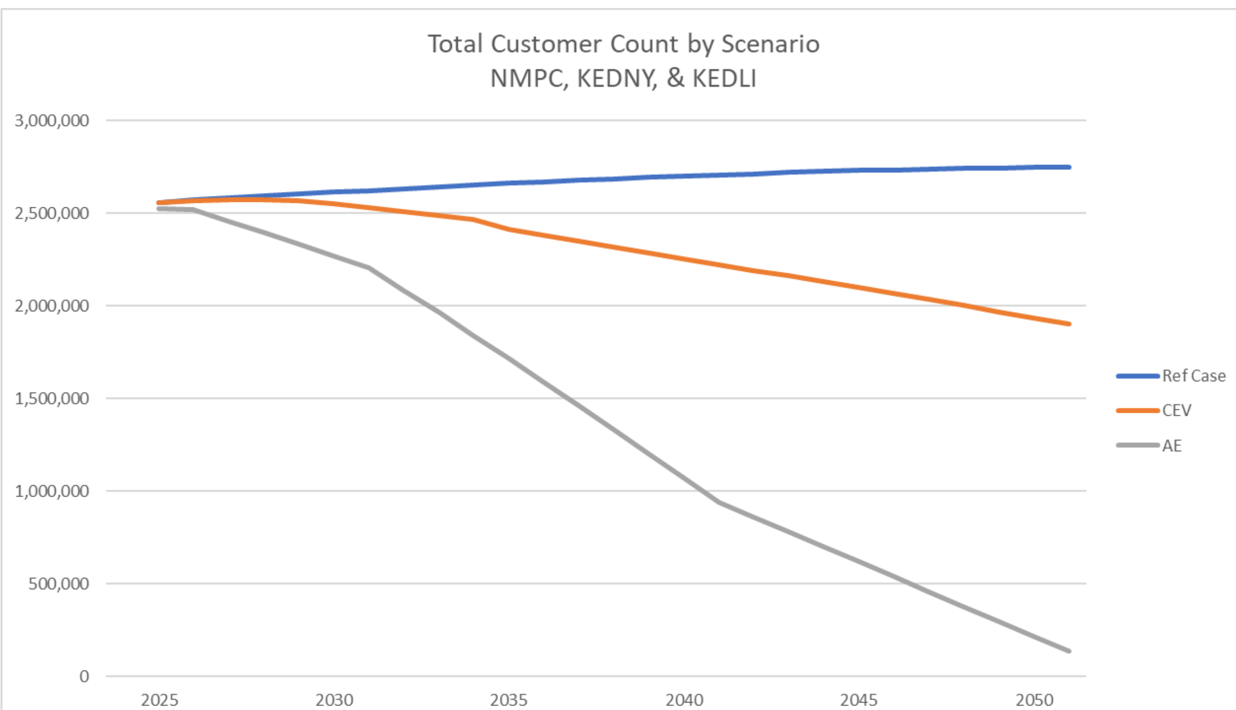
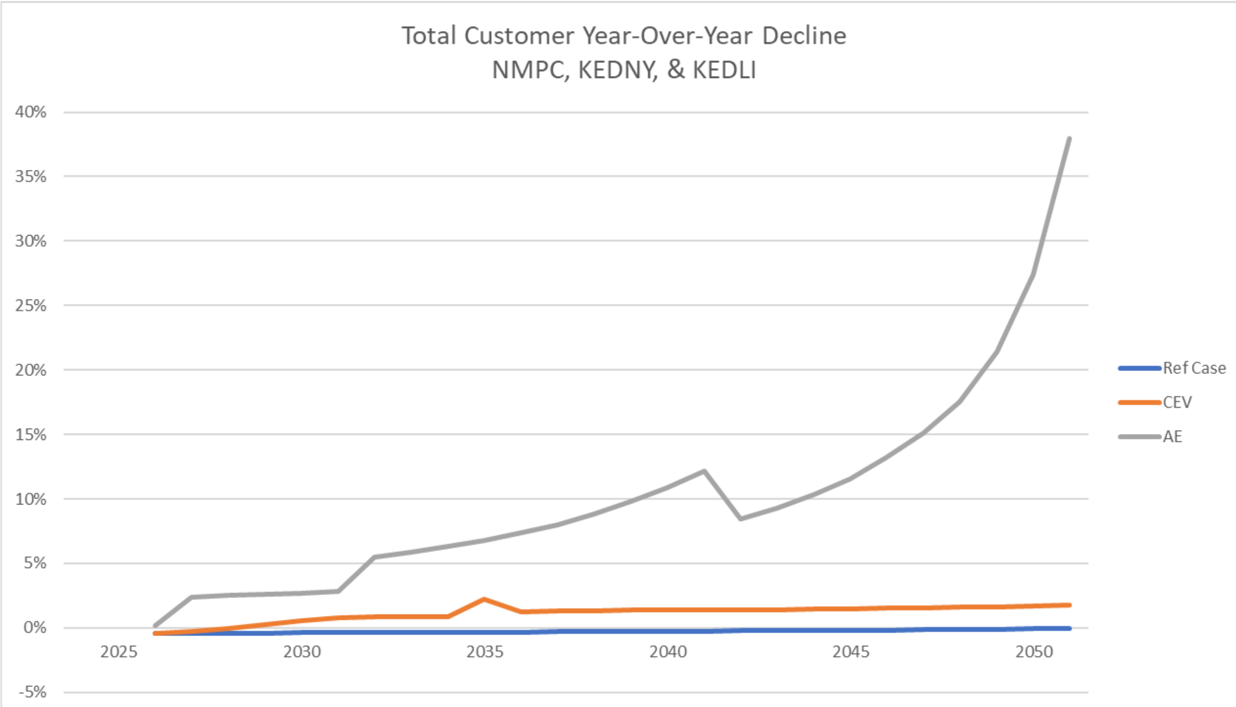


Figure 7-7: Total Customer Decline



This dynamic affects both the delivery and commodity portions of customer bills:

While the 2050 revenue requirement for delivery costs – that is, for the portion of customers' bills related to the construction, operation, and maintenance of the gas system – is actually *higher* under the CEV than the AE (about $10 billion vs about $7 billion), the total revenue requirement *per customer* for delivery costs is just $6,400 for CEV, compared to $58,000 for the AE. The per-customer delivery revenue requirement for the AE is 13 times greater than the 2050 Reference Case and 32x more than the 2024 baseline. For the CEV, per-customer delivery revenue requirement in 2050 is 45% greater than the 2050 Reference Case, and about 4 times greater than in 2024. As a result, the delivery portion of residential customer bills under the CEV is much lower each year through 2050 compared to the AE scenario, with the largest difference in 2050 when the average residential customer would pay $4,460 *per month* for delivery in the AE scenario, a more than 40-fold increase from 2024. CEV delivery bills in 2050 would be 92% lower than the AE even though CEV delivery bills triple from 2024. The increase in AE delivery bills is most extreme between 2045 and 2050 when the year-over-year rate of customer departures accelerates.[124]

Customer count also affects the commodity portion of customer bills through higher per-therm rates for fixed pipeline capacity demand charges, even though the price of the physical RNG and clean hydrogen fuel commodity is forecasted to decline over time. As a result, the commodity portion of residential customer bills under the AE scenario increases seven-fold between 2024 and 2050 and is more than three times as high as the CEV in 2050. Even as most customers leave the gas network in the AE scenario, pipeline contracts must be maintained to ensure the gas system has adequate pressure to serve year-round AE scenario demand requirements for RNG and hydrogen. This has a pronounced effect Downstate, where more contracts are needed on more pipelines to meet demand. With fewer customers to share the costs of these contracts, commodity rates increase even as the price of fuel goes down.

[124] Under the AE scenario, customers exit the gas network at an annual rate of 21% between 2045 and 2050, compared to a 7% annual rate between 2024 and 2045.

Under the CEV, commodity costs are relatively minor factor in overall bill increase, making up just 13% of the overall 2050 bill increase relative to 2024. Commodity makes up a larger portion of the AE scenario bill increase, at 23%.

Declining customer counts put upward pressure on the price customers pay for delivery and supply in both the CEV and the AE scenarios. However, the CEV is significantly more affordable for customers and likely more equitable, as it is likely many of the residential customers who continue to heat their homes with gas in 2050 will do so because they are unable to afford the high cost of electrification, or because they live in a community where alternatives to gas are not available. This finding supports policies that seek to balance affordability with the pace and scale of full electrification and enable more customers to access low-carbon fuels, as well as policies to bring down the cost of electrification.

Bill increases associated with the CEV scenario, while lower than the AE scenario, also must be addressed to ensure an affordable and equitable transition. Residential CEV bill impacts are relatively modest in 2050 compared to the 2050 Reference Case, as discussed above, but roughly triple relative to 2024 baseline. While more customers to share fixed costs helps make the CEV more affordable and likely more equitable than the AE, there are additional factors contributing to bill increases in both the CEV and the AE that must be addressed. These factors include high costs for energy efficiency and demand reduction, which both scenarios rely upon equally;[125] the price of RNG and hydrogen, which both scenarios use in large volumes and existing forecasts indicate will be significantly higher than fossil gas,[126] and the impact of future undepreciated rate base on the smaller future customer base in both scenarios.[127] We recommend policymakers and regulators begin immediately to address the affordability and equity risk associated with declining customer count, as well as risks common to both the AE and CEV scenarios including the costs of energy efficiency and clean alternative fuels, and future inequities related to current depreciation approaches. The direct costs of electrification, including up-front costs and the cost of electricity, while not addressed in this bill impact analysis must also be brought down for any decarbonization pathway to be affordable and equitable, as discussed in the following Section 7.4. We look forward to working with policymakers, regulators, and stakeholders to build solutions to these challenges through the development of a comprehensive statewide gas transition plan as called for in the Scoping Plan and urge the Commission to begin this process immediately.

7.4. Benefit-Cost Analysis

7.4.1. Background

We also compared the three LTP scenarios through a benefit-cost analysis ("BCA"), adopting the methodology established in the BCA Framework Order.[128] The BCA Framework Order is focused on electric utilities. In the absence of a consistent BCA framework for gas utilities, this analysis follows guidance previously provided in the BCA Framework Order as well as industry best practices.

The Company applied the BCA analysis to its three operating companies in New York—NMPC, KEDNY, and KEDLI—and for three planning scenarios—Reference Case, CEV, and AE.

[125] Energy efficiency accounts for 2,361 TBtus of demand reduction in both the CEV and the AE between 2024 and 2050.
[126] The CEV uses 2,505 TBtus of clean alternative fuels between 2023 and 2050 (1,653 TBtus of RNG and 853 TBtus of clean hydrogen). The AE uses 1,488 TBtus of clean alternative fuels over the same period (1,366 TBtus of RNG and 123 TBtus of clean hydrogen).
[127] See Section 8.2: Gas Depreciation Policy.
[128] New York State Public Service Commission, Order Establishing the Benefit-Cost Analysis Framework, January 21, 2016. ("BCA Framework Order").

This BCA compares quantifiable benefits and costs accrued to customers, the electric and gas systems, and society over the period from 2025 through 2050 from a Societal Cost Test ("SCT") perspective. This section provides an overview of the SCT, the applicable benefit and cost streams, and resulting net present value ("NPV") and benefit-cost ratio results.

The analysis is presented both in terms of the ratio of benefits to costs as well as in terms of the present value of benefits net of costs. A benefit-cost ratio greater than 1.0 indicates a positive NPV (i.e., present value of benefits exceeds present value of costs over the lifetime of an investment). It is informative to review both the NPV and benefit cost ratio resulting from an investment analysis to understand the lifetime benefits relative to costs and the magnitude of these expected benefits.

Societal Cost Test ("SCT"): The BCA Framework Order designated the SCT as the primary BCA method. The SCT takes the holistic perspective of society, and includes electric and gas system costs, electric and gas energy supply costs, and customer costs relevant to initiatives captured in the scope of the LTP. The SCT also incorporates the societal impacts of greenhouse gas emissions, including carbon dioxide, nitrous oxide, and methane.

Relevant costs in this analysis include gas and non-gas utility administrative spending, customer incremental technology costs from energy efficiency and electrification, LPP removal, and additional investment in hydrogen and renewable natural gas infrastructure and supply, as well as UTENs investment. Increases in electric consumption and demand from electrification, as well as the associated increase in GHG emissions from incremental electricity consumption are also considered costs in this test.

The SCT accounts for key benefits including avoided gas supply costs, avoided gas infrastructure costs, avoided GHG emissions from gas combustion, and methane leak reduction.[129]

There are several categories that were not included in our BCA model as they are difficult to quantify, especially for the gas network. These include changes in reliability and resiliency, non-energy benefits, reductions in bill arrearages, and impacts on public health and air quality. The Commission concluded in the BCA Framework Order that societal non-energy benefits were "speculative" and not able to be valued by any commentator with "sufficient specificity to include them in the BCA Framework at this time".[130] Utility customer incentives are considered a transfer payment and are also excluded from this test.

In the Company's view, the SCT is the most appropriate test for benefit cost analysis of LTP scenarios given the broader energy system, customer, and societal implications of gas network decarbonization. However, it is important to note that under the SCT, as currently implemented, many important impacts are not captured, such as broader direct and indirect economic and employment impacts, as well as measures of equity of the distribution of benefits and costs across customers. Table 7-4 below summarizes the benefit and cost streams included in the SCT.

Table 7-4: Benefit-Cost Test Definitions in the SCT

Benefit-Cost Category	SCT
Avoided Gas Supply	Benefit

[129] Consistent with NYSERDA guidance, this analysis utilizes standard biogenic CO_2 accounting for monetization of the value of GHG emissions reductions. See NYSERDA, 2023. Fossil and Biogenic Fuel Greenhouse Gas Emissions Factors. Report Number 22-23, at p. 5, Revised May 2023.
[130] 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.

Avoided Gas Infrastructure Revenue Requirement	Benefit
Avoided GHG Emissions from Gas Combustion	Benefit
Avoided Emissions from Methane Leakage	Benefit
Avoided Electricity Consumption	Benefit
Avoided Electric Capacity	Benefit
Added Hydrogen and RNG Fuel Supply	Cost
Added Future of Heat Infrastructure Revenue Requirement	Cost
LPP Retirement Revenue Requirement	Cost
Increased Electricity Consumption	Cost
Increased Electric Capacity	Cost
Increased GHG Emissions from Electricity	Cost
Gas Utility Energy Efficiency Administrative Costs	Cost
Incremental Participant Cost	Cost
Non-Gas Utility Electrification Administrative Costs	Cost

See Appendix 11.6 for benefit and cost stream input sources and assumptions and Appendix 11.7 for detailed BCA results.

7.4.2. Benefit-Cost Analysis Results

Table 7-5 summarizes the benefit-cost ratio results for each operating company and scenario. The CEV and AE scenarios result in higher benefit-cost ratios than the Reference Case for NMPC, KEDNY, KEDLI, and the territory total.[131] The CEV and AE scenario results are similar across operating companies with the CEV scenario resulting in the most favorable cost test for the total service territory. A primary driver of this difference is that in aggregate, incremental electricity transmission, distribution, and supply capacity, as well as energy and electricity-related emissions costs in the AE scenario are larger than the additional costs of gas network infrastructure and renewable fuels under the CEV scenario. All scenarios result benefit cost ratios below 1.0 across operating companies.

Table 7-5: Benefit-Cost Test Ratios by Operating Company and Scenario

Operating Company	Benefit-Cost Test	Reference Case	CEV	AE
NMPC	**Societal Cost Test (SCT)**	0.69	0.70	0.76
KEDNY	**Societal Cost Test (SCT)**	0.36	0.50	0.48
KEDLI	**Societal Cost Test (SCT)**	0.49	0.68	0.65
National Grid Territory Total	**Societal Cost Test (SCT)**	0.46	0.60	0.59

[131] A higher benefit-cost ratio indicates more benefits per dollar of cost.

Table 7-6 summarizes net present value benefits and cost results for each operating company and scenario in 2025 dollars. As measured by the SCT, costs outweigh benefits for all scenarios, resulting in a negative NPV. For each operating company, net costs are greater for the CEV and AE scenarios than for the Reference Case. This can occur while a scenario maintains a relatively higher benefit cost ratio due to the relative sizes of the benefits and costs. The CEV and AE scenarios have much greater levels of investments and benefits than the Reference Case. Therefore, the negative NPV for these two scenarios is relatively small compared to the total benefits that accrue under these scenarios. See Appendix 11.7 for details on PV benefits and PV costs by benefit stream.

Table 7-6: Benefit-Cost Test NPVs ($2025) by Operating Company and Scenario

Operating Company	Benefit-Cost Test	Reference Case ($M)	CEV ($M)	AE ($M)
NMPC	**Societal Cost Test (SCT)**	-$2,187	-$14,591	-$11,558
KEDNY	**Societal Cost Test (SCT)**	-$12,321	-$50,395	-$56,081
KEDLI	**Societal Cost Test (SCT)**	-$5,790	-$17,552	-$21,633

7.4.3. Discussion

Participant incremental costs associated with energy efficiency and heat electrification represent the largest costs the CEV and AE scenarios. For AE, the costs of the electric system are higher than CEV due to deeper electrification of the heating sector and the resulting capacity and supply needs. The CEV scenario has greater investment in future of heat-related infrastructure and LPP removal costs than AE given the larger gas network and number of customers remaining on the gas system in that scenario. Similarly, gas utility energy efficiency administrative costs are higher in the CEV scenario and non-gas utility electrification administrative costs are higher in the AE scenario. LPP revenue requirement represent the largest costs in the Reference Case scenario.

Avoided GHG emissions from gas combustion represent the majority of benefits, with reduced avoided gas supply, infrastructure revenue requirement, and avoided methane leakage from LPP following. There are no benefits from avoided electric system costs as all scenarios show a net increase in electric consumption and demand.

In assessing the BCA results, it is important to consider the implications of using a framework that has been traditionally used to assess the benefits and costs of specific programs or targeted investments such as advanced metering infrastructure to assess the benefits and costs of the broad suite of investments and programs needed to enable the clean energy transition across electric and gas networks. Given the scale of investments, the implications of the clean energy transition across the broader economy, the inherent uncertainty in projecting many key inputs out into 2050, and the dynamic interactions that will occur between inputs and outputs, a static view of quantifiable benefits is of limited value in terms of the insights that it can provide decisionmakers. However, such analysis is instructive for understanding key tradeoffs across scenarios, and areas where uncertainty may be important in making these comparisons.

At a high level, however, the findings of this analysis support National Grid's recommendations for immediate policy action in support of gas network decarbonization. The central tenet of this Long-

Term Plan is that the near-term actions necessary to enable achieving the gas transition – whether the future looks more like the CEV scenario or the AE scenario – are the same. Both the CEV and the AE require transformative levels of gas demand reduction, rapid increases in customer adoption of electric heating, significant volumes of low-carbon alternative fuels, and new frameworks for integrated energy planning and utility cost allocation to support equity and energy affordability.

7.5. GHG Emissions Reductions

We evaluated the emissions impacts of the CEV scenario and the AE scenario to illustrate the respective GHG emissions reductions relative to the Reference Case scenario. This analysis reflects GHG emissions calculated in a manner consistent with the New York DEC's current accounting framework.[132] The calculations underlying this analysis leverage the relative allocation of energy resources by scenario using the set of GHG emissions factors for comparison. Results are presented below in units of metric tons of CO_2-equivalent ("CO_2e") GHGs, using the 20-year Global Warming Potential ("GWP") approach as required by the CLCPA. This analysis reflects emissions reductions from avoided gas combustion net of increased electric sector emissions to deliver the energy previously served by the gas network. Emissions from the electric grid are assumed to decline through 2040, after which the electrical demand system is assumed to have zero emissions as required by the CLCPA.

Table 7-7: GHG Emissions Reductions by Scenario and OpCo

Operating Company	Impact Type	Reference Case	CEV	AE
NMPC	**CO_2e (metric tons)**	64,064,604	299,328,384	321,310,675
KEDNY	**CO_2e (metric tons)**	84,910,484	464,975,112	496,770,362
KEDLI	**CO_2e (metric tons)**	74,808,236	333,241,644	372,236,435
Total	**CO_2e (metric tons)**	223,783,325	1,097,545,140	1,190,317,472

While total emissions reductions differ slightly between the CEV and AE scenarios, both scenarios reduce over 1 billion metric tons of CO_2e through 2050, significantly more than the Reference Case. Emissions reductions are substantially the same for the CEV and AE scenarios, with the CEV reducing 80% more emissions than the Reference Case, and the AE scenario reducing 82% more than the reference case, at the same incremental societal cost per ton of CO2e reduced.

According to the BCA results discussed in Section 7.4, the net costs of the CEV scenario total $82.5 billion, and the net costs of the AE scenario totals $89.2 billion. Net costs divided by total emissions reductions produces a net cost per metric ton of CO_2e, which can be thought of as the premium paid by society at large to reduce one metric ton of emissions.[133] The emissions reduction premium for the CEV and AE scenarios is $75/ton.

[132] NYSERDA (2023). "Fossil and Biogenic Fuel Greenhouse Gas Emission Factors". Available at: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/22-23-Fossil-and-Biogenic-Fuel-Greenhouse-Gas-Emission-Factors.pdf.

[133] All scenarios have net costs after accounting for the value of GHG reductions based on NY DEC, Establishing a Value of Carbon: Guidelines For Use By State Agencies, Appendix: Annual Social Cost Estimates (August 2023). The 3% discount rate method was used for each GHG and adjusted to 2025 dollars using the utility WACC.

Notably, the societal cost per ton of emissions reductions from both the CEV and AE scenarios improve substantially under the standard US and international GHG accounting standard for bioenergy, which is discussed in footnote 145. According to NYSERDA, this approach excludes CO_2 emissions from the combustion of bioenergy such as RNG, known as "biogenic CO_2," because "CO_2 emissions from combustion are offset by the sequestration of carbon associated with feedstock production."[134] As discussed later in Section 8.3.4.2, this approach is endorsed by the Intergovernmental Panel on Climate Change ("IPCC"), the GHG Protocol and the US EPA. However, New York's current approach to accounting -- referred to as "gross" accounting -- treats biogenic CO_2 emissions differently for comparing emissions the CLCPA's statutory emissions targets, *including* them in such totals, but *excluding* them for purposes of "assessing the value of emission reductions." The emissions totals reported in Table 7-7 above use the "gross" accounting method, since this is not technically "assessing the value of emission reductions," and therefore include CO_2 emissions from bioenergy combustion, artificially inflating them relative the US and international standard. For the purposes of illustrating how the "gross" approach erroneously inflates emissions, we present the emissions reduction totals by scenario under standard accounting, in which biogenic CO_2 is excluded, in Table 7-8.

Table 7-8: GHG Emissions Reductions by Scenario and Op Co, Standard Accounting

Operating Company	Impact Type	Reference Case	CEV	AE
NMPC	**CO_2e (metric tons)**	64,064,604	362,981,717	383,814,824
KEDNY	**CO_2e (metric tons)**	84,910,484	491,023,312	510,372,301
KEDLI	**CO_2e (metric tons)**	74,808,236	353,347,135	381,498,706
Total	**CO_2e (metric tons)**	223,783,325	1,207,352,165	1,275,685,832

Emissions reductions under the standard approach are 10% greater for the CEV than under the "gross" approach, and 7% greater for the AE. The resulting net societal cost premium under standard accounting is \$68/ton for the CEV and \$70/ton for the AE, helping illustrate why New York should adopt the standard accounting approach for biogenic CO_2, as we discuss in Section 8.3.4.2 below.

8. Taking Action

8.1. Gas Transition Resource Requirements

The demand reduction and energy supply resources necessary to achieve the gas transition are common to the CEV and AE scenarios. Choosing between the two scenarios is not necessary at this time because neither is achievable without rapidly achieving scale in the following areas. Below we present visualizations of the volume of energy supply or demand reduction required for each essential resource by scenario.[135] The Reference Case illustrates what is achievable under the

[134] See NYSERDA, 2023. Fossil and Biogenic Fuel Greenhouse Gas Emissions Factors. Report Number 22-23, p. 2, Revised May 2023.

[135] Note that the data series are additive on the y-axis. That is, the total volume of energy or demand reduction for each scenario is equal to the number of TBtus on the implied y-axis gridline that intersects with the top of the area chart for that scenario at any given point on the x-axis. This is to better represent the comparative volumes for each scenario over time.

current policy and regulatory regimes and forecasted market dynamics. *None* of these resources will be available in sufficient volumes to achieve the CEV or the AE without transformational innovations. This underscores an essential theme of this report: we should focus on developing as much of all of these resources as possible with utmost haste, while balancing affordability and seeking to mitigate risks. We urge the Commission to initiate workstreams dedicated specifically to developing each of these resources, and to address the related policy and regulatory recommendations discussed in Section 8.3.

8.1.1. Electrification of Heat

Electrification accounts for 5,528 TBtus of gas demand reduction between 2024 and 2050 in the AE scenario, and 3249 TBtus in the CEV (1,554 TBtus of full electrification, and 1,695 TBtus of partial electrification). The CEV uses 59 % as much electrification as the AE. The Reference Case includes forecasted levels of electrification based on existing policy and market trends, amount to 569 TBtus of gas demand reduction by 2050. While the main modality for electrification under the CEV is full building electrification, including targeted electrification and decommissioning of segments of the gas network, a significant amount of demand reduction is also achieved through partial electrification, where customers install heat pumps to serve the majority of their heating needs, but keep their gas service for use on the coldest days. Partial electrification allows customers to reduce upfront costs by right sizing their heat pumps as part of a hybrid system, and also lowers societal costs by reducing peak demand on the electric system.

Figure 8-1: Full Building Electrification by Scenario

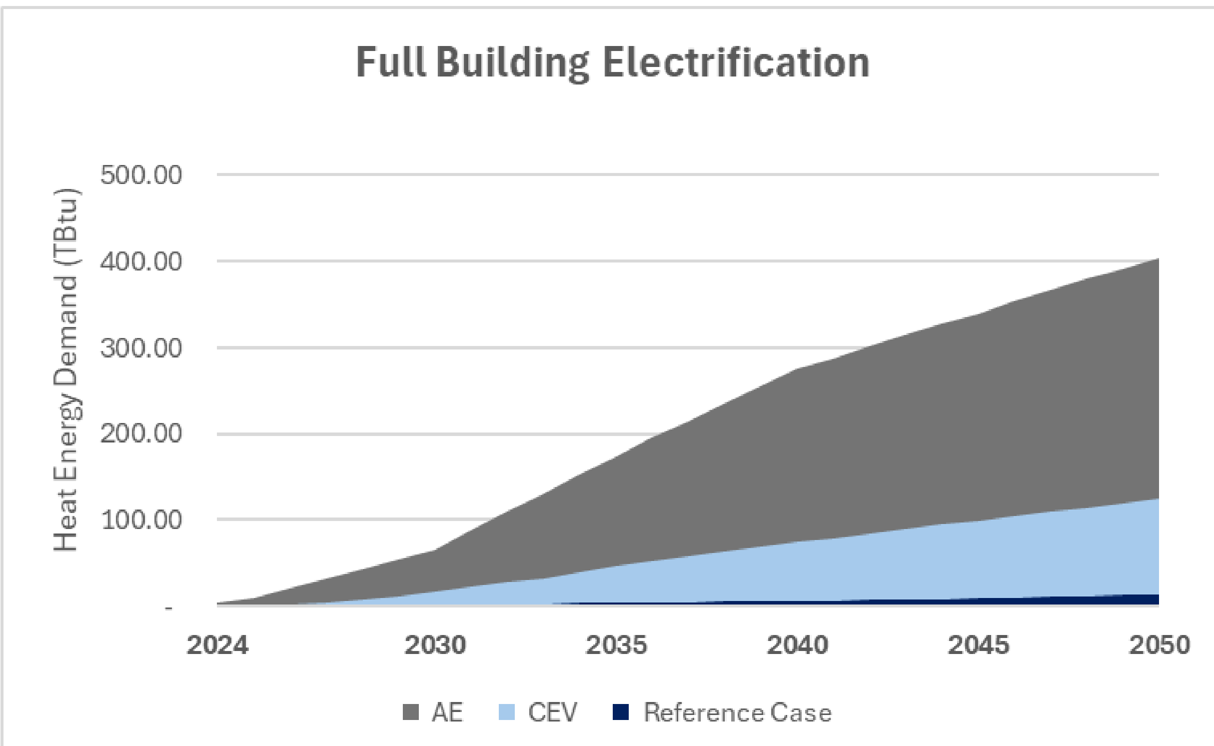
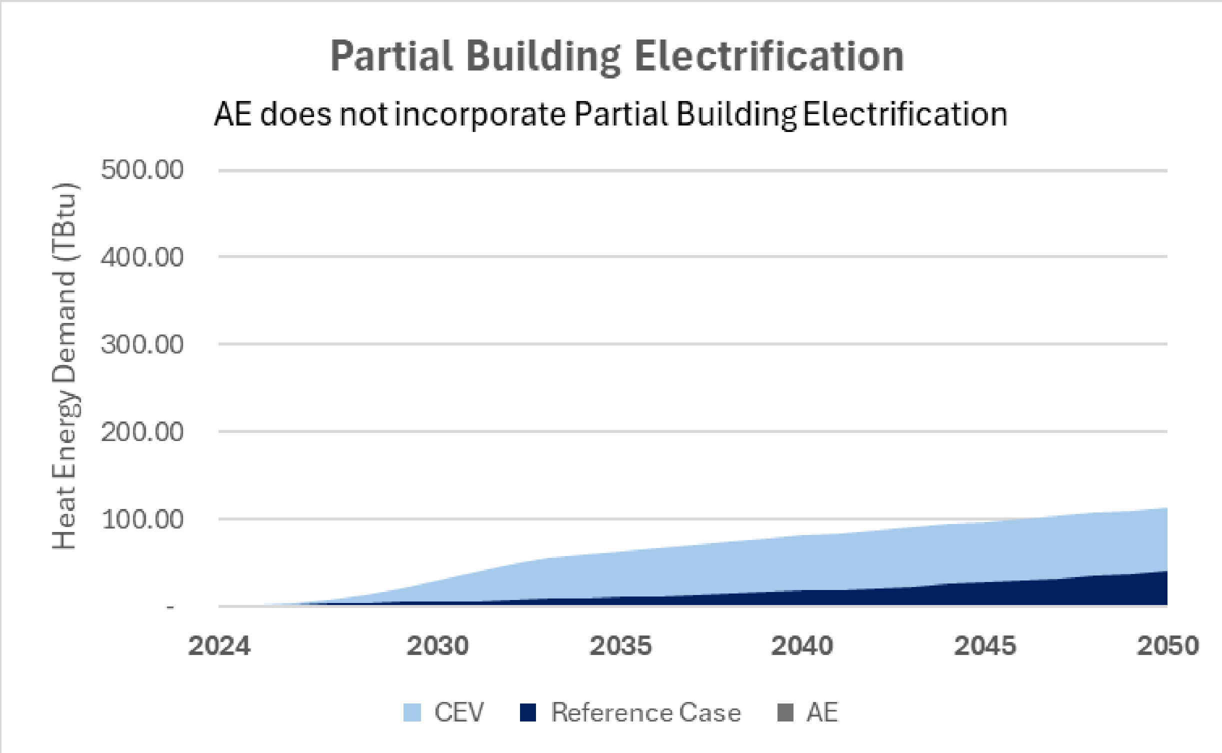


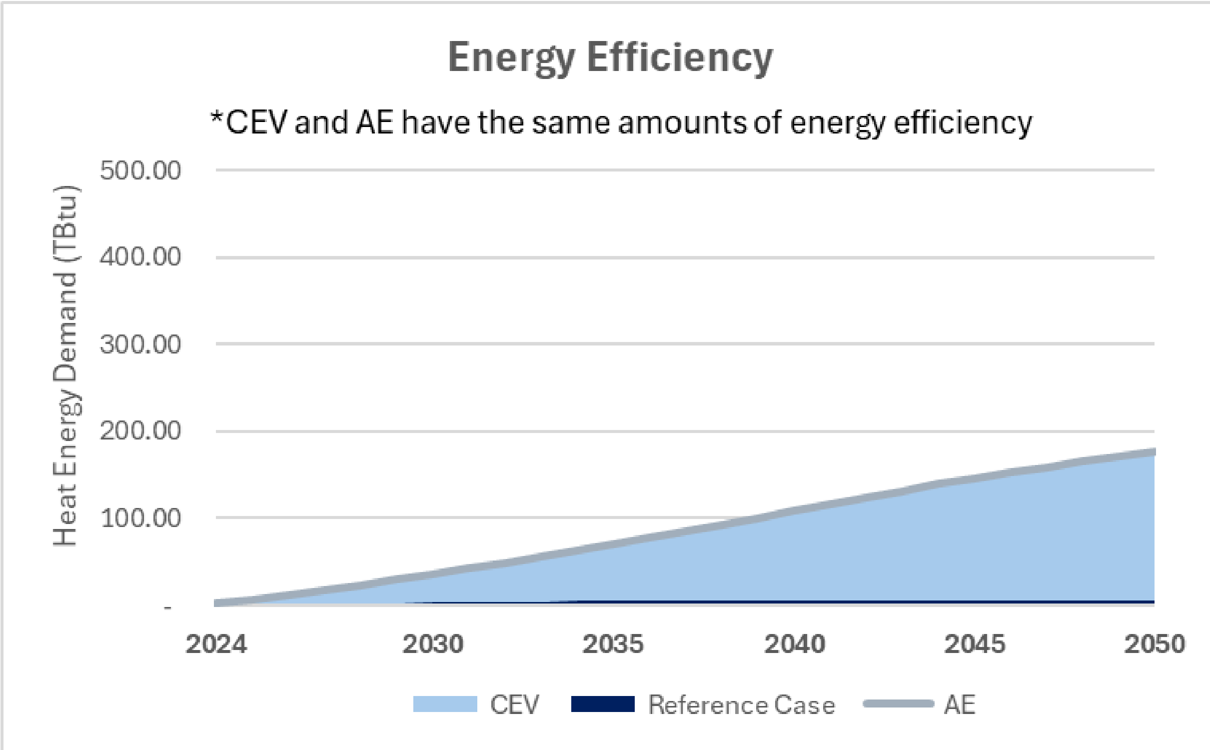
Figure 8-2: Partial Building Electrification by Scenario



8.1.2. Energy Efficiency

The CEV and AE scenarios use the same amount of energy efficiency, significantly more than is forecasted to be achieved under the Reference Case. Scaling up energy efficiency and bringing down costs must be a focus for policymakers and regulators, as we discuss further in Section 8.3.3.

Figure 8-3: Energy Efficiency by Scenario



8.1.3. Clean Alternative Fuels

Both scenarios use substantial amounts of RNG and clean hydrogen. The CEV uses 1,653 TBtus of RNG and 852 TBtus of clean hydrogen for a total of 2,505 TBtus through 2050. The AE uses 1,489 TBtus of clean alternative fuels over the same period (1,366 TBtus of RNG and 123 TBtus of clean hydrogen). Both scenarios require RNG to begin replacing fossil gas immediately and begin incorporating clean hydrogen in the 2030s. Customers continue using RNG and clean hydrogen through 2050 and beyond in both scenarios. Overall demand for RNG is very similar in both scenarios, although the AE requires more between 2035 and 2040, and the CEV requires about 11 % more overall. There is no RNG or hydrogen in the Reference Case because current frameworks do not allow utility procurement and delivery of RNG, although RNG is currently being produced and consumed in New York while the associated environmental attributes are being sold elsewhere. The CEV uses a small amount of hydrogen to support decarbonizing the legacy gas system (up to 7% of total energy delivered by the gas network, which is the currently accepted feasibility limit for hydrogen blending), while the majority of CEV hydrogen is delivered the same way as in the AE scenario, over dedicated 100% hydrogen networks to customers with difficult to electrify energy needs.

Figure 8-4: RNG by Scenario

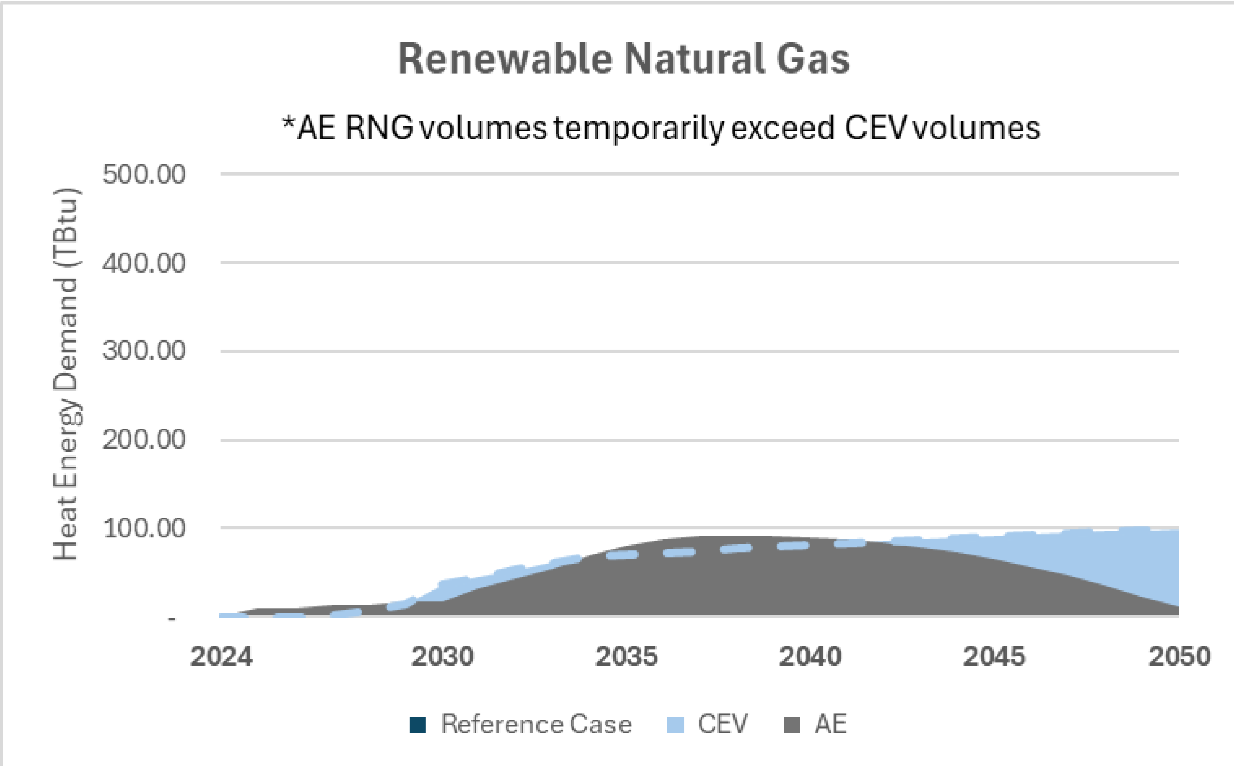


Figure 8-5: 100% Hydrogen by Scenario

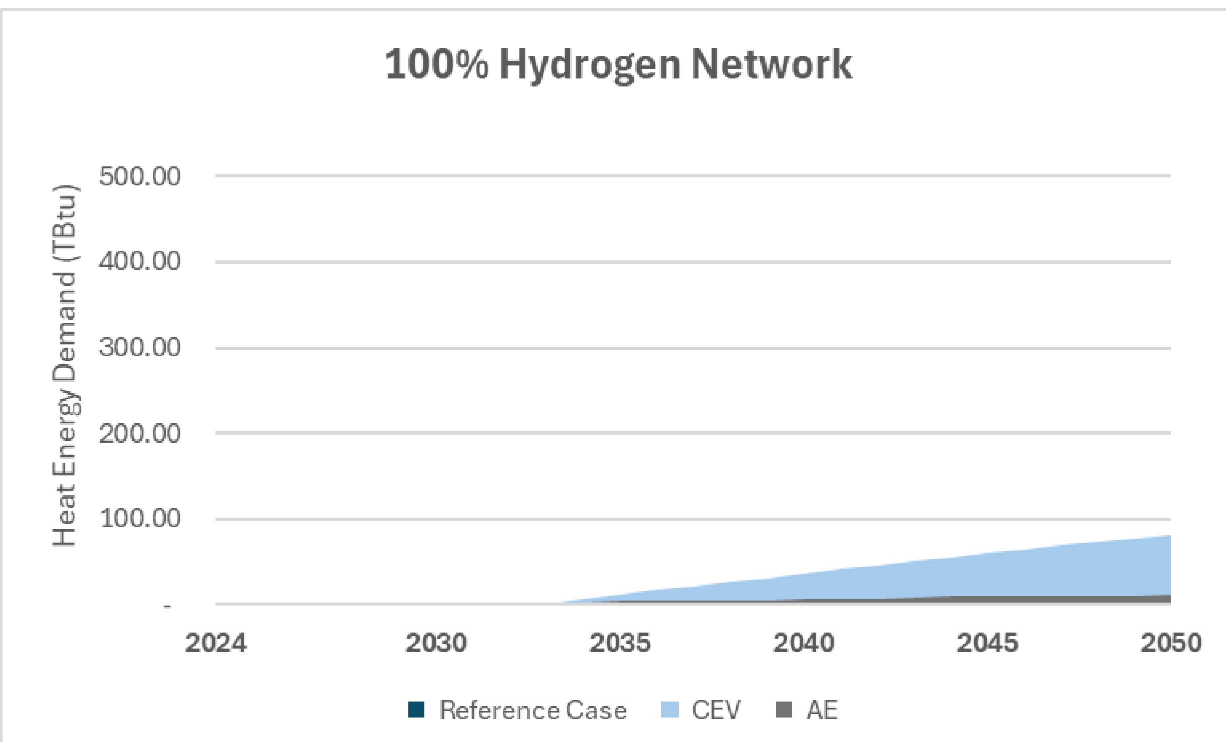
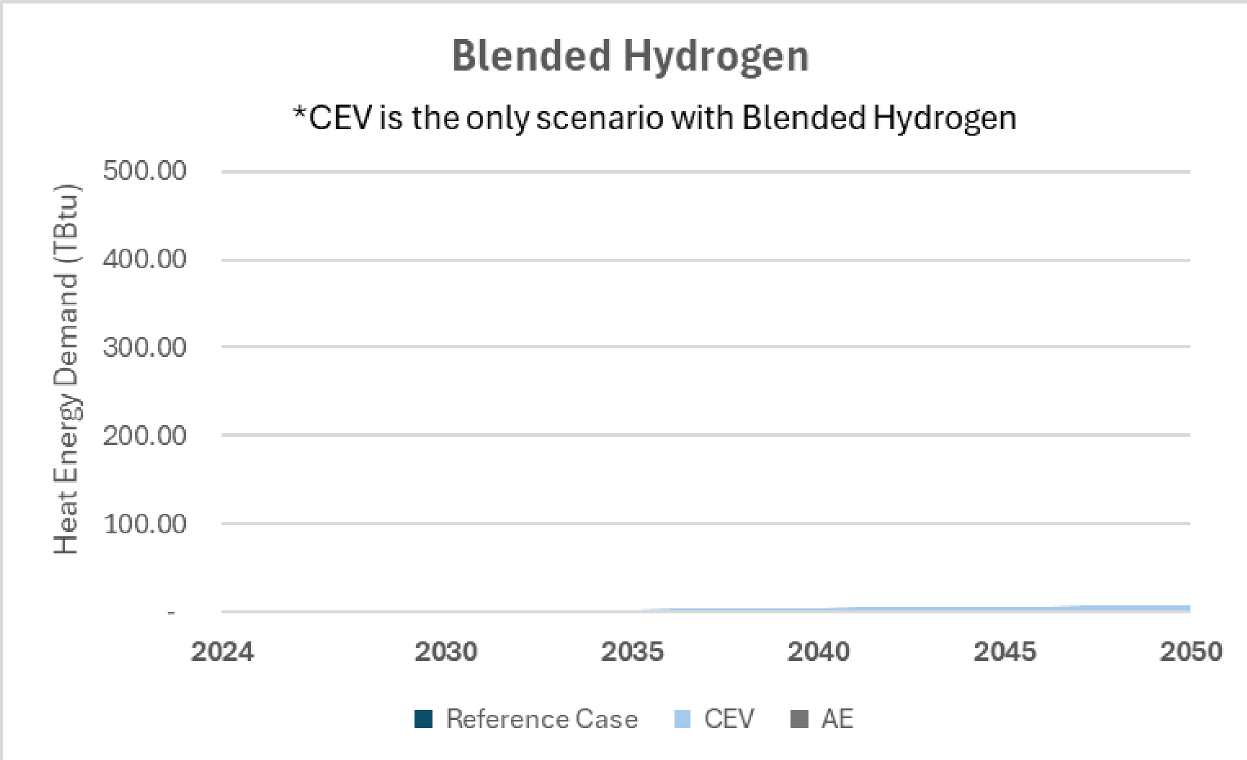


Figure 8-6: Blended Hydrogen by Scenario



8.2. Common Risks

The key risks associated with the gas transition are common to both the CEV and AE scenarios, including:

8.2.1. Affordability

As described in Section 7.2, customer bills increase in all scenarios. The largest component of customer bills in later years for both scenarios are costs associated with gas infrastructure: annual cost of rate base and depreciation expenses. Figure 8-7 and Figure 8-8 below detail the components of total revenue requirement on a per-customer basis for both scenarios, illustrating how individual components change over time. While the relative positions of many components are similar for the CEV and the AE, and trend in the same direction toward higher customer bills, the rate of change scales with the annual rate of change in customer count, as discussed in Section 7.2. Common strategies for managing affordability for customers who remain on the gas network include reducing gas system costs, enacting equitable depreciation approaches, and bringing down the cost of RNG and hydrogen. All of these approaches will benefit customers under either scenario but are more urgent under the AE scenario as customer bills will increase exponentially unless action is taken.

Figure 8-7: AE – Revenue Requirement Per Customer

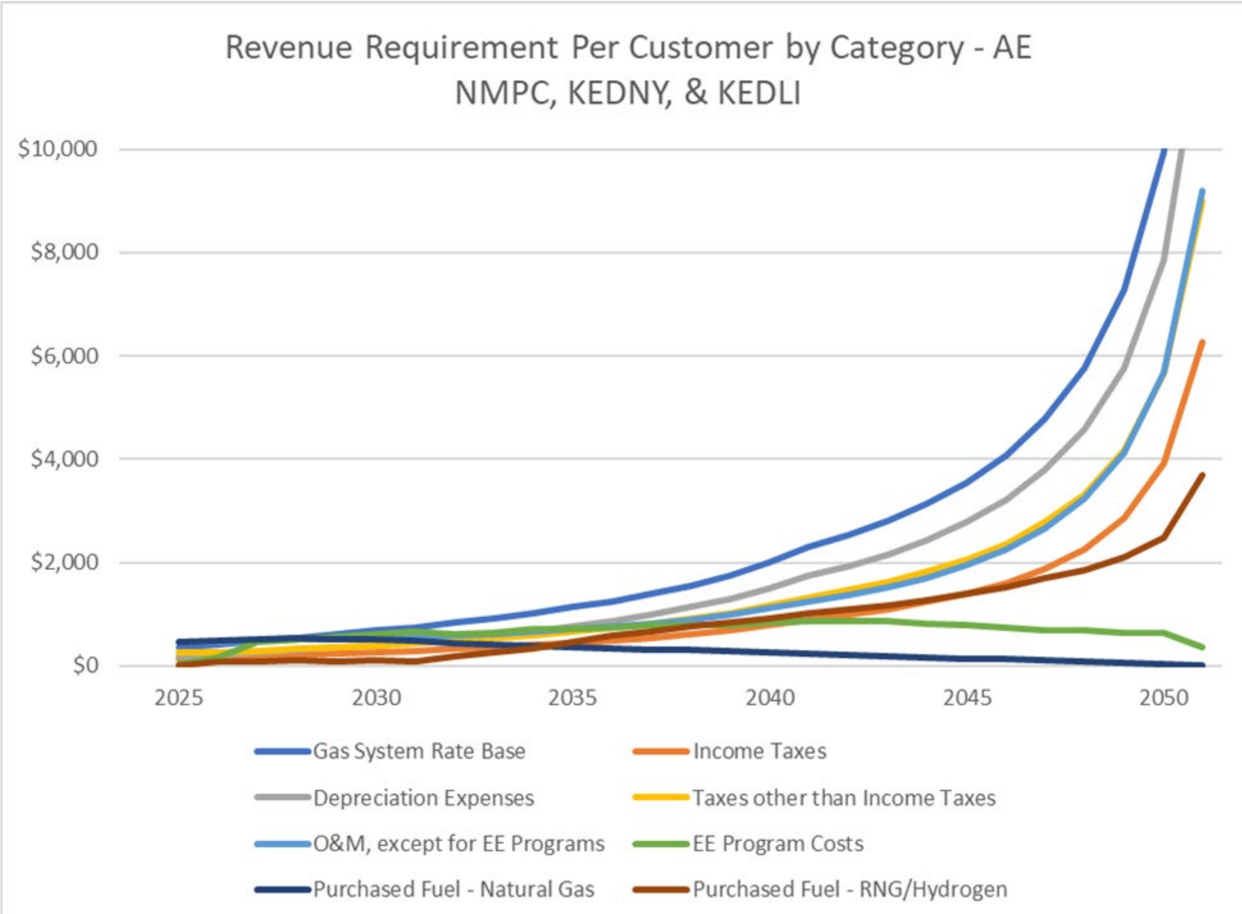
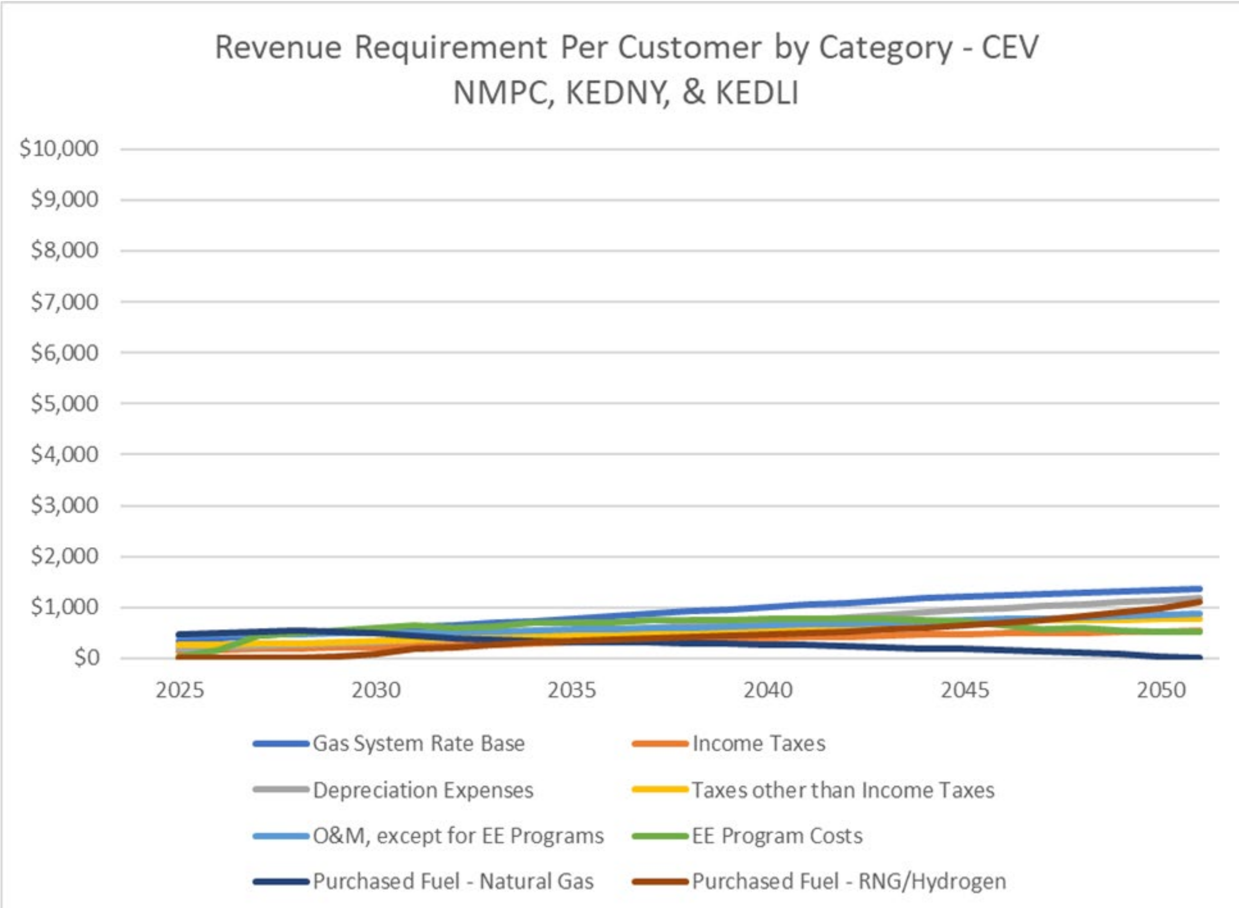


Figure 8-8: CEV – Revenue Requirement Per Customer



8.2.2. Equity

Addressing costs and ensuring access to clean energy are essential to enhance the equity of the gas transition. Low-income customers and those in disadvantaged communities are disproportionately likely to face barriers to electrification, underscoring the importance of lowering costs associated with energy efficiency and heat electrification, which are the largest contributors to societal costs under both scenarios. Making RNG and clean hydrogen available in the near term will help provide access to customers who are unable to electrify today and help build the market for clean alternative fuels and lower the cost of clean fuels through scale.

National Grid is committed to working transparently and collaboratively with stakeholders and communities to support equity and environmental justice in the clean energy transition. We are working to ensure customers in DACs benefit from improved infrastructure, expanded outreach to provide accessible, authentic engagement and representation in our processes, expanded participation in energy efficiency and affordability programs that can help customers manage their bills, and specific community economic benefits through programs such as workforce development grants as well as our shareholder-funded community initiatives.

Our draft Equity and Environmental Justice Stakeholder Engagement Framework, included in the Appendix, which summarizes our principles and intentions for meeting these objectives. We welcome feedback on this framework and how to best support customers in disadvantaged communities through the gas transition.

Finally, intergenerational equity must be a central focus of the gas transition, as gas system planning choices made today like avoiding unnecessary costs, recovering costs sooner, or to taking steps to balance the long term customer base so that more customers can share system costs, will be essential for ensuring gas customers in the future are not forced to pay costs associated with providing gas service to other customers today.

8.2.3. Jobs and Economic Development

Affordable clean energy is essential to support a thriving economy in New York in the future. Economic opportunity from clean technology development presents meaningful up-side for New York's economy, and building more clean energy production capacity in the state will support a more achievable and affordable clean energy transition. At the same time, there is a risk that choices made today related to the gas transition could harm economic development by making essential energy more expensive and threatening the reliability of the energy system. Some of the most promising sectors for economic growth, including semiconductor manufacturing and artificial intelligence, are very energy intensive. Decarbonizing the gas network while also ensuring sufficient energy system capacity is available to serve growing energy demand from these emerging sectors while continuing to provide safe and reliable service to the mainstays of today's economy like finance, real estate, manufacturing, and health care will be a challenge, especially as the number of customers using the gas network declines, leaving the costs of the gas system to an increasingly small customer base. Absent mitigation, the most dramatic bill increases will flow to the largest hard-to-electrify customers in 2050 when only a few remain in their respective service classifications. Bill impacts for these edge-cases are not presented in this in this analysis but will be addressed further in the revised filing.

Further, a just and equitable transition for gas workers must be a priority under any gas decarbonization pathway. Gas workers are already playing a crucial role in the clean energy transition, putting their skills to work in their communities to make the clean energy transition succeed by modernizing the gas network and eliminating methane emissions. This workforce will be essential for in both the CEV and AE scenarios, and their skills must be harnessed to avoid resource deployment bottlenecks.

Agriculture is also an essential part of New York's economy. Increasing in-state RNG production will provide an important revenue stream to farmers, helping keep family operations open and supporting a more affordable food system. The benefits of RNG production, which also help municipalities through the production of RNG from wastewater and landfills, will not be fully realized without new policies to enable utilities to procure and deliver RNG, which is essential for the CEV and AE scenarios.

8.2.4. Energy System Reliability

The gas network supports the reliability and resiliency of the overall energy system by bridging the power generation and heating sectors, helping provide backup power, and helping make sure families and businesses can stay warm even during extreme winter weather. While we support right sizing the gas system, there is a serious risk that a disorderly transition which does not consider the reliability and resiliency value of the gas network could cause major harm. Understanding the costs of ensuring the necessary levels of system reliability and resilience, and the societal costs of losses to reliability and resulting harms is essential for assessing the risk of policy and system planning decisions and is necessary for an effective approach to Integrated Energy Planning, all of which are required in either the CEV or AE scenarios.

8.2.5. Electrification Adoption Rate

The rate customers install electric heat pumps must rapidly accelerate to be on track with the pace of adoption required under either the AE or CEV. The following figures represent necessary electrification conversion rates on a weekly and cumulative basis in each year between now and 2050. The y-axis in Figures 8-9 and 8-11 represents the number of National Grid gas customers who must convert to electric heat *every week* for the entire year, while the y-axis in Figures 8-10 and 8-12 represent the total number of National Grid customers who must convert to electric. In Figure 8-9 and 8-10, the CEV data series includes only customers who fully electrify, eliminating their gas service. In Figure 8-11 and 8-12, the CEV data series includes both customers who fully electrify as well as customers who install heat pumps while maintaining their gas service in a hybrid configuration, referred to as “partial electrification.”

Both CEV and AE scenarios have aggressive electrification conversation rates. More aggressive conversion rates depend on adequate workforce to convert buildings and overall greater risk of implementation. These risks include practical challenges, including equipment turnover cycles not being aligned with building renovation cycles, complex logistics and capital constraints. The analysis below provides a high-level snapshot that does not consider different building typologies, which will vary in technical feasibility, cost, and strategy for conversion.

Importantly, the needed rate of heat pump installations is similar under the AE and the CEV after 2040, although a portion of the CEV installations is partial, meaning some customers retain their gas service alongside their new heat pump. Nonetheless, while partial electrification will likely be more affordable for the customer and contribute less to increased incremental costs of electric system capacity expansion, the challenges for achieving partial heat pump installations at scale is the same as for a full electrification installation. Both scenarios will require a policy and regulatory frameworks to enable the necessary pace of heat pump adoption.

Figure 8-9: Weekly Electrification Adoption (Full Electrification under CEV)

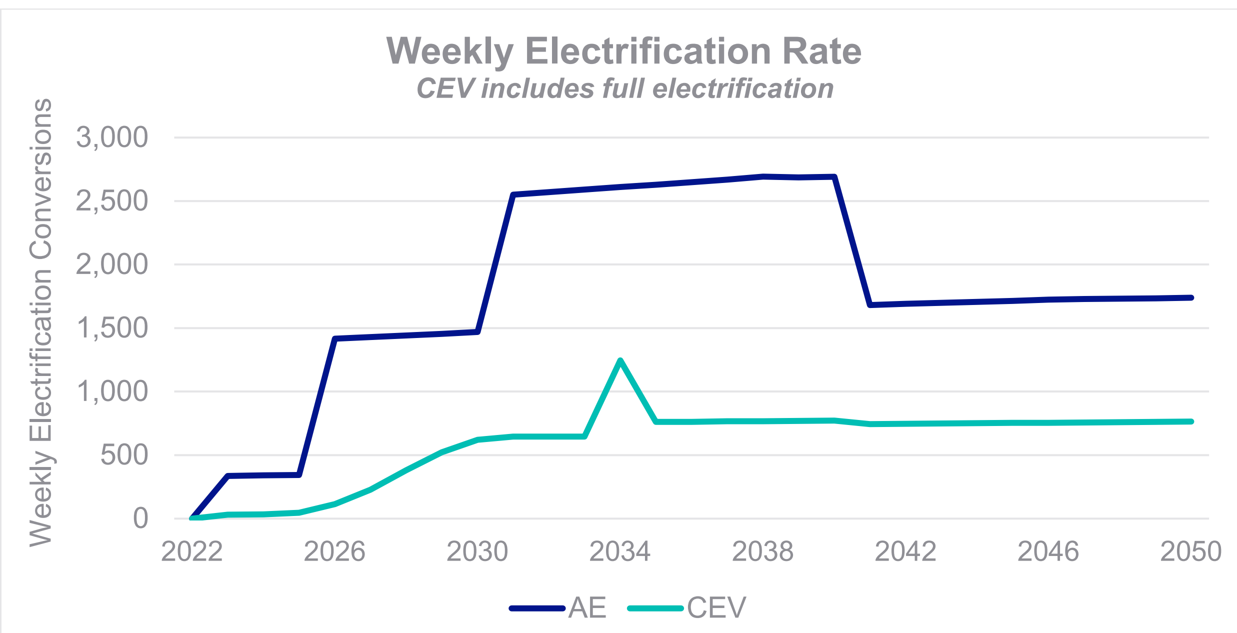


Figure 8-10: Cumulative Electrification Adoption (Full and Partial Electrification under CEV)

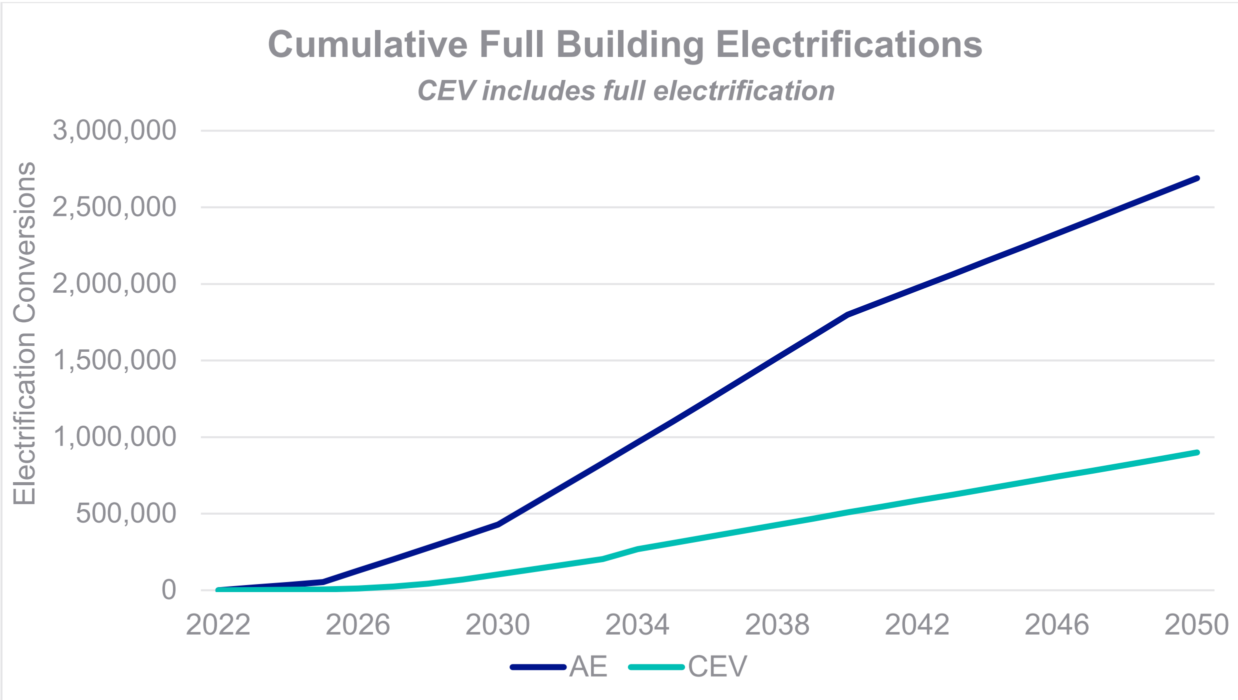


Figure 8-11: Weekly Electrification Adoption (Full and Partial Electrification under CEV)

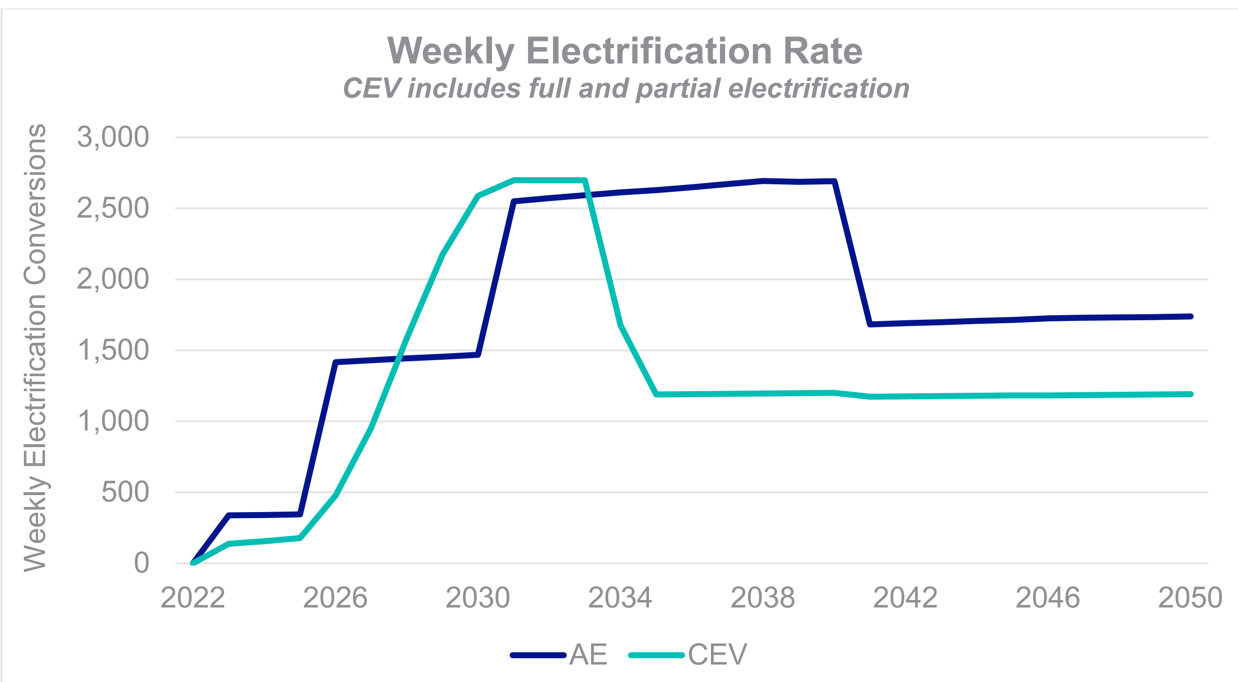
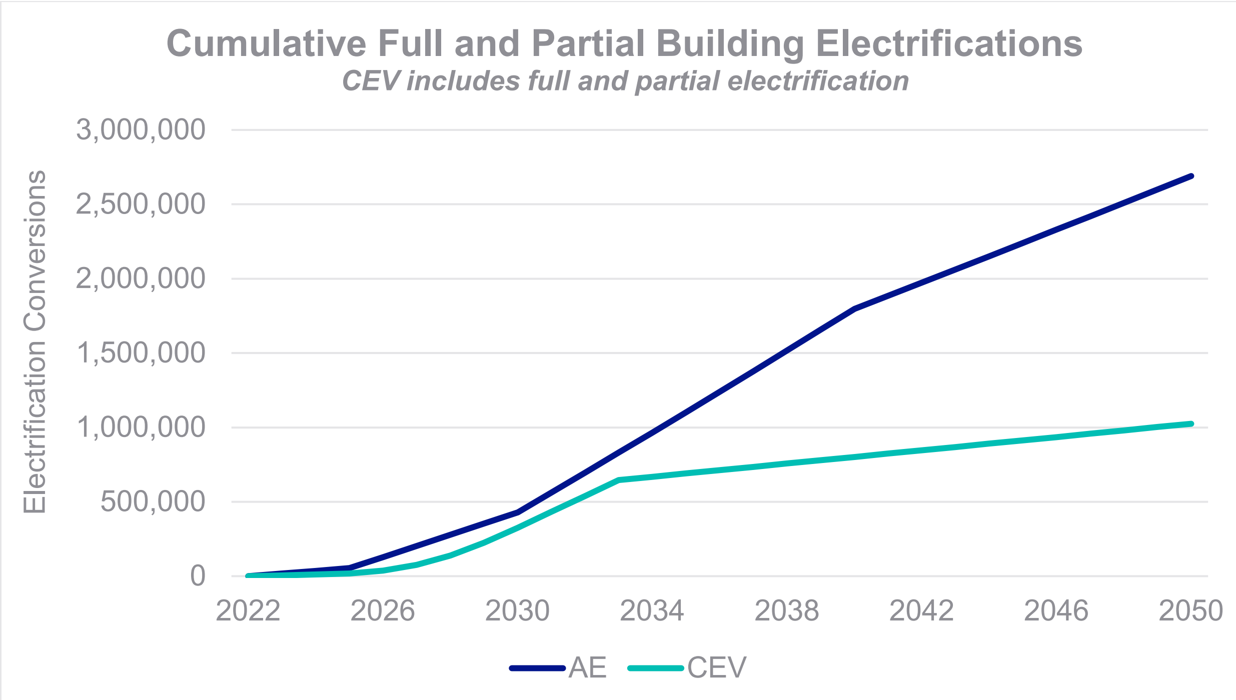


Figure 8-12: Cumulative Electrification Adoption (Full and Partial Electrification under CEV)



8.2.6. Electric System Capacity

The costs of additional electric system capacity to replace the heating load currently served by the gas network are a large proportion of total societal costs for both scenarios according to the BCA. These costs make up 27% of total costs for the CEV ($57.2 billion), and 40% of total costs for the AE ($85.8 billion). There is no question that the clean energy transition will require upgrading the electric grid at an unprecedented scale, or that electrification of a significant portion of the heat energy currently delivered by the gas network should be pursued. However, the magnitude of these costs for the AE scenario effectively erases the total value of the comparative advantage of the AE over the CEV for every category of costs and benefits where the AE is better, including the value of greater GHG reductions from gas combustion, avoided methane leakage, the cost of low carbon fuels, cost of “future of heat infrastructure” like hydrogen networks, and savings from avoiding LPP costs. Put another way, the incremental costs of increased electric capacity in the AE relative to the CEV ($28.6 billion) more than 5 times greater than the combined net benefits of the AE relative to the CEV in all of the categories in which the AE has the advantage, which add up to $5.4 billion in benefits for avoided gas supply, avoided emissions from gas combustion, avoided methane leakage. The cost of electric capacity hurts the value of the AE scenario significantly, more so than any single category of cost hurts the CEV scenario.

There is no way to avoid increased electric capacity costs in a decarbonized future. Demand growth from energy intensive industries alone is likely to drive increases, even putting aside the massive build-out needed for economy-wide decarbonization. Indeed, the Reference Case has $8.5 billion worth of these costs. The need for new clean power generation, transmission upgrades, and distribution system investments will be significant in the future for any gas transition pathway, but understanding the scale of these costs is essential for planning and executing on our shared goals and bringing down these costs and managing their impacts on customers’ total energy wallet must be a priority for policymakers and regulators.

8.2.7. Emissions Leakage

Finally, any policies or regulations for advancing the gas transition must consider the effect on emissions leakage, which would occur when a policy or regulation results in reduced emissions within New York, but also causes emissions to increase somewhere else. Climate change is a global phenomenon caused by the concentration of anthropogenic GHGs in the atmosphere, and the effect of GHG emissions is the same no matter where they occur. Emissions do not respect borders. Therefore, it is imperative that any policies and regulations related to climate action are measured and implemented on the basis of lifecycle assessment (LCA) of GHG emissions. Standard protocols and frameworks for LCA are in place in other states, and the federal level, and around the world. Implementing a comprehensive LCA framework in New York should be a priority.

8.3. Recommended Regulatory & Policy Actions

Achieving the CLCPA's emissions reduction targets while ensuring equitable access to safe, reliable, and affordable energy will require National Grid and our peer gas utilities to transform our businesses. As regulated utilities, our business models are substantially defined through regulation, while regulatory frameworks are governed by state policy established in statute. While existing programs give utilities some important decarbonization tools, including the DSM programs discussed in Section 5, existing programs are not sufficient to achieve the CLCPA's targets. Both the CEV and AE scenarios presented here require new policies and regulations to reshape how utilities plan and construct gas infrastructure, procure fuel, incentivize customer choices, and recover costs.

The current regulatory business model under which gas LDCs operate developed from a historical premise of continued demand growth and infrastructure investment to serve that growth. The core regulatory objective is the provision of safe and reliable gas delivery service at just and reasonable rates. Moving forward, utility regulations must also consider decarbonization without diminishing the importance of safety, reliability, and affordability.

Multiple reforms will be necessary to facilitate the transition to a clean energy future. Regulatory frameworks will need to ensure the affordability of essential energy services, including clean alternative fuels to serve difficult-to-electrify applications in a future that may be characterized by declining gas demand and increased electric load. New processes must be established for planning, building, and operating the electric and gas systems in a coordinated manner. From a regulatory perspective, there is currently minimal, if any, interaction between gas and electric network planning, demand forecasting, and regulatory reviews. Further, gas utilities will need regulatory clarity on cost recovery for new technologies, alternatives to traditional investments, and actions that can ensure long-term affordability of service for customers.

The Company has identified four key categories of regulatory and policy reforms that will be necessary to enable the transition to net zero, all of which are necessary to enable both the CEV and AE:

- **Establishing frameworks for an orderly transition**
- **Ensuring long-term energy affordability**
- **Scaling efficiency and electrification to equitably reduce customer gas demand**
- **Enabling procurement and integration of affordable clean alternative fuels.**

We recommend that the Commission immediately begin a formal and comprehensive process to address the requirements and risks discussed in Sections 8.1 and 8.2, and that due consideration be given to the actions and concepts discussed below. These recommendations are consistent with the Scoping Plan's call for a comprehensive gas system transition plan.

8.3.1. Establishing frameworks for an orderly transition

An orderly gas transition will have common features whether it more closely resembles the CEV or the AE. Those features include but are not limited to:

- Coordination and integration of system planning between overlapping gas and electric utilities.
- Sufficient electric capacity to serve incremental heating load without sacrificing system reliability, and without causing unreasonable cost increases for electric customers or society overall.
- Mitigating affordability risk to gas customers in the future who are unable to electrify.
- Ensuring adequate and affordable alternatives to gas service are available for any customers who may be required to electrify through policy or regulation.
- Enabling sections of the gas network to be decommissioned and incremental gas utility costs to be avoided through the deployment of efficient electric heating technologies while maintaining safety and reliability of the gas and electric systems.
- Regulatory and policy assurance of timely recovery of utilities' prudently incurred costs.
- An equitable transition for gas system workers.

We have identified the policy and regulatory concepts discussed below as some of the most necessary and urgent to shape an orderly gas transition and reduce associated barriers and risks to the CEV and the AE.

8.3.1.1 Integrated Energy Planning

The Scoping Plan calls for ensuring "close coordination [of the gas transition] with electric system expansion," including "a detailed, strategic, and coordinated approach to optimization of the electric and gas systems." National Grid refers to these concepts together as Integrated Energy Planning ("IEP"). IEP involves considering and incorporating critical interactions between the gas, electric, and customer energy systems into utility planning processes in the context of long-term climate goals. By recognizing the interdependent and complementary nature of today's energy systems, integrated energy planning can help advance decarbonization goals at the lowest achievable cost and with the greatest and most equitable benefits for customers. New policies and regulatory frameworks will be necessary to enable the coordinated planning of gas and electric distribution systems, especially in areas where gas and electric service are delivered by separate utility companies. Frameworks to enable IEP include[136]:

- Regulatory support for cross utility data sharing.
- Enabling partnerships between utilities and municipalities to ensure alignment, build community support, and incorporate local priorities in project planning.
- Enhancements to gas system planning processes, including updated cost-effectiveness tools.
- Regulatory changes discussed in the following sections.

8.3.1.2. Regulatory changes to encourage heat electrification

The current statutory and regulatory requirements for service line extensions and provision of service are barriers to cost-effective electrification of some segments of the gas network. Altering

[136] These concepts are discussed in detail in the joint whitepaper National Grid published with RMI: Non-Pipeline Alternative: Emerging Opportunities in Planning for US Gas System Decarbonization: https://www.nationalgridus.com/News/2024/05/National-Grid-and-RMI-Examine-Role-of-Non-pipeline-Alternatives-in-the-Energy-Transition/

these statutory or regulatory frameworks, however, could be inconsistent with a fair, equitable, and affordable transition unless adequate care is taken to mitigate cost and feasibility risks and avoid unreasonably disrupting customer choice. Statutory and regulatory changes should be considered to gas utilities' obligation to connect new customers to the gas system and to provide service extension allowances such as the 100-foot rule and should be enacted once adequate guardrails to protect customers have been incorporated into regulatory frameworks.

National Grid believes strongly in customers retaining choice. There are some who advocate that policies should be enacted to modify the obligation to serve existing customers' gas service, including granting the Commission statutory authority to curtail or discontinue gas service to those customers, thereby allowing the decommissioning of segments of the gas network pursuant to a program approved by the commission. National Grid does not support such action unless accompanied by provisions requiring such programs to require the following:

- An orderly transition.
- Customers retain continuous access to safe, reliable, and affordable energy services and can secure adequate substitutes for gas-fired space heating, water heating, and cooking appliances prior to discontinuance of gas service.
- Adequate electric infrastructure be in place to assume the gas load being shifted, and there is sufficient firm generation from zero emissions sources to accommodate the customer demand.
- The safety and reliability of the gas system and the electric system is maintained at all times.
- Strategies are in place to ensure unreasonable burdens are not imposed on gas customers, especially low-to-moderate income customers and those in disadvantaged communities.
- Necessary and appropriate financial and technical support, including for the purchase and installation of customer-owned equipment and energy efficiency and electrical upgrades.
- A just and equitable transition for gas system workers.
- Replacement and repair of leak prone pipe necessary for safety and emissions reduction is not impeded, except that the Commission may approve alternatives to replacement and repair of leak prone pipe.
- Provision for the timely recovery by gas utilities of investment in the gas system at just and reasonable rates.

8.3.1.3. Regulatory Frameworks to Scale Targeted Electrification and NPAs

Targeted electrification refers to the process of replacing heating load currently served by the gas network with efficient electric alternatives like air source heat pumps and UTENs in specific localized areas such that decommissioning of the local segment of the gas network may be achieved and incremental gas system costs may be avoided. Targeted electrification is an umbrella term that includes NPAs, another critical lever for ensuring an orderly and affordable energy transition. We urge the Commission to develop an orderly framework for targeted electrification irrespective of the status of legislation.

Where solutions involve targeted electrification, it will be critical to address the processes, standards, and policies relevant to their implementation. It will be most effective when it relies on a coordinated IEP process that enables the identification of locations where investment for gas system expansion or replacement can be avoided, sufficient electric capacity is available, and customer propensity for electrification is high.

In order to develop insights from other entities in the United States and Europe that have pursued NPA initiatives and developed IEP processes, National Grid conducted research with RMI (formerly known as Rocky Mountain Institute) during 2023 as discussed in section 5.1.4. The resulting whitepaper demonstrates that there has been limited success at encouraging entire groups of customers in targeted geographic areas to fully electrify, even when the customers' costs to do so are fully subsidized. It also drew the following conclusions, which are described in more detail in the full report.[137]

- NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions.
- NPA projects can identify value in cost savings on the gas system, emissions reductions or other societal benefits, and can be funded from a series of different sources while protecting ratepayers' long-term affordability.
- Integrated gas and electric network planning offers the opportunity to achieve net zero goals as cost-effectively and equitably as possible.
- Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning.
- Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects.
- Policy change will be needed to evolve the utility business model and obligation to serve, while still retaining the opportunity for cost recovery in a transition away from the use of gas.

  Absent regulatory or legislative mandates that effectively remove customers' ability to remain connected to gas networks, enacting targeted electrification and gas system decommissioning will be challenging to scale.

Practically, solutions that require coordination among groups of customers raise implementation challenges that must be addressed. For example, switching a neighborhood currently served with gas service to networked geothermal service or another electric heat solution will require participation of most, if not all, the customers in the immediate area; if one customer does not wish to participate, the viability of the project may be threatened. Key considerations for process, standards, and policies include, but are not limited to, the requirements and timeline around customer notification, customer response timelines and options, and financial and logistical support for participating customers. Advancing the regulatory framework for UTENs will also support enabling successful targeted electrification.

National Grid intends to develop and propose projects that will help identify how we can mitigate these challenges. Those projects will aim to address, among other issues: ways of working more closely with local communities to increase customer uptake, inclusion of electric system planning needs within the NPA process, development of customer propensity data to evaluate levels of incentives needed to drive adoption at scale, and improved collaboration with peer utilities.
In addition, the existing statewide NPA framework in New York should evolve to overcome the hurdles mentioned in this report. The Company seeks to coordinate with New York regulators and policy makers on the following recommendations:

- Identify potential additional funding sources that may be required to scale targeted electrification.
- Consider required timelines for NPA project identification and developments, in order to enable customer participation and allow time for electric infrastructure upgrades that may be necessary.
- Identify ways to engage with municipalities to support NPA project success.
- Better enable system mapping, data sharing across utilities, and other tools needed to support integrated energy planning.

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[137] May 2024. Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization. https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

- Identify updates to rate design and depreciation methodologies that will ensure equity for ratepayers in a long-term future scenario with declining customer base.

8.3.2. Ensuring long-term energy affordability

According to the Scoping Plan, "reduc[ing] energy burdens and address[ing] energy affordability concerns" is a "key principle" of the gas system transition. The Scoping Plan recommends identifying "ways to mitigate impacts on remaining gas customers as customers transition to electrification and away from the use of the gas system, with a particular focus on low-income customers." This is consistent with our analysis, which indicates customer bills increase exponentially if the overall year-over-year rate of gas customer departures accelerates due to high levels of total customer departures. Ensuring the gas transition is affordable will require new frameworks for cost recovery so that remaining gas customers are not burdened with the costs of today's gas system in the future.

8.3.2.1. Equitable Depreciation

Effective and equitable decarbonization will require recovery of utility gas network capital costs through depreciation at a more rapid rate than in the past in anticipation of declining demand and related retirement of assets. Under any decarbonization pathway, depreciation expense recovery approaches should be advanced to ensure that a smaller number of customers are not bearing a disproportionate share of overall depreciation expense in the future. There is value in beginning to accelerate recovery of depreciation now, and considering novel depreciation mechanisms that can balance the traditional principles of intergenerational equity, cost causation, and avoidance of rate shock, while maintaining near-term affordability most effectively. If the collection of depreciation expenses is accelerated early and sustained over time, then even relatively modest increases in depreciation expenses recovered would allow for reductions in future bill impacts and undepreciated rate base by 2050. Depreciation policy is discussed in greater detail in Section 8.4.

8.3.2.2. Cross-utility Cost Coordination

Today, the systems that produce, move, and deliver energy for electricity and heat are largely subject to separate and distinct regulatory frameworks. In the future these systems will become more intertwined as heating load is electrified and the role of the gas network shifts to play a complementary but essential role providing heat on the coldest days of the year, serving difficult-to-electrify demand, balancing the intermittency of renewable power generation, and enhancing the reliability and resiliency of the overall energy network. As the gas transition progresses, coordination among gas and electric utilities will be essential to ensure costs associated with meeting today's gas demand are not borne disproportionately by gas customers who are unable to electrify in the future. New policies and regulatory frameworks will be necessary so the costs of today's energy system, which are the direct result of the public policy priorities and market dynamics of the past, may be apportioned in a manner that is equitable and affordable for future gas and electric customers. Specifically, we recommend regulatory enablement of coordination between electric utilities whose service territories overlap with that of a gas utility on system planning and the evaluation of options to support the financing of alternatives to gas capital investment.

8.3.2.3. Optimizing New York Cap & Invest ("NYCI") for affordability

National Grid supports a well-designed price on GHG emissions and is pleased to work closely with NYSERDA to support the development of such a program. National Grid filed comments on March 1, 2024, detailing several recommendations to ensure NYCI is affordable for customers and is as effective as possible. Those recommendations include:

- **Ensure gradualism is reflected in every aspect of program design to avoid price shocks both up-front and over time, by:**
    - Establishing the beginning period price ceilings at or near the levels modeled by the Agencies.
    - Using a historical method for the initial allowance budget, rather than projecting theoretical reductions for the first year of the program.
    - Avoiding designing the allowance budget trajectory with large step-change reductions from one program year to the next (or one compliance period to the next) that are unsupported by technology deployment.
    - Adopting compliance periods of three years.
    - Including program stability mechanisms that gradually increase.
    - Allowing unrestricted allowance banking by compliance entities.

- **Use a combination of strategies to effectively tailor the price signals seen by different types of energy consumers, including:**
    - Ensuring low-income residents see no cost increases from the NYCI program.
    - Providing no-cost allowances for gas companies to sell at auction to support customer affordability, especially for low-income customers.
    - Providing no-cost allowances for EITE businesses starting at 100% of historical emissions to limit leakage and enable continued economic development in the state.

- **Provide for administrative simplicity and efficiency for utility compliance entities.**
    - Aligning mandatory GHG reporting rules as closely as possible to the federal government's emission reporting rule.
    - Making fuel suppliers the obligated entity for their customers (and not the delivery companies), so that GHG emissions obligation flows with the commodity.

- **Obligate as many sectors as possible to achieve broad reach and to drive incremental emissions reductions.**
- **Design near-term revenue reinvestment strategies to prioritize cost-effective emissions reductions and support energy affordability.**
- **Advance key complementary policies in parallel with NYCI rules, including sectoral performance standards for heating and transportation fuels.**

8.3.3. Scaling energy efficiency and electrification to equitably reduce customer gas demand

The CEV and AE scenarios require the same level of demand reduction from energy efficiency, which is more than 3.5 times greater than what can be achieved through current policies, regulations, and market dynamics as forecasted in the Reference Case. Both scenarios require rapid acceleration of electric heat as well. According to the BCA, incremental energy efficiency and electrification program costs are $19 billion for both scenarios and make up a meaningful albeit declining share of per-customer revenue requirement over time in both scenarios. Considering essentially equivalent importance of these resources to both the AE and CEV, optimizing programs and policies for rapidly scaling energy efficiency and electrification should be a top priority within a future gas transition plan.

8.3.3.1. New sources of funding for DSM programs

The CEV and the AE will require the funding mechanisms for energy efficiency to be expanded. The current model of energy efficiency programs puts the cost burden on electric and gas customers. While this model worked well in the past, as building upgrade and conversion strategies become more aggressive, additional outside funding will be needed to continue the proven success of New York's building efficiency and decarbonization programs. Policymakers and regulators should consider options for leveraging additional state and federal funding, including targeting revenues from the NYCI program to support expanded DSM.

8.3.3.2. Enhanced program design to ensure equity and balance customer bill impact with emissions reductions

In addition to expanding funding sources, program design must ensure that customer bill impacts of efficiency programs remain reasonable. This will require setting program targets in a way that balances the level of ambition necessary to make rapid progress toward decarbonization with allowing for the market developments (i.e., customer education, installation contractor training and workforce development investments, distribution network development) necessary to support sustained market transformation. Further, to ensure stable bill impacts, energy efficiency plans must find innovative ways to reduce customer acquisition and program delivery costs to make room for incentivizing more expensive technologies and increasing incentives for moderate income customers.

Ongoing close attention will need to be focused on low-income customers and Disadvantaged Communities. National Grid is steadfast in its commitment to ensuring equitable access to our energy efficiency programs for all customers and specifically, increasing the participation of hard-to-serve residential, commercial, and industrial customer segments. Program designs will need to continue to consider and evaluate equity goals and consider the systemic and institutional structures that may make it easier for some customers to access energy efficiency products and programs but more challenging for others to do so.

New York State could improve access to clean energy technologies and demand-side management measures through energy transition equity programs – income-based and community-based incentive structures and geotargeted deployments designed to improve access to clean energy, demand-side management programs, electrification programs, and thermal energy networks such as networked geothermal systems. Funding for these programs could come through multiple avenues including direct funding from the federal or state government and funds generated through an energy transition surcharge or other rate rider included on electricity and/or gas utility bills. Revenue raised under a potential economywide cap-and-invest program, as called for in the final Scoping Plan, could also be directed toward such initiatives.

8.3.3.3. Improved portfolio planning to ensure the most cost-effective and achievable mix of demand-side tools for achieving emissions reductions

On top of expanded funding and enhanced programs, National Grid recommends building a new portfolio planning process and supporting tool to evaluate the most affordable, equitable, and reliable mix of demand-side levers that is needed to achieve state climate goals – e.g., incentive programs, gas service requirements, rate design changes, targeted electrification / NPAs, building codes, and mandates. Given the complexity of undertaking a new process state-wide, National Grid recommends initiating the process within the Companies' service territories, incorporating lessons learned, and then expanding to other regions of the state.

Underpinning the process and tool, we envision a baseline quantitative analysis of the technical, economic, and market potential of the demand-side levers at New York's disposal for reducing gas demand. For existing levers, such as incentive programs and building codes, the baseline analysis would seek to build on assumptions used from existing potential studies (such as those conducted by NYSERDA) and program evaluation reports. For newer levers, such as targeted electrification, the analysis would establish an initial baseline and identify gaps in assumptions to improve reliability going forward. The analysis would also identify plans to improve assumptions where necessary for existing or new demand-side levers. Throughout the development of the baseline analysis, coordination with other program administrators in National Grid's territory as well as policy makers and regulators would be critical to ensuring assumptions for levers not administered by National Grid are as accurate as possible.

With a baseline analysis complete, a new process and tool can be utilized in collaboration with stakeholders to test new portfolios of demand-side levers against the existing portfolio. The tool would need to be updated periodically to account for changes in policies, funding sources, technology advancements, new regulatory frameworks under consideration, and any other market factors impacting assumptions underlying the tool. Furthermore, running the process periodically would allow for us to shift priority to levers that may be more impactful or cost-effective than those we rely on today. Only with a collaborative, data-driven approach will we be able to plan towards the most affordable, equitable, and reliable mix of demand-side levers to take forward for meeting state climate goals.

8.3.4. Enabling procurement and integration of affordable clean alternative fuels.

Alternative fuels such as RNG and clean hydrogen are not a substitute for electrification, but instead as the Scoping Plan put it, "rapid and widespread building efficiency and electrification is needed *and supported by the strategic utilization of alternative fuels."*[138] All Scoping Plan "integration analysis" scenarios showed substantial demand for fuels in 2050 to serve difficult-to-electrify applications, including building heat and industrial processes. The Scoping Plan calls on Department of Public Service ("DPS") to "consider strategic use of alternative fuels…to meet customer needs for space heating or process use where electrification is not yet feasible or to decarbonize the gas system as it transitions."[139] Such evaluation should proceed as soon as possible to further develop the new policies and regulatory frameworks necessary to ensure sufficient clean alternative fuels are available to meet New Yorkers' needs in 2050 and to maximize cost-effective decarbonization while electrification scales up.

Fifteen US states have adopted RNG and/or enabling frameworks through legislation or regulation, and at least 11 more are actively considering them, providing ample examples of best practices to guide development of frameworks to enable clean alternative fuels in New York.[140]

As described in Section 8.1.3, both the CEV and AE scenarios require large volumes of RNG and clean hydrogen, with the AE scenario requiring more between 2035 and 2040, and the CEV requiring incrementally more overall. The incremental societal cost of RNG and hydrogen is a meaningful contributor to net costs for both scenarios but is essential meeting difficult-to-electrify gas demand. The emissions benefits of RNG[141] and clean hydrogen[142] are well established, and policies to enable utilities to procure them to support decarbonization should be enacted as soon as possible to ensure the market for clean alternative fuels has time to scale up to meet future demand.

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[138] Final Scoping Plan, p. 176. Emphasis added.
[139] Id., p. 361
[140] See Appendix 11.3
[141] According to US EPA, "[w]hen fossil natural gas is replaced by RNG, the resulting GHG emission reductions provide a climate benefit." US EPA, 2024. An Overview of Renewable Natural Gas from Biogas, p. 11. https://www.epa.gov/system/files/documents/2024-01/lmop_rng_document.pdf
[142] According to US DOE, "[h]ydrogen can be produced from diverse domestic resources with the potential for near-zero greenhouse gas emissions." US DOE Alternative Fuels Data Center. https://afdc.energy.gov/fuels/hydrogen-benefits#:~:text=Hydrogen%20can%20be%20produced%20from,stationary%20and%20transportation%20energy%20sectors.

8.3.4.1. Gas Utility Decarbonization Performance Standard

National Grid recommends adoption of a gas utility decarbonization performance standard to require gas utilities to reduce the carbon intensity of the fuel they deliver. Such a standard should increase over time to enable achievement of the CLCPA's targets, should be designed to ensure the reduction of lifecycle GHG emissions at the lowest achievable cost per ton, and may be linked to new frameworks for earnings adjustment mechanisms or other performance incentives. Gas utility decarbonization performance standards are consistent with the CLCPA, and we believe the Commission has the authority to develop and enact such standards under existing law.

8.3.4.2. Accurate GHG Accounting

Targeting and optimizing the use of alternative fuels to support decarbonization requires a regulatory framework to quantify the GHG emissions reduction benefits of replacing fossil fuels with low-carbon alternatives. Accurate GHG accounting must be embedded within regulatory constructs related to gas utility decarbonization, including BCA framework for NPAs, the criteria for evaluating gas supply contracts, alternative rates and performance incentive frameworks, and any future decarbonization performance standard. GHG emissions associated with alternative fuels should be considered on a lifecycle basis, as called for in the Scoping Plan and consistent with US federal law established in the Inflation Reduction Act, to ensure real, verifiable emissions reductions. Established US and international standards for GHG accounting should be utilized to avoid conflicts and double counting.

Realizing RNG's full decarbonization potential depends on accurate GHG accounting. At present, New York's approach to GHG accounting for bioenergy like RNG is at odds with US and international standards and the best available science. The established international, national, and state standard for bioenergy GHG accounting is to *exclude* CO_2 emissions from the combustion of bioenergy from energy sector emissions totals. This is because these emissions – known as "biogenic CO_2" – are accounted for in the sector where the biomass was originally harvested. Reporting these emissions as energy sector emissions causes them to be double counted. Instead, CO_2 emissions from the combustion of bioenergy are typically reported as an "informational item" or "memo item," but don't formally count as energy sector emissions under established US and international standards.

New York's current approach for biogenic CO_2 is to *include* these emissions in energy sector emissions totals for the purposes of assessing compliance with the statewide emissions limits. The annual Statewide Emissions Report includes an informal assessment of "net" emissions that purports to exclude biogenic CO_2 emissions,[143] but this unofficial "net" ledger is not applied in determining the state's statutory emissions limits. Consequently, if the current approach is not modified, <u>New York will double-count biogenic CO_2 for regulatory compliance purposes, resulting in overreporting of annual emissions, and increasing the cost and difficulty of complying with the CLCPA's statewide limits.</u>

Aligning New York's GHG accounting approach with US and international standards can be achieved without amending the CLCPA or the state's Greenhouse Gas Emission Limits regulation (6 NYCRR Part 496). To avoid double counting and to incentivize the most cost-effective emissions reductions, biogenic CO_2 emissions should be reported separately from "gross" emissions under Part 496. Doing so is consistent with methodologies adopted by federal government through the Inflation Reduction Act and by international authorities including the GHG Protocol, the IPCC, and other US and international jurisdictions. DEC could adopt the approach used by the California Air Resources Board, in which biogenic CO_2 is "tracked separately from the rest of the emissions in the

[143] New York State Department of Environmental Conservation, "2022 NYS Greenhouse Gas Emissions Report," p. 3, available at https://extapps.dec.ny.gov/docs/administration_pdf/ghgenergy22.pdf.

inventory and are not included in the total emissions when comparing to California's 2020 and 2030 GHG Limits."[144] This approach is recommended by the GHG Protocol and is also followed by the US EPA in reporting the national GHG inventory. Recognizing DEC is empowered by the CLCPA to make determinations with respect to the state-wide greenhouse gas emissions limits, DEC has the authority to alter its approach without changes to the CLCPA.[145]

8.3.4.3. Support for pilots and demonstrations

The Scoping Plan calls for enhanced support for Research, Development, and Demonstration for alternative fuels. The Company is exploring the potential for alternative fuels to contribute to decarbonization through numerous proposals across its service territories. These and future pilots and demonstrations are necessary to understand the value and role of alternative fuels in an orderly gas system transition. Pilots and demonstration projects will ensure the Scoping Plan's proposed "research agenda" for alternative fuels is advanced, including the development of "rigorous energy, GHG, and environmental sustainability guidelines and metrics," assessment co-pollutant impacts, development of lifecycle accounting approaches, and hydrogen safety research.

8.4. Gas Depreciation Policy

8.4.1. What is depreciation policy and why is it important to the Long-Term Plan?

Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets).

State laws to address climate change, together with technological change, may result in a transformation of energy systems in New York. Depreciation policy is an important part of long-term planning for New York's gas networks, to ensure appropriate and equitable cost recovery of gas investments from the state's gas customers, accounting for likely changes in gas network utilization through the energy transition. A portion of our customer base could change energy sources, either ceasing to be gas customers or significantly reducing their consumption. Many assets will probably experience different service lives than has historically been the case. Depreciation policy is an important part of long-term planning for New York's gas networks to ensure appropriate and equitable cost recovery of gas investments from the state's gas customers, accounting for likely changes in gas network utilization through the energy transition.

The Company's current depreciation policy is called Straight-line depreciation (Average Service Lives). Straight-line depreciation implies that for every gas asset, the Company collects the same amount of depreciation in each year of the asset's depreciable life.

8.4.1.1. Commission's Investigation of Gas Depreciation

In the Gas Proceeding Order 20-G-0131, the Commission directed all gas LDCs to file long-term depreciation studies based on potential gas transition scenarios to 2050. National Grid filed its study on November 8, 2022, evaluating the potential impacts of these scenarios to long-term cost recovery and customer affordability.

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[144] California Air Resources Board, "California Greenhouse Gas Emissions for 2000 to 2020 Trends of Emissions and Other Indicators" available at https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf

[145] Implementing such an alternative also does not require altering the 1990 baseline (which is established in Part 496), only that—consistent with the IPCC and other jurisdictions—biogenic CO_2 emissions not be reported under annual "gross" emissions total for the purposes of assessing compliance with the state-wide limits.

The results of the study illustrate the need for new depreciation approaches to help ensure equitable recovery of costs from customers over time. At current depreciation rates, customers who leave the gas system soon will have only paid for part of the gas system assets from which they have derived benefits. By modifying the current depreciation methodology, the Commission can ensure these departing gas customers pay an equitable share of the costs of building and maintaining a safe and reliable gas delivery system. A modified depreciation methodology should also provide benefits for customers in Disadvantaged Communities, as it is likely that higher-income households would exit the gas system faster than lower-income households, leaving more vulnerable customers facing escalating gas system rates.

8.4.2. Depreciation Policy Options Available to Policymakers

There are many different depreciation alternatives available to policymakers. The following section describes some of these alternatives featured in the November 2022 depreciation study, as well as other methodologies the Company has evaluated. These methodologies could be considered individually or in combination, to begin increasing depreciation in anticipation of future declines in throughput and customer count. These include:

8.4.2.1. Shortening Lives

The Shortening of Gas Asset Lives is a technique used to bring the depreciable life of gas assets into better alignment with the actual life of the gas assets. Shortening an asset's depreciable life could be justifiable due to (i) new evidence showing that the asset will not physically last as long as expected in the depreciable life or (ii) decarbonization policies suggesting that the asset may not be used for its full physical life.

For a simplified example, a 10-year shortening of life on a new 60-year gas asset would increase its depreciation expense each year by 20 percent. Several New York LDCs have proposed shortening service lives for gas distribution assets in recent cases. Orange and Rockland recently proposed to shorten service lives by 15 years in Case No 24-G-0061. Previously, in Case No. 21-G-0073, Orange and Rockland proposed to shorten service lives for certain accounts by five years. In Case 22-G-0065, Con Edison proposed to shorten service lives for several accounts by as many as 10 years.

8.4.2.2. Equal Life Group Depreciation

Equal Life Group ("ELG") depreciation is a method where a gas asset is depreciated by the same amount over each year of its depreciable life. This is different from the Company's currently used Average Life Group ("ALG") Depreciation, where there is a lag in depreciation due to the depreciation grouping of assets. The ALG procedure depreciates every unit of property within an account over the same life, that is, the average life of the entire account. By contrast, the ELG procedure allocates costs in a manner that approximates the result of each asset being depreciated over its actual life.

Equal Life Group depreciation would ensure that for all assets, half of their required depreciation and cost of removal expense would be collected after half their life. However, while ELG is a more precise method than the ALG method and more accurately recovers the costs of shorter-lived assets, it is still a straight-line method and does not account for future anticipation of declining demand. The ELG procedure is accepted for use for gas assets by the Pennsylvania Public Utility Commission and the Texas Railroad Commission. It is also used in jurisdictions in Canada.

8.4.2.3. Units of Production

Units of Production ("UoP") is a depreciation method whereby the amount of depreciation that is paid each year on an active asset is formulaically derived from the amount of gas throughput in that year relative to a long-term forecast. For example, if gas system throughput in 2025 were double the forecasted throughput for 2050, then the proportion of depreciation paid on pre-2025 capex would be double in 2025 than in 2050.

The UoP method has been accepted by US depreciation authorities for natural gas or oil producing facilities for which the production is variable over the life of the production facility. In California, Pacific Gas and Electric proposed the use of UoP for gas assets in a recent general rate case to begin adjusting depreciation in light of that state's climate and energy policy. The implementation of the Units of Production method requires an approved throughput forecast for the Operating Company through the life of all of its gas assets.

8.4.2.4. Economic Planning Horizon

An Economic Planning Horizon for gas assets (aka Life Span Method) is a potential depreciation technique where the Commission establishes a date after which it believes the return of capital on a set of accounts is no longer assured based on future market conditions. This date is reconsidered with every depreciation study and moved as required to respond to new information. The Horizon is not a prediction of the assets' useful life, but rather an assumed economic life used to establish depreciation schedules that would fully recover the cost of all depreciation and cost of removal by this time. This method has been previously approved for power plants and other assets facing technological obsolescence.

8.4.3. The Company's Proposal in the NMPC Case

In its NMPC gas rate case filed May 28th, 2024 (Case 24-G-0323), the Company proposes to begin phasing in modifications to gas depreciation methods to begin accounting for state energy policy over the course of a multi-year rate period. The proposed modifications would make modest changes appropriate to the current outlook for gas system utilization, while creating optionality for additional future changes based on future changes to that outlook. The Company proposes to:

- Shorten Gas Asset Lives for certain accounts by five years to help begin to bring asset depreciable lives in line with expected lives under decarbonization scenarios.
- Implement Equal Life Group depreciation method to remove the lag in the depreciation method.
- Change from a 20-year amortization of the Reserve Imbalance[146] to a 10-Year amortization to ensure these costs are not deferred over as long a period.

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[146] Under New York State's Whole Life Accounting technique, a Reserve Imbalance is created when the amount of depreciation and cost of removal expense collected for an asset is insufficient (due to an early/late retirement of an asset, or a change in the depreciation method). In this case, the shortfall is represented as a Reserve Imbalance. If the Reserve Imbalance is sufficiently large (over 10% of the expected accumulated depreciation reserve balance), the Commission has allowed those costs to be amortized over 20 years. Under historic conditions, there has been no risk associated with this practice. However, the persistence of a large Reserve Imbalance into the future could contribute to under-recovery of costs from today's system users, pushing costs onto a future generation of users which may be smaller than current system users. Shortening the amortization period of the reserve imbalance, for example from 20 years to 10 years, could help ensure more depreciation expense and cost of removal are paid for by today's gas customers before they leave the system.

This proposal would increase annual depreciation expense by approximately 33% compared to a 'business as usual' scenario[147], representing an affordable step toward long-term risk mitigation and customer equity in line with the state's climate and energy policy.

8.4.4. Alternative Depreciation Approaches Modeled for this Long-Term Plan

For the purposes of this Long-Term Plan, the Company has evaluated potential long-term cost recovery trajectories associated with the CEV scenario (a moderate electrification scenario) and the Accelerated Electrification scenario (a more dramatic electrification scenario), to illustrate the potential future costs and risks associated with these energy system scenarios absent changes to today's gas asset depreciation methods. This analysis points to the potential future risks faced by customers and the Company under scenarios involving a significant reduction in customer demand, as well as the potential value of depreciation changes to begin to mitigate these risks as they begin to emerge and ensure more equitable outcomes for customers over time.

In this analysis, the Company shows the potential costs and benefits associated with a series of potential depreciation changes across its three NY operating companies over the course of each operating company's next two to three rate cases (inclusive of its proposal in the NMPC gas rate case). Importantly, the depreciation scenarios are tailored to reflect that a greater amount of acceleration would be warranted under Accelerated Electrification compared to the more moderate electrification Clean Energy Vision scenario.

The tables below describe the depreciation changes applied in the 'Modified Depreciation Methods' analysis for each of the two energy system scenarios.

Table 8-1: Modified Depreciation Methods: Clean Energy Vision Scenario

	First Policy Action	Second Policy Action
KEDNY KEDLI	Rate Case: 2027 New Rates. • Shorten Gas Asset Lives by Ten Years • Begin Equal Life Group Depreciation. • Change from a 20-Year Amortization of the Reserve Imbalance to a 10-Year Amortization of the Reserve Imbalance.	Rate Case: 2030 New Rates • Shorten Gas Asset Lives by a further Five Years
NMPC	Rate Case: 2025 New Rates • Shorten Gas Asset Lives by Five Years. • Begin Equal Life Group Depreciation. • Change from a 20-Year Amortization of the Reserve Imbalance to a 10-Year Amortization of the Reserve Imbalance.	Rate Case: 2028 New Rates • Shorten Gas Asset Lives by a further Five Years

Table 8-2: Modified Depreciation Methods: Accelerated Electrification Scenario

	First Policy Action	Second Policy Action	Third Policy Action
KEDNY KEDLI	Rate Case: 2027 New Rates. • Shorten Gas Asset Lives by Ten Years • Begin Equal Life Group Depreciation. • Change from a 20-Year Amortization of the Reserve Imbalance to a 10-Year Amortization of the Reserve Imbalance.	Rate Case: 2030 New Rates • Institute an Economic Planning Horizon 2050 (New Assets).	No further action at this stage

[147] Calculation based on Table 2 of NMPC Depreciation Panel Testimony, page 62, as filed in Case 24-G-0323. 139.90 million / 104.81 million

NMPC	Rate Case: 2025 New Rates • Shorten Gas Asset Lives by Five Years. • Begin Equal Life Group Depreciation. • Change from a 20-Year Amortization of the Reserve Imbalance to a 10-Year Amortization of the Reserve Imbalance.	Rate Case: 2028 New Rates • Shorten Gas Asset Lives by a further Five Years	Rate Case: 2031 New Rates • Institute an Economic Planning Horizon 2050 (New Assets).

These changes are represented in the charts in the following section, and they are shown relative to the 'Historic Depreciation Method' which would continue a straight-line depreciation technique with existing asset lives.[148] Results are shown for the combination of National Grid NY operating companies.

8.4.5. Findings & Recommendations

8.4.5.1. Findings

First, with regard to rate base, analysis shows that in both the CEV and AE scenarios (regardless of depreciation approach), the level of gas net plant[149] will almost double in the next decade under ongoing capital programs required primarily for safety and reliability. This trend is shown in the solid lines in both Figures 8-11 and 8-12. In the AE scenario, the amount of net plant is at a somewhat lower level than in the CEV, due to some avoidance of investment related to gas demand reduction.

Second, the level of net plant beyond the next decade could be reduced, in parallel with the reduction in overall utilization of the Company's gas systems under these scenarios, through changing depreciation methods (in the dotted lines in Figure 8-13 and Figure 8-14), resulting in:

- a 29% reduction in 2050 Net Plant under the CEV.
- a complete reduction in 2050 Net Plant under the AE scenario, with a negative Net Plant[150] to pay for remaining decommissioning costs.

These reductions in net plant would result from a better temporal matching of gas cost recovery with system utilization compared to historic methods.

[148] In the Accelerated Electrification Scenario, continuing straight-line depreciation technique with existing asset lives would not recover the value of invested capital by 2050, and is only shown here for comparative purposes.
[149] In the final report, National Grid has chosen to use Net Plant for depreciation cost recovery purposes instead of Rate Base to center on cost recovery and neutralize deferred income taxes which are included in Rate Base.
[150] Negative Net Plant implies that the accumulated depreciation for total utility plant is greater than the plant value. This extra accumulated depreciation would be used to pay for remaining decommissioning costs.

Figure 8-13: CEV - Net Plant

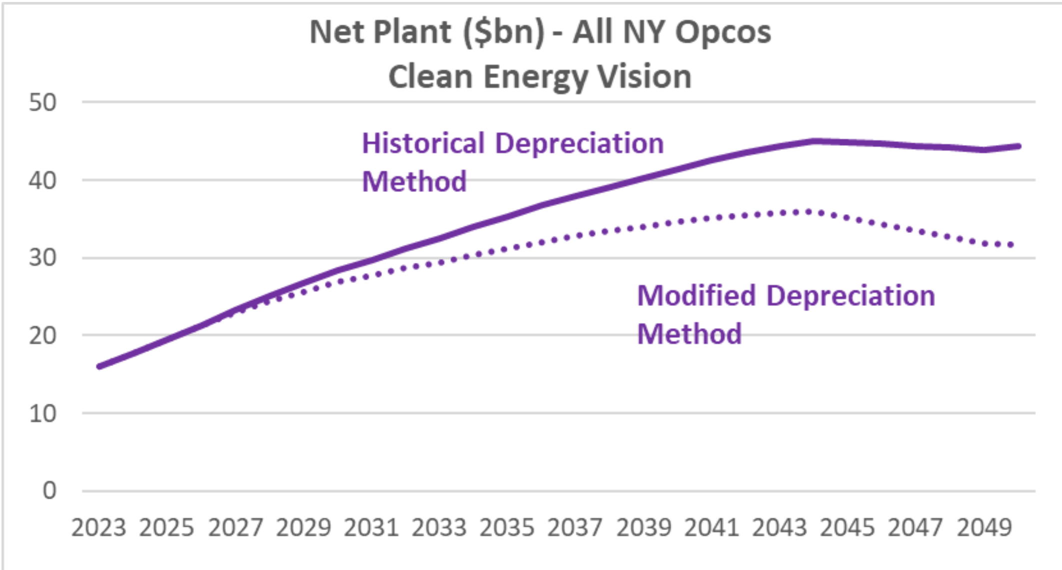
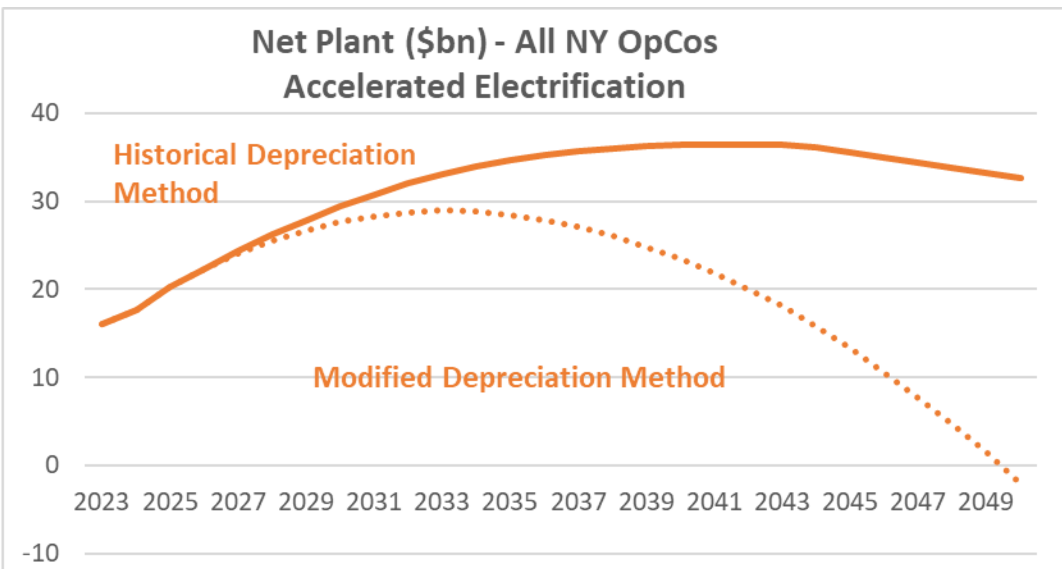


Figure 8-14: AE - Net Plant



These modeled reductions in rate base result from increases in annual depreciation expense that are shown below in Figures 8-13 and 8-14 for the two energy system scenarios. In both scenarios, depreciation changes result in somewhat similar levels of increase through to 2030, but in the AE scenario, the recovery of all new capex investment under a 2050 Economic Planning Horizon results in an a larger increase in depreciation expense to the end of the period. In the CEV scenario, depreciation expense remains much closer to the baseline trajectory as a result of not requiring recovery of all investment by 2050, given the level of continued customer demand beyond that date.

Figure 8-15: CEV - Annual Depreciation Expense

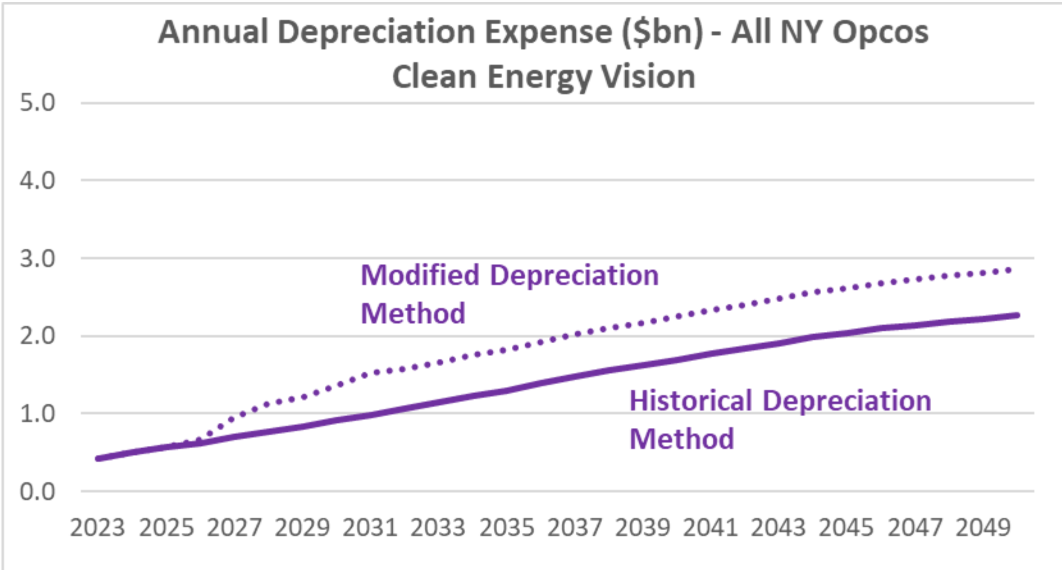
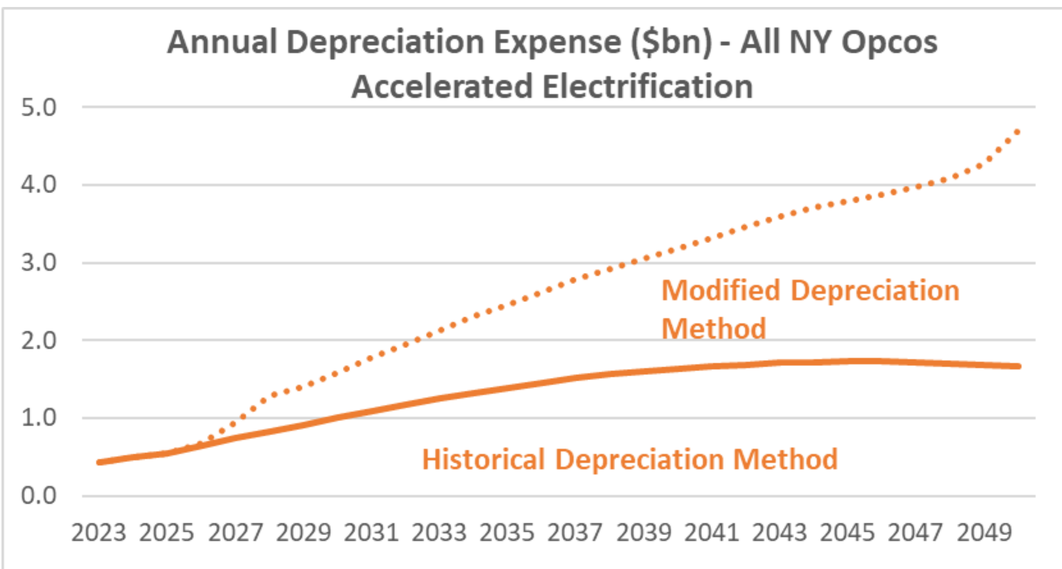
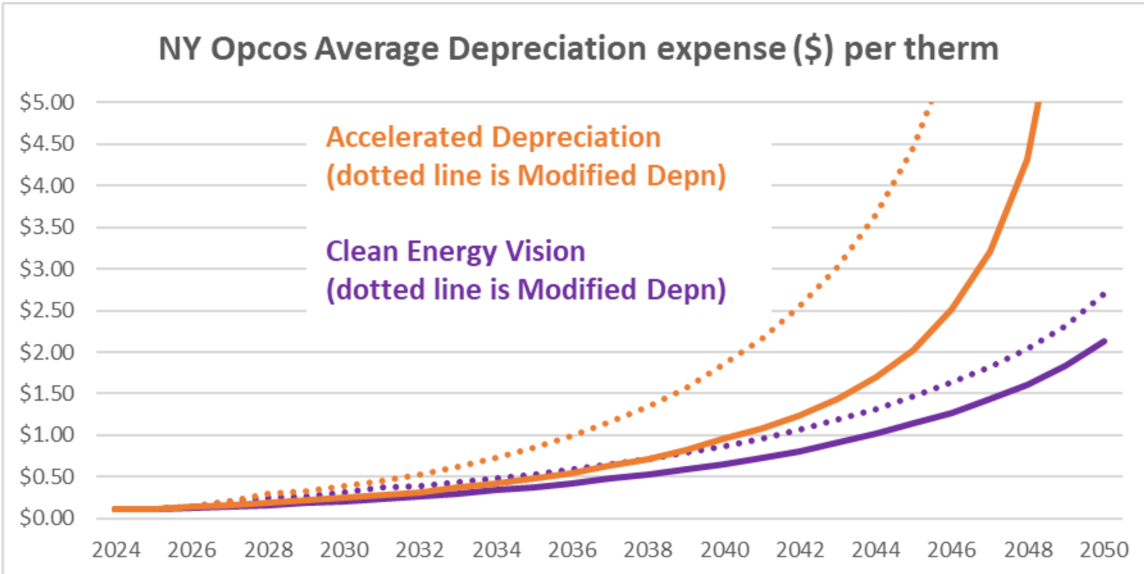


Figure 8-16: AE - Annual Depreciation Expense



To approximate the potential impacts of these depreciation scenarios on a per-customer basis, Figure 8-15 below shows the depreciation-cost-per-therm that would be required under each of the scenarios and methods described above. This analysis suggests a very wide range of potential cost trajectories that customers could see over the next 25 years under these potential futures, driven by the widely varying assumptions regarding future utilization of gas by the Company's customers.

Figure 8-17: Depreciation Expense $ per Therm by Scenario



8.4.5.2. Recommendations

Given the potential for dramatic cost escalation and inequitable burdens on future gas customers in scenarios involving material gas demand reductions, the Commission should begin updating gas depreciation methodologies to account for the expected impact of state policy. At the same time, the Commission can avoid relying on a single future energy system scenario to justify modifications, since demand loss occurs in both moderate and accelerated electrification scenarios.

In addition to avoiding significant intergenerational equity problems, the acceleration of depreciation can also create long-term savings for customers relative to current depreciation approaches, beyond simply moving cost recovery from one period to another. By reducing the level of rate base faster over a given period, accelerated depreciation reduces the cost of financing (return on rate base) and tax liability over that same period which would otherwise be required to recover from customers.

In the Company's NMPC gas case, the Company has proposed an initial change to gas depreciation methodology (as described above) that is consistent with the near-term horizon of this long-term analysis, beginning to reduce future risk for customers and the Company, while preserving optionality for further regulatory action in the future, if warranted based on the pace of energy system change that unfolds over time.

At the same time, if gas customer demand falls dramatically in the coming decades, such as in the Accelerated Electrification Scenario, analysis suggests that it could be challenging to recover all required depreciation expense from remaining gas ratepayers, given the cost per customer in those scenarios. In such a scenario, New York could require methods for recovering invested costs of gas networks from a larger group than just remaining gas customers, potentially including electric customers or taxpayers, to avoid unsustainable cost burdens for gas customers.

9. Conclusions and Next Steps

9.1. Summary and Recommended Path Ahead

We hope this Long-Term Plan can serve as a catalyst for urgent action necessary to resolve barriers and risks to the gas decarbonization transition. While continued investment in the gas network is required to ensure customers have access to safe and reliable service in the near-term, we remain committed to transforming our gas utilities to eliminate the use of fossil fuel and achieve net zero by 2050, and to reduce emissions consistent with the SBTi 1.5C pathway. This is what animates our company from our gas yards to our call centers to our executive suites. We are bringing the entirety of National Grid to the generational challenges of climate action and the clean energy transition, and we are very pleased to have this opportunity to share our vision and our ideas.

This Long-Term Plan describes the state of play for the gas network today – where customer demand continues to grow and threatens to outpace available supply in the near-term, and investment is needed to maintain critical infrastructure like Greenpoint – and maps out two plausible boundary cases for the transition to the decarbonized gas network of the future. We believe the CEV scenario is the best path forward, and our scenario analysis indicates that the CEV does have advantages over other pathways – some marginal, some more pronounced. We recognize the value offered by a scenario in which the end state is mostly electrification as in the case of the AE scenario, and want to ensure there is enough flexibility in our plan to achieve our shared decarbonization goals through a variety of potential pathways.

Our plan is activated by working with policymakers, regulators, and stakeholders to build consensus for tangible actions we can take together to resolve the common barriers and risks associated with both scenarios and put New York on a path to our shared goals.

While we support the CEV, we believe that picking a preferred scenario at this time is unnecessary, and we aim to move beyond the zero-sum debates that have held up progress on climate action and the clean energy transition for too long. There are few if questions remaining that could be answered definitively enough to achieve consensus around any specific vision for the future of the gas system out to 2050. Let's put aside false choices between affordability and emissions reductions, or electrification and clean alternative fuels, and recognize that the barriers to either a high-electrification future like the AE or a hybrid approach like the CEV are the same. We need the same resources in vastly greater quantities that we can achieve under current policies and regulations for either, so let's get to work scaling up electrification, energy efficiency, and clean alternative fuels as much as we can and as fast as we can.

We already have a roadmap for the gas transition in the form of Climate Action Council's Scoping Plan, which reflects the best available science, analysis, and expertise available to the State of New York. We should get to work implementing it. We urge the Commission to implement the Scoping Plan's recommendations to develop a coordinated gas system transition plan and look forward to participating in that process. We welcome feedback from anyone who cares about building an equitable, affordable, and effective clean energy transition, and look forward to taking action together soon.

9.2. Our Stakeholder Engagement Plan

National Grid is committed to transforming our networks with smarter, cleaner energy solutions to deliver a more robust, resilient, and secure energy network for our customers and communities. We are looking forward to continued engagement with stakeholders to inform our Plan. We are striving for a just, fair, and affordable energy transition that achieves our shared climate goals without sacrificing safety and reliability for our customers.

We invite stakeholders to visit our website, https://ngridsolutions.com, which contains our prefiling information session presentation and other LTP-related materials; it will be continuously updated throughout the LTP process. National Grid will be working closely with DPS Staff to ensure stakeholder concerns are understood through the information request process, comments filed in the case, and virtual meetings that provide opportunities for the Company and stakeholders to interact directly.

We look forward to your participation as we refine our Long-Term Plan into the revised and final reports.

9.3. Next Steps

9.3.1. Procedural

Over the next months, interested parties will have an opportunity to submit feedback on National Grid's Revised Long-Term Plan through a mix of informational sessions, meetings, and comment periods, similar to the process for its Initial Long-Term Plan. Staff and PA Consulting will also participate in the process and provide an analysis of National Grid's filing. National Grid will submit its Final Long-Term Plan in January 2025.

Moving forward, National Grid will submit updates to the LTP annually as well as a revised long-term gas plan on a three-year cycle.

10. Acronyms and Abbreviations

ACEEE – American Council for an Energy-Efficient Economy
ADA – Advanced Data Analytics
AE – Accelerated Electrification
AEB – All-Electric Building
AEC – Alkaline Electrolysis Cell
AGE – Ag-Grid Energy
AGF – American Gas Foundation
ALG – Average Life Group
AMA – Asset Management Arrangements
AMEEP – Affordable Multifamily Energy Efficiency Program
AMI – Advanced Metering Infrastructure
AOE – American Organic Energy, LLC
ASHP – Air-source heat pump
BCA – Benefit-Cost Analyses
BCF – Billion Standard Cubic Feet
BDR – Behavioral Demand Response
BE – Building Electrification
BPI – Building Performance Institute
BTU – British Thermal Unit
BYOT – Bring Your Own Thermostat
C&I – Commercial & Industrial
CAC – Climate Action Council
CBO – Community Based Organization
CEF – Clean Energy Fund
CEV – Clean Energy Vision
CHP – Combined Heat and Power
CIAC – Contribution in Aid of Construction
CLCPA – Climate Leadership and Community Protection Act
CNG – Compressed Natural Gas
CO_2 – Carbon Dioxide
CO_2e – Carbon Dioxide Equivalent
Con Edison – Consolidated Edison Company of New York, Inc.
CMM – Customer Management Module
CT DEEP – Connecticut Department of Energy & Environmental Protection
DAC – Disadvantaged Communities
DEC – Department of Environmental Conservation
Demand-Supply Gap – Gap between peak period gas under the Adjusted Baseline Demand Forecast and Existing Capacity
DEP – Department of Environmental Protection
DIS – Distributed Infrastructure Solution
DMM – Document and Matter Management
DNY – Downstate New York
DOB – Department of Buildings
DOE – U.S. Department of Energy
DPS – Department of Public Service
DR – Demand Response
DSM – Demand-Side Management
Dth – Dekatherms
Eastern – Eastern Gas Transmission & Storage
EBB – Electronic Bulletin Board
EDC – Electric Distribution Company

EE – Energy Efficiency
EGOMP – Emergency Gas Outage Management Plan
EGTS – Eastern Gas Transmission & Storage
EIA – Energy Information Administration
EIS – Environmental Impact Statement
EJ – Environmental Justice
Empire – Empire Pipeline
ELG – Equal Life Group
ESCOs – Energy Service Companies
ESS – Eminence Storage Service
ETS2 – Energy Transfer Site #2
EUL – Effective Useful Life
ExC – Enhancement by Compression
Existing Capacity – Total Portfolio of Available Gas Capacity
°F – Degree Fahrenheit
FERC – Federal Energy Regulatory Commission
FY – Fiscal Year
GDU – Gas Distribution Utility
GEC – Greenpoint Energy Center
GHG – Greenhouse Gas
GIS – Graphical Information System
GJGNY – Green Jobs – Green New York
GSHP – Ground-source heat pump
GSSP - Gas System Strategic Planning
GTOP – Gas Transportation Operating Procedures
HDD – Heating Degree Day
HP – High Pressure
ICS – Incident Command Structure
IEP – Integrated Energy Planning
IGTS – Iroquois Gas Transmission System, L.P.
IPCC – Intergovernmental Panel on Climate Change
Iroquois – Iroquois Gas Transmission System, L.P.
Joint Facility Model – Joint Facilities Hydraulic Analysis Model
KEDLI – KeySpan Gas East Corporation d/b/a National Grid
KEDNY – Brooklyn Union Gas Company d/b/a National Grid NY
LAUF – Lost-and-unaccounted-for
LCFS – Low Carbon Fuel Standard
LDC – Local Distribution Company
LIPA – Long Island Power Authority
LL 97 – Local Law 97
LL 154 – Local Law 154
LMI – Low- to moderate-income
LNG – Liquefied Natural Gas
LP – Low Pressure
LPP – Leak Prone Pipe
LTCR – Long-term Capacity Report
MDDO – Maximum Daily Delivery Obligation
MDQ – Maximum Daily Quantity
MDth – thousand Dekatherms
MRI – Metropolitan Reliability Infrastructure
MWBE – Minority and/or Women-owned Business Enterprise
NAESB – North American Energy Standards Board
NE07 – Northeast 07

NE:NY – New Efficiency: New York
NESE – Northeast Supply Enhancement
NMPC – Niagara Mohawk Power Corporation
NOx – Nitrogen oxides
NPA – Non-Pipeline Alternative
NWA – Non-Wires Alternative
NYCI – New York Cap & Invest
NYF – New York Facilities
NYPA – New York Power Authority
NYPSC – New York Public Service Commission
NYSERDA – New York State Energy Research and Development Authority
O&M – Operations and Maintenance
OFO – Operational Flow Order
Order – Commission's Order Adopting Gas System Planning Process issued May 2022 (20-G-0131)
PTC – Production Tax Credit
PSEG-LI – Public Service Enterprise Group– Long Island
R&R – Reliability & Reinforcement
RCV – Remote Control Valves
RD&D – Research, Development and Demonstration
RFI – Request for Information
RFP – Request for Proposal
RFS – Renewable Fuel Standard
RIM – Ratepayer Impact Measure
RMI – Rocky Mountain Institute
RNG – Renewable Natural Gas
SBS – Small Business Services
SBTi – Science Based Target Initiative
SCCC – Suffolk County Community College
SCT – Societal Cost Test
SEEP – System Energy Efficiency Plans
Tennessee – Tennessee Gas Pipeline Company
Tetco – Texas Eastern Transmission Gas Pipeline
TGP – Tennessee Gas Pipeline Company
Transco – Transcontinental Gas Pipeline
TOU – Time of Use
UCT – Utility Cost Test
UFG – Unaccounted For Gas
UNY – Upstate New York
UoP – Units of Production
UTENs – Utility Thermal Energy Networks
VEOP – Voluntary Emission Offset Program
VLR – Voluntary Load Reduction
WACOG – Weighted Average Cost of Gas
WRRF – Water Resource Recovery Facility
WSE – Winter Storm Elliott
WSR – Winter Supply Review
WWTP – Wastewater Treatment Plant
Wx – Weatherization

11. Appendices

11.1. Gas Supply Portfolio

Table 11-1: KEDNY Firm Transportation Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms

Table 4a - Firm Transportation Capacity

(2024-25 Winter)

Company: The Brooklyn Union Gas Company
Submission Date: 7/15/2024
Version #: 1

Pipeline Company Name	Rate Schedule	Daily Quanity (DT)	Winter Quanity (MDT)	Annual Quanity (MDT)	Expiration Date
Flowing Gas To Citygate					
Transco	FT	245,955	37,139	89,774	6/1/2028
Transco	FT	115,000	17,365	41,975	10/31/2032
Transco	FT	100,000	15,100	36,500	5/14/2030
Transco	FT	13,945	2,106	2,106	4/1/2026
Transco	FT	4,244	382	382	7/31/2028
Transco	FT (X-285)	3,970	599	1,449	12/13/2025
Transco	FT (X-268)	3,250	491	1,186	1/1/2026
Transco	FT	1,969	297	719	3/19/2028
Transco (Not in city gate total - link to contracts 9170392, 9204696)	FDLS	353,700	53,409	129,101	5/14/2030
Transco	FT	10,000	1,510	3,650	11/18/2024
Transco	FT	78,000	11,778	28,470	10/31/2036
Texas Eastern	CDS	51,315	7,749	18,730	10/31/2025
Texas Eastern	FT-1	27,500	4,153	10,038	3/31/2026
Texas Eastern	X-130	12,161	1,836	4,439	10/31/2025
Texas Eastern	CDS	5,403	816	1,972	10/31/2025
Texas Eastern	FTS-4	5,000	755	1,825	12/1/2025
Texas Eastern	FTS	2,560	387	934	10/31/2025
Texas Eastern (Not included in total - 16,193 flows from Equitrans storage)	FTS-2	17,477	2,639	6,379	3/31/2026
Texas Eastern	FT-1	50,000	7,550	18,250	10/31/2033
Texas Eastern	FT-1	25,000	3,775	9,125	10/31/2026
Iroquois	RTS	80,936	12,221	29,542	11/1/2027
Tennessee	FT-A	30,292	4,574	11,057	10/31/2029
Upstream Pipeline Support [1]					
Transco	FT	10,688	1,614	3,901	10/31/2025
Texas Eastern	FT-1	20,604	3,111	7,520	10/31/2026
Tennessee	FT-A	50,000	7,550	18,250	10/31/2033
Eastern Gas Transmission & Storage	FT	82,000	12,382	29,930	10/31/2032
Eastern Gas Transmission & Storage	FTNN	40,301	6,085	14,710	3/31/2028
Equitrans	STS-1	16,193	2,445	5,910	4/1/2026
Enbridge Gas (Dawn to Parkway)	M12	40,917	6,178	14,935	10/31/2026
TransCanada (Parkway to Waddington)	FT	40,468	6,111	14,771	10/31/2026
Deliveries from Storage					
Transco	GSS	180,137	11,129	65,750	3/31/2028
Transco	LSS	31,940	3,354	11,658	3/31/2028
Transco	S-2	22,838	2,053	8,336	4/15/2026
Transco	FT (X-285)	46,105	6,962	16,828	12/13/2025
Texas Eastern	SS-1	114,190	7,370	41,679	4/30/2030
Texas Eastern	FTS-2	16,193	2,445	5,910	3/31/2026
Texas Eastern	FTS-8	10,340	1,561	3,774	3/31/2027
Texas Eastern	FTS-7	21,332	3,221	7,786	4/15/2027
Tennessee	FT-A	27,530	4,157	10,048	10/31/2029
Winter Peaking Service					
Total (Flowing Gas to City Gate, Deliveries from Storage, and Winter Peaking Service)					
		1,337,105	**172,836**	**483,892**	

* Please highlight any changes from the previous year's report.

[1] Capacity used to deliver gas to pipelines that deliver to the citygate.

Except where noted, contracts with expiration dates before the upcoming winter season are in evergreen status.

Table 11-2: KEDLI Firm Transportation Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms

Table 4b - Firm Transportation Capacity

(2024-25 Winter)

Company: KeySpan Gas East Corporation
Submission Date: 7/15/2024
Version #: 1

Pipeline Company Name	Rate Schedule	Daily Quanity (DT)	Winter Quanity (MDT)	Annual Quanity (MDT)	Expiration Date
Flowing Gas To Citygate					
Transco (MDQ=154,287 Dt/day, 30,303 Dt/day released to BNY)	FT	123,984	18,722	45,254	6/1/2028
Transco	FT	25,000	3,775	9,125	11/1/2026
Transco	FT	25,000	3,775	9,125	12/1/2026
Transco (excess transport after max storage withdrawal)	FT	718	108	262	12/12/2027
Transco (excess transport after max storage withdrawal)	FT	718	108	262	12/12/2027
Transco	FT	17,433	2,632	2,632	4/1/2026
Transco	FT (X-271)	2,100	317	767	2/1/2026
Transco	FT	1,863	168	168	7/31/2028
Transco	FT	1,811	273	661	2/24/2028
Transco	FT (X-287)	637	96	233	10/31/2025
Transco (Not in city gate total - link to contracts 9170392, 9204696)	FDLS	293,300	44,288	107,055	5/14/2030
Transco	FT	5,000	755	1,825	10/31/2031
Texas Eastern	CDS	25,001	3,775	9,125	10/31/2025
Texas Eastern	FT-1	22,500	3,398	8,213	3/31/2026
Texas Eastern	CDS	8,106	1,224	2,959	10/31/2025
Texas Eastern	FTS	1,110	168	405	10/31/2025
Texas Eastern	FT-1TME	40,000	6,040	14,600	10/31/2031
Texas Eastern	FT	3,500	529	1,278	10/31/2031
Iroquois (contract MDQ = 200,000 dt/day but upstream limits is 196,000)	RTS	196,000	29,596	71,540	4/1/2029
Iroquois	RTS	87,760	13,252	32,032	11/1/2026
Iroquois	RTS	25,000	3,775	9,125	11/1/2026
Iroquois	RTS	7,000	1,057	2,555	11/1/2026
Iroquois	RTS	40,468	6,111	14,771	10/31/2031
Tennessee	FT-A	2,546	384	929	10/31/2029
Upstream Pipeline Support [1]					
Texas Eastern	FT-1	12,578	1,899	4,591	10/31/2025
Eastern Gas Transmission & Storage	FTNN	26,021	3,929	9,498	3/31/2028
Algonquin	AFT-1	196,000	29,596	71,540	3/31/2029
Millennium	FT-1	150,000	22,650	54,750	3/31/2029
Millennium	FT-1	50,000	7,550	18,250	3/31/2029
Millennium (Backhaul contract, allowed to expire)	FT-1	0	0	0	12/31/2023
Enbridge Gas (Dawn to Parkway)	M12	37,850	5,715	13,815	10/31/2026
TransCanada (Parkway to Waddington)	FT	37,433	5,652	13,663	10/31/2026
Deliveries from Storage					
Transco	GSS	112,484	6,669	41,057	3/31/2028
Transco	FT	49,283	7,442	17,988	12/12/2027
Transco	FT	49,283	7,442	17,988	12/12/2027
Transco	FT (X-287)	35,588	5,374	12,990	10/31/2025
Transco	SS-2	23,184	2,550	8,462	3/31/2028
Transco	LSS	19,807	2,100	7,230	3/31/2028
Texas Eastern	FTS-5	15,000	2,265	5,475	3/31/2027
Texas Eastern	SS-1	15,572	934	5,684	4/30/2030
Texas Eastern (subject to fuel)	FTS-5	14,879	2,247	5,431	3/31/2027
Texas Eastern (subject to fuel)	FTS-5	20,000	3,020	7,300	3/31/2026
Texas Eastern	FTS-8	14,771	2,230	5,391	3/31/2027
Texas Eastern	SS-1	2,076	187	758	4/30/2026
Tennessee	FT-A	5,174	781	1,889	10/31/2029
Eastern Gas Transmission & Storage	FT-GSS	100,000	15,100	15,100	3/31/2027
Eastern Gas Transmission & Storage	FT-GSS	15,000	2,265	2,265	3/31/2027
Winter Peaking Service					
City gate peaking #1 (available December - March only)	Iroquois	38,000	1,140	1,140	3/31/2025
City gate peaking #2 (available December - March only)	Iroquois	20,000	600	600	10/31/2031
Total (Flowing Gas to City Gate, Deliveries from Storage, and Winter Peaking Service)					
		1,098,355	145,018	377,227	

* Please highlight any changes from the previous year's report.

[1] Capacity used to deliver gas to pipelines that deliver to the citygate.

Except where noted, contracts with expiration dates before the upcoming winter season are in evergreen status.

Table 11-3: NMPC Firm Transportation Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms

Table 4c - Firm Transportation Capacity

(2024-25 Winter)

Company: Niagara Mohawk Power Corporation

Submission Date: 7/15/2024

Version #: 1

Pipeline Company Name	Rate Schedule	Daily Quantity (DT)	Winter Quantity (MDT)	Annual Quantity (MDT)	Expiration Date
Flowing Gas To Citygate					
Eastern Gas Transmission & Storage Inc.	FTNN	340,122	51,358	117,975	3/31/2026
Iroquois Gas Transmission	RTS	51,596	7,791	18,833	11/1/2026
Eastern Gas Transmission & Storage Inc.	FT	10,000	1,510	2,712	3/31/2026
Eastern Gas Transmission & Storage Inc.	FT	17,700	2,673	6,461	10/31/2025
Eastern Gas Transmission & Storage Inc.	FT	30,000	4,530	10,950	10/31/2032
Eastern Gas Transmission & Storage Inc.	FT	26,200	3,956	9,563	6/30/2035
Tennessee	FT-A	20,000	3,020	7,300	10/31/2038
Tennessee	FT-A	30,000	4,530	10,950	10/31/2037
Upstream Pipeline Support [1]					
Enbridge Gas (Dawn to Parkway)	M12	52,247	7,889	19,070	10/31/2026
TransCanada (Parkway to Waddington)	FT	51,596	7,791	18,833	10/31/2026
Deliveries from Storage					
Eastern Gas Transmission & Storage Inc.	FTNN-GSS	434,078	65,546	65,546	3/31/2026
Eastern Gas Transmission & Storage Inc.	FT	4,000	604	604	3/31/2026
Winter Peaking Service					
Total (Flowing Gas to City Gate, Deliveries from Storage, and Winter Peaking Service)					
		963,696	145,518	250,893	

* Please highlight any changes from the previous year's report.

[1] Capacity used to deliver gas to pipelines that deliver to the citygate.

Table 11-4: KEDNY Firm Storage Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms
Table 5a - Firm Storage Capacity *
(2024-25 Winter)

Company: The Brooklyn Union Gas Company
Submission Date: 7/15/2024
Version #: 1

Storage Company Name	Rate Schedule	Daily Quantity (DT)	Winter Quantity (MDT)	Expiration Date
Marcellus/Utica Region				
Transco	GSS	180,137	11,129	3/31/2028
Transco	LSS	31,940	3,354	3/31/2028
Transco	S-2	22,838	2,053	4/15/2026
Texas Eastern	SS-1	114,190	7,370	4/30/2030
Equitrans-Keystone	SS-3/STS-1	16,193	1,693	4/1/2026
Tennessee	FS-MA	20,808	2,497	10/31/2029
Honeoye	SS-NY	10,220	1,226	4/1/2026
Eastern Gas Transmission & Storage	GSS	46,351	2,874	3/31/2028
Eastern Gas Transmission & Storage	GSS-TE	32,267	3,098	3/31/2027
Total		**474,944**	**35,294**	
Gulf Coast Region				
Transco	WSS	162,680	15,455	4/1/2025
Total		**162,680**	**15,455**	
Canadian				
Total	0	0		

* Please highlight any changes from the previous year's report.

Table 11-5: KEDLI Firm Storage Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms

Table 5b - Firm Storage Capacity *

(2024-25 Winter)

Company: KeySpan Gas East Corporation
Submission Date: 7/15/2024
Version #: 1

Storage Company Name	Rate Schedule	Daily Quantity (DT)	Winter Quantity (MDT)	Expiration Date
Marcellus/Utica Region				
Transco	GSS	112,484	6,669	3/31/2028
Transco	LSS	19,807	2,100	3/31/2028
Transco	SS-2	23,184	2,550	3/31/2028
Texas Eastern	SS-1	15,572	934	4/30/2030
Texas Eastern	SS-1	2,076	187	4/30/2026
Tennessee	FS-MA	5,202	468	10/31/2029
Eastern Gas Transmission & Storage	GSS	100,000	6,000	3/31/2027
Eastern Gas Transmission & Storage	GSS	35,814	2,164	3/31/2028
Eastern Gas Transmission & Storage	GSS-N Summit	35,000	3,500	3/31/2027
Eastern Gas Transmission & Storage	GSS-TE	15,000	1,443	3/31/2027
Eastern Gas Transmission & Storage	GSS-APEC	15,000	1,500	3/31/2027
Total		**379,139**	**27,515**	
Gulf Coast Region				
Transco	WSS	46,939	4,459	4/1/2025
Total		**46,939**	**4,459**	
Canadian				
Total	0	0		

* Please highlight any changes from the previous year's report.

Table 11-6: NMPC Firm Storage Capacity

Case 24-M-0205 - Winter Supply 2024-25 Forms

Table 5c - Firm Storage Capacity

(2024-25 Winter)

Company: Niagara Mohawk Power Corporation
Submission Date: 7/15/2024
Version #: 1

Storage Company Name	Rate Schedule	Daily Quantity (DT)	Winter Quantity (MDT)	Expiration Date
Marcellus/Utica Region				
Eastern Gas Transmission & Storage Inc.	GSS	438,078	22,917	3/31/2026
Total		438,078	22,917	
Gulf Coast Region				
Total		0	0	
Canadian				
Total		0	0	

* Please highlight any changes from the previous year's report.

Figure 11-1: NMPC Flow Diagram

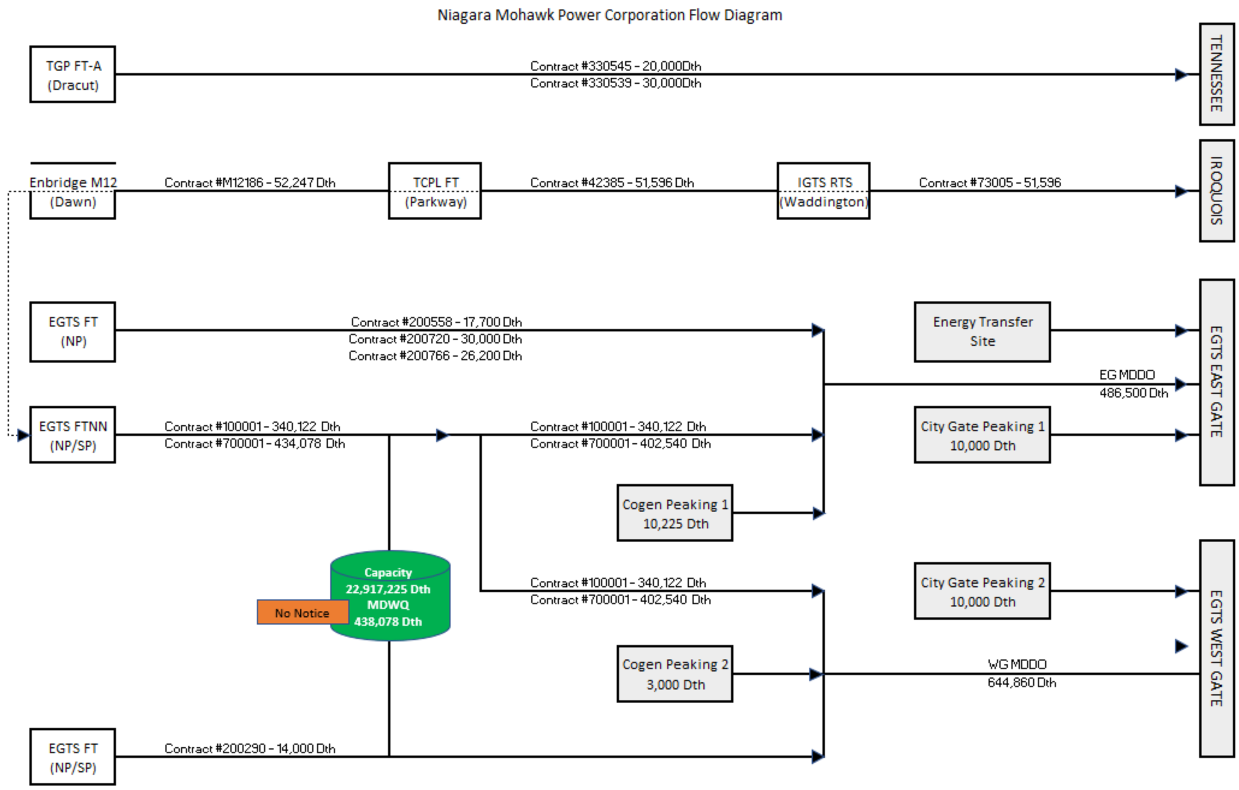
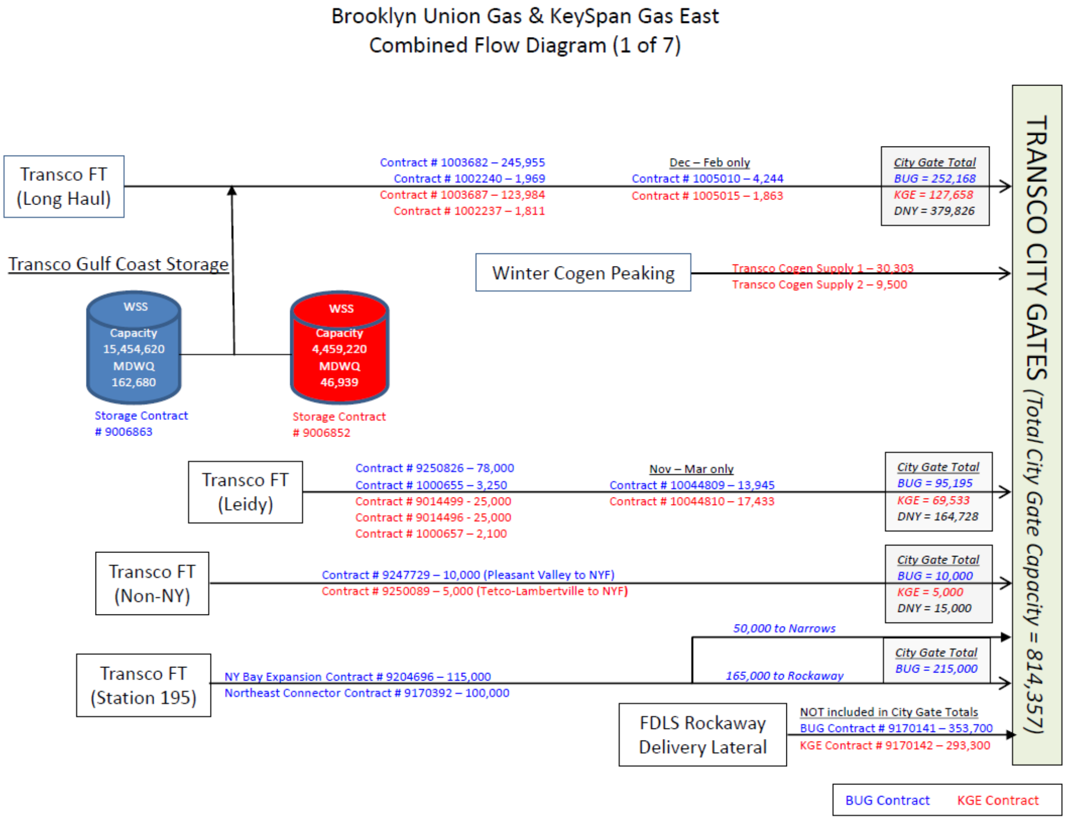
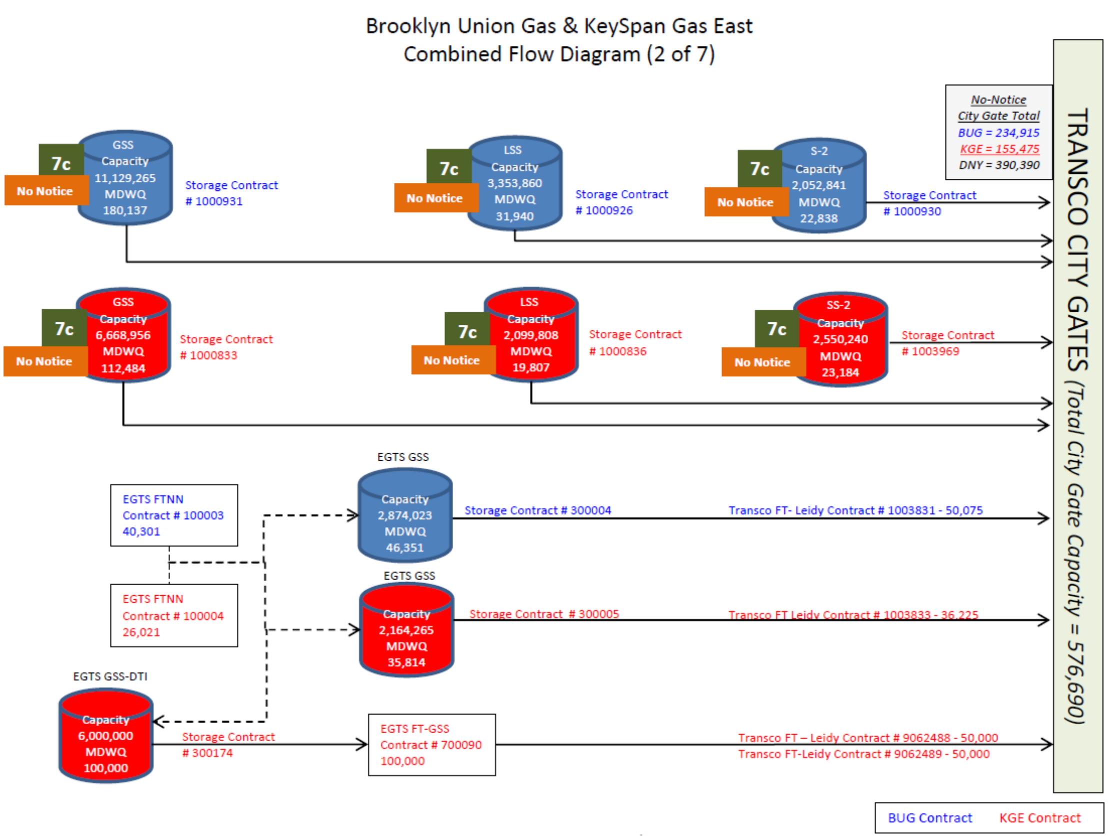
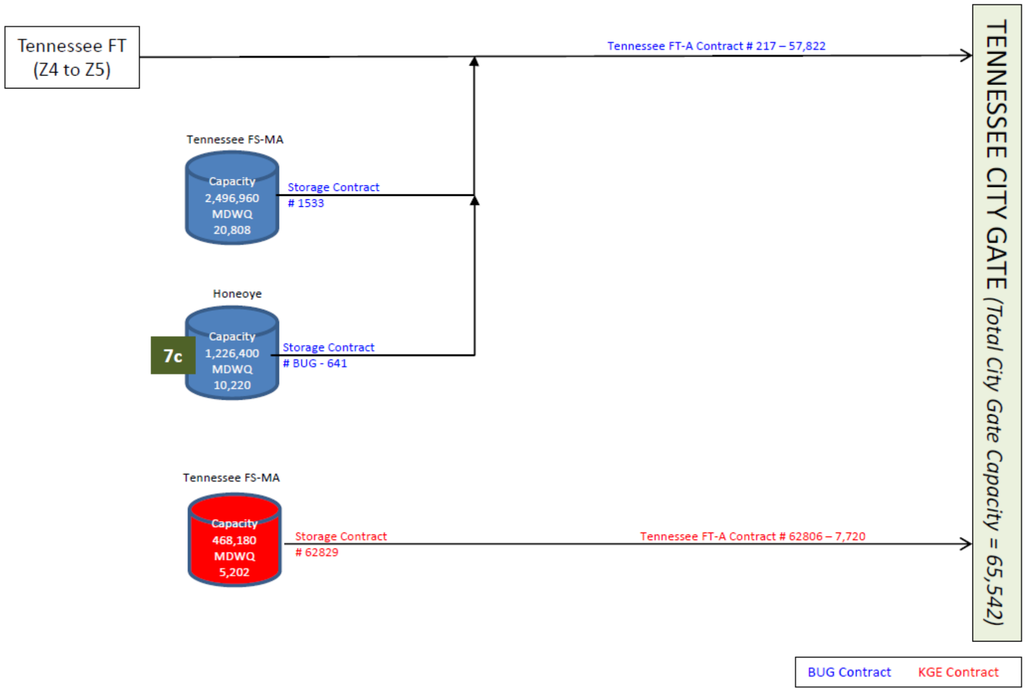


Figure 11-2: KEDNY/KEDLI Flow Diagram

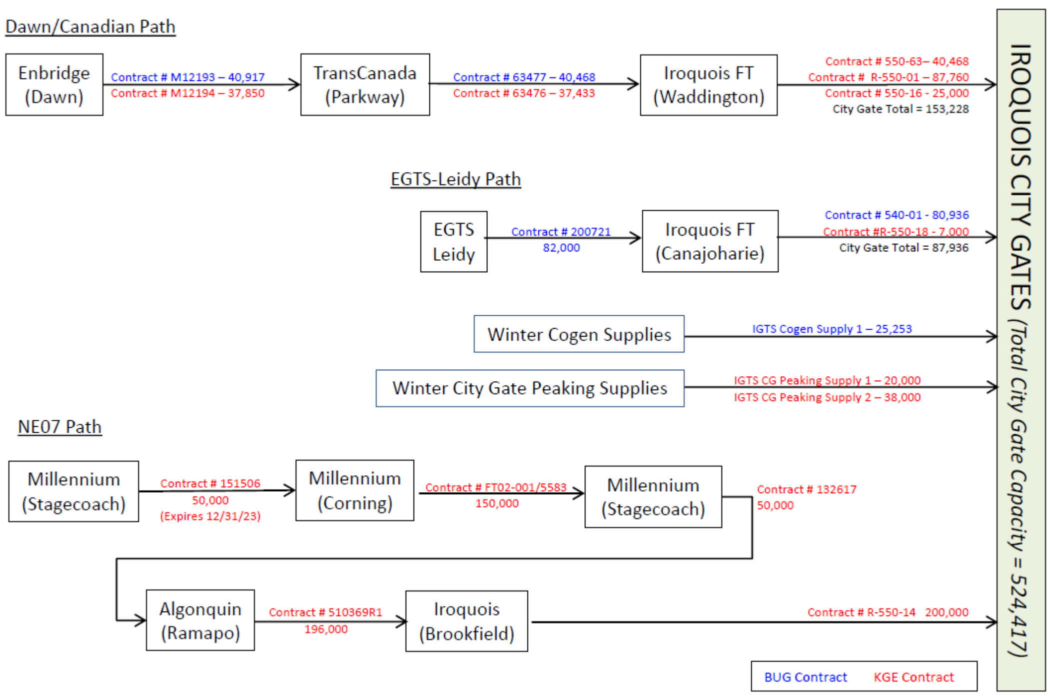




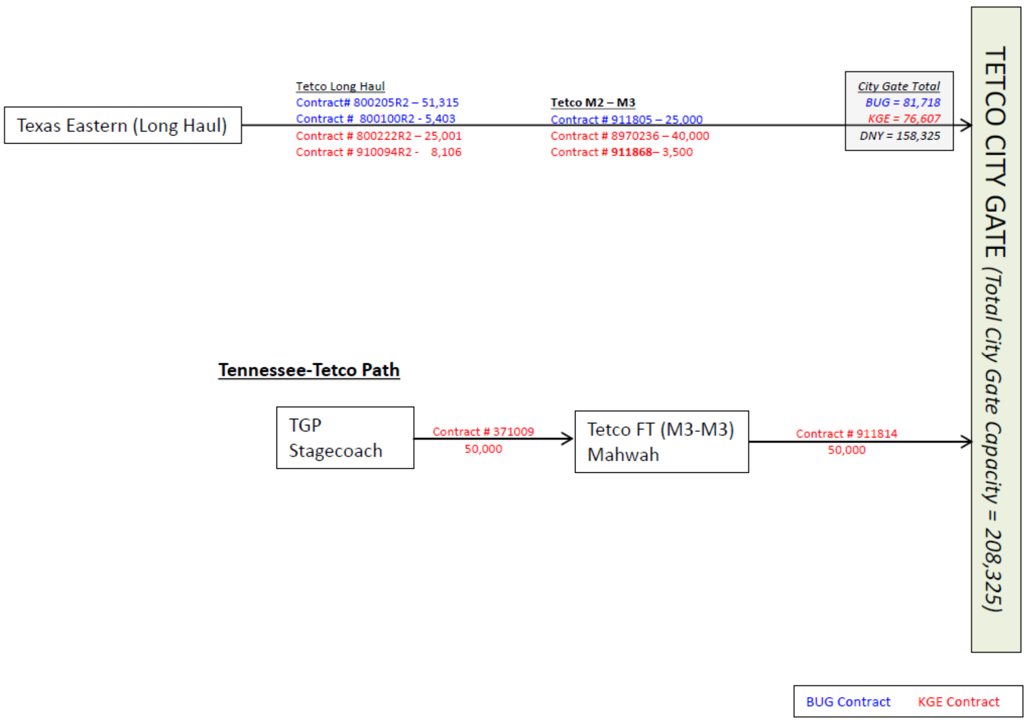
Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram (3 of 7)



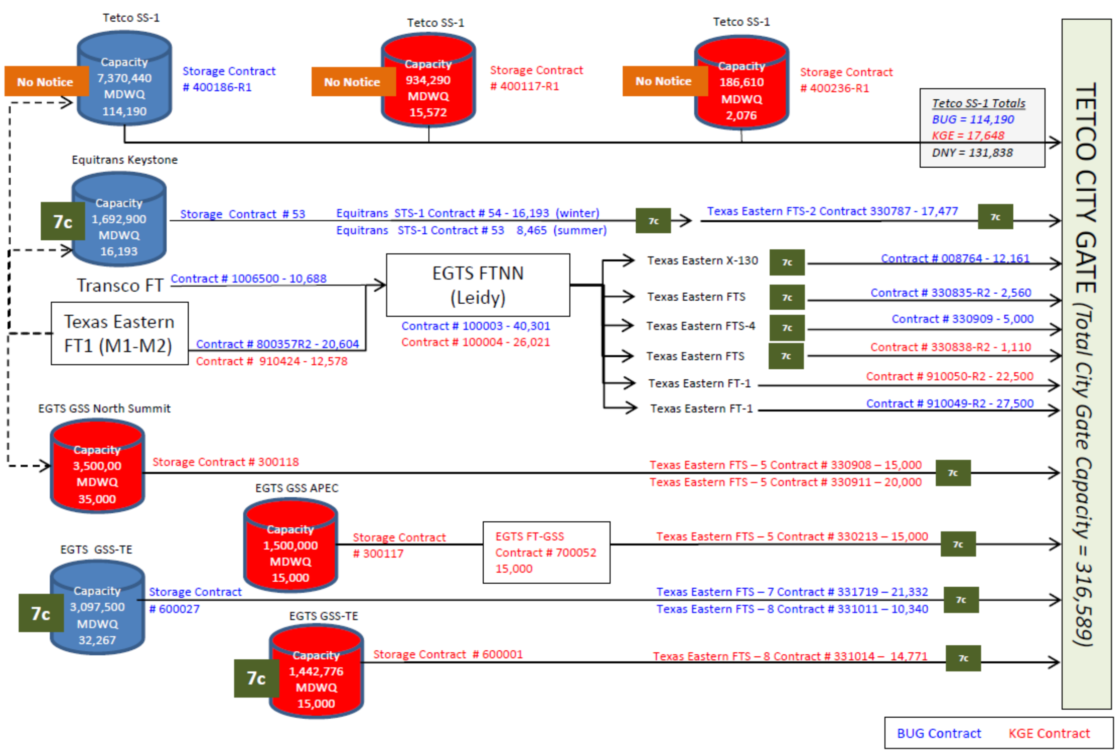
Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram (4 of 7)



Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram (5 of 7)



Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram (6 of 7)



Brooklyn Union Gas & KeySpan Gas East
Combined Flow Diagram (7 of 7)

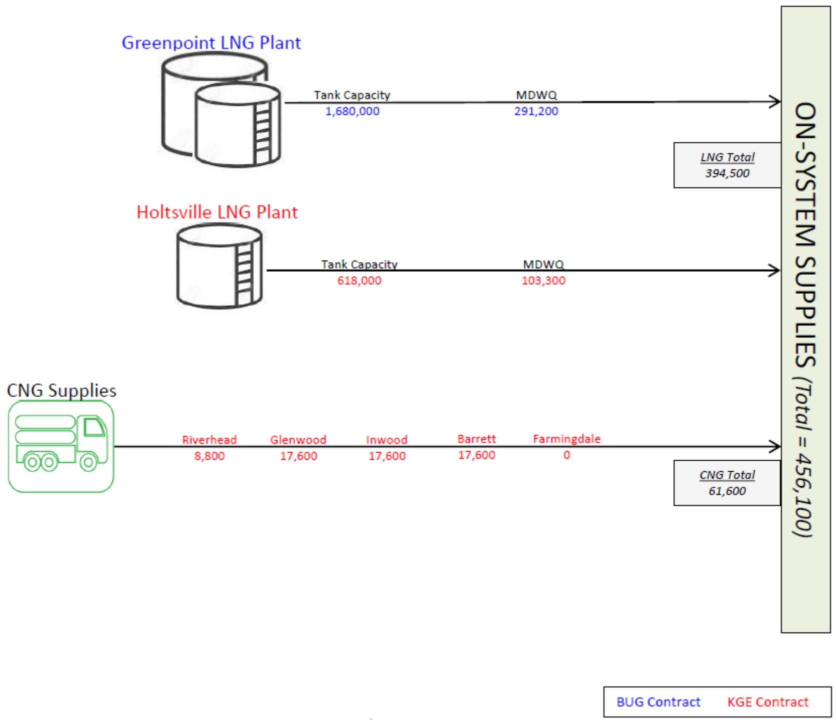
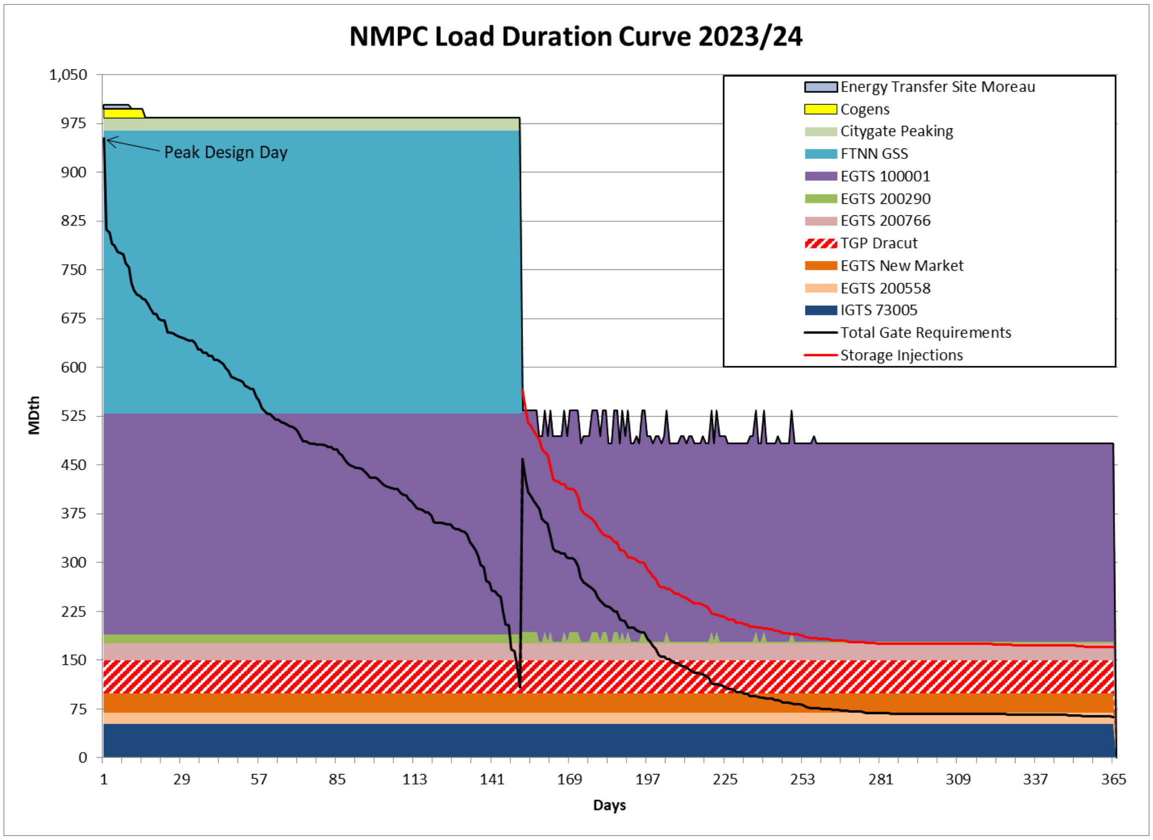
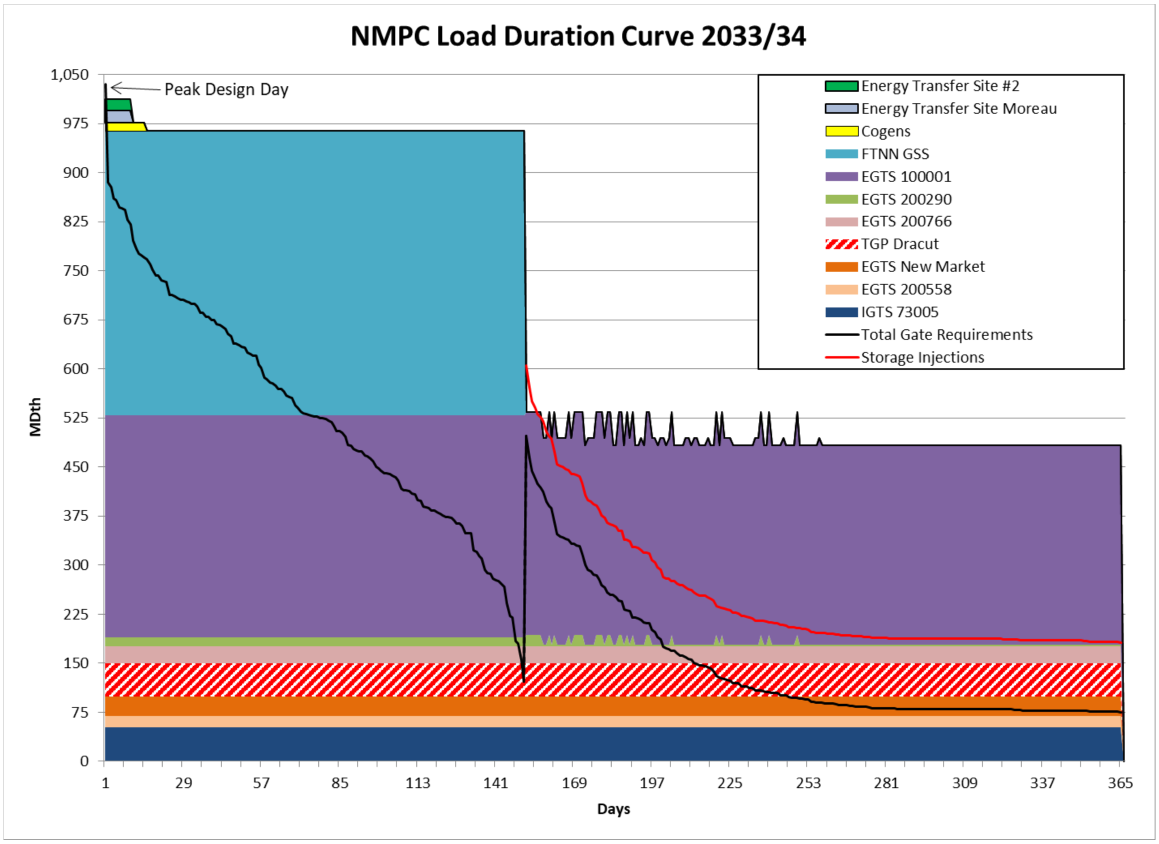


Figure 11-3: Upstate Load Duration Curves




NMPC Load Duration Curve 2033/34
Peak Design Day
Energy Transfer Site #2
Energy Transfer Site Moreau
Cogens
FTNN GSS
EGTS 100001
EGTS 200290
EGTS 200766
TGP Dracut
EGTS New Market
EGTS 200558
IGTS 73005
Total Gate Requirements
Storage Injections
MDth
1,050
975
900
825
750
675
600
525
450
375
300
225
150
75
0
1
29
57
85
113
141
169
197
225
253
281
309
337
365
Days

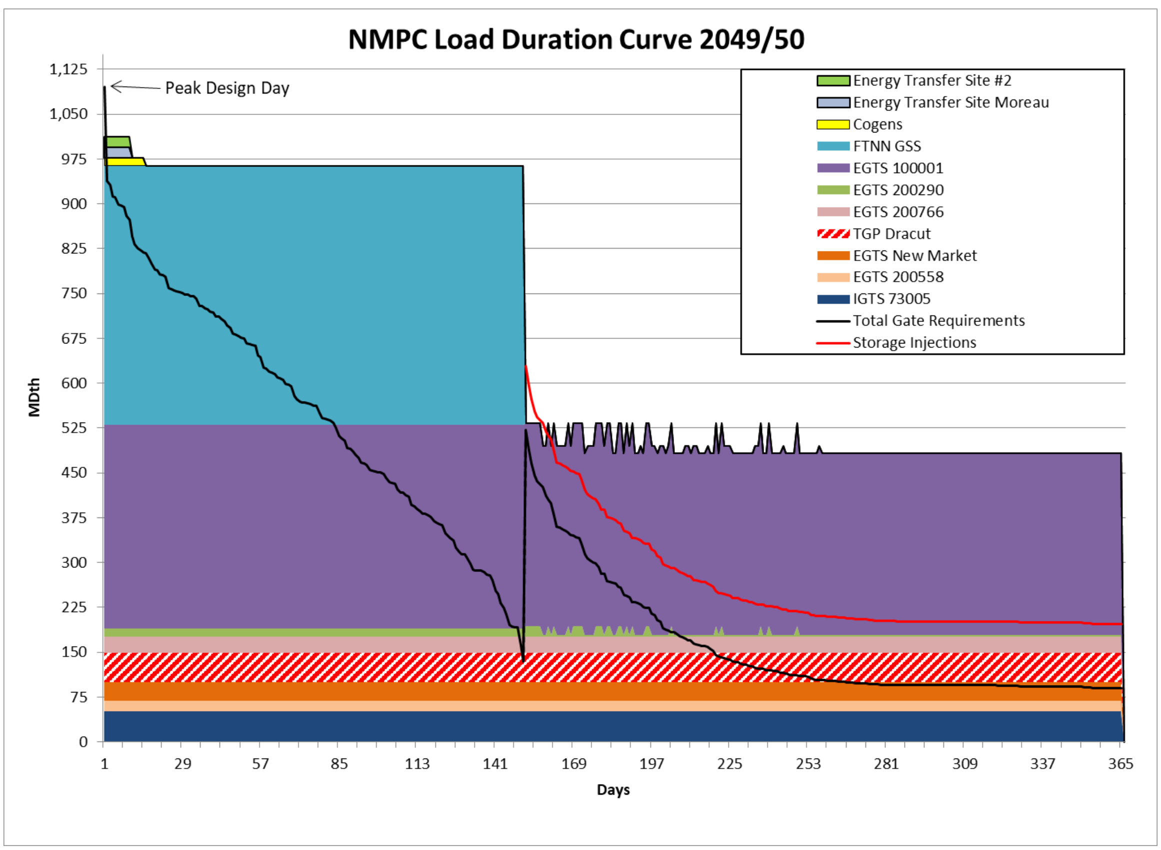
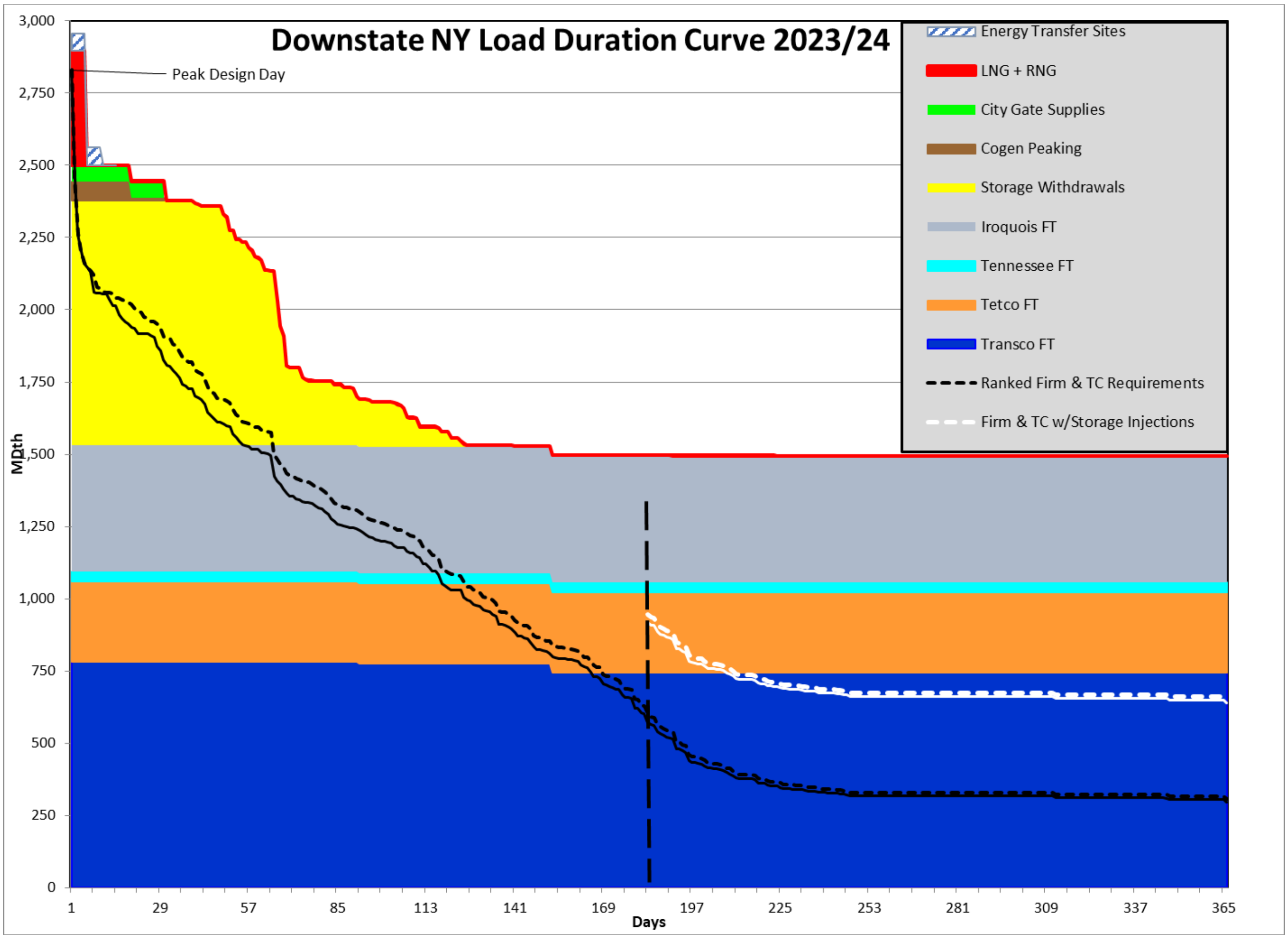
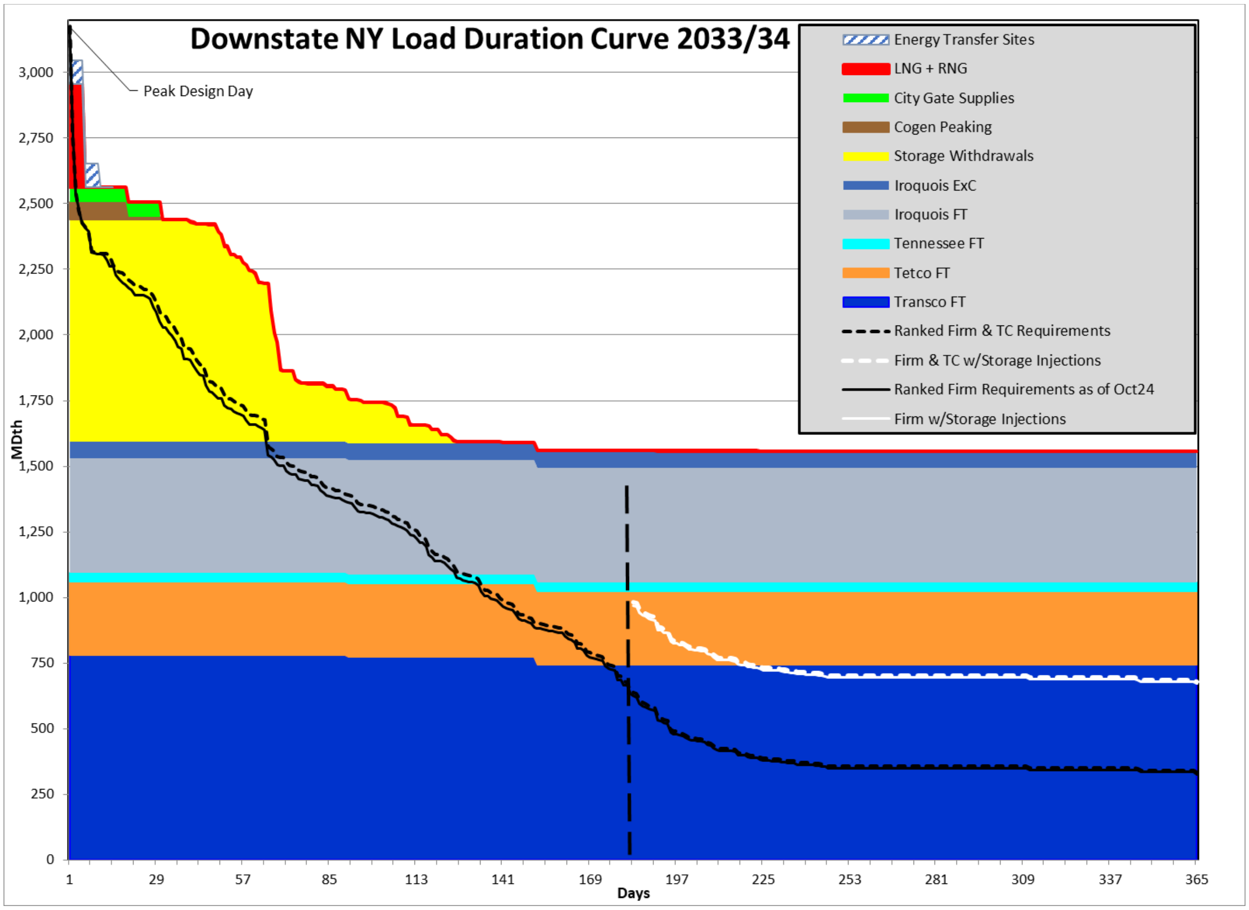
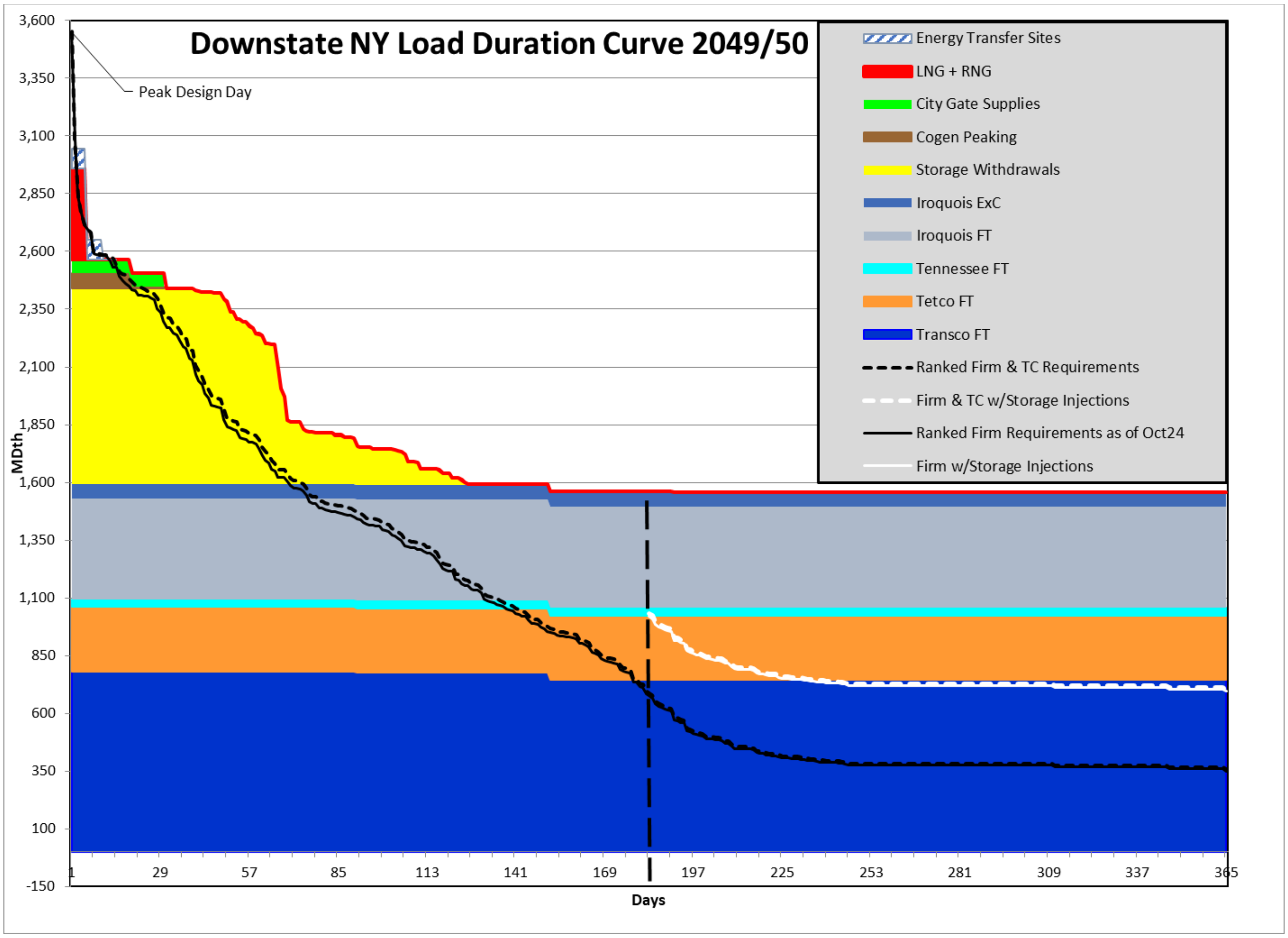

NMPC Load Duration Curve 2049/50
Peak Design Day
Energy Transfer Site #2
Energy Transfer Site Moreau
Cogens
FTNN GSS
EGTS 100001
EGTS 200290
EGTS 200766
TGP Dracut
EGTS New Market
EGTS 200558
IGTS 73005
Total Gate Requirements
Storage Injections
MDth
1,125
1,050
975
900
825
750
675
600
525
450
375
300
225
150
75
0
1
29
57
85
113
141
169
197
225
253
281
309
337
365
Days

Figure 11-4: Downstate Load Duration Curves





Downstate NY Load Duration Curve 2033/34
Peak Design Day
Energy Transfer Sites
LNG + RNG
City Gate Supplies
Cogen Peaking
Storage Withdrawals
Iroquois ExC
Iroquois FT
Tennessee FT
Tetco FT
Transco FT
Ranked Firm & TC Requirements
Firm & TC w/Storage Injections
Ranked Firm Requirements as of Oct24
Firm w/Storage Injections
MDth
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1
29
57
85
113
141
169
197
225
253
281
309
337
365
Days



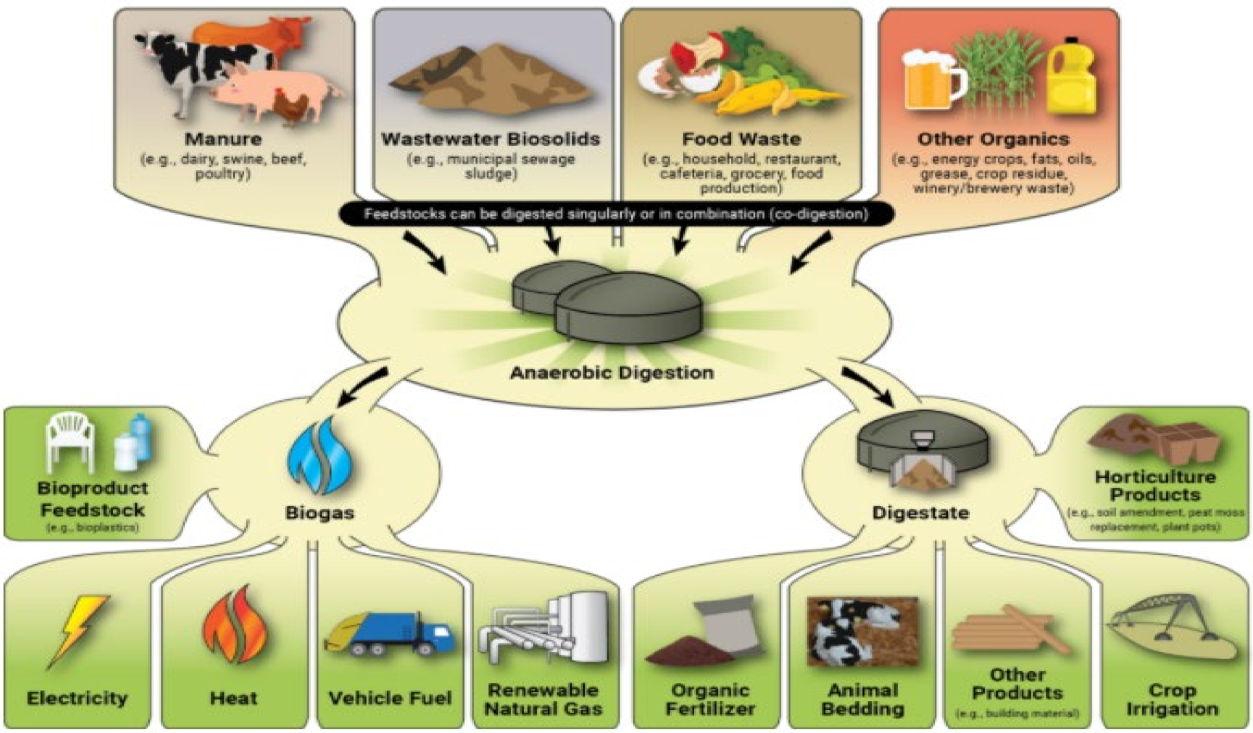
In the two figures referenced above, the load duration curves illustrate the available supplies by portfolio compared to the forecasted requirements as shown by the black line. The supplies closer to the bottom of each figure represents supplies that are available year-round to the Company, whereas the supplies higher on the left y axis requirements illustrates the limited, or seasonal supplies available to the Company. The red line for NMPC and the white line for Downstate represent forecasted requirements plus projected storage injections. It is assumed that the assets under each forecasted requirement line would be used to meet forecasted demand. The number of days on the X-axis is intended to go from highest requirement down to lowest requirement and the first day representing the Design Day in that portfolio for the year.

11.2. RNG Production Pathways

11.2.1. Anerobic Digestion

The most common way to produce RNG today is via anaerobic digestion. Anaerobic digestion ("AD") for biogas production takes place in a sealed vessel called a reactor (also known as a Digester), which house microbial communities that break down (digest) the organic matter in an oxygen free environment and produce resultant biogas and digestate (the solid and liquid material end-products of the AD process). Figure 11-5 below illustrates the flow of feedstocks through the AD system to produce biogas and digestate.

Figure 11-5: Anerobic Digestion Pathways



Additional technologies to produce RNG include thermal gasification and Power to Gas ("P2G"). Both technologies offer promise but are less established compared to anerobic digestion.

11.2.2. Thermal Gasification

Gasification calls for a complete thermal breakdown of the biomass particles into a combustible gas, volatiles, and ash in an enclosed reactor (gasifier). Gasification is an intermediate step between pyrolysis and combustion. It is a two-step, endothermic process whose primary products are gas, char, and tar. Gasification products, their composition and amount are strongly influenced by gasification agent, temperature, pressure, heating rate and fuel characteristics (composition, water content, granulometry).

11.2.3. Power to Gas

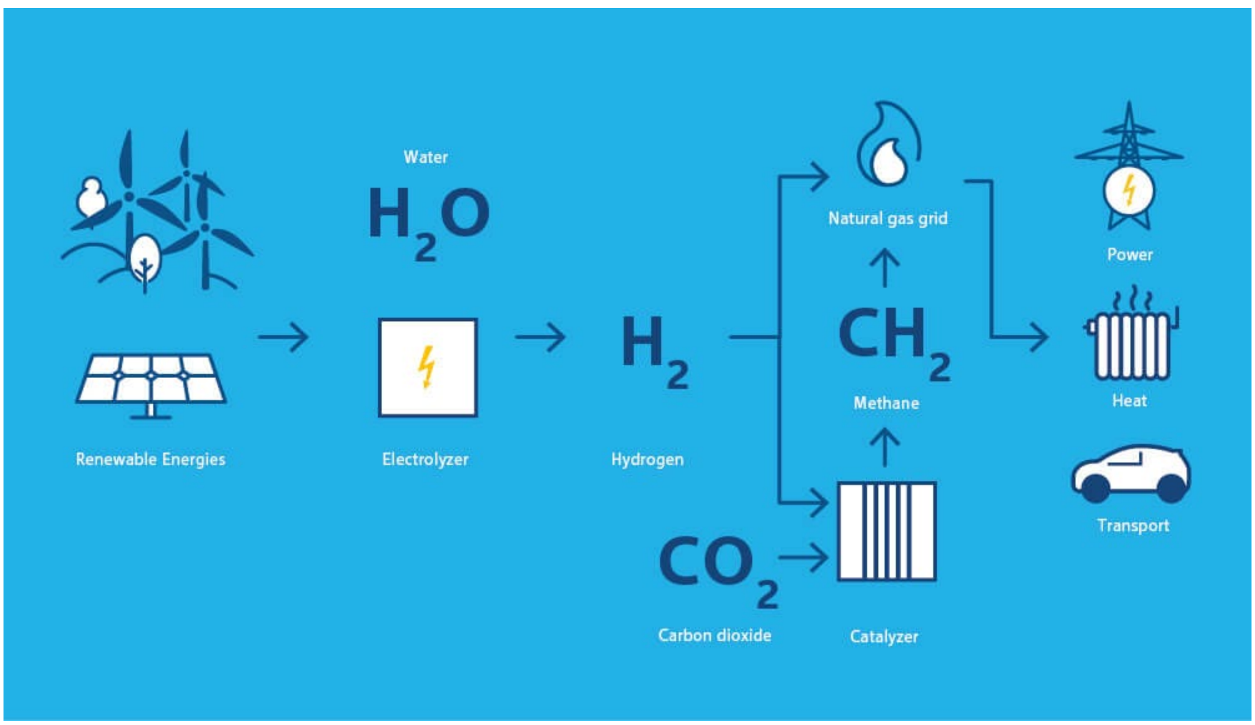
Power to Gas ("P2G") is a form of energy technology that converts electricity to a gaseous fuel. Electricity provides the power to split the water molecules in into O_2 and H_2. P2G utilizes the carbon dioxide ("CO_2") in the air and the hydrogen gas produced during electrolysis to produce methane. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon neutral. Figure 11-6 below gives an illustration of the process. The hydrogen produced from P2G is a highly flexible energy product that can be used in multiple ways. It can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies.
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply.
- Converted to methane and injected into the natural gas system.

The last option, methanation, involves the combination of hydrogen with CO_2, and converting the two gases into methane. The methane produced is RNG and is a clean alternative to conventional fossil natural gas. While the merits of H_2 use via fuel cells or as an injected fuel are valid, methanation permits much easier introduction into the gas network.

The P2G RNG conversion process can also be coordinated with conventional biomass-based RNG. Methane produced via anerobic digestion would be kept while the surplus CO_2 in biogas is used to produce the methane. This creates a productive use for the CO_2 that is typically difficult and costly to remove.

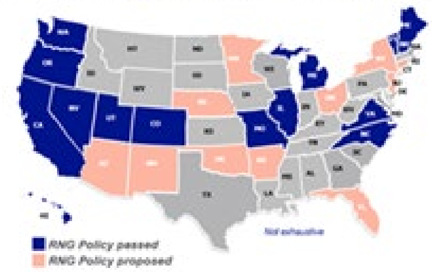
Figure 11-6: Power to Gas (P2G) Process Flow



11.3. RNG Enabling Policies in US States

Figure 11-7: Summary of state efforts to advance RNG and other renewable fuels

RNG Policies: Other states have advanced policies to enable a clean gas future, mainly focused on advancing RNG mandates and customer programs



National Grid 2

Policy Mechanism	States	Example(s)
Renewable gas portfolio or procurement standards	CA, CT, HI, IL, NJ, NV, OR, VT	California PUC unanimously approved 12% x 2030 RNG procurement requirement for all core customers (2022) Oregon established RPS setting RNG target of 15% x 2030, 30% x 2050 (2019)
RNG supply incentives, financing, or cost recovery	FL, HI, ME, MI MN, MO, NH, NY, NV, OH, OR, VA, WA	Washington state law provides tax incentives to promote investment in RNG supply (2018)
Voluntary customer tariff / adder / service	CA, CO, IL, ME, MI, MN, MO, UT, VT, WA	Many states allow gas utilities to offer voluntary tariffs to customers seeking to decarbonize faster to choose higher blends of renewable gas

Table 11-7: Summary of state efforts to advance RNG and other renewable fuels

State	Description
California	CA Public Utilities Commission required to establish biomethane procurement targets.[1] Proposed Decision issued by California Public Utility Commission on February 18, 2022 would require California gas utilities to procure, by 2030, 12 percent of 2020 core customer natural gas demand, creating a total 2030 annual market for RNG of approximately 72.8 BCF of gas statewide.
Colorado	In June 2021, enacted into law Senate Bill 21-264 to advance Colorado's goal to reduce GHG emissions from gas distribution utilities by requiring gas distribution utilities ("GDUs") to implement clean heat plans which demonstrate the GDU's strategy to meet specified clean heat targets. The law defines a clean heat resource as including gas demand side management programs, recovered methane, green hydrogen, and beneficial electrification.[1]
Illinois	Illinois Commerce Commission approved proposal of Nicor Gas Company to offer a program called "TotalGreen" to provide Nicor Gas customers with a way to offset the environmental effects of their natural gas use through the acquisition of environmental commodities, including RNG environmental attributes. The TotalGreen program will offer two primary blended options to customers: a product that includes a higher proportion of RNG credits (between 5% and 20%, with the remaining balance from carbon offsets). Participating customers will pay higher price for environmental commodity acquisition with no impacts to non-participating ratepayers.[1]

State	Description
Maine	Maine Public Utility Commission approved the voluntary RNG attribute program of Summit Natural Gas of Maine, Inc. that provides the option to residential and small-commercial customers of purchasing enough RNG attributes to offset 10%, 25%, 50%, or 100% of their average monthly natural-gas usage. The monthly cost would equal Summit's costs to acquire the attributes.[1]
Michigan	Michigan PSC approved a voluntary emission offset program ("VEOP") that modified the DTE Gas Company. BioGreenGas program approved in 2015 that had allowed DTE to charge an additional $2.50 monthly fee to offset premium price of RNG: The new approved VEOP pilot program enables residential customers to offset all or a portion of their natural gas usage by purchasing blocks and paying a commensurate monthly fee - 95% of emissions reductions would be from carbon offsets and 5% of emissions reductions will be from RNG.[1]
Minnesota	Passed Natural Gas Innovation Act in June 2021 that allows a natural gas utility to submit an "innovation plan" for approval by the Minnesota Public Utilities Commission. An innovation plan could propose the use of renewable energy resources and innovative technologies such as: (1) renewable natural gas (2) renewable hydrogen gas (3) energy efficiency measures and (4) innovative technologies that reduce or avoid greenhouse gas emissions[1]
Missouri	Enacted law effective as of August 28, 2021 requiring the Public Service Commission to adopt rules for gas corporations to offer a voluntary RNG program with prudent, just, and reasonable costs to be recovered by an automatic adjustment clause.[1]
Nevada	Requires the Commission to adopt regulations authorizing utilities that purchase natural gas for resale to engage in RNG activities and directed these natural gas utilities to incorporate 1% of RNG into their supply by 2025; 2% by 2030; and 3% by 2035.[1]
New Hampshire	Enacted law enabling utility procurement of RNG up to 5% of annual gas sales in June 2022. Law establishes standard for Commission approval based on value of associated environmental attributes and consistency with state energy policy.[1]
North Carolina	Commission order from 2022 requires recovery of .2% of energy from swine waste and 900,000 MWh of energy recovery from poultry waste by 2023 to meet requirements under 2007 Renewable Energy and Energy Efficiency Portfolio Standard (REPS).[1]
Oregon	Oregon Public Utility Commission required to adopt by rule a RNG program for large and small natural gas utilities.[1] In 2020, the Oregon Public Utilities adopted regulations establishing a RNG procurement process and standards, targets, and limits for large and small natural gas utilities in procuring RNG. [1]
Utah	Public Service Commission approved Dominion's GreenTherm program, a voluntary program that provides Dominion Energy Utah natural gas customers an opportunity to support clean RNG. Customers can elect to have a number of units, known as "blocks," or five therms of RNG added as a surcharge to their monthly gas bill, and Dominion Energy then purchases "green attributes" (credits associated with the production of RNG) on the customers' behalf. The voluntary monthly surcharge for one block was set at $5 and would be the minimum monthly surcharge.[1]
Vermont	Vermont Public Utility Commission approved RNG program for Vermont Gas Systems produced from agricultural waste, manure, municipal waste, plant material and compost, which will allow retail customers to choose to buy RNG in amounts equal to 10%, 25%, 50%, or 100% of their total monthly requirements.[1]

State	Description
Washington	Requires gas companies to offer by tariff a voluntary RNG service to all customers to replace any portion of the natural gas provided by the gas company.[1]

11.4. Service Classifications

Table 11-8: NMPC Service Classifications[151]

Service Class	Description
SC 1	Residential Service
SC 2	Small General Service
SC 5	Firm Gas Sales and Transportation Service
SC 6	Large Volume Interruptible Transportation Service
SC 7	Small Volume Firm Gas Sales and Transportation
SC 8	Gas Sales and Transportation Service with Standby Sales Service
SC 9	Transportation Service for Long-Term Large Volume Customers
SC 11	Load Aggregation
SC 12	Non-Residential Distributed Generation Service
SC 13	Residential Distributed Generation Service

Table 11-9: KEDLI Service Classifications[152]

Service Class	Description
SC 1	Residential Service
SC 2	Non-Residential Service
SC 3	Multiple-Dwelling Service
SC 5	Firm Transportation Service
SC 9	Uncompressed Natural Gas Vehicle Full Service
SC 15	High Load Factor Service
SC 16	Year-Round Space Conditioning Service
SC 17	Baseload Distributed Generation Sales Service
SC 18	Non-Firm Demand Response Service
SC 19	Non-Firm Demand Response Transportation Service

Table 11-10: KEDNY Service Classifications[153]

Service Class	Description
SC 1A, 17-1A	Residential Non-Heating Service
SC 1B, 17-1B	Residential Heating Service
SC 1AR, 17-1AR	Residential Non-Heating Service, Energy Affordability Program
SC 1BR, 17-1BR	Residential Heating Service, Energy Affordability Program
SC 1B-DG, 17-1B-DG	Family Residential Heating Conversion Service
SC 2-1, 17-2-1	Non-Residential Non-Heating Service
SC 2-2, 17-2-2	Non-Residential Heating Service
SC 3, 17-3	Multi-Family Non-Heating/Heating Service
SC 4A, 17-4A	High Load Factor Service
SC 4A-CNG, 17-4A-CNG	CNG Service
SC 4B, 17-4B	Year Round Air Conditioning Service
SC 7	Season (April - November) Off-Peak Service
SC 21	Baseload Distributed Generation Sales Service
SC 22, 18-22	Non-Firm Service

[151] https://www.nationalgridus.com/media/pdfs/billing-payments/gas-rates/upstate-ny/psc_no-219_rates.pdf
[152] https://www.nationalgridus.com/media/pdfs/billing-payments/gas-rates/nyl/kedli-rate-code-service-class-conversion-table.pdf
[153] https://www.nationalgridus.com/media/pdfs/billing-payments/gas-rates/nym/kedny_gas_delivery_charges.pdf

11.5. Bill Impact Results by Operating Company, Service Classification, and Scenario

Table 11-11: NMPC Bill Impacts by Scenario

NMPC

Reference Case

Avg. Monthly Bill Estimate - Delivery Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$62	$160	$2,170	$5,318	$27,092
2030	$110	$288	$3,992	$9,979	$49,454
2035	$124	$328	$4,547	$11,554	$57,263
2040	$129	$344	$4,773	$12,263	$60,775
2045	$132	$355	$4,930	$12,757	$63,222
2050	$138	$372	$5,164	$13,413	$66,475

Avg. Monthly Bill Estimate - Commodity Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$23	$110	$2,217	$10,193	$52,345
2030	$30	$143	$3,265	$13,315	$75,035
2035	$31	$155	$3,537	$14,159	$83,632
2040	$32	$163	$3,735	$14,739	$98,079
2045	$32	$166	$3,790	$14,901	$108,591
2050	$32	$171	$3,885	$15,172	$110,975

Avg. Monthly Bill Estimate - Total Bill

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$85	$270	$4,387	$15,511	$79,437
2030	$140	$431	$7,256	$23,294	$124,489
2035	$156	$483	$8,083	$25,713	$140,895
2040	$161	$507	$8,508	$27,002	$158,855
2045	$164	$522	$8,720	$27,658	$171,814
2050	$170	$543	$9,049	$28,585	$177,450

CEV (Current)

Avg. Monthly Bill Estimate - Delivery Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$62	$160	$2,170	$5,318	$27,089
2030	$162	$414	$5,729	$14,206	$70,463
2035	$185	$448	$6,199	$15,978	$77,536
2040	$218	$515	$7,118	$17,893	$87,334
2045	$241	$558	$7,682	$19,491	$93,305
2050	$273	$624	$8,607	N/A*	N/A*

Avg. Monthly Bill Estimate - Commodity Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$23	$110	$2,217	$10,193	$52,345
2030	$35	$167	$3,908	$17,174	$96,234
2035	$41	$198	$4,705	$23,805	$140,430
2040	$43	$216	$5,131	$28,232	$224,965
2045	$49	$251	$5,969	$36,638	$461,060
2050	$71	$380	$9,123	N/A*	N/A*

Avg. Monthly Bill Estimate - Total Bill

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$85	$270	$4,387	$15,511	$79,434
2030	$197	$581	$9,637	$31,380	$166,697
2035	$226	$647	$10,904	$39,783	$217,965
2040	$262	$731	$12,249	$46,126	$312,299
2045	$291	$809	$13,651	$56,129	$554,365
2050	$344	$1,004	$17,730	N/A*	N/A*

AE (Current)

Avg. Monthly Bill Estimate - Delivery Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$62	$160	$2,169	$5,315	$27,076
2030	$179	$492	$6,829	$14,264	$70,505
2035	$231	$649	$9,051	$17,251	$86,026
2040	$361	$958	$13,484	$21,632	$107,049
2045	$552	$1,405	$19,816	$25,546	$140,600
2050	$2,166	$4,752	$59,295	N/A*	N/A*

Avg. Monthly Bill Estimate - Commodity Only

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$23	$110	$2,217	$10,193	$52,345
2030	$32	$151	$3,507	$14,177	$79,628
2035	$55	$274	$6,565	$27,080	$167,104
2040	$71	$368	$8,866	$36,962	$298,972
2045	$84	$447	$10,798	$45,046	$631,328
2050	$114	$685	$13,937	N/A*	N/A*

Avg. Monthly Bill Estimate - Total Bill

	Residential (SC-1)	Small Comm (SC-2) < 50k Therms	C&I (SC-7) Annual Use 50k-250k Therms	C&I (SC-5) Annual Use 250k-1M Therms	C&I (SC-8) Annual Use > 1M Therms
Current	$85	$270	$4,386	$15,508	$79,421
2030	$210	$643	$10,336	$28,442	$150,132
2035	$286	$923	$15,616	$44,332	$253,129
2040	$432	$1,326	$22,350	$58,594	$406,021
2045	$636	$1,851	$30,615	$70,592	$771,929
2050	$2,280	$5,437	$73,232	N/A*	N/A*

*Note: Bill impacts marked N/A are outlier values not indicative of the actual per-customer bill trend due to rapid decline in customer count for the relevant rate class.

Avg. Monthly Residential Bill - NMPC						
	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$85		$85		$85	
2030	$140	65%	$197	132%	$210	148%
2035	$156	83%	$226	166%	$286	237%
2040	$161	89%	$262	208%	$432	409%
2045	$164	93%	$291	242%	$636	649%
2050	$170	100%	$344	305%	$2,280	2585%

Table 11-12: KEDNY Bill Impacts by Scenario

KEDNY

Reference Case

Avg. Monthly Bill Estimate - Delivery Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$131	$484	$348	$1,001
2030	$203	$789	$541	$1,535
2035	$252	$991	$679	$1,897
2040	$296	$1,174	$804	$2,217
2045	$336	$1,345	$922	$2,508
2050	$361	$1,444	$988	$2,657

Avg. Monthly Bill Estimate - Commodity Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$37	$254	$156	$622
2030	$48	$344	$206	$785
2035	$50	$376	$224	$846
2040	$52	$411	$244	$925
2045	$53	$457	$269	$1,017
2050	$52	$486	$284	$1,062

Avg. Monthly Bill Estimate - Total Bill	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$168	$738	$504	$1,623
2030	$251	$1,133	$747	$2,319
2035	$302	$1,367	$903	$2,742
2040	$348	$1,586	$1,048	$3,142
2045	$389	$1,802	$1,191	$3,525
2050	$413	$1,930	$1,271	$3,719

CEV (Current)

Avg. Monthly Bill Estimate - Delivery Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$131	$484	$348	$1,001
2030	$242	$953	$653	$1,818
2035	$305	$1,257	$861	$2,328
2040	$380	$1,600	$1,095	$2,852
2045	$422	$1,892	$1,298	$3,228
2050	$453	$2,117	$1,448	$3,456

Avg. Monthly Bill Estimate - Commodity Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$37	$254	$156	$622
2030	$52	$413	$245	$878
2035	$51	$484	$281	$907
2040	$51	$514	$300	$870
2045	$52	$570	$335	$809
2050	$60	$685	$406	$662

Avg. Monthly Bill Estimate - Total Bill	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$168	$738	$504	$1,622
2030	$294	$1,366	$898	$2,696
2035	$356	$1,742	$1,142	$3,236
2040	$431	$2,114	$1,394	$3,722
2045	$474	$2,462	$1,633	$4,037
2050	$513	$2,802	$1,854	$4,118

AE (Current)

Avg. Monthly Bill Estimate - Delivery Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$131	$484	$348	$1,001
2030	$280	$1,136	$778	$2,096
2035	$452	$1,773	$1,215	$3,299
2040	$850	$3,140	$2,147	$5,858
2045	$1,505	$5,084	$3,486	$10,372
2050	$6,108	N/A*	N/A*	N/A*

Avg. Monthly Bill Estimate - Commodity Only	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$37	$254	$156	$622
2030	$49	$361	$219	$838
2035	$75	$586	$356	$1,374
2040	$96	$788	$486	$1,881
2045	$117	$1,025	$649	$2,460
2050	$304	N/A*	N/A*	N/A*

Avg. Monthly Bill Estimate - Total Bill	SC-1B Residential (Heat)	SC 2-1 Small Commercial (Non-Heat)	SC 2-2 Small Commercial (Heat)	SC-3 Multi-Family
Current	$168	$738	$504	$1,622
2030	$329	$1,498	$997	$2,934
2035	$527	$2,358	$1,571	$4,673
2040	$946	$3,928	$2,634	$7,738
2045	$1,621	$6,110	$4,135	$12,832
2050	$6,413	N/A*	N/A*	N/A*

*Note: Bill impacts marked N/A are outlier values not indicative of the actual per-customer bill trend due to rapid decline in customer count for the relevant rate class.

Avg. Monthly Residential Bill - KEDNY

	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$168		$168		$168	
2030	$251	50%	$294	75%	$329	96%
2035	$302	80%	$356	112%	$527	214%
2040	$348	107%	$431	156%	$946	463%
2045	$389	132%	$474	182%	$1,621	865%
2050	$413	146%	$513	205%	$6,413	3717%

Table 11-13: KEDLI Bill Impacts by Scenario

KEDLI

Avg. Monthly Bill Estimate - Delivery Only

Reference Case

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$117	$517	$342	$1,276
2030	$172	$828	$538	$1,964
2035	$200	$1,012	$658	$2,360
2040	$229	$1,202	$781	$2,775
2045	$277	$1,464	$953	$3,357
2050	$272	$1,438	$934	$3,269

CEV (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$117	$517	$342	$1,276
2030	$211	$1,010	$656	$2,363
2035	$257	$1,286	$836	$2,965
2040	$315	$1,584	$1,030	$3,719
2045	$354	$1,757	$1,141	$4,247
2050	$379	$1,816	$1,183	$4,556

AE (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$117	$517	$342	$1,275
2030	$247	$1,246	$810	$2,778
2035	$386	$1,932	$1,254	$4,254
2040	$683	$3,125	$2,034	$7,092
2045	$1,302	$5,507	$3,588	$12,214
2050	$5,105	N/A*	N/A*	N/A*

Avg. Monthly Bill Estimate - Commodity Only

Reference Case

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$39	$350	$156	$956
2030	$48	$446	$213	$1,164
2035	$50	$494	$239	$1,200
2040	$51	$536	$262	$1,220
2045	$52	$586	$287	$1,266
2050	$51	$609	$299	$1,280

CEV (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$39	$350	$156	$956
2030	$54	$510	$239	$1,322
2035	$56	$584	$271	$1,395
2040	$57	$613	$291	$1,336
2045	$59	$673	$324	$1,245
2050	$91	$1,095	$542	$1,386

AE (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$39	$350	$156	$956
2030	$51	$465	$223	$1,231
2035	$76	$735	$357	$1,866
2040	$93	$950	$471	$2,341
2045	$112	$1,216	$647	$2,841
2050	$274	N/A*	N/A*	N/A*

Avg. Monthly Bill Estimate - Total Bill

Reference Case

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$156	$868	$498	$2,231
2030	$220	$1,274	$751	$3,129
2035	$250	$1,506	$896	$3,560
2040	$279	$1,738	$1,043	$3,995
2045	$329	$2,050	$1,240	$4,623
2050	$323	$2,046	$1,233	$4,549

CEV (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$156	$868	$498	$2,231
2030	$264	$1,520	$895	$3,684
2035	$313	$1,870	$1,107	$4,360
2040	$372	$2,197	$1,321	$5,055
2045	$413	$2,430	$1,466	$5,492
2050	$470	$2,911	$1,725	$5,942

AE (Current)

	SC-1B Residential (Heat)	SC 2-A Small Commercial (Non-Heat)	SC 2-B Small Commercial (Heat)	SC-3 Multi-Family
Current	$156	$868	$498	$2,231
2030	$297	$1,711	$1,033	$4,009
2035	$461	$2,667	$1,610	$6,120
2040	$777	$4,075	$2,505	$9,432
2045	$1,414	$6,723	$4,235	$15,055
2050	$5,380	N/A*	N/A*	N/A*

*Note: Bill impacts marked N/A are outlier values not indicative of the actual per-customer bill trend due to rapid decline in customer count for the relevant rate class.

Avg. Monthly Residential Bill - KEDLI

	Reference Case	% increase	CEV	% increase	AE	% increase
Current	$156		$156		$156	
2030	$220	41%	$264	69%	$297	90%
2035	$250	60%	$313	101%	$461	195%
2040	$279	79%	$372	139%	$777	397%
2045	$329	111%	$413	165%	$1,414	806%
2050	$323	107%	$470	201%	$5,380	3345%

11.6. Benefit and Cost Categories

Avoided Gas Supply
The avoided commodity cost of geologic natural gas supply through 2050, relative to the counterfactual, is estimated based on both the reduction in geologic natural gas consumption and the change in geologic natural gas prices under each scenario. Geologic natural gas savings occurs through reduction in demand caused by energy efficiency and electrification under each scenario, as well as by the increased use of renewable natural gas and hydrogen to meet heating demands. The increased commodity cost of renewable natural gas and hydrogen supply is captured separately in the BCA. National Grid developed estimates of geologic natural gas commodity prices for each scenario based on forward pricing curves and current/contracted/negotiated rates where possible. These costs include the fixed and variable charges associated with supply currently. Supply costs also account for the quantity of supply expected individually from interstate pipeline deliveries, LNG, and CNG.

Avoided Gas Infrastructure Revenue Requirement
The annual revenue requirement was estimated through 2050 for each scenario, including the counterfactual. This revenue requirement was based on assumed capital expenditures based on the latest filed Capital Expenditure Plans, annual operation and maintenance expenses, and the existing rate base for each operating company. The difference between the revenue requirement under each scenario compared to the counterfactual – excluding contributions from investments in the Future of Heat and leak prone pipe retirement, which are counted as net costs separately – yielded the avoided gas infrastructure revenue requirement.

Avoided GHG Emissions from Gas Combustion
GHG emissions from avoided gas combustion include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Avoided GHG emissions from gas combustion include fuel mixing programs and reductions in end-use consumption through demand side management programs. All reductions through demand side management programs are assumed to be geologic gas. Fuel mixing incorporates a transition to LNG, CNG, RNG, and H_2 through time until 2050. Pounds per MMBtu of avoided gas combustion are sourced from the NYSERDA Report 22-23[1] as shown in Table 11-14. The Standard accounting method is used for BCA calculations and the Gross accounting method is used for total reductions. Avoided societal costs for each GHG are sourced from the NY DEC Establishing a Value of Carbon Appendix[1]. The 3% discount rate method was used for each GHG and adjusted to 2025 dollars using the utility WACC.

Table 11-14: lbs./MMBtu of Avoided Gas Combustion by GHG Type and Accounting Method

	GHG Type	Geologic Pipeline Natural Gas	Liquefied Natural Gas (LNG)	Compressed Natural Gas (CNG)	Renewable Natural Gas (RNG)	Hydrogen (H_2)
Standard	CO_2 (lbs./MMBtu)	143.3000	143.3000	143.3000	0.0000	0.0000
	NOX (lbs./MMBtu)	0.0005	0.0005	0.0005	0.0002	0.0000
	CH_4 (lbs./MMBtu)	0.7981	0.7981	0.7981	0.0116	0.0000
Gross	CO_2 (lbs./MMBtu)	143.3000	143.3000	143.3000	116.6200	0.0000
	NOX (lbs./MMBtu)	0.0005	0.0005	0.0005	0.0002	0.0000
	CH_4 (lbs./MMBtu)	0.7981	0.7981	0.7981	0.0116	0.0000

Avoided Emissions from Methane Leakage
Avoided emissions from methane leakage are obtained through leak prone pipe (LPP) retirement. Based on the Company's assumptions, LPP is replaced in KEDNY and KEDLI through the end of 2044 and in NMPC through the end of 2033 in all scenarios. In the Reference Case scenario none of the network is assumed to be decommissioned, but in the CEV.NY scenario 10% is assumed to be

decommissioned by 2050 and in the Accelerated Electrification scenario 90% decommissioning is assumed. In the Reference Case all the LPP is replaced by 2044, and for the CEV.NY and Accelerated Electrification scenarios, LPP is assumed to be replaced if it is not decommissioned. To determine emissions from methane leakage, emissions factors from “New York State Oil and Gas Sector: Methane Emissions Inventory” were applied as seen below in Table 5[1]. Emissions from LPP were assumed to be a weighted average between emission factors for unprotected/bare steel and cast iron. Emissions from current non-LPP were assumed to be a weighted average of protected steel and plastic. LPP was assumed to be replaced with plastic pipeline, so the emissions factor for plastic was assumed for replaced LPP. The emissions from all scenarios were compared to a counterfactual where none of the LPP was replaced.

As with GHG reductions from gas combustion, the avoided societal costs for methane are sourced from the NY DEC Establishing a Value of Carbon Appendix. The 3% discount rate method was used for each GHG and adjusted to 2025 dollars using the utility WACC.

Table 11-15: Emissions Factors for Distribution Mains

Pipeline Material	Emissions Factor (MT CH4/mile/year)
Cast Iron	4.5974
Unprotected Steel	2.1223
Protected Steel	0.0588
Plastic	0.1909
Copper	0.4960

Added Hydrogen and RNG Supply
The additional commodity cost of hydrogen and RNG under each scenario through 2050, based on the commodity prices utilized in the CLCPA study.

Added Future of Heat Infrastructure Revenue Requirement & LPP Retirement Revenue Requirement
The incremental revenue requirement associated with increased investment in Future of Heat infrastructure, such as network geothermal, hydrogen, and RNG interconnection, and in leak prone pipe retirement. The counterfactual assumes neither of these activities occur moving forward, such that the cost to the BCA reflects the full revenue requirement impact of these activities through 2050.

Increased Electricity Consumption
Increased electricity consumption occurs through heat electrification measures adding end-use consumption to the electricity system. Location-based marginal prices (LBMPs) are developed for each operating company based on their representative NYISO zones. NYISO 2020 CARIS 2 values are applied for the Reference Case for four time periods, summer off/on-peak and winter off/on-peak. For the CEV.NY and AE scenarios, the S2 LBMP 2021-2040 System and Resource Outlook[1] values are applied to better represent likely costs from increased electrification.

Increased Electric Capacity
Increased electric capacity requirements occur through heat electrification measures increasing demand on the existing electricity system. The avoided generation capacity cost (AGCC), marginal cost of transmission, and marginal cost of distribution contribute to this cost. The AGCC is sourced from DPS Staff BCA Attachment A Capacity Price Forecast, published to Case 14-M-0101 on October 13, 2023. The marginal cost of transmission and distribution are sourced from the Marginal Cost of Service Study for NMPC Electric, and for KEDNY are sourced from ConEd’s 2023 BCA Handbook. Because PSEG Long Island does not identify separate distribution and transmission marginal capacity costs, KEDLI’s marginal distribution capacity cost was assumed to be the same as

NMPC Electric and KEDLI's marginal transmission capacity costs were based on LIPA's Phase 2 Local Transmission Project Proposals identified under Case 20-E-0197.

Increased GHG Emission from Electricity
Increased GHG emissions from electricity occur through heat electrification measures adding end-use consumption to the electricity system. There are differing estimates for heat electrification penetrations through time with the greatest seen in the AE scenario. These emissions are quantified through the application of marginal emissions rate forecasts sourced from the Projected Emission Factors for New York Grid Electricity Annex study by NYSERDA[1] to estimates of increased electricity consumption. A monetary GHG value for the reduction in electricity consumption is calculated by multiplying the social cost of GHG by the marginal emissions rates.

Gas Utility Energy Efficiency Admin Costs
Administrative costs incurred by the gas operating companies associated with incremental energy efficiency pursued under each scenario, based on actual administrative expenses per unit of savings achieved in existing gas energy efficiency programs.

Incremental Participant Cost
The incremental cost of demand-side management technology adoption to society, relative to typical technology baselines. Note that these costs exclude the impact of incentives, which are considered a pass-through in the societal cost test.

Non-Gas Utility Electrification Admin Costs
Administrative costs associated with implementation of the energy efficiency and electrification efforts that are not borne by the gas operating companies. Note that this is a net cost from the perspective of the societal cost test.

Global Economic Inputs
Table 11-16 provides economic inputs by operating company used for all cost and benefit streams where applicable. The discount rate is used to present value future cash flows and expenditures to 2025 dollars. Company retained gas represents the gas utilized for utility operations that is a function of end-use consumption. Electric loss factors represent the electricity lost in delivery to customers as a percent of end-use consumption. Gas and electric benefits are calculated at the city gate and generator, respectively. The inflation rate is used where applicable to adjust input variables to nominal dollars before discounting.

Table 11-16: Global Economic Inputs by Operating Company

Input	NMPC	KEDNY	KEDLI	Source
Discount Rate	6.49%	6.26%	6.26%	Weighted annual cost of capital (post-tax) for individual OpCos. 2018 for NMPC, settled; 2019 for KEDNY/KEDLI, settled.
Company Retained Gas	0.76%	1.18%	1.37%	Half of LAUF in OpCo Tariff Leave details. 2018 for NMPC, settled; 2019 for KEDNY/KEDLI, settled.
Electric Loss Factor	7.67%	6.64%	6.84%	ConEd and NMPC Handbooks 2020 for NMPC/KEDNY and NENY Analysis of Heat Pump Economics, Table 7-1 for KEDLI
Inflation Rate	2.00%	2.00%	2.00%	NMPC BCA Handbook V3.0

11.7. Detailed BCA Results

Table 11-17: Societal Cost Test for NMPC – Portfolio

Benefit or Cost Category	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Avoided Gas Supply	$167	$5,859	$5,891
Avoided Gas Infrastructure Revenue Requirement	$62	$992	$981
Avoided GHG Emissions from Gas Combustion	$4,406	$27,038	$28,260
Avoided Emission from Methane Leakage	$280	$331	$571
Avoided Electricity Consumption	$0	$0	$0
Avoided Electric Capacity	$0	$0	$0
Total PV Benefits	**$4,916**	**$34,219**	**$35,702**
Added Hydrogen and RNG Supply	$0	$10,900	$3,917
Added Future of Heat Infrastructure Revenue Requirement	$335	$1,722	$5
LPP Retirement Revenue Requirement	$517	$513	$482
Increased Electricity Consumption	$451	$4,658	$6,908
Increased Electric Capacity	$1,356	$9,832	$14,458
Increased GHG Emission from Electricity	$29	$185	$253
Program Administrative Costs	$232	$630	$486
Incremental Participant Cost	$4,146	$20,122	$20,344
Electric Utility Admin	$38	$248	$406
Total PV Costs	**$7,103**	**$48,810**	**$47,259**
NPV	**-$2,187**	**-$14,591**	**-$11,558**
SCT Ratio	**0.69**	**0.70**	**0.76**

Table 11-18: Societal Cost Test for KEDNY – Portfolio

Benefit or Cost Category	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Avoided Gas Supply	$906	$12,279	$12,634

Avoided Gas Infrastructure Revenue Requirement	$527	$1,690	$1,715
Avoided GHG Emissions from Gas Combustion	$4,302	$35,252	$36,456
Avoided Emission from Methane Leakage	$1,277	$1,296	$1,427
Avoided Electricity Consumption	$0	$0	$0
Avoided Electric Capacity	$0	$0	$0
Total PV Benefits	**$7,013**	**$50,518**	**$52,232**
Added Hydrogen and RNG Supply	$0	$11,256	$5,182
Added Future of Heat Infrastructure Revenue Requirement	$363	$1,821	$4
LPP Retirement Revenue Requirement	$6,742	$6,543	$4,952
Increased Electricity Consumption	$834	$6,466	$9,596
Increased Electric Capacity	$4,459	$31,356	$45,583
Increased GHG Emission from Electricity	$46	$368	$474
Program Administrative Costs	$439	$990	$663
Incremental Participant Cost	$6,333	$41,235	$40,648
Electric Utility Admin	$118	$877	$1,212
Total PV Costs	**$19,334**	**$100,912**	**$108,313**
NPV	**-$12,321**	**-$50,395**	**-$56,081**
SCT Ratio	**0.36**	**0.50**	**0.48**

Table 11-19: Societal Cost Test for KEDLI – Portfolio

Benefit or Cost Category	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Avoided Gas Supply	$537	$10,226	$10,547
Avoided Gas Infrastructure Revenue Requirement	$271	$2,056	$1,397
Avoided GHG Emissions from Gas Combustion	$3,337	$24,378	$25,973
Avoided Emission from Methane Leakage	$1,425	$1,491	$1,784

Avoided Electricity Consumption	$0	$0	$0
Avoided Electric Capacity	$0	$0	$0
Total PV Benefits	**$5,570**	**$38,151**	**$39,701**
Added Hydrogen and RNG Supply	$0	$8,947	$3,610
Added Future of Heat Infrastructure Revenue Requirement	$173	$1,369	$4
LPP Retirement Revenue Requirement	$5,512	$5,376	$4,288
Increased Electricity Consumption	$738	$4,692	$7,581
Increased Electric Capacity	$2,683	$15,990	$25,749
Increased GHG Emission from Electricity	$32	$214	$360
Program Administrative Costs	$71	$560	$356
Incremental Participant Cost	$2,108	$18,328	$18,925
Electric Utility Admin	$43	$227	$462
Total PV Costs	**$11,360**	**$55,703**	**$61,334**
NPV	**-$5,790**	**-$17,552**	**-$21,633**
SCT Ratio	**0.49**	**0.68**	**0.65**

Table 11-20: Societal Cost Test for NMPC by Program

Program	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Energy Efficiency	$2,719	$6,463	$4,461
Electrification	$1,687	$17,126	$22,061
Demand Response	$0	$0	$0
Revenue Requirement	$230	$6,851	$6,872
LPP	$280	$331	$571
Fuel Mixing	$0	$3,449	$1,738
Total PV Benefits	**$4,916**	**$34,219**	**$35,702**
Energy Efficiency	$3,484	$15,001	$14,667
Electrification	$2,767	$20,674	$28,188
Demand Response	$0	$0	$0
Revenue Requirement	$852	$13,135	$4,405
LPP	$0	$0	$0
Fuel Mixing	$0	$0	$0
Total PV Costs	**$7,103**	**$48,810**	**$47,259**
NPV	**-$2,187**	**-$14,591**	**-$11,558**
SCT Ratio	**0.69**	**0.70**	**0.76**

Table 11-21: Societal Cost Test for KEDNY by Program

Program	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Energy Efficiency	$1,407	$9,690	$5,495
Electrification	$2,895	$21,915	$29,290
Demand Response	$0	$0	$0
Revenue Requirement	$1,434	$13,969	$14,349
LPP	$1,277	$1,296	$1,427
Fuel Mixing	$0	$3,647	$1,671
Total PV Benefits	**$7,013**	**$50,518**	**$52,232**
Energy Efficiency	$4,048	$21,261	$21,156
Electrification	$8,181	$60,031	$77,020
Demand Response	$0	$0	$0
Revenue Requirement	$7,104	$19,620	$10,137
LPP	$0	$0	$0
Fuel Mixing	$0	$0	$0
Total PV Costs	**$19,334**	**$100,912**	**$108,313**
NPV	**-$12,321**	**-$50,395**	**-$56,081**
SCT Ratio	**0.36**	**0.50**	**0.48**

Table 11-22: Societal Cost Test for KEDLI by Program

Program	Reference Case ($M)	CEV.NY ($M)	Accelerated Electrification ($M)
Energy Efficiency	$931	$6,889	$3,757
Electrification	$2,405	$14,663	$21,079
Demand Response	$0	$0	$0
Revenue Requirement	$808	$12,282	$11,944
LPP	$1,425	$1,491	$1,784
Fuel Mixing	$0	$2,825	$1,137
Total PV Benefits	**$5,570**	**$38,151**	**$39,701**
Energy Efficiency	$1,198	$13,560	$13,506
Electrification	$4,478	$26,452	$39,926
Demand Response	$0	$0	$0
Revenue Requirement	$5,685	$15,691	$7,902
LPP	$0	$0	$0
Fuel Mixing	$0	$0	$0
Total PV Costs	**$11,360**	**$55,703**	**$61,334**
NPV	**-$5,790**	**-$17,552**	**-$21,633**
SCT Ratio	**0.49**	**0.68**	**0.65**

11.8. Clean Energy Initiatives

National Grid has emphasized energy efficiency, a fossil free gas network, hybrid electric gas heating systems and targeted electrification/network geothermal as the four main pillars to enable the company to achieve its Clean Energy Vision targets. The table below incorporates all National Grid's publicly available clean energy initiatives, related to gas demand reduction, that have been completed or are being actively pursued. All project descriptions are eligible to change based on new findings.

Table 11-23: National Grid's Current & Pending Clean Energy Projects

Category	Name	Region	Description
RNG	Newtown Creek	KEDNY	Completed joint project between National Grid and the New York City Department of Environmental Protection ("NYC DEP") to reuse gas from a Water Resource Recovery Facility ("WRRF"). It's estimated Newtown Creek will produce a minimum 437 Dth/day.
RNG	American Organic	KEDLI	Project underway where American Organic is planning to use an anaerobic digester to process food waste in the N.Y. Metropolitan Region. It's estimated American Organic will produce 1,499 Dth/day.
RNG	Jamaica WWTP	KEDNY	Project proposed in KEDNY rate case where National Grid and the New York City DEP are looking to reuse gas produced at Jamaica WRRF. It's estimated Jamaica will produce 600 Dth/day.
RNG	Bay Park	KEDLI	Project proposed in KEDLI rate case where National Grid and Nassau County Public Works are looking to reuse gas produced at South Shore Water Reclamation Facility (Bay Park). It's estimated Bay Park will produce 450 Dth/day.
RNG	Staten Island Green Waste	KEDNY	Project proposed in KEDNY rate case where National Grid and an RNG developer are looking to use biogas from anaerobic digestion of green waste in Staten Island. It is estimated to produce 2,100 Dth/day.
RNG	Enterprise Park	KEDLI	Project proposed in KEDLI rate case where National Grid and an RNG developer are planning to use biogas from anaerobic digestion of food waste in Calverton, NY. It's estimated to produce 400 Dth/day with plans to double production up to 800 Dth/day in the near future.
RNG	Adams Region Hub and Spoke Dairy	NMPC	Project proposed in recent NMPC rate case filing. Ag-Grid Energy ("AGE") is planning to construct a hub and spoke style renewable natural gas project using dairy manure produced in the Adams, NY region. The project is expected to produce over 750 Dth/day.
RNG	Ideal Dairy	NMPC	Project proposed in recent NMPC rate case filing. To be developed by RevLNG. Project is expected to produce over 250 Dth/day.
RNG	Saratoga WWTP	NMPC	Project proposed in recent NMPC rate case filing. Partnership with municipal wastewater treatment facility in Saratoga, NY. To be developed by Arcadis. Project is expected to produce over 250 Dth/day.
RNG	Watertown Hub and Spoke Dairy	NMPC	Project proposed in recent NMPC rate case filing. Ag-Grid Energy is planning to construct a hub and spoke style renewable natural gas project using dairy

Category	Name	Region	Description
			manure produced in the Watertown, NY region. Project is expected to produce over 950 Dth/day.
UTEN	KEDNY UTEN Pilot	KEDNY	Project proposed in UTEN pilot proceedings on NYCHA Vandalia Avenue consisting of two 10-story apartment buildings and a low-rise community center, together totaling 335,000 square feet. The project seeks to interconnect with nearby commercial buildings to balance the load profile.
UTEN	Syracuse UTEN Pilot	NMPC	Project proposed in UTEN pilot proceedings for the city of Syracuse in the Inner Harbor area utilizing the existing Metro Wastewater Treatment Plant outfall to Onondaga Lake as a thermal resource to be distributed to 15 buildings.
UTEN	Troy UTEN Pilot	NMPC	Project proposed in UTEN pilot proceedings in the city of Troy consisting of nine mixed use commercial and multifamily buildings in downtown Troy, all located in a Disadvantaged Community, with a geothermal bore field in Riverfront Park.
NPAs / Targeted Electrification	NPAs to Support Targeted Electrification	KEDNY KEDLI NMPC	Annually, National Grid targets at least 5 segments of LPP in each territory as potential candidates for full electrification of all customers on that segment and, if successful, retirement of the LPP to serve as the NPA funding mechanism.
NPAs / Targeted Electrification	NPAs to Support Targeted Electrification	KEDNY KEDLI NMPC	Proposed NPA projects where request for new gas connections that involve at least 500’ of main and more than 5 customers are offered NPA incentives as an alternative to installing gas service.
Targeted Electrification	Saratoga County Farm Taps	NMPC	Completed project where three customers will fully electrify and receive a ground source heat pump, heat pump hot water heater, electric stove, and electric dryer at no cost.
Firm Gas Demand Response	Load Shedding Demand Response	KEDNY KEDLI NMPC	A program for large commercial, industrial, and multi-family firm service customers capable of reducing peak day gas load over a 4 or 8-hour period on event days.
Firm Gas Demand Response	Load Shifting Demand Response	KEDNY KEDLI NMPC	A program for large commercial, industrial, and multi-family firm service customers capable of reducing peak hour gas load over a 4 hour period on event days.
Firm Gas Demand Response	Behavioral Demand Response Neighborhood Device Program	KEDLI	Program where pole-mounted devices are installed to capture hourly customer meter data, where AMI isn’t available. Customers get notified of demand response events and have access to the collected data.
Firm Gas Demand Response	Gas Demand Response Hybrid Electrification Pilot	KEDNY	Single Family Track- Pilot in which gas heating customers that own heat pumps primarily used for cooling are offered incentives for utilizing the heat pumps during periods of peak gas demand.

Category	Name	Region	Description
			Multifamily Track – Pilot in which remotely controlled heat pump window units are being installed in multifamily apartments, where these heat pumps can be leveraged to reduce gas usage during periods of peak gas demand.
Firm Gas Demand Response	BYOT	KEDNY KEDLI NMPC	A current program directed towards residential and small commercial customers which utilizes Wi-Fi connected thermostats to remotely lower temperature set points and shift peak hour gas loads on event days.
Firm Gas Demand Response	Behavioral Demand Response	KEDNY KEDLI	A current non-incentivized program that uses email messaging to notify customers of impending cold weather and suggests methods to lower gas consumption during peak hours.
Energy Efficiency	Gas C&I Program	KEDNY KEDLI NMPC	Current program that provides technical services along with prescriptive and custom incentives to encourage the installation of a wide variety of energy-efficient gas measures.
Energy Efficiency	Gas Non-Residential Online Marketplace Program	NMPC	Current program that provides an online shopping platform for small businesses to receive instant rebates for gas energy efficiency products.
Energy Efficiency	Gas Multifamily Program	KEDNY KEDLI NMPC	Current program that is designed to increase the installation of energy efficiency measures in existing multifamily buildings within National Grid's service territory by working with property owners, managers, trade allies, and tenants.
Energy Efficiency	Gas Residential Program	KEDNY KEDLI NMPC	A current program that educates customers, HVAC/plumbing contractors and vendors regarding the benefits of high-efficiency gas space and water heating equipment, along with associated controls The program offers an in-store option delivery for energy efficient gas equipment and controls at participating stores.
Energy Efficiency	Gas Residential Engagement Program	KEDNY KEDLI NMPC	A current behavioral initiative to encourage residential customers to change their energy usage behavior to conserve energy.
Energy Efficiency	Gas Residential Online Marketplace Program	KEDNY KEDLI NMPC	A current program that includes individualized customer education on specific energy efficiency opportunities for customers' homes. The Online Marketplace allows customers to purchase energy efficiency products with instant rebates.
Energy Efficiency	Gas Non-Residential Weatherization Program	KEDNY KEDLI	A current program that incentives any measures that improve energy efficiency through building envelope improvements including air sealing, insulation, and window replacements.

Category	Name	Region	Description
Energy Efficiency	Gas Residential Weatherization Program	KEDNY KEDLI	A current program that educates customers, program partners and vendors regarding the benefits of weatherization and building envelope improvements.
Electrification of Heat	NYS Clean Heat Program	NMPC	Incentives offered to spur adoption of eligible heat pump technologies, including cold climate air source heat pump systems, ground source heat pump systems, and heat water pump heaters. The program is implemented in coordination with a portfolio of NYSERDA led market development initiatives, which aim to build market capacity including through education, marketing and training regarding building electrification opportunities.
Electrification Referrals	Referrals to EDCs	KEDNY KEDLI	Customers in DNY who contact National Grid's call centers to request new or upgraded gas connections are offered information on heat pumps and referred to Con Edison's and PSEG-LI's heat pump programs

11.9. Draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework

National Grid is working to enable New York's clean energy transition by advancing a smarter, stronger, cleaner, and more equitable energy system for the customers and communities we serve. There is a critical need to combat climate change and drive down climate pollution and we are committed to meeting the clean energy, equity, and disadvantaged community goals established by New York's Climate Leadership and Community Protection Act (CLCPA). In addition to enabling equitable access to safe, reliable, and resilient energy service for customers, we are working to deliver the technology, economic and environmental benefits of the clean energy transition fairly and in a way that supports the principles articulated in our Vision and Values and Responsible Business Charter.

National Grid is committed to working transparently and collaboratively with stakeholders and communities to support equity and environmental justice in the clean energy transition. We are reviewing and enhancing our current engagement practices, with a focus on public outreach surrounding our major infrastructure projects, especially in disadvantaged and low-income communities. Many customers in these communities face barriers to accessing clean energy solutions, managing their energy bills, and engaging meaningfully in stakeholder processes regarding energy projects and programs that affect them. The needs and preferences of customers across these groups are diverse and solutions should account for and reflect this diversity.

Defining Equity and Environmental Justice

National Grid considers equity to mean enabling all stakeholders to engage in the pursuit of a clean, fair, and affordable energy system that provides broad-based benefits and opportunities, while recognizing and working to address potential disparities in access and outcomes.

This definition is grounded in three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Framework:

- **Procedural equity,** which focuses on creating transparent, inclusive, and accessible processes for engagement such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation.

- **Distributional equity,** which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition.
- **Structural equity,** which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities.

Environmental justice is defined by US EPA as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Our efforts on environmental justice are informed by an understanding that the communities we serve vary in terms of the environmental, public health, and economic burdens they experience, as well as their vulnerabilities to the risks of climate change, all factors that are recognized in the Disadvantaged Communities Criteria established by the New York Climate Justice Working Group.[154]

Our Commitments

We will continue to work to integrate equity and environmental justice across our business by:

- Increasing transparency and education about future infrastructure investment plans, including the need for investments and the benefits and impacts to a host community;
- Meaningfully engaging stakeholders, including directly and via trusted community sources, and enhancing open communication that supports clear and timely information sharing, community feedback, and ongoing dialogue;
- Expanding our understanding of community concerns and priorities;
- Enhancing project and program outcomes by identifying opportunities to mitigate adverse impacts and support community and customer benefits;
- Reducing barriers to participation in customer programs that can benefit low-income customers, customers in disadvantaged communities, and environmental justice populations;
- Partnering with communities and local organizations in support of broader social, economic, and environmental progress;
- Directly supporting economic opportunity and advancement through the development of a more local, diverse workforce and the utilization of diverse and sustainable businesses in our jurisdictions; and
- Monitoring and informing on our progress in supporting equity and environmental justice on a regular and transparent basis.

Operationalizing Equity and Environmental Justice

Integrating equity and environmental justice into our operations, planning, programs, and day-to-day business more effectively will require new efforts that build upon existing initiatives. Full operationalization of equity and environmental justice through an intentional approach will take time. We are actively working to build upon and learn from our existing efforts and create new processes and procedures to advance the intentions outlined above, and to develop the necessary training and resources for our employees to ensure that key business areas are equipped to implement this framework. We are also working to engage external perspectives to help us in this process.

[154] Disadvantaged Communities Criteria - New York's Climate Leadership & Community Protection Act (ny.gov).

As we implement this framework, we will continue to build upon and be informed by multiple successful recent and ongoing efforts including:

- Processes and practices to mitigate environmental impacts of construction.
- Public outreach and stakeholder engagement via multiple channels and with translation where needed in support of obtaining project permits and approvals and addressing construction impacts.
- Consideration of input from environmental justice and disadvantaged community stakeholders in the design of customer programs. For example, our Energy Efficiency programs include specific goals related to achieving equitable outcomes among specific customer segments and include explicit commitments around service to disadvantaged communities, and our Electric Vehicle programs include enhanced incentives for public charging and residential customers in disadvantaged communities as well as direct support of fleet electrification to reduce local air pollution.
- Our Project C program unites over 10,000 employees in New York around four core priorities: (1) clean energy and sustainability, (2) workforce development, (3) neighborhood investment and community engagement, and (4) environmental justice and social equity with the primary purpose to give back to the communities in which we operate.
- Our Economic Development Grant Program aligns with the Project C initiative and maintains a strong focus on site development, urban revitalization, strategic marketing, and facilitating customer growth through infrastructure assistance, energy efficiency and productivity improvement.

Evaluating our Progress
National Grid intends this framework to be a living document, updated and modified based on stakeholder feedback and lessons learned through experience. We are committed to collaborating with stakeholders to inform future review and development of these efforts.

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