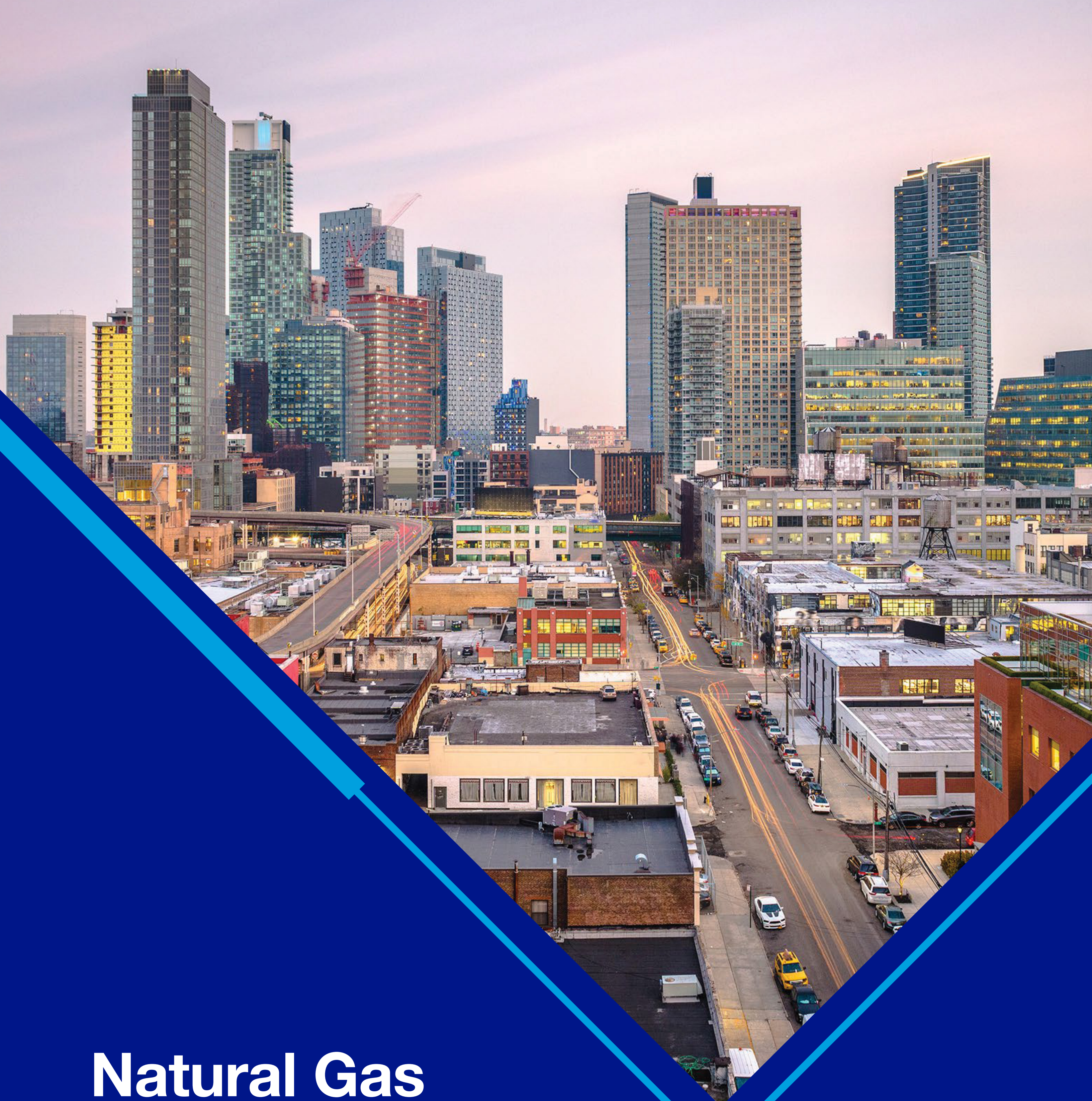


Natural Gas Long-Term Capacity Report

for Brooklyn, Queens, Staten Island
and Long Island ("Downstate NY")
February 2020

nationalgrid

Contents

List of Tables

List of Figures

1. Introduction

National Grid provides natural gas to 1.9 million customers throughout Brooklyn, Queens, Staten Island and Long Island. Over the past 10 years, demand for gas in this Downstate New York region has increased by 2.4% per year, driven by 1.9% real economic growth per year[1], the addition of 32 million square feet per year of housing and non-residential building space, ~12,400 conversions to gas heat per year, and a favorable cost profile vs. available alternatives for heating, cooking and many industrial uses.

This demand growth has placed constraints on National Grid's existing gas network. Quite simply, we are at risk of not having enough gas to meet the needs of our customers during periods of peak demand on cold winter days. In the near term – to ensure sufficient supply for the winter of 2019/2020 and the winter of 2020/2021 – we are taking a series of measures including:

- Installation of additional Compressed Natural Gas ("CNG") capacity, which allows up to 42 trucks per day in the winter of 2019/20 to bring CNG from upstream of National Grid's system to be injected into our gas system as needed during periods of peak demand, with plans to expand to 108 trucks for the winter of 2020/21
- A company-funded $8M incremental investment in energy efficiency, demand response and other gas conservation measures designed to reduce peak-day gas usage among current customers to enable certain new customer connections

As we look beyond the next two winters and consider the needs of our customers over the next 2 – 15 years, continued growth in natural gas demand – even after factoring in incremental energy efficiency and electrification under recently proposed and agreed to programs – creates a supply vs. demand gap which must be anticipated and resolved. It is a complex challenge with a need for timely decisions and with multiple potential solutions that must consider safety and reliability, environmental and community impact, and cost.

To facilitate constructive dialog and help get to some answers, National Grid has agreed with the New York State Department of Public Service Staff to publish this Long-Term Capacity Report (the "Report") that provides a comprehensive analysis of capacity constraints and all reasonably available options for meeting long-term demand.

After providing a forecast for Downstate New York natural gas demand through 2035 and a summary of National Grid's current supply capacity and operating characteristics, the Report will describe different options available for expanding capacity and/or further reducing demand to meet customer needs. Our intention is not to make a specific recommendation on the "best" solution, but rather to provide the facts on each option and combination of options that could comprehensively resolve a supply vs. demand gap that starts by the winter of 2021/22 and continues to grow until at least 2032/33.

We invite readers to provide feedback on the contents of the Report, including the options considered and the assumptions used in our analysis. We will also be hosting a series of public meetings to share more information and solicit feedback. For more information on how to submit written comments, and the dates, times and locations of the public meetings, please go to **www.ngrid.com/longtermsolutions**.

[1] Moody's Analytics, January 2020. Data are for Kings, Queens, Richmond, Nassau and Suffolk counties.

2. Executive Summary

2.1 Background

For more than 100 years, National Grid and its predecessors have provided natural gas service to customers throughout Brooklyn, Queens, Staten Island and Long Island ("Downstate NY"). We are a regulated utility, with New York Public Service Commission (PSC) oversight of our operations. Because we are the sole provider of natural gas throughout our Downstate NY service territory, we have an "obligation to serve" – as long as we believe we can provide safe, reliable service, we must fulfill all customer requests for a natural gas connection as described in 16 NYCRR Part 230.

In addition to connecting and serving all our customers in a safe, reliable fashion, National Grid is committed to decarbonization goals. We are supportive of partnering with the state of New York to achieve its Climate Leadership and Community Protection Act (CLCPA) goal of net zero Greenhouse Gas (GHG) emissions by 2050, with 85% reductions from New York's energy and industrial emissions compared to 1990 levels and 15% carbon offsets. We are fully cognizant of the changing role of utilities, and the desire to include non-pipeline alternatives as part of the pathway to a sustainable energy future.

Downstate NY contains vibrant, growing communities with increasing energy needs. Over the last 10 years, the number of natural gas customers that National Grid serves has grown by more than 115,000, and gas demand during peak usage periods – extreme cold weather conditions which we model as the Design Day[2] – has grown by 2.4%/year. This growth has been driven by oil-to-gas conversions, new connections, and higher gas usage per customer.

2.2 Downstate New York Natural Gas Demand Growth is Expected to Continue, but at a Slower Rate

Due to continued growth in population, business activity and new construction, and continued oil-to-gas conversions[3], it is projected that baseline Design Day gas demand growth under current policies and customer usage patterns will be 1.8% per year between now and 2035. However, there are proposed actions and emerging trends that are expected to lower this demand growth:

- **Additional Energy Efficiency and Demand Response Programs**. National Grid has agreed to invest $8M in energy efficiency, demand response and other natural gas conservation measures over and above our current rate case as part of a recent settlement.[4] More broadly, Local Law 97 will drive incremental efficiency for buildings in New York City that are larger than 25,000 square feet, and the recently announced New Efficiency New York (NENY) program lays out an aggressive efficiency agenda and targets which will further expand funding and programs.

[2] Please see Section 3 for a more detailed explanation of Design Day

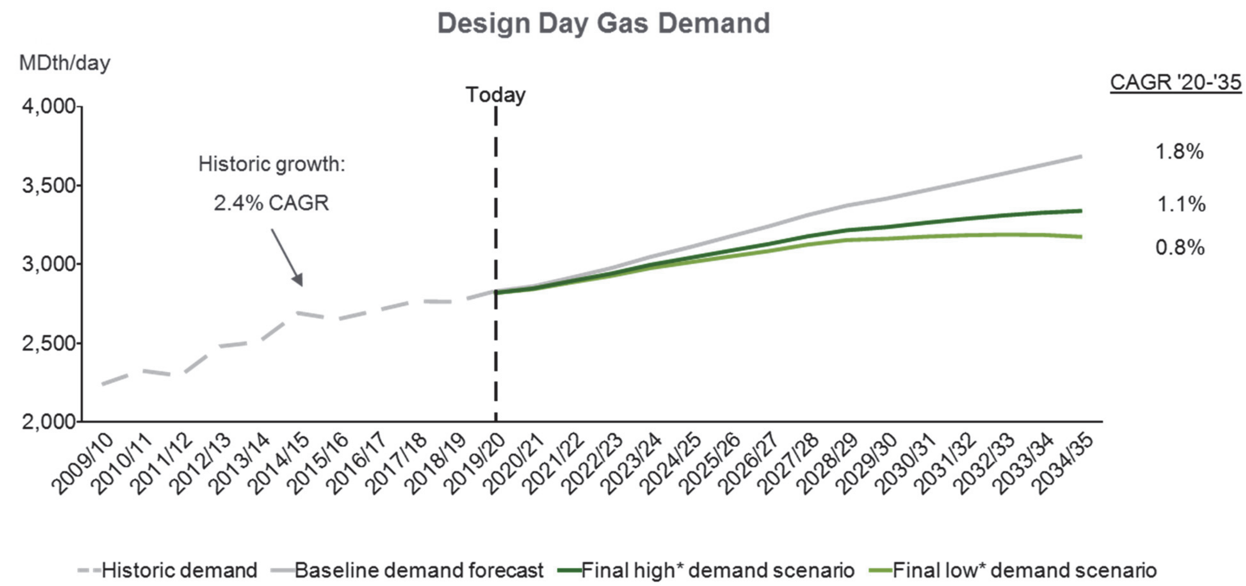
[3] Source: Moody's Analytics and National Grid analysis. Please see Section 5 of this Report for more details.

[4] 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 (Issued and Effective November 26, 2019)

- **Growth in Electrification**. Aligned with NENY, new programs are being launched by the electric utilities in Downstate NY (Con Edison and PSEG Long Island), with specific targets for converting their customers to electric heat pumps. It is also expected that over time air source and ground source electric heat pumps will take an increasing share of new construction and of customers converting away from the use of oil for space heating, therefore reducing the need for new gas connections.

Factoring in these additional programs and trends, compliance with Local Law 97, and 80-100% of all New Efficiency New York (NENY) target achievement in the specified time frames[5], it is projected that Downstate NY natural gas demand growth will be reduced to a range of 0.8% - 1.1% per year. Figure 1 below shows historic and projected demand in Downstate NY through 2035.

Figure 1: Historic and Projected Design Day Natural Gas Demand in Downstate New York, 2009 – 2035



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.

** High and low demand scenarios are based on ranges of incremental Energy Efficiency, Demand Response, and Electrification. See Section 5 for more details*

Source: National Grid analysis based on projections and data from Advanced Data Analytics team, rate case filings, New Efficiency New York Order, Con Edison and PSEG Long Island Downstate NY electrification programs.

2.3 National Grid Natural Gas Supply is Stretched to Meet Today's Needs, and is Not Sufficient to Meet Forecast Needs

National Grid provides natural gas supply into Downstate NY from multiple sources, including:

- Long-term contracts for delivery via pipeline that provide a year-round volume baseline. This is our largest source of supply, representing more than 70% of Design Day capacity;
- Liquefied Natural Gas (LNG) facilities to accommodate periods of high demand, designed to run for 10-15 days per year (~15% of Design Day capacity); and

[5] Assumes NENY energy efficiency and electrification budgets and targets continue through 2035 at the 2025 levels

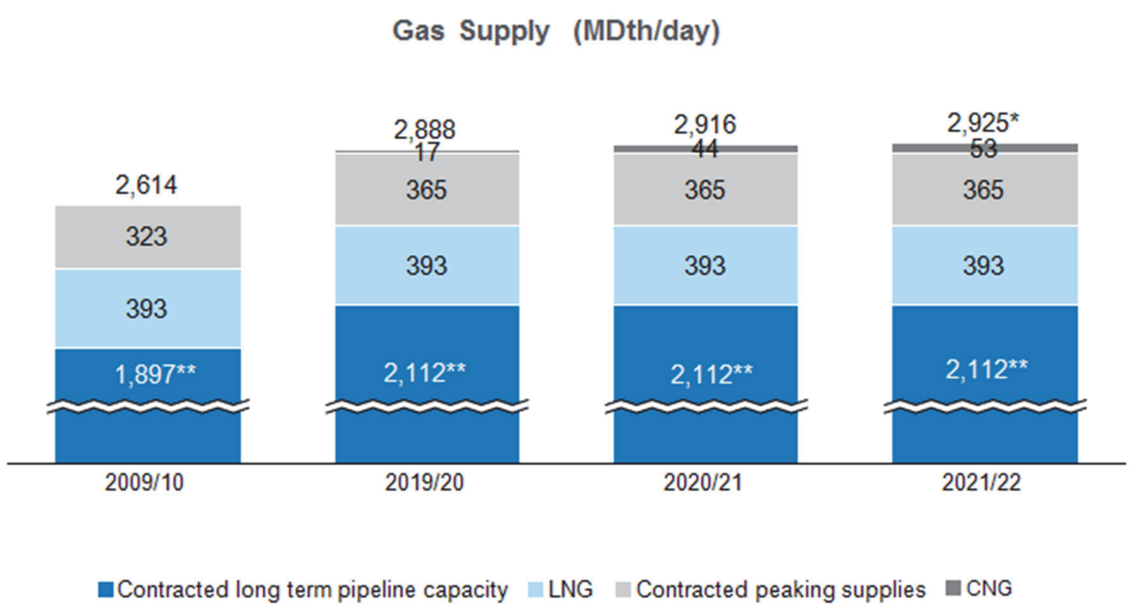
- Peak contracting supplies, which are short-term (1-5 year) contracts to deliver gas via pipeline for up to 30 days per year, that we can access during periods of high demand (~14% of Design Day capacity)

As part of our ongoing supply planning over the last 10 years, we have increased our available supply by 10% or 274 MDth/day via additions to long-term pipeline and short-term peak contracting capacity. However, over this same time period, Design Day demand has grown by 23% or 523 MDth/day. This has created constraints to our network.

To address these constraints in the short-term, we have added 17 MDth/day of peak capacity from Compressed Natural Gas (CNG) trucking[6], with plans over the next two years to expand capacity to 53 MDth/day and will be adding a small amount of year-round capacity by connecting a new Renewable Natural Gas (RNG) plant in Newtown Creek in 2020.

A summary of our historic, existing and near-term natural gas supply capacity (the "Supply Stack") is shown in Figure 2 below.

Figure 2: National Grid Natural Gas Supply for Downstate NY, 2009 - 2022



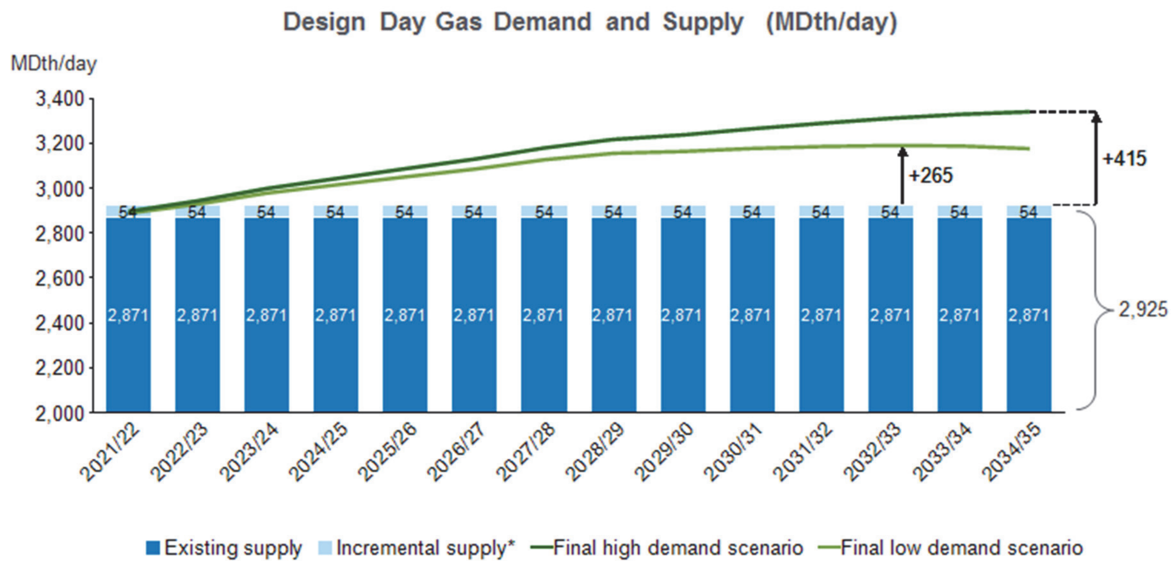
Source: National Grid analysis

**Total supply includes RNG capacity (2 MDth/day in 2009/10 and 2019/20, 3 MDth/day in 2020/21 and 2021/22)*
*** Chart is not to scale*

National Grid's current capacity of 2,888 MDth/day is challenged to meet existing peak demand during cold winter days, leaving our network with little room for error, and stressing contingency plans for supply interruption and LNG tank maintenance. And looking ahead, our existing and planned expansion capacity to supply natural gas is not sufficient to meet forecast demand. There is a gap between expected demand and capacity of supply that grows to a range of 265 - 415 MDth/day by 2032-2035.

[6] See appendix for more details on our recent and planned CNG efforts

Figure 3: Comparison of Downstate NY Forecast Natural Gas Demand and Existing Supply, 2021 – 2035



** Incremental supply includes addition of CNG (53 MDth/day) and RNG (1 MDth/day) capacity*

Source: National Grid analysis

There are two important additional factors to consider when looking at Figure 3:

- In the short-term - over one-year time periods - National Grid's Design Day forecasts have proven to be accurate to 98% (2% error rate). So, while the forecast indicates we are just balancing demand and supply in 2021/22 with our incremental supply, an under-forecast on demand of up to 2% would create a meaningful shortfall.
- Figure 3 represents the entire National Grid Downstate NY network for a Design Day. Higher usage during certain parts of the day, particularly morning and evening hours, creates Design Hour supply shortages in 2021/22, even after factoring in the impact of incremental CNG (see Section 3 for a more detailed explanation of Design Day/Hour).

Based on this assessment of forecast demand and our supply capacity, we need to find natural gas supply enhancement and/or demand reduction solutions that:

- Close the gap between existing supply and forecast demand
- Make delivery safe and reliable, with appropriate contingencies
- Are environmentally friendly and reduce Greenhouse Gas (GHG) emissions
- Are cost effective and minimize impact to customer bills
- Are feasible and timely

2.4 In All Scenarios, Low-Carbon Opportunities Should be Pursued to Help Reduce the Demand-Supply Gap and Support Achievement of Carbon/GHG Reduction Targets

National Grid is pursuing low-carbon gas options such as Renewable Natural Gas (RNG) and Hydrogen to increase supply and help meet carbon reduction targets. For RNG, we are connected to a 1.6 MDth/day plant in Staten Island, and expect to have a 1.0 MDth/day plant in Newtown Creek online before next winter. There are six more plants that have been proposed by developers in Downstate NY, which if brought online and connected to National Grid's network could deliver up to 23 MDth/day of supply.

We also believe there are significant opportunities to bring RNG into our supply network outside of Downstate NY, which does not increase overall capacity but contributes significantly to reduction of GHG. Accelerating development of this RNG market will likely require policy support similar to the Renewable Portfolio Standard (RPS) for electric utilities, and renewable energy credits for the heating sector such as those seen in the gas generation and transmission sectors.

We are also investigating opportunities to blend hydrogen into our gas distribution network. Recently, National Grid proposed a hydrogen blending study to be conducted by The Institute of Gas Innovation and Technology (I-GIT) with support from NYSERDA over the next two years. This project will assess the impact of hydrogen on New York's natural gas infrastructure to determine acceptable blend amounts and identify any required alterations to accomplish safe and cost-effective inclusion of hydrogen in gas systems. Filling these knowledge gaps can enable the development of hydrogen blending in New York, opening the opportunity to achieve deep decarbonization of the gas network.

Geothermal Heat Pumps (GHP) present another significant opportunity to expand a low-carbon solution. Following a successful 2016-2019 pilot with 10 homes, National Grid has proposed a $12M program to connect 900 homes in Downstate NY to geothermal ground loops over the next four years. For those customers switching from heating oil to geothermal systems, it is estimated they could realize average annual energy cost savings of $1,000 - $1,500 while reducing nearly 6.75 metric tons of CO_2 emissions.

With program funding and support, we anticipate that RNG, Hydrogen and incremental Geothermal Heat Pump programs can cover 15 – 35 MDth of the gap between Downstate NY gas demand and currently available supply through the time period to 2035, while also significantly increasing levels of low-carbon gas that are brought into our network and positioning our distribution network as a viable component of achieving long-term zero carbon goals.

2.5 To Close the Remaining Gap Between Forecast Demand and Available Supply, We Have Evaluated the Attractiveness of Multiple Options

After factoring in the estimated impact of incremental RNG, Hydrogen and GHP, the gap between forecast demand and available supply is reduced to 230 – 400 MDth/day. To close this remaining gap, we have evaluated the level of attractiveness for multiple individual options across a range of important factors, utilizing both internal National Grid resources and external experts including Guidehouse (formerly Navigant) and MJ Bradley. These options include Large-Scale Infrastructure capable of providing ~400 MDth of Design Day supply; Distributed Infrastructure that adds to supply in smaller increments (63 – 100 MDth/day); and No-Infrastructure that examines incremental Energy Efficiency, Demand Response and electrification to further reduce demand. Each option was evaluated based on the following:

- **Safety** – requirements, risks and how the risks can be mitigated
- **Reliability (certainty of meeting demand)** – likelihood that the option will be able to deliver on its projected capacity, and the risks that it might not deliver
- **Cost** – aggregate cost to bring the capacity online, and annual costs with and without a discount rate, which includes infrastructure and/or program costs and adjustments for commodity costs
- **Environmental impact** – greenhouse gas (GHG) emissions; air quality considerations; potential impact from construction and operation; environmental risk; and decarbonization potential (i.e. the ability of the option to support New York's decarbonization goals)

- **Community impact** – impact on business growth and development, and on customer convenience and choice; how components such as location of infrastructure and amount of trucking impact affected communities
- **Permitting, policy and regulatory requirements** – permits that will need to be approved, policy changes that could enable the option, and regulatory obstacles that would require approvals or changes
- **Requirements for implementation** – location siting; hiring for construction/program implementation; requirements to place equipment orders; etc.

The results of this analysis in terms of safety, reliability (certainty of meeting demand), cost, environmental impact, and community impact are summarized in Table 1 below, followed by a summary of permitting, policy, regulatory and implementation requirements in Table 2 below.

Table 1: Level of Attractiveness of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

OPTION	SIZE (MDth/ day)	Level of Attractiveness				
		SAFETY	RELIABILITY	COST	ENVIRONMENT	COMMUNITY
Large-Scale Infrastructure Options						
Offshore LNG Port	400	◕	◕	◑	◔	◑
LNG Import Terminal	400	◕	◕	○	◔	◔
Northeast Supply Enhancement (NESE) Project	400	◕	●	◕	◑	◕
Distributed Infrastructure Options						
Peak LNG Facility	100	◕	◕	◑	◑	◑
LNG Barges	100 (2 barges)	◕	◕	◕	◑	◑
Clove Lakes Transmission Loop Project	80	◕	●	◔	◑	◔
Gas Compression on the Iroquois Gas Transmission System	63	◕	●	●	◑	◕
No Infrastructure Options						
Incremental Energy Efficiency*	Up to 216	●	◔***	◔	●	●
Incremental Demand Response**	Up to 108	◕	◔***	●	◕	◕
Incremental Electrification*	Up to 86	◕	◔***	○	◕	◕

*In excess of Local Law 97, 80-100% of NENY and Downstate NY electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, all of which are assumed in Demand forecasts

** In excess of planned demand response programs that are assumed to reduce Demand by up to 53 MDth by 2035

*** Reliability could improve over time as programs mature

Table 2: Permitting, Policy, Regulatory and Implementation Requirements for Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

OPTION	PERMITTING, POLICY, REGULATORY	IMPLEMENTATION REQUIREMENTS
Large-Scale Infrastructure		
Offshore LNG Deepwater Port ("Offshore LNG")	• Requires FERC (under NEPA) approval and state specific approval (e.g., NY, NJ, etc.) • NY, NJ and CT opposed two FERC approved Floating LNG projects in 2008 and 2015 • Requires NYS DEC and FDNY (if within NYC jurisdiction) approval • Permits would likely include BOEM, NEPA, NOAA, USFWS, USACE, US EPA	• Estimated timeline: 6-8 years • Considering new FSRU vessel construction required, permitting would need to be completed prior to placing construction order • Estimating two years post-permitting to build vessel interconnecting facilities, and system upgrades • Offshore LNG developers may be unwilling to take on development cost/permitting risk in the region
LNG Import Terminal	• Requires a change or waiver to NYS Law 6 NYCCR 570 that limits any on land storage to less than 70,000 gallons – this law was reviewed in 2015 and upheld • Requires FERC (under NEPA) approval and state specific approval (e.g., NY, NJ, etc.) • Permits will likely include USFWS, USACE, US EPA, NY PSC, NY SEQRA, NYSDEC.	• Estimated timeline: 5-6 years • Requires a change or waiver from current NY Law (6 NYCCR 570) – current filing process takes ~3 years, acceleration would reduce timeline • No land area considered yet – could consider an adjacent state (NJ) to accelerate timeline, which would likely require additional infrastructure improvements • Once the Order is received, the Company can begin construction, which would take 2-3 years • The process would require a full Environmental Assessment and EIS (required for import terminals)
Northeast Supply Enhancement (NESE) Project	• Received FERC approval, but still requires state / local approvals (NY, NJ) – PA has already approved • Requires NYS DEC approval • NYSDEC rejected water permit in 2018 and 2019 based on concerns relating to water quality in the NY Harbor during construction	• Estimated timeline: ~2 years • Anticipate completion date as early as December 2021, assuming all permitting and approvals are secured by June 2020 • Project is entirely offshore in NY, while work in NJ is at brownfield locations
Distributed Infrastructure		
Peak LNG Facility	• Requires a change or waiver to NYS Law 6 NYCCR 570 that limits any on land storage to less than 70,000 gallons – this law was reviewed in 2015 and upheld • All approvals are within NY jurisdictions • Permits will likely include NY PSC, NY SEQRA, NYSDEC, NYC DOB, and FDNY (if within NYC) • May require new regulations for fire departments to address storage and other safety issues	• Estimated timeline: 5-6 years • Assuming a changes or waiver from current NY Law (6 NYCCR 570) and all required regulatory changes are completed, feasibility and site selection studies would need to occur
LNG Barges	• Permits would likely include USFWS, USACE, NY SEQRA, NYSDEC • Dock facilities and interconnecting gas systems may require FERC EIA; at a minimum NY DEC WQC is needed	• Estimated timeline is 5-6 years • Total permitting process estimated to take 3-4 years; acceleration would reduce timeline • Pier construction and barge order to delivery could be done in parallel in 2 years

OPTION	PERMITTING, POLICY, REGULATORY	IMPLEMENTATION REQUIREMENTS
Distributed Infrastructure, continued		
Clove Lakes Transmission Loop	• Requires permits from NYC DEP/DOB, NYS DEC, and EPA • State / local (e.g., NYC DOT) specific approval for urban construction	• Estimated timeline is 5+ years • Feasibility and engineering studies are being planned to confirm timing and requirements
Gas Compression on the Iroquois Gas Transmission System	• Requires FERC (under NEPA) approval and state specific approval • Air permits required in NY and CT for new compression at existing sites. • Formal application with FERC was submitted in February 2020 and decision on approval is anticipated in early 2021	• Estimated timeline is ~3 years • If all approvals are acquired in a timely fashion, the project is expected to be in-service by November 2023
No Infrastructure		
Incremental Energy Efficiency*	• Enhanced energy efficiency will require policies that support programs that exceed current cost tests by including value of carbon reduction and mechanisms to support increased use of renewable and clean energy sources. • Rate case approvals and incentive programs to drive behaviors and increase adoption rates will be required to implement new programs	• Estimated timeline: will need to have impact starting in 2021/22, and continue to build over time • Success will require a >3x increase in Energy Efficiency (EE) from 0.4% of total sales currently to 1.3% of total sales by 2025 (vs. 0.8% NENY target) • Success will require an incremental 20,000 – 40,000 customers per year starting in 2021 to complete energy efficiency programs (50% annual increase vs. current baseline plus NENY)
Incremental Demand Response**	• New demand response programs will require new thermostat set back programs, enhanced program for Temperature-Controlled (TC) customers, incentives for adoption and new rate structures	• Estimated timeline: starting in 2021, all TC customers will be retained; over next five years, incremental demand response will reach roughly half of all residential customers
Incremental Electrification*	• More aggressive electrification will require policies and incentives to drive behaviors to increase customer adoption	• Estimated timeline: starting in 2021, will need 5,000 to 15,000 incremental customers per year to move to electric heat/cooking/industrial use • Electric power generation and transmission/ distribution infrastructure buildout may be required to satisfy increased electric demand driven by electrification

**In excess of Local Law 97, 80-100% of NE NY and Downstate NY electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, all of which are assumed in Demand forecasts*

*** In excess of planned demand response programs that are assumed to reduce Demand by up to 53 MDth by 2035*

Note: Please see Section 13 of the Report for a full list of Acronyms

2.6 These Options Can be Utilized to Design Three Possible Approaches to Close the Demand - Supply Gap

Creating a comprehensive solution requires looking at how the individual options can be individually or collectively utilized to solve the gap between demand and supply. In summary, there are three possible approaches:

- Build out **Large-Scale Infrastructure**, capable of providing ~400 MDth of Design Day supply. Once operational, a Large-Scale infrastructure option would enable termination of CNG trucking, reduce the need for many of our Temperature-Controlled (TC) Multi-family and Commercial & Industrial (C&I) customers to switch to burning fuel oil during cold weather events, and create short-term contingency supply should challenges occur with upstream pipelines or LNG tank maintenance and availability. To the extent infrastructure is not in place before 2021/22, incremental Energy Efficiency (EE), Demand Response (DR) and electrification would be required to reduce demand and meet customer needs.
- Combine a **Distributed Infrastructure solution(s) with incremental No-Infrastructure solutions**. Because each of these infrastructure options can only individually close 63 – 100 MDth/day of the 230-400 MDth/day gap, it will be necessary to combine one or two of these options with incremental demand reductions from a portfolio of EE, DR, and electrification to provide a comprehensive solution. To the extent the incremental demand reductions can exceed the amount required to close the gap, there could be a reduction or elimination of CNG trucking. Conversely, if projected or incremental EE, DR, and electrification targets are not met, there would have to be restrictions on new customer connections.
- Fully rely on a portfolio of **incremental No-Infrastructure solutions**, where demand is reduced through more aggressive incremental EE, DR and electrification to the point where existing National Grid gas supply will meet customer needs. This option may be dependent on buildout of electric power generation and transmission/distribution infrastructure to support the increased electric demand. To the extent the incremental demand reductions can exceed the amount required to close the gap, there could be a reduction or elimination of CNG trucking. Conversely, if projected or incremental EE, DR, and electrification targets are not met, there would have to be restrictions on new customer connections.

A summary of considerations for the three different approaches is included in Table 3 below.

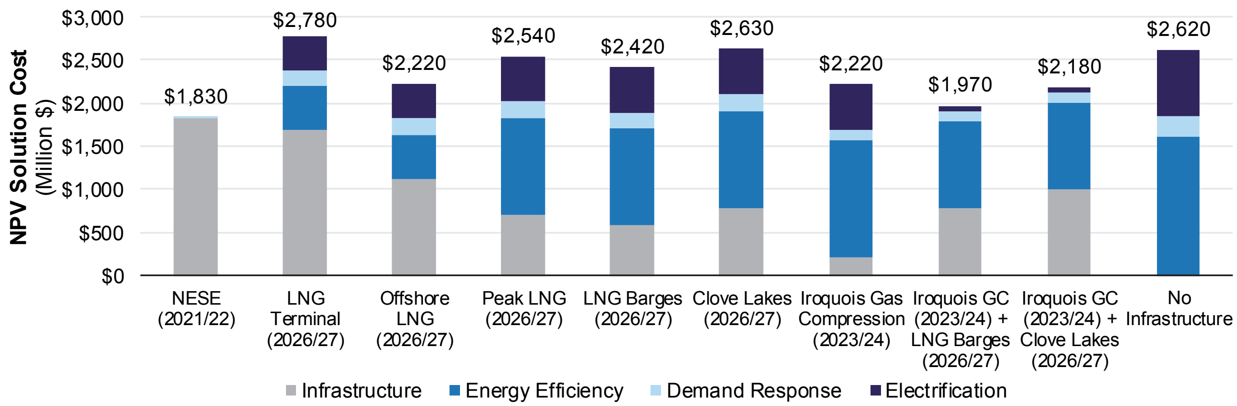
Table 3: Summary of Supply and Demand Approaches and Implications to National Grid Supply Stack

	Impact from Infrastructure (MDth/day)	Required Impact from Incremental EE/DR/ Electrification (MDth/day)*		Impact to National Grid Supply Stack	
		2026/27	2034/35	2026/27	2034/35
Large-Scale Infrastructure	400	0	0	• No CNG trucking • Contracted peaking supplies flex down to 166 – 217 MDth • 201 – 252 MDth short-term contingency available • Temperature Controlled (TC) customers continue to move to firm gas and away from burning fuel oil at peak • Need for incremental EE/DR/electrification if infrastructure not in place by 2021/22	• Under High Demand scenario, CNG trucking required again starting in 2031/32 • Contracted peaking supplies flex down to 223 – 365 MDth • 0 – 195 MDth short-term contingency available • TC customers continue to move to firm gas and away from burning fuel oil at peak
Distributed Infrastructure Combined with No-Infrastructure Solutions	63-100	48-136	130-337	• Contracted peaking supplies continue at 100% of available to meet planned needs • TC customers do not move to firm gas, continue to burn fuel oil at peak • If projected or incremental EE/DR/electrification targets to close the gap are exceeded, reduces/eliminates CNG trucking and creates some short-term contingency • If targets are met, CNG trucking continues and zero short-term contingency available • If targets are not met, will have to restrict new gas customer connections	
Incremental Portfolio of No-Infrastructure Solutions	0	148-199	230-400	• Contracted peaking supplies continue at 100% of available to meet planned needs • TC customers do not move to firm gas, continue to burn fuel oil at peak • If projected or incremental EE/DR/electrification targets to close the gap are exceeded, reduces/eliminates CNG trucking and creates some short-term contingency • If targets are met, CNG trucking continues and zero short-term contingency available • If targets are not met, will have to restrict new gas customer connections	

**Required amounts in excess of Local Law 97 achievement, 80-100% achievement of NENY targets and electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, and up to 53 MDth of incremental demand response programs, all of which are assumed in Demand forecasts*

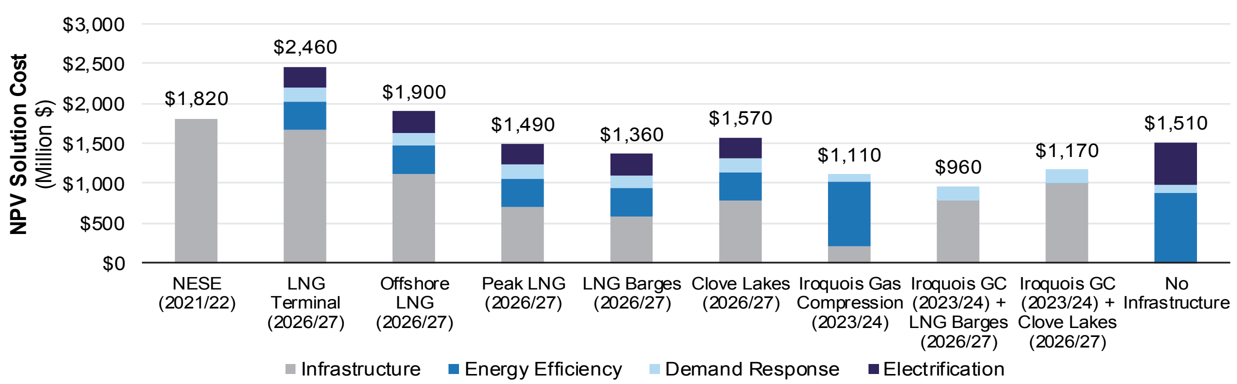
With regards to cost, we have developed a comparison of different approaches, based on detailed assumptions on capital costs and timing of infrastructure, annual costs of operations, and one-time and annual costs to implement programs. Looking at the total cost package that would impact customers from 2020-2035, Figures 4 and 5 below provide a cost comparison across different alternatives.

Figure 4: NPV of Net Costs for Different Alternatives to Close Demand-Supply Gap – High Demand Scenario



Notes: Net present value of costs over contracted lifetime of resources, using a 6.3% discount rate (average after-tax Weighted Average Cost of Capital betw een KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, w hich are assumed to have a 15 year life that starts in the listed operational year, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. High gap scenario is described in Section 5.

Figure 5: NPV of Net Costs for Different Alternatives to Close Demand-Supply Gap – Low Demand Scenario



Notes: Net present value of costs over contracted lifetime of resources, using a 6.3% discount rate (average after-tax Weighted Average Cost of Capital betw een KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, w hich are assumed to have a 15 year life that starts in the listed operational year, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap scenario is described in Section 5.

The report that follows provides more details on each of the elements outlined above. We look forward to feedback and discussion surrounding the contents of this report.

3. Report Methodology

3.1 Planning Duration Considerations

In addition to annual operations planning, effective natural gas supply planning requires thorough evaluation of future needs, typically over a horizon that extends out for at least 10 years. There are several reasons for this time frame, which may be longer than what is typical in many other industries:

- **Long lead times for infrastructure.** Between engineering design, permitting, construction, and addressing community/environmental considerations, many of these projects can take more than five years to complete
- **Time required to design, implement and ramp programs.** Programs in areas such as Energy Efficiency, or studies/pilots of new solutions such as hydrogen blending and geothermal heat pumps, can take several years to ramp up and reach their full potential
- **Scale efficiencies of investments.** Typically, it is not cost-effective to make a series of small infrastructure investments that will cover needs over a short (1-3 year) time period. Investments are made to cover needs over 5-10+ years, taking advantage of scale efficiencies while spreading the costs over a longer duration to smooth out annual impact to customer bills.

For purposes of this Report, we are looking at the emerging imbalance between demand and supply and how we can put solutions in place that start to impact this challenge as early as 2021/22. We also look at the time to bring different solutions on line and their impact over a 5-7 year horizon that is typical for getting many projects fully executed. And, finally, we have done our analysis out to 2035 to provide perspective on ongoing demand trajectory and how we are solving for longer term needs considering the changes and transition of the energy industry.

Over the years, we have focused on progressing what we then believed were the most favorable and cost-effective options for meeting customer needs in Downstate NY. Therefore, these options are more developed in terms of detailed engineering design, progress on permitting, cost assumptions, etc., and generally have a shorter lead time when compared to other alternatives where such development has not occurred.

While this Report looks at environmental considerations, it does not go into an assessment of broader CLCPA emission reduction goals out to 2050 or attempt to project exactly how different solutions will meet those goals. We believe there are multiple pathways to achieving significant emissions reduction, and are considering different approaches that are supportive of these goals.

3.2 Design Day Methodology and Design Hour Considerations

As we look at natural gas demand, supply, and different alternatives, it is important that we compare these things on an “apples to apples” basis. For this report, we are expressing natural gas demand and supply capacity in terms of thousands of dekatherms, or MDth, that can be delivered on what is called the Design Day. The Design Day is the level of gas delivery required to service all our customers during a cold weather event that occurs on an infrequent basis, typically only once every ~40 years. This Design Day is used to build all of our long-term capacity models.

For example, when we look at natural gas demand, we are looking at the number of MDth required on the Design Day to service the needs of our customers. And, similarly, when we are looking at different options to increase supply or reduce demand, we are sizing those in terms of the MDth each one can provide on the Design Day.

In Downstate NY, the Design Day is based on a 24-hour period that averages 0 degrees Fahrenheit in Central Park. This is the same Design Day standard that is used by Con Edison for the gas customers that it serves in New York City and Westchester County – as explained later in the report, we share pipeline infrastructure with Con Edison, and thus it is important to synchronize how we plan for gas delivery in the region.

Within the Design Day, we are also required to ensure there is enough capacity during peak hours – when maximum gas is consumed as customers turn up their thermostats, cook, and use gas for hot water heating. If customers used the same volume of gas each hour, it would be sufficient to look at the daily demand and divide by 24 to ensure the system could provide that amount of gas each hour. The reality is that customers tend to use more gas in the early morning hours, typically 6 – 10 a.m., and again in the evening from 4 – 8 p.m. To ensure we can provide the gas needed by our customers during those time periods, we look at our supply needs during what we refer to as Design Hour.

Whereas historically our pipeline operators have allowed us to take more gas for a few hours as long as we average out to the Design Day capacity over a 24-hour period, increasingly these operators have indicated that they will not have that flexibility. This further exacerbates the Design Hour challenge, creating a potential supply shortfall that we are currently addressing with short-term measures as described in the Report.

So, while we believe MDth on the Design Day is the cleanest way to model demand and supply and compare options, it is important to note that even if the temperature reaches 0 degrees or less for a short period of time, or is close to 0 during a time of high gas usage, the spike in hourly peak demand on the network could trigger Design Day capacity and response requirements.

For reference, the last day that averaged 0 degrees or lower for 24 hours in Central Park – a complete Design Day event - was February 9, 1934. Meanwhile, the last two times the temperature went to 0 or below for a period of time less than 24 hours, creating a Design Hour challenge, was February 14, 2016 (-1 degrees) and January 19, 1994 (-2 degrees) (source: weather.gov).

3.3 Other Notes Regarding Our Methodology and Approach

Some options, such as energy efficiency or a pipeline, can be utilized throughout the year, while others, such as customer demand response or a Peak LNG facility, would only be used during periods of peak demand. In our report, we have indicated whether utilization is ongoing or periodic, and we are taking the total annual volume from each potential solution into account when estimating cost impact.

To derive our assumptions on demand growth, supply capacity, and our evaluation of different alternatives to close the gap between supply and demand, we have relied on multiple sources, including:

- National Grid's internal experience, expertise, and subject matter experts from multiple departments including Gas Engineering, Gas Operations, Customer, Advanced Data Analytics, Strategy, Regulatory, Energy Procurement, and Finance
- Reports from various consultants and agencies that have been produced regarding gas demand projections, gas supply options, energy efficiency, demand response, electrification of heat, etc.
- External consultants that we have retained to advise National Grid in specific areas where they bring knowledge, data and an outside perspective regarding what other companies and jurisdictions are doing. Specifically, we have worked with Guidehouse (formerly Navigant) on all the no-infrastructure options and scenarios (encompassing EE, DR and Electrification), a

review of the environmental impacts of different options, and overall report review; DNV-GL on some specific components of Energy Efficiency (EE) and Demand Response (DR); and MJ Bradley with regards to their report on the environmental impact of the Northeast Supply Enhancement (NESE) project.

Our intent is to be transparent regarding our assumptions, and to document our sources and references wherever applicable.

4. Background – An Overview of the Natural Gas System and National Grid's Role, Our Downstate NY Service Territory, and Our Service Obligations

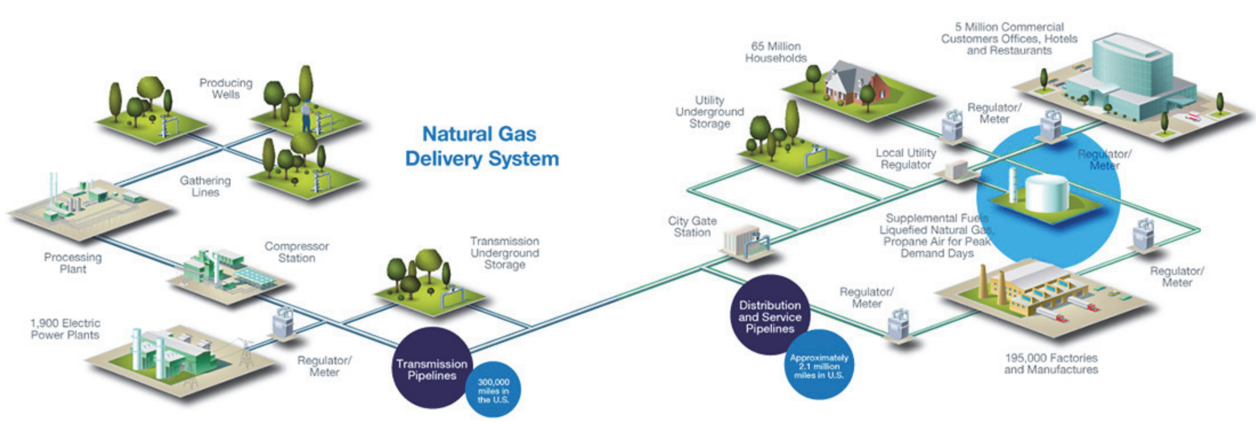
4.1 The Natural Gas System and National Grid's Role

In the United States natural gas supply chain, there are three major roles:

- **Production**, which is the upstream extraction of natural gas from the ground and any necessary processing to make it a usable fuel, including liquefaction to create Liquefied Natural Gas (LNG)
- **Transmission**, which involves moving the gas from the point of Production to where it can be distributed out to customers. This often occurs through pipelines, though it could also occur through trucking or shipping of compressed or liquefied natural gas from the point of production.
- **Distribution**, which involves moving the natural gas from Transmission connection points out to commercial, industrial and residential end users. This is typically done through a network of gas mains, though it could also occur through trucking Compressed Natural Gas to where it can be injected into the distribution systems. It is also important to note that if LNG is to be used for distribution it needs to be re-gasified/vaporized.

The figure below provides an overview of how this supply chain operates.

Figure 6: United States Natural Gas Supply Chain



Source: National Grid

National Grid is focused on natural gas distribution and is served by third party transmission pipelines. We operate three Local Distribution Companies ("LDC") in New York State associated with Upstate New York, New York City, and Long Island. Upstate New York comprises large areas of northeastern, central, and western New York and represents the territories of the former Niagara Mohawk Power Corporation. The remaining two geographic areas – New York City (territories associated with the former KeySpan Energy Delivery New York, or KEDNY) and Long Island (territories associated with KeySpan Energy Delivery Long Island, or KEDLI) are the focus of this Report. The LDC's are charged with procuring natural gas on the market and passing the cost of the fuel through, with no markup, to our end customers. National Grid owns, operates, and maintains the local community gas systems that ultimately deliver the procured gas to our customers, and increases the capacity of that system as needed to ensure safe and reliable service to our customers. National Grid charges customers for every cost component for delivered gas, but we only earn our regulated profit margin on the distribution portion of the bill – gas commodity cost and transmission charges are a "pass-through" item for the Company.

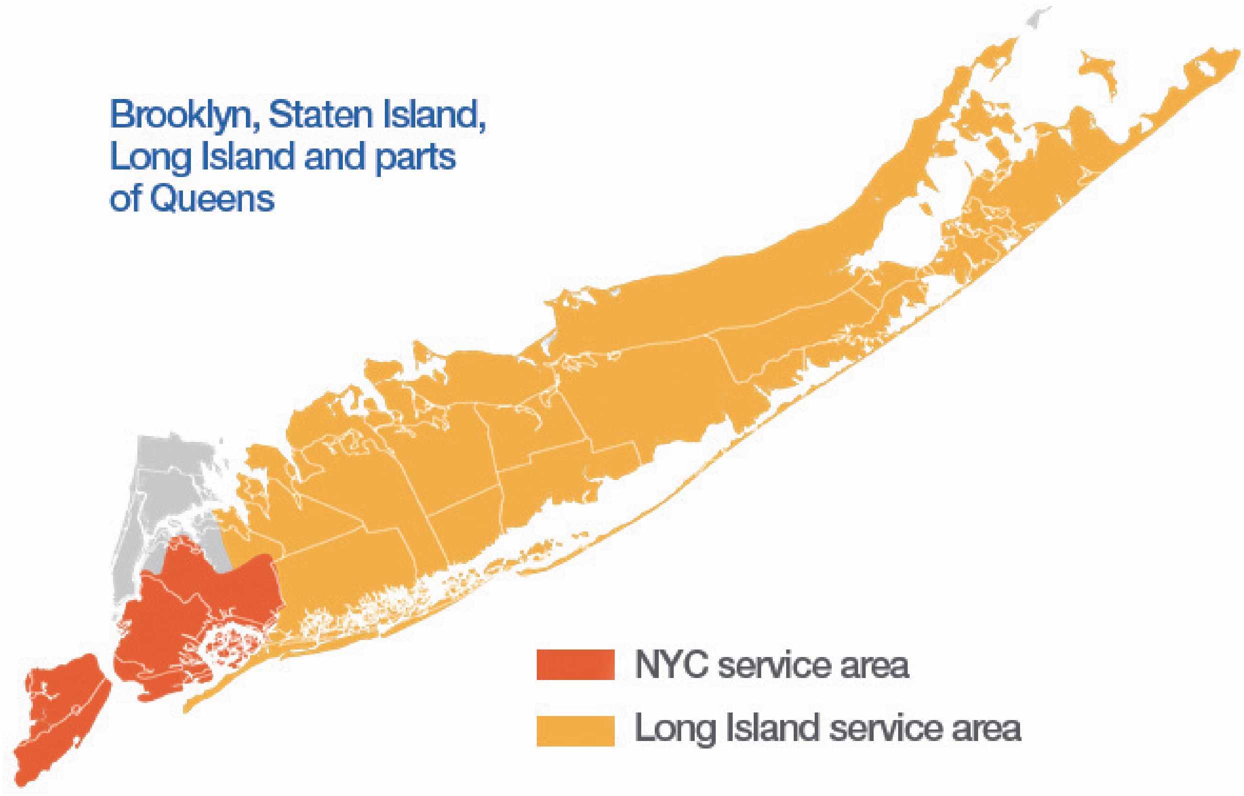
As customers move away from coal and oil, they have found that natural gas is a cost effective and environmentally preferable alternative fuel with much lower maintenance costs, which continues to drive demand growth in the local communities that National Grid serves. As such, the need to increase supply deliveries to the LDCs from the production areas has increased, requiring a commensurate increase in the capacity of the interstate gas transmission system into Downstate NY. To date, incremental increases in the interstate system capacity have come on-line in various sizes and have added capacity to meet Design Day needs for various lengths of time. However, the demand for gas in National Grid's Downstate NY LDCs is now starting to exceed the capacity of the interstate system and any supplemental supplies from LNG and market contracts for peaking supplies.

4.2 Downstate NY Service Territory

For more than 100 years, National Grid and its predecessors have been providing natural gas service to downstate New York customers. Today, we provide natural gas to 1.9 million customers – 1.3 million throughout Brooklyn, parts of Queens, and Staten Island, and 0.6 million across Long Island.

Natural gas delivery in these geographies is managed through two different operating companies and corresponding regulatory agreements, KeySpan Energy Delivery New York (KEDNY) and KeySpan Energy Delivery Long Island (KEDLI). A map of our service areas can be seen in Figure 7 below. For purposes of this report, we will refer to the collective KEDNY and KEDLI service territories as Downstate NY.

Figure 7: Map of National Grid Natural Gas KEDNY and KEDLI ("Downstate NY") Service Area

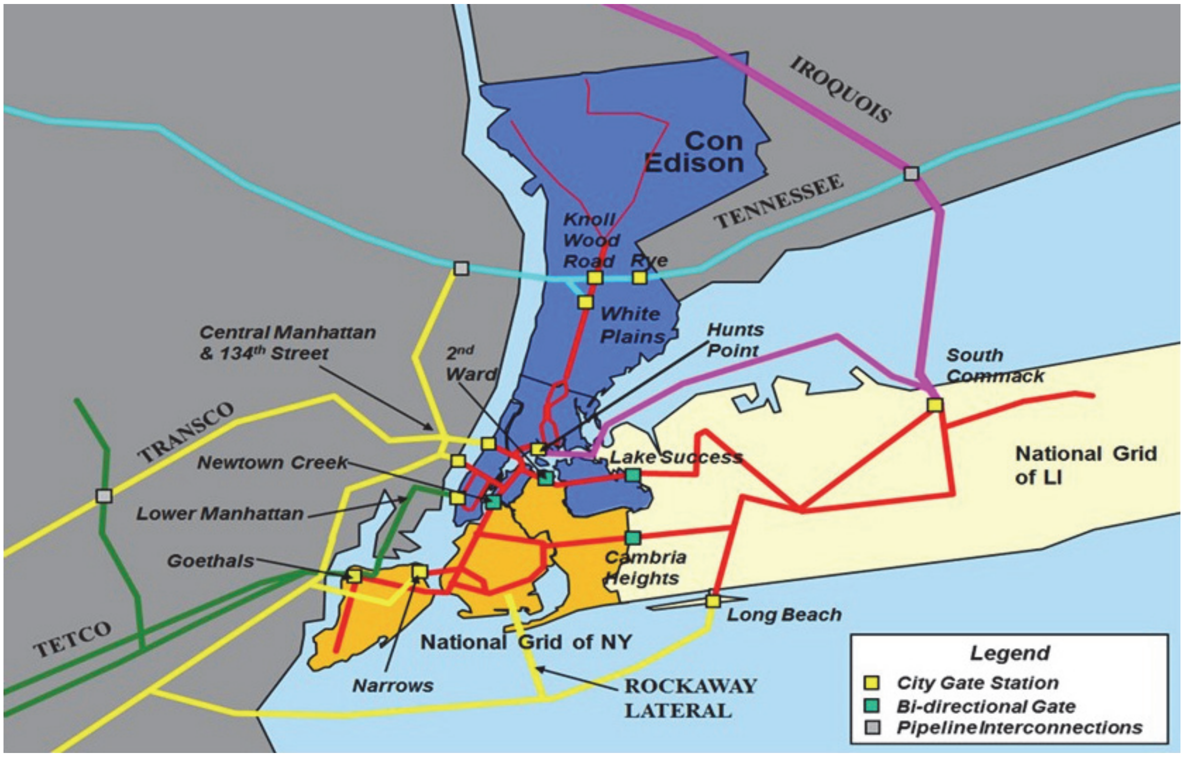


Source: National Grid

National Grid's Downstate NY LDC's have a unique agreement with Consolidated Edison ("Con Edison") called the New York Facilities Agreement. Under this agreement, we exchange gas across our systems and take delivery of gas on each other's behalf to maximize the benefits of the supply diversity available to us and minimize the capital asset base that is needed to move gas to our combined customer bases. Through the most recent revision of this agreement, up to 10 gate stations from four pipelines contribute some portion of the gas delivered on any given day. While we work in cooperation for mutual benefit and improved reliability, all LDCs are separately operated to provide safe and reliable service to the ratepayers of each LDC.

Figure 8 below provides a map of National Grid's Downstate NY third party transmission network and how it connects to our distribution network.

Figure 8: National Grid Downstate NY Transmission Network



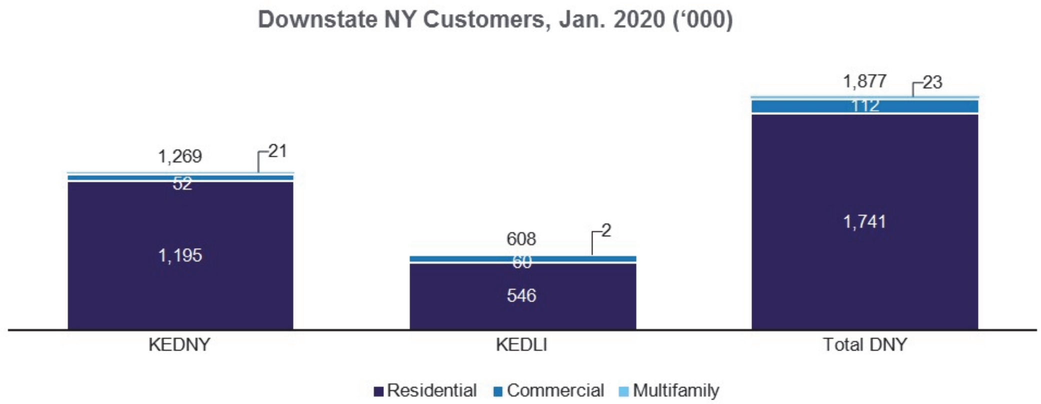
Source: National Grid

4.3 Our Customer Base and Their Natural Gas Usage

National Grid serves 1.9 million customers in Downstate NY, almost entirely across the Residential, Multi-family and Commercial & Industrial (C&I) sectors that are defined as follows:

- **Residential customers** - individuals that live in individually metered dwellings. These customers consist of two subgroups: Non-Heat customers who use gas primarily for cooking, and may also use gas for clothes drying; and Heat customers who also use gas for space and water heating
- **Multi-family customers** - companies or individuals managing multi-unit residential buildings that are centrally metered
- **Commercial & Industrial ("Commercial" or "C&I")** - companies that are managing properties used for business purposes (e.g., office buildings, restaurants, manufacturing facilities)

Figure 9: Downstate NY Customer Base as of January 2020



Source: National Grid analysis of customer data

Residential represents 93% of our customer base, and accounts for 60% of Design Day demand. Commercial and Multi-family customers are much fewer in number, but collectively account for 40% of Design Day consumption, due to larger demand per customer. Table 4 below provides a breakdown of customer numbers and share of demand.

Table 4: Downstate NY Customers and Their Gas Demand

	Customer population, 2020		Design Day Gas Demand, 2019/20	
Customers	**Number (000s)**	**Share, %**	**Volume, MDth/day**	**Share, %**
Residential	1,741	93%	1,709	60%
Commercial & Industrial	112	6%	726	26%
Multi-family	23	1%	401	14%
Total	1,877*	100%	2,836	100%

Source: National Grid analysis of customer data

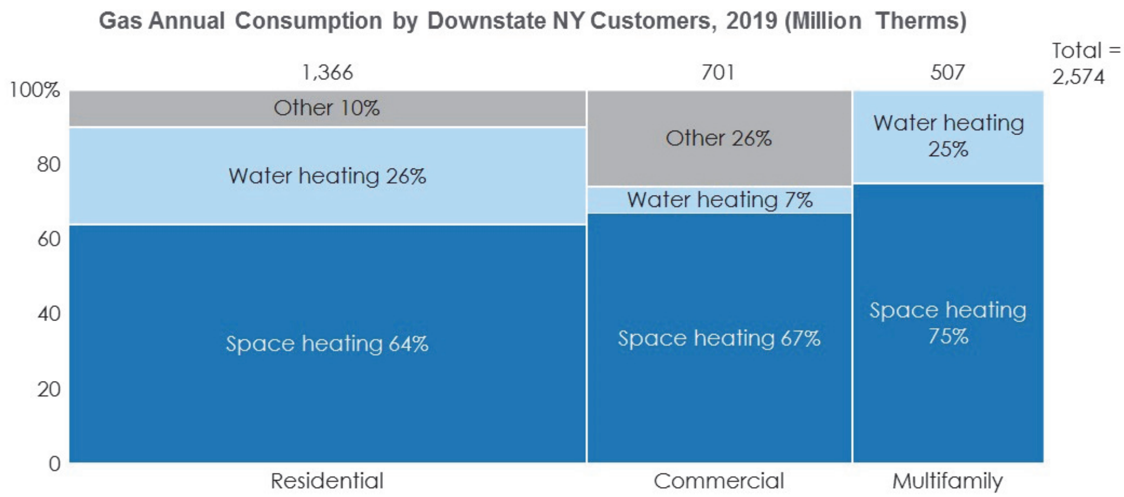
**Includes ~2,400 customers that are on temperature-controlled rates with contractual obligation to switch to alternative fuel if the outside temperature falls below a certain threshold (e.g., 16 Degrees Fahrenheit); this customer group consists of multi-family (85%) and commercial (15%) customers*

Our customers use gas for a wide range of purposes, including:

- **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 the majority of gas consumption, 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 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 appliances (e.g., gas fireplaces, gas cloth dryers)

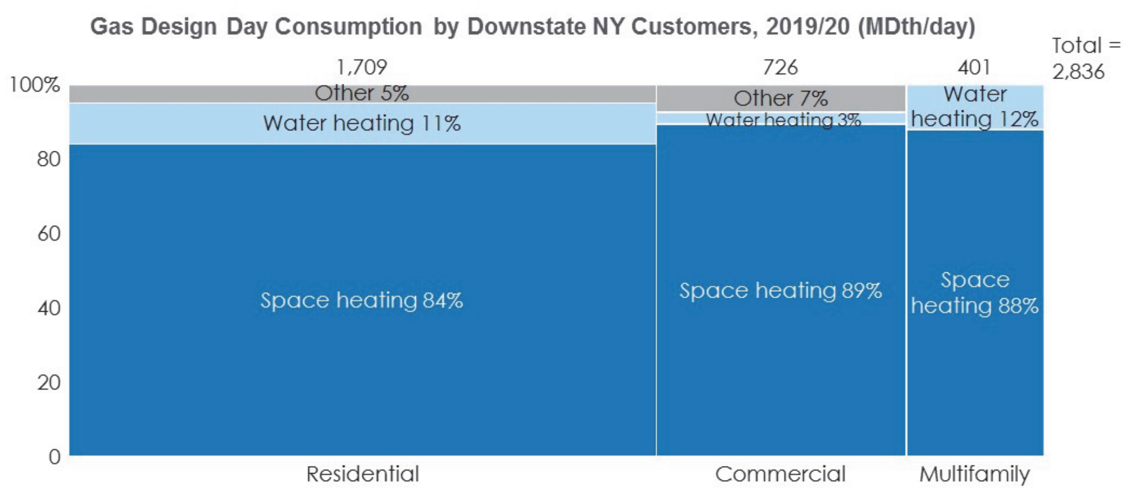
Figures 10 and 11 below show consumption by customer and usage type on an annual basis, and on a Design Day basis.

Figure 10: Downstate NY Natural Gas Annual Consumption by Customer and Usage Type, 2019



Source: National Grid analysis of customer data

Figure 11: Downstate NY Natural Gas Design Day Consumption by Customer and Usage Type, 2019/20

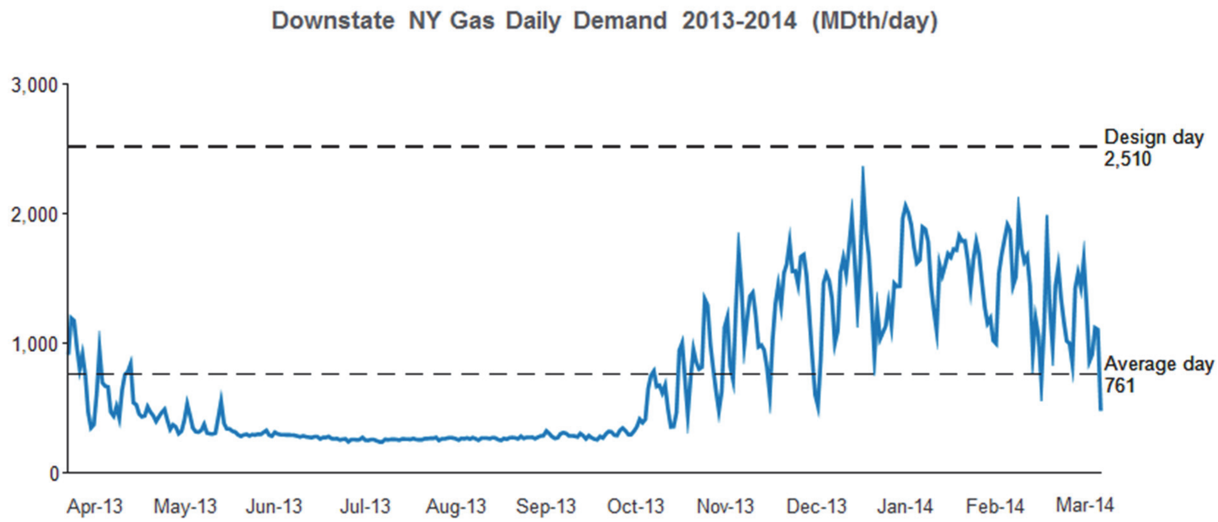


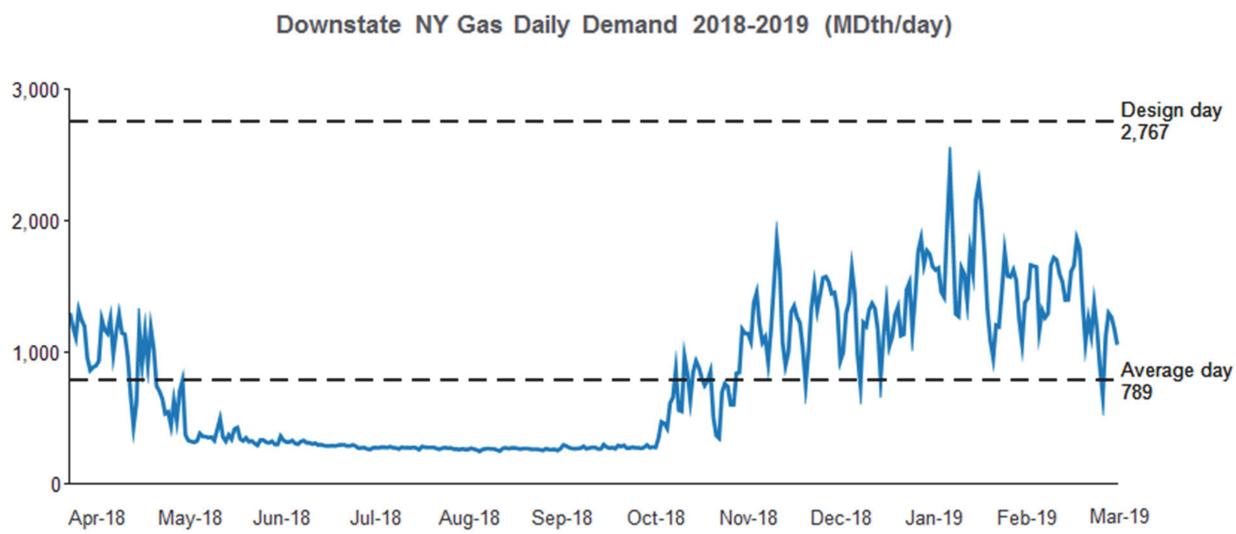
Source: National Grid analysis of customer data

As Figures 10 and 11 show, the need for space heating increases substantially when going from an average day to the Design Day. This high need for space heating during cold days drives significant variance in demand throughout the course of the year.

Figure 12 below provides an example of Downstate NY gas demand over a 12-month period, and how that compares to Design Day capacity.

Figure 12: Downstate NY Gas Daily Demand Variability Over a Twelve-Month Period in 2013-2014 (colder year) and 2018-2019 (warmer year).





Note: Design Day demand has increased over time due to addition of new customers and increased usage per customer, as explained further in Section 5 of the Report

Source: National Grid analysis

4.4 Our Service Obligations

In general, gas utilities have an affirmative duty to provide service to qualifying applicants in their service territories. This obligation is set forth in the New York State Public Service Law §31 and the Transportation Corporations Law §12, and further defined in the New York Public Service Commission's regulations and each utility's tariff. Therefore, for both residential and non-residential applicants, National Grid is required to connect and service all customers that request gas service in Downstate NY unless precluded by certain conditions, such as the incomplete construction of necessary facilities, insufficient supply, or considerations for public safety.

While it is critically important that we provide this gas service to all our customers in a safe, reliable way, recent and continued growth provides a challenge. Over the last 10 years, the number of natural gas customers that National Grid serves has grown by more than 115,000, and gas demand during peak usage periods has grown by 2.4%/year. Because these increases have occurred without a corresponding increase in the available supply of gas, it has placed increasing constraints on our Downstate NY gas operating network.

During periods of peak demand – the coldest days in winter – if there is not enough gas supply running through the network, the risk is that pressure will get too low and heat and other end-use equipment will stop working for customers. In these circumstances, the only way to prevent this from occurring and ensure customer safety is to shut off parts of the distribution network so the remaining parts maintain enough pressure.

While infrequent, there are several examples of low pressure in the gas network causing a shutdown on parts of a network and leaving impacted customers without heat precisely when they need it most. These outages are longer than a typical electric outage, with more challenging consequences. Lessons learned from historical gas distribution outages include the following:

- **Gas outages require labor-intensive responses and mass-mobilization of resources**. Due to the nature of the gas distribution system, gas outages require customer-by-customer meter shutoffs and restorations. Also, during service restoration a technician needs to enter customer premises to relight appliances. When outages occur, it is common for full restoration of the gas system to take about seven days to complete.
- **A gas outage can have unforeseen impacts on the electric distribution system.** If an outage coincides with high gas demand due to cold weather, the loss of space heating poses a threat to public safety requiring speedy deployment of alternative heating equipment (in the form of electric space heaters) and relocation of vulnerable residents. The mass deployment of electric space heaters can lead to periods of time where electric supply cannot fulfill electric demand. For cold weather restorations where electric space heaters are deployed, it is important that the electric service provider has sufficient and reliable capacity and can coordinate with the gas provider to ensure the electric system is not overloaded.
- **The gas transmission system is dynamic; one issue or decision can cause ripple effects felt many miles away:**
  - For example, an upstream valve malfunction on a transmission pipeline can impact distribution many miles away
  - Historically, gas transmission companies have allowed flexibility in terms of hourly takes and regional balancing. However, more recently these transmission companies have been more constrained and have signaled they will no longer allow this flexibility. This effectively lowers the available peak-hour gas supply at National Grid take stations along the transmission pipeline, creating an additional constraint for gas supply planning.

Capacity concerns are what led to us issuing a moratorium on new gas connections in May of 2019. We have since worked with the state of New York to lift this moratorium through the winter of 2020/21 by taking the following actions:

- Addressing potential Design Hour and Design Day shortages by adding supply capacity through Compressed Natural Gas (CNG), where we can accommodate up to 42 CNG trucks per day coming from Pennsylvania to our Glenwood Landing and Riverhead locations in

Long Island to help ensure we can service customers during periods of peak demand, with plans over the next two years to expand to accommodate up to 130 CNG trucks per day[7]

- Making a company-funded incremental investment of $8M in energy efficiency, demand response and other natural gas conservation measures, as part of our recent settlement agreement with the state of New York

While we have confidence this will enable sufficient supply through the winter of 2020/21, it is critically important that we plan ahead for natural gas demand and ensure that we have appropriate ongoing supply to meet customer needs. There are significant lead times for adding supply infrastructure as projects need permits, engineering design and construction to bring new capacity online. Likewise, programs to increase energy efficiency, reduce peak demand, and increase the use of alternative energy sources take time to fund, implement and ramp up. This Long-Term Capacity Report is part of the process, providing an analysis of expected natural gas demand, how that compares to existing supply, and the alternatives for reliably closing the gap between the two.

5. Projected Natural Gas Demand Through 2035 in Downstate NY

5.1 Background: 2010-2019 Growth and Key Drivers

Over the last 10 years, Downstate NY natural gas Design Day demand grew 523 MDth, or 2.4% per year on average, while total annual demand grew 1.8% per year. This growth was driven by increases across all customer types. Design Day demand has grown faster than annual demand largely due to two factors: 1) the shift of residential customers from non-heat to heat, which drives load expansion, particularly during colder days, and 2) a reduction in the temperature-controlled customer base, as customers have a preference to use natural gas vs. switching to burn fuel oil when the temperature drops.

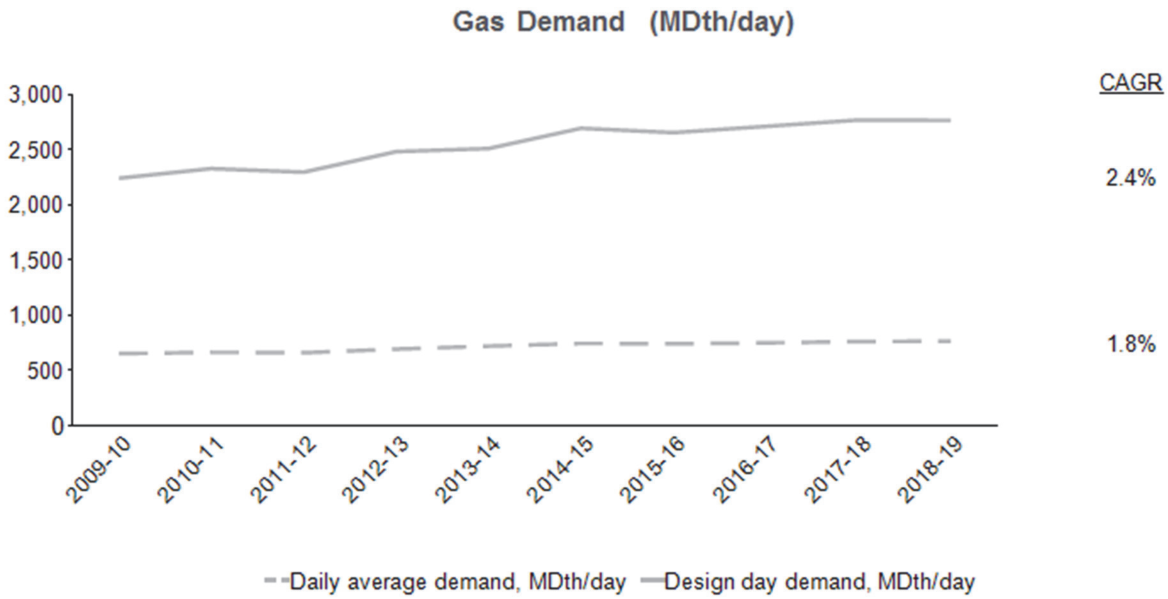
Table 5: Change in Design Day Demand, 2010-2019

	Design Day Demand Change, 2010-2019	
Customers	**MDth/day**	**Share of total change, %**
Residential	251	48%
Commercial	133	26%
Multi-family	138	26%
Total	523	100%

Source: National Grid analysis

[7] See appendix for more details on our recent and planned CNG efforts

Figure 13: Natural Gas Daily Average and Design Day Demand in Downstate NY, 2010-2019



Source: National Grid analysis

The historic growth is a result of growth in the number of customers as well as average customer consumption.

The number of customers grew 0.6% (11,634 customers) per year, driven by population growth, business and economic growth, and continued conversions from oil to gas. Within the specific customer categories, the greatest increases have come from residential heat and multi-family, offset by reductions in residential non-heat and temperature-controlled customers as these customers switched to firm gas heat.

Table 6: Annual Change in Customer Count, 2010-2019

	Average Change Per Year, 2010 - 2019	
Customer type	**# of Customers**	**%**
Residential non-heat	(7,023)	-1.0%
Residential heat	17,436	1.8%
Commercial	865	0.8%
Multi-family	497	2.8%
Temperature controlled	(141)	-4.4%
Total	**11,634**	**0.6%**

Source: National Grid analysis

Key drivers of this historic growth include the following:

Population growth – The Downstate NY region continues to be an attractive place to live with high access to desirable jobs. This led to growth in the number of households of 0.7% per year. Growth is projected to continue in the future, though at a slower pace.

Business and economic growth – The region's economy is vibrant and saw real GDP growth of 1.9% per year, corresponding to businesses expanding output, employment, building space and gas use. Going forward, these trends are expected to continue, though at a slower pace.

Table 7: Macroeconomic Factors in Downstate NY

	Compound Annual Growth Rates			
Years	Number of Households	Building Area (total sq. ft.)	GDP	Income Per Capita
2009-2019	0.7%	1.2%	1.9%	3.8%
2020-2029	0.3%	0.9%	1.5%	3.2%

Source: Moody's Analytics, January 2020 – Data are for Kings, Queens, Richmond, Nassau, and Suffolk counties; National Grid analysis

Increased gas usage per customer - Natural gas usage per customer was also on the rise, driven by expanding square footage of building areas and existing customers expanding their gas usage across applications.

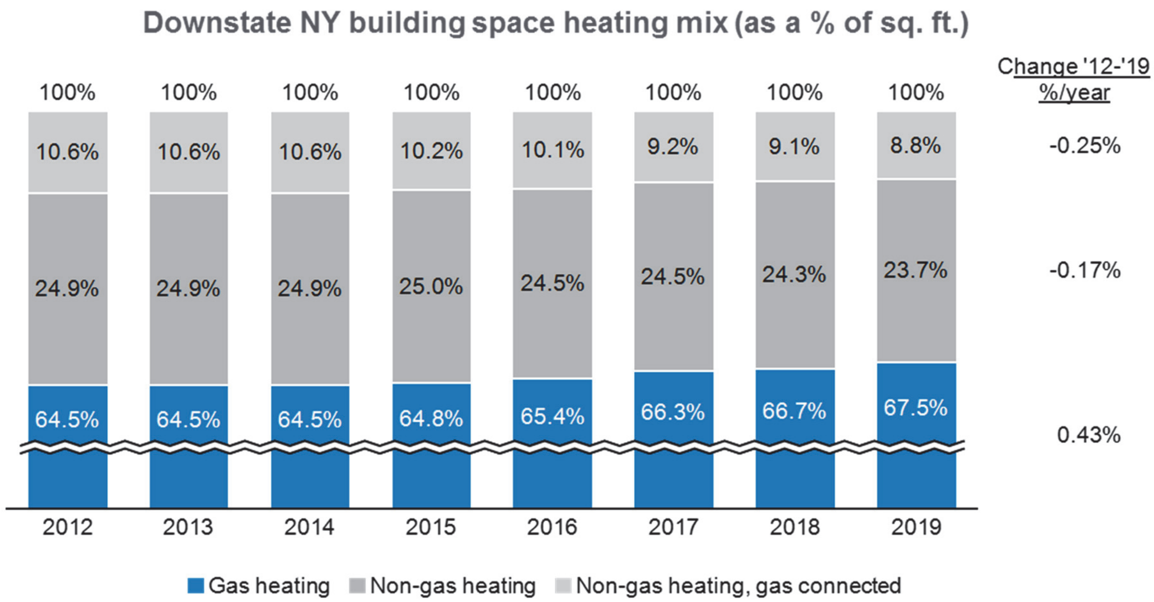
Existing gas customers have been increasing their load, most notably temperature-controlled customers switching to firm supply (year-round) and existing non-heating customers choosing to heat their houses with gas.

Continued conversions from oil to gas – ~5,400 new customers per year join National Grid by converting from non-gas fuels to gas, in addition to an existing ~7,000 non-heat customers becoming heat customers. These conversions from oil to gas were fueled by significant gas advantages over oil when it comes to commodity cost (~50% cheaper), convenience and environmental advantages (estimated 43% less GHG emissions[8]). These advantages have made gas a fuel of choice for new construction and retrofits, resulting in gas heating increasing its space heating market share from 64.5% to 67.5% between 2012 and 2019.

In the Baseline Demand scenario, this conversion trend is expected to continue, with almost 33% of building space in the Downstate NY area still heated by non-gas sources – 23% from oil heating and 10% from electric resistance, propane and other fuels. As we adjust the baseline to account for increases in electrification, this will lower the number of oil-to-gas conversions (please see Section 5.2 that follows for more details).

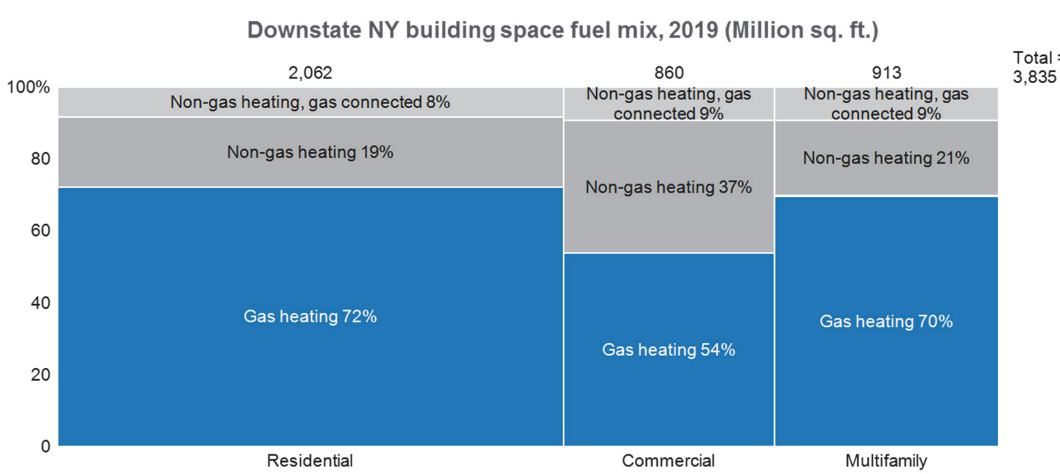
[8] –MJ Bradley, June 2019, Estimated Life Cycle Greenhouse Gas Emissions by Energy Option for a New Single-Family Home in the Downstate NY Geographic Area (metric tons CO_2-e per year)

Figure 14: Historic Evolution of Heating Fuel Mix Across Downstate NY



Source: Building Tax Assessment Records Data for Kings, Queens, Richmond, Nassau, and Suffolk counties; National Grid analysis

Figure 15: Downstate NY Building Space Distribution by Heating Fuel Type, 2019



Source: Building Tax Assessment Records Data for Kings, Queens, Richmond, Nassau, and Suffolk counties; National Grid analysis

Offsetting these growth drivers described above has been an increase in energy efficiency. National Grid and NYSERDA have implemented multiple energy efficiency programs designed to reduce natural gas consumption, including:

- **Residential programs** – helping residential customers reduce their gas consumption by providing advice, assistance, products and incentives.
- **Commercial and industrial programs** – helping commercial and industrial customers reduce their gas consumption by offering products and incentives for becoming more energy efficient
- **Multifamily programs** – helping multi-family customers reduce building energy consumption to help their tenants to save money and be more comfortable

Since 2010 National Grid has invested $135M and helped customers to save 51 million therms. National Grid has continued to increase energy efficiency efforts, helping to slow growth in Design Day gas demand by ~-0.2% per year, resulting in Design Day demand reduction of 41 MDth/day (1.4% of total) in 2019.

Table 8: National Grid Energy Efficiency Efforts and Their Effect on Design Day Demand, 2010-2019

Type of Energy Efficiency program	Annual Design Day Demand Reduction (MDth/day)					Program examples
	2010-2015 (average)	2016	2017	2018	2019	
Residential	3	6	7	10	13	Home energy reports, incentives for high efficiency heating equipment
Commercial	6	15	17	19	21	Incentives for customized and prescriptive solutions (e.g., installation of steam traps)
Multi-family	1	3	4	6	6	Incentives for insulation, high efficiency heating equipment
Total	**10**	**23**	**28**	**35**	**41**	

Source: National Grid analysis

Note: totals may not add due to rounding

5.2 2020-2035 Demand Forecast

In building our forecast, we have followed a three-step process:

1. **<u>Project "Baseline" demand growth through a statistically validated econometric forecast</u>** driven by key variables under current policies and customer usage patterns. In this step, it is assumed that current energy efficiency programs continue; that there are similar rates of oil-to-gas conversions; and that any alternatives such as electrification continue at the same rate as today. The model looks at the most predictive drivers of gas customer count and usage per customer based on the last 10 years of actual data (with a higher weighting to recent activity), and then projects future customer count and usage per customer based on external forecasts of underlying macroeconomic drivers. Baseline demand growth is largely driven by expected changes in number of customers due to population, housing, and business growth; oil-to-gas conversions; and any changes in usage per customer based on existing patterns and trends. For reference, we have historically

achieved 98% forecast accuracy on a one-year basis (e.g., there is a +/- 2% error rate in predicting Design Day demand for the upcoming year).

2. **Factor in increases in Energy Efficiency and Customer Demand Response.** Over and above what is in place today, National Grid is launching incremental Energy Efficiency ("EE") and Customer Demand Response ("DR") programs as part of our recent settlement and has analyzed the expected EE impacts of the recently announced New Efficiency New York (NENY) program and Local Law 97. We are assuming this program and the related funding will be approved to move forward, and that the program will continue through 2035. So, in step 2, we take the Baseline forecast and reduce demand by a range of expected impacts from these programs and regulations.
3. **Factor in increases in electrification.** In addition to the expected increases in EE and DR, we expect electrification to increasingly penetrate the energy market and serve as a substitute for natural gas. Recently proposed programs from the electric utilities that serve Downstate NY (Con Edison and PSEG Long Island) have specific customer conversion targets. Furthermore, by the early 2030s it is anticipated that electric heat pumps in the U.S. will reach cost parity with natural gas systems[9], although current energy prices specific to Downstate NY make the economics more difficult. In step 3, we project a range of how this increased electrification will reduce demand under current and recently launched incentive programs and policies, and with increased organic adoption.

At the end of step 3, we arrive at a high demand scenario and low demand scenario forecast range for 2020-2035.

5.2.1 Step 1: Baseline Demand

Baseline demand for 2020-2035 is driven by growth in key variables under current policies (pre-NENY and Local Law 97) and customer usage patterns:

- Number of customers will continue to grow at a slightly reduced pace, related to slow down in household number and GDP growth
- Usage per customer will likewise show reduced rates of growth, driven by observed trends in energy efficiency and modest declines in square footage growth

Table 9: Key Drivers of Baseline Demand

Driver	2010-2019		2020-2035 Baseline	
	#/yr.	%/yr.	#/yr.	%/yr.
Baseline # of Customers	11,634	0.64%	11,259	0.57%
Residential Non-heat	(7,023)	-1.0%	(7,614)	-1.3%
Residential Heat	17,436	1.8%	17,909	1.5%
Commercial & Industrial	865	0.8%	509	0.4%
Multi-family	497	2.8%	594	2.4%
Temperature Controlled	(141)	-4.4%	(140)	-13.1%

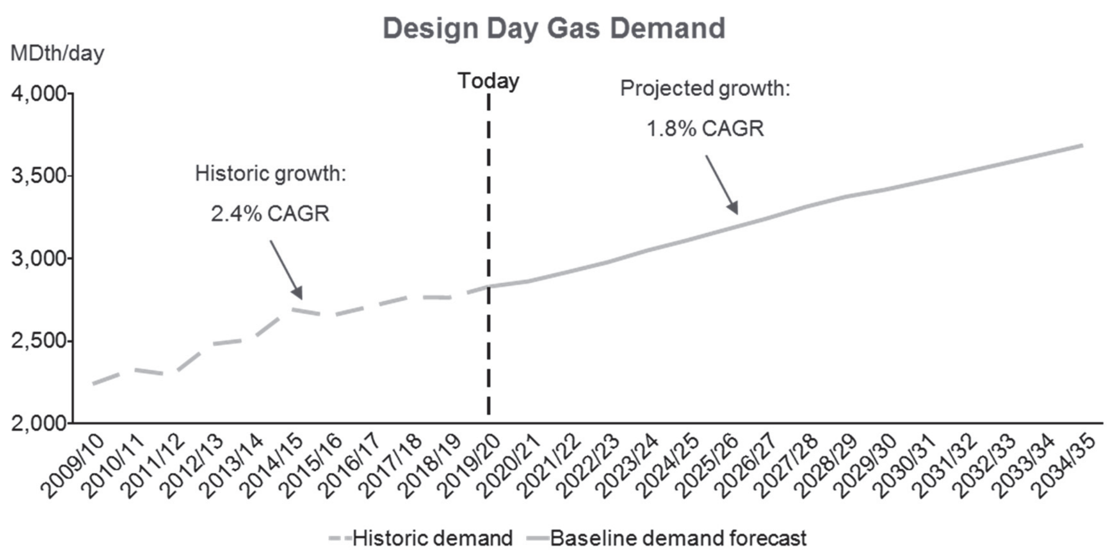
[9] McKinsey Global Energy Perspective: Accelerated Transition November, 2018

Driver	2010-2019		2020-2035 Baseline	
	#/yr.	%/yr.	#/yr.	%/yr.
Usage Per Customer	N/A	1.7%	N/A	1.2%
Residential Non-heat		0.4%		-0.5%
Residential Heat		0.1%		0.2%
Commercial & Industrial		1.8%		0.6%
Multi-family		1.9%		1.2%
Temperature Controlled		N/A		N/A

Source: National Grid analysis

Based on these assumptions, it is forecast that Baseline Design Day demand will grow 30% by 2035, which is an annual growth rate of 1.8%, as shown in Figure 16 below.

Figure 16: Baseline Natural Gas Demand Growth in Downstate NY Under Current Policies and Customer Usage Patterns, 2020-2035



Source: National Grid analysis

5.2.2 Step 2: Factor in Increases in Energy Efficiency and Customer Demand Response

National Grid has a successful track record in Downstate NY of implementing Energy Efficiency and Customer Demand Response programs to reduce natural gas demand. As explained in Section 5.1, the Company has achieved Design Day demand reduction of 41 MDth through programs it has put in place over the last decade, the results of which are included in our Baseline (Step 1) projections.

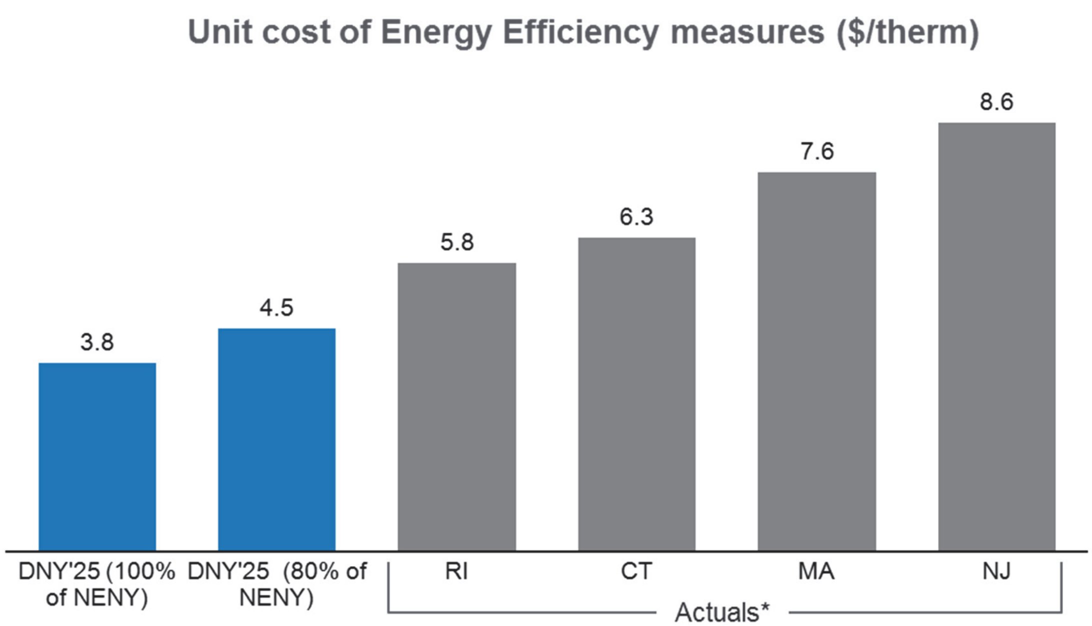
In Step 2, we are adding incremental programs to this Baseline to further reduce natural gas demand. This includes programs we have committed to beyond our existing rate case, and the impact of NENY assuming it is fully funded and that NENY or something similar continues through 2035.

In our Low Demand scenario, we are assuming 100% of NENY targets are achieved, and in the High Demand scenario, we are assuming 80% of NENY targets are achieved.

To achieve 100% of NENY targets, energy efficiency efforts need to double over six years, from a 2019 level of annual energy efficiency savings of 0.4% of gas sales to 0.8% of gas sales in 2025. Under the current funding proposal Downstate NY will have to accomplish these targets at a spend of $3.8 per therm, which is 35-56% more efficient than surrounding states achieved in 2017.

In the High Demand scenario, we are assuming 80% of NENY targets are achieved. This would still require an increase from 0.4% of gas sales today to 0.7% of gas sales by 2025, and assumes that Downstate NY can accomplish the targets at a spend of $ 4.5 per therm, which is 23-48% more efficient than what surrounding states achieved in 2017.

Figure 17: Average Unit Cost of Energy Efficiency Measures: Projected Downstate NY Cost vs. Surrounding States Actuals



**2017 Actual Achievement*

Source: New Efficiency New York (NENY) order January 2020; American Council for an Energy Efficient Economy (ACEEE); National Grid analysis

National Grid is also expanding customer Demand Response (DR) efforts, which include a variety of programs for Residential, Multi-family and Commercial & Industrial (C&I) customers to reduce or eliminate natural gas usage during periods of peak demand. We are launching several programs for Residential and C&I customers that we expect can ramp up to 20 MDth/day of Design Day demand reduction. Additionally, we believe there is opportunity to keep more of our Temperature Controlled (TC) customers, which requires them to switch away from gas during cold weather events (at or below 16 degrees Fahrenheit). We have proposed new incentives for this program and believe this could reduce TC conversions to firm service by 25%.

A summary of the incremental EE and DR assumptions being used for the High and Low demand forecast, and the related impact, is included in Tables 10 and 11 below.

Table 10: Energy Efficiency and Demand Response Assumptions Used for Demand Forecast

Area	Assumptions
Energy efficiency	• 2020-2025 KEDNY/KEDLI EE targets are based on NENY • 2026-2035 investments continue at 2025 levels, and impact continues to ramp at 2025 rates • Assume 80% achievement in High Demand scenario, and 100% achievement in Low Demand scenario
Demand response	• Commercial & Industrial and Residential Heat Programs ○ Select customers with access to other heating fuels will switch off gas during peak events ○ Select customers will participate in programs to reduce consumption during peak events ○ Reduction in Design Day demand ramps from 9 to 20 MDth/day • Temperature Controlled (TC) Customers ○ Under High Demand scenario, TC conversions to firm service will occur at historic rates ○ Under Low Demand scenario, assume newly proposed TC tariff will go into effect and TC conversion rates are 25% slower than historic

Table 11: Projected Impact of Energy Efficiency and Customer Demand Response Programs in Downstate NY

Program	Cumulative Investment ($MM)*	Reduction of Design Day Demand (MDth/day)			
		2019/20	2024/25	2029/30	2034/35
Energy Efficiency (EE)	958	1	39-49	129-161	199-249
Customer Demand Response (DR)	94-109	9	10-36	20-47	20-53
TOTAL	1,052-1,067	10	59-85	149-208	219-302

** EE - NENY through 2025, then assumes 2025 rate through 2035. DR – includes current and known planned program launches; high end of range includes proposed incremental TC incentives*

Source: NENY order, January 2020; National Grid analysis

As the table above shows, the total estimated impact of these programs is a reduction in demand from the Baseline that starts at 10 MDth/day in 2020 and grows to 219-302 MDth/day by 2035.

5.2.3 Step 3: Factor in Increases in Heat Electrification

The final step in building our Demand forecast range is to estimate the impact of additional heating electrification in Downstate NY. Historically, some customers have used electricity for water and space heating, though it has experienced limited growth due to high operating costs and concerns about cold weather performance. This is changing driven in part by improving heat pump performance and economics, and by growing policy support in the forms of incentives.

For example, Con Edison as part of their Smart Solutions programs has launched efforts to install more than 17,000 heat pumps across their service territory over 2020-2025.

Historical electrification trends are embedded in the Baseline scenario. Going forward, and driven by recent policy changes that promote electrification, we expect electrification trends will accelerate. Specifically, this step explicitly represents the impacts of two distinct policy instruments:

- **Local Law 97 compliance** in the boroughs of NYC
- **New Efficiency New York heat pump targets** enacted in the KEDNY/KEDLI territories by Con Edison and PSEG Long Island

In addition, we estimate heat pump adoption that may occur without policy support, i.e. 'organic' heat pump adoption driven by economics and/or customer choice. Below is a brief description of the methodology employed to represent heat electrification driven by LL97, NENY, and organic adoption.

- **LL97 Compliance.** Passed in April 2019, and targeting a compliance period beginning in 2024, LL97 mandates that buildings >25,000 sq. ft. must achieve an emissions performance target or pay a compliance penalty. The target is denominated in terms of CO_2 emissions per square foot (specifically the target is kg CO_2 equivalent/sf/year) and can be met through reduction in electric load or reductions in on-site fuel consumption. In other words, heat electrification is not the only compliance mechanism for LL97 compliance; building efficiency and electric efficiency can also be used for compliance.
    - The precise share of LL97 compliance that will be met through heat electrification is uncertain, as each building owner will face a range of compliance options. We modeled LL97 compliance as a growing rate of heat pump adoption by existing customers in the KEDNY Commercial and Multi-family meter classes. We assumed that heat pump adoption will grow as a share of annual HVAC turnover. We assume that 5% of building owners replace the HVAC equipment of their buildings in any given year (representing a 20-year lifetime for HVAC equipment), and that heat pumps will capture more of this annual turnover market over time. This results in reductions to existing KEDNY commercial and multi-family gas meter counts, with a corresponding reduction to Design Day demand.

- **NENY Heat Pump targets.** Subject to the January 16, 2020 PSC ruling, Con Edison will target 17,000+ heat pump conversions through 2025, and PSEG Long Island will also target to achieve a similar level of heat pump installations over the same period. Due to geographic mismatches and the presence of fuel oil-heated buildings as a compliance mechanism, only a subset of the Con Edison and PSEG Long Island customer base will impact National Grid's Downstate NY gas demand. We allocated 30% of Con Edison's and PSEG Long Island's targets to the KEDNY and KEDLI territories and represented these targets as reductions in meter count growth that would have otherwise accrued to KEDNY and KEDLI.
    - Given that NENY targets are only set through 2025, we made assumptions about the pace of heat pump adoption post-NENY. We assume these heat pump targets and programs will stay at the 2025 level through 2035.

- **Organic adoption.** Beyond policy-driven adoption, organic adoption driven by economics and/or customer choice is represented in the model. The precise timing of when electrified heat may achieve organic adoption is uncertain, driven by such factors as underlying electric and gas rates, changes to upfront costs of various heating technologies, changes in heat pump seasonal Coefficients of Performance (COPs), and customer preferences. We assume adoption growing in the early 2030s and escalating thereafter in the KEDNY Residential market and the KEDLI Residential, Commercial, and Multi-family markets.

There is a high degree of uncertainty of the exact impact of electrification on Downstate NY gas demand. To show a range of possibilities we have considered high and low gas demand scenarios, detailed assumptions for which are listed in Table 12 below.

Table 12: Electrification Assumptions Used in Constructing Demand Forecast

<table>
<tr><th>Area of Electrification</th><th>Assumptions</th></tr>
<tr><td>Residential new construction and oil conversions</td><td>2020-2025 Con Edison and PSEG Long Island electrification targets are based on NENY
2026-2035 targets set at 2025 levels
30% of the targets are assumed to be National Grid Downstate NY natural gas customers, who completely convert to electric (i.e. do not keep gas as a backup source of heat)
Assume 80% target achievement in High Demand scenario, and 100% target achievement in Low Demand scenario</td></tr>
<tr><td>Residential gas to electric conversions</td><td>Heat pump share of organic turnover will grow starting at <1% in 2030
Heat pumps will account for 15% -25% of turnover by 2035 (15% in High Demand scenario, 25% in Low Demand scenario)</td></tr>
<tr><td>Commercial & multi-family gas to electric conversions</td><td>KEDLI territory
Heat pump share of organic turnover will grow starting at <1% in 2030
Heat pumps will account for 15% - 25% of turnover by 2035 (15% in High Demand scenario, 25% in Low Demand scenario)
KEDNY territory
Local Law 97 will drive faster growth of heat pump share of organic turnover
Heat pumps will account for 29% - 49% of turnover by 2035 (29% in High Demand scenario, 49% in Low Demand scenario)</td></tr>
</table>

Factoring in the Low and High Demand assumptions above regarding Local Law 97, NENY heat pump targets, and estimates of organic adoption, we arrive at an estimated range for Downstate NY Design Day gas demand reduction due to electrification, which is captured in the table below.

Table 13: Projected Incremental Impact of Electrification Under Current Programs and Policies

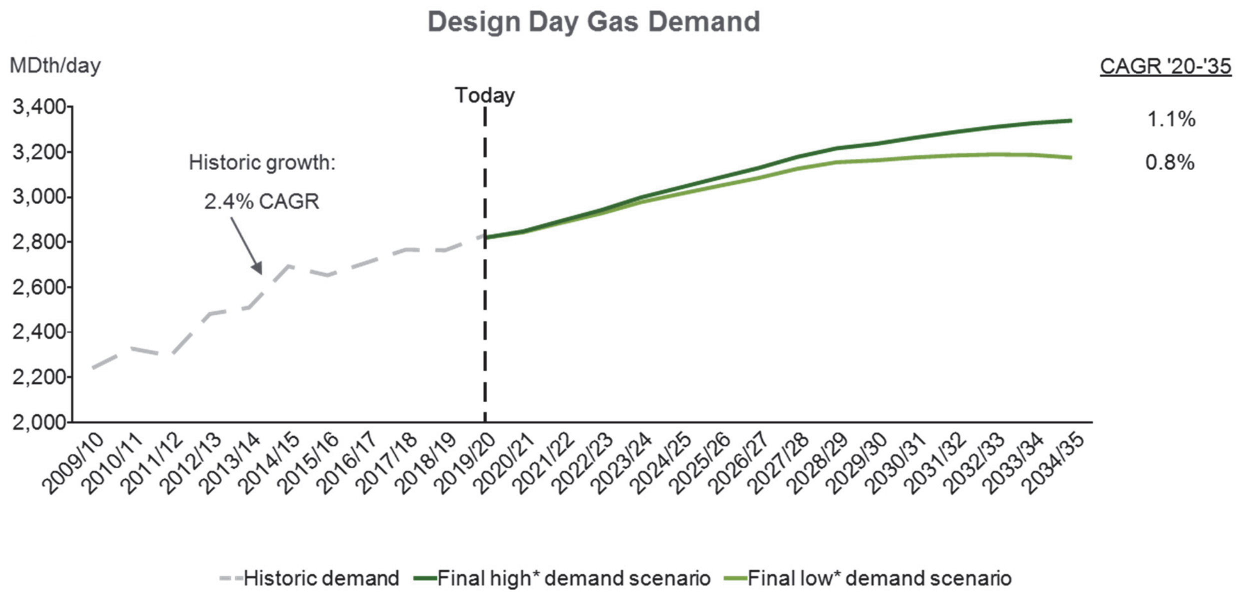
Area of Electrification	Incremental Impact on Design Day Demand (MDth/day)			
	2019/20	2020/25	2029/30	2034/35
Residential new construction and oil conversions	0	8-11	30-36	50-62
Residential gas to electric conversions	0	0	0-1	26-43
Commercial & multi-family gas to electric conversions	0	0-1	2-10	52-104
TOTAL	0	8-11	32-46	127-209

Source: National Grid analysis

Note: Due to rounding, numbers presented may not add precisely to the totals

Once we factor in these assumed increases in electrification, and add them to the estimated impact from incremental Efficiency and Demand Response, we arrive at a final projected Demand curve range for Downstate NY natural gas from 2020-2035.

Figure 18: Projected 2020-2035 Downstate NY Natural Gas Demand Curve Factoring in Increases in Energy Efficiency, Customer Demand Response and Electrification



Source: National Grid analysis

** High and low demand scenarios are based on ranges of incremental Energy Efficiency, Demand Response, and Electrification.*

In the Low Demand scenario, Design Day demand peaks in 2032/33 at 3,190 MDth/day. In the High Demand scenario, Design Day demand continues to grow, reaching 3,340 MDth/day in 2034/35, at which point growth has slowed to 0.3%/year. These demand scenarios represent an increase of 370-520 MDth/day vs. current Design Day demand over a 13-15 year period. For comparison, Downstate NY Design Day demand in the last 10 years has increased by 523 MDth/day.

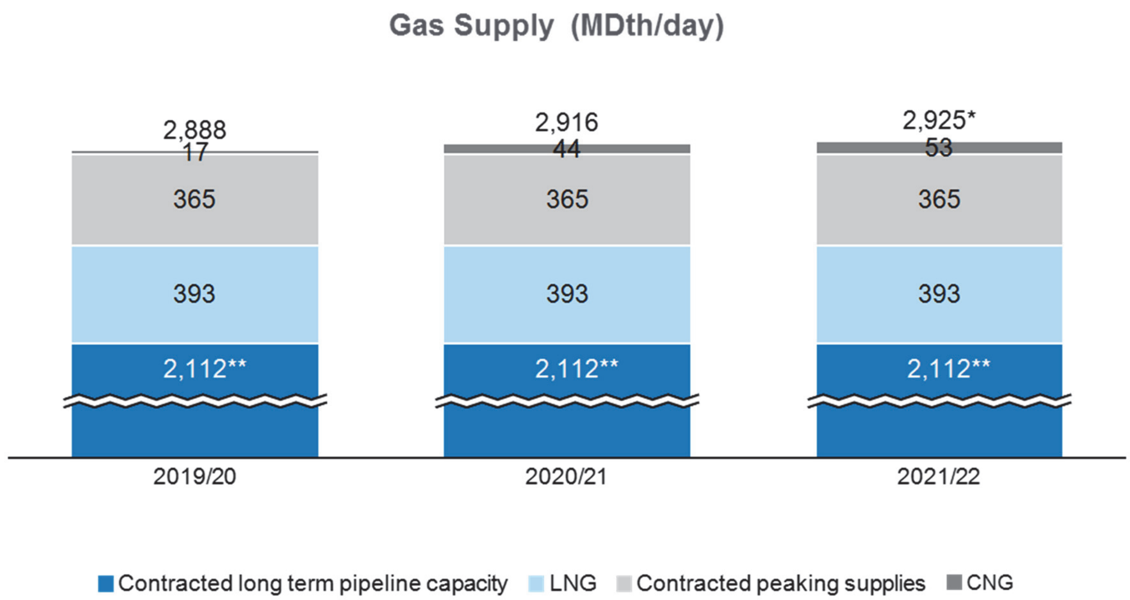
6. National Grid's Downstate NY Natural Gas Supply Capacity

6.1 Our Current Supply Capacity

National Grid provides natural gas supply into Downstate NY from multiple sources. We have long-term contracts for delivery via pipeline that provide a year-round volume baseline. To accommodate periods of peak usage, we operate Liquefied Natural Gas (LNG) facilities, which are designed to run for 10-15 days per year. We also contract for peak supplies for up to 30 days per year. And, more recently, we have added peak capacity using trucks to bring in Compressed Natural Gas (CNG) and will be adding a small amount of year-round capacity by connecting a new Renewable Natural Gas (RNG) plant.

Figure 19 below shows a summary of our existing and near-term sources of Downstate NY gas supply, followed by a more detailed description in Table 14 of each current source of supply, the Design Day volume that it can provide, a description of the commercial arrangement, and the constraints and opportunities (both commercial and operational) that exist.

Figure 19: Summary of existing and near-term sources of Downstate NY gas supply



**Total supply includes RNG capacity (2 MDth/day in 2019/20, 3 MDth/day in 2020/21 and 2021/22)*
*** Chart is not to scale*
Source: National Grid analysis

Table 14: A Description of National Grid's Current Downstate NY Natural Gas Supply Capacity

Supply Source	Design Day MDth	Description	Commercial and Operational Constraints and Opportunities
Contracted Long-Term Pipeline Capacity	2,112	• Multiple long-term contracts with Transco, Tetco, Tennessee and Iroquois	• Generally highly reliable. Subject to third-party interstate pipeline winter compression events. Across all of National Grid's US network, the company experienced 3-5 winter compression issues per year in 2014-2017; 23 events in 2017-2018, and 13 events in 2018-2019 • Historically, these pipelines have allowed hourly volume to exceed Design Day average hourly volume, as long as National Grid maintains Design Day average. However, as capacity issues increase, we have seen hourly restrictions increasingly enforced.
LNG Tanks: one tank in Holtsville (Suffolk County, in service since 1971) and two in Greenpoint (Brooklyn, in service since 1968)	393	• Facilities are owned and operated by National Grid	• Required maintenance will take tanks off line for several months. Currently projecting Holtsville (103 MDth) offline in 2022 and one tank in Greenpoint (175 MDth) in 2024. Current maintenance operations plan is to have them offline April-October so as not to disrupt peak demand periods. A contingency plan will be required in case maintenance stretches into winter.

Supply Source	Design Day MDth	Description	Commercial and Operational Constraints and Opportunities
Delivered Services (CityGate and CoGen Peaking Supply)	365	• Contract out 1-3 years for CityGate peaking supply (300 MDth) • Brooklyn Navy Yard (BNY) via Brooklyn Union Gas Co. contracted through winter of 2024 (25 MDth) • NCP contracted through winter of 2025 (10 MDth) • BNY on Transco contracted through winter of 2027 (30 MDth) • Contracts range for 10-30 days of peak demand	• While there is 700 MDth of CityGate peaking supply available, we are operationally constrained to 300 MDth, and we are constrained in the market as Con Edison relies on 400 MDth • If additional capacity comes on line, or if gas demand is reduced, we are flexible to reduce what we need from these sources • Most of the Delivered Services suppliers have no obligation to re-contract with National Grid each year; there is risk that the current level of Delivered Services will not be available to National Grid indefinitely
Compressed Natural Gas (CNG) trailers/ trucking[10]	17-53	• For the last three years, National Grid has operated a facility in Glenwood Landing (NYC) that can accommodate 20 trucks/day (8 MDth) • Starting in the winter of 2019/2020, we have added a facility at Riverhead (Long Island) that can accommodate 22 trucks/day (9 MDth) • Current plan calls for expansion to four sites and 130 trucks/ day to satisfy Design Day and Design Hour needs into 2021/22	• National Grid has worked diligently with local officials and fire departments to ensure understanding of trucking requirements and safety plans • This supply option has historically been viewed as a contingency operation to augment baseload supply in the event of an unplanned shortage • By comparison, in New England National Grid has built out CNG capacity for up to 55 trucks • System could be impacted by events such as road/bridge closures, high winds and inclement weather • If additional capacity comes on line, or if gas demand is reduced, we are flexible to reduce what we need from CNG
Renewable Natural Gas	2-3	• Currently operating Staten Island with 1.6 MDth capacity • Newtown Creek is under construction, once online will bring 1.0 MDth of capacity	• Unlike other gas contracts, RNG contracts are not "firm capacity" – they are not guaranteed to deliver during peak periods of demand • Options to expand RNG will be addressed in assessment of opportunities to close gap between supply and demand
TOTAL	**2,888 – 2,925**	Once planned CNG buildout is complete: • 72% of supply capacity is "fixed" through longer-term pipeline contracts • 14% is peak LNG that is owned and operated by NG • 14% is flexible through shorter term peaking contracts and CNG	

Source: National Grid

[10] See appendix for more details on our recent and planned CNG efforts

Over the last ten years, natural gas Design Day demand in Downstate NY has grown by 523 MDth. Meanwhile, National Grid has only added 274 MDth/day of capacity, with plans to add another 36 MDth/day of CNG trucking.

Table 15 below describes the capacity additions that have occurred since 2009.

Table 15: National Grid Downstate NY Additions to Supply Capacity, 2009-2019

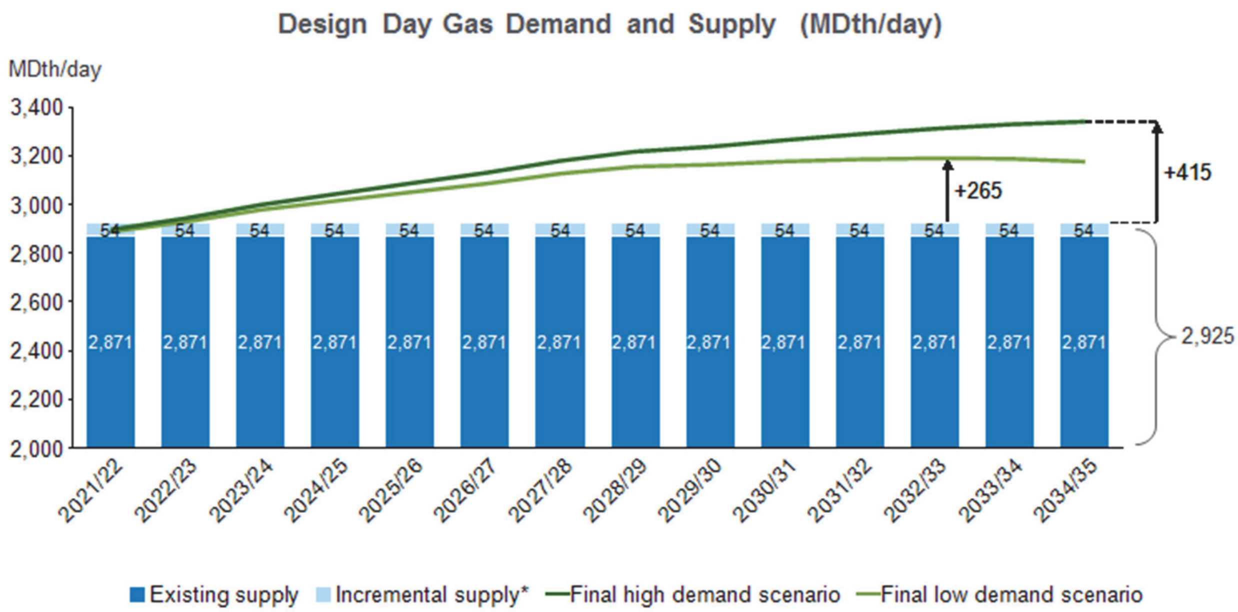
Date	Name	Description	Size (Design Day MDth/day)
2015	Transco Rockaway Lateral and Northeast Connector Projects	Pipeline delivery of gas to the newly constructed Floyd Bennett Field delivery point in Brooklyn	100
2015-2016	Iroquois contracted peaking supply	Existing capacity that became available through a pipeline open season	42
2017	Transco NY Bay Expansion for New York City	Added capacity to Downstate NY city gate capacity, with delivery to Transco Narrows and Transco Rockaway	115
2017	Dominion New Market for New York City	Allowed Company to de-contract some upstream Canadian capacity and reduce commodity costs, but did not change the amount of supply coming into Downstate NY	0
2017-2019	CNG Trucking	Glenwood Landing added 8 MDth of capacity in 2017; added Riverhead in winter of 2019/2020 (9 MDth)	17 (will go to 53 by 2021)
TOTAL			**274 (310 by 2021)**

Source: National Grid analysis

7. The Gap Between Downstate NY Projected Natural Gas Demand and National Grid's Supply Capacity

Having constructed a forecast demand curve for 2020-2035 in Section 5, and compiled National Grid's Supply Capacity in Section 6, we can now bring these two components together. Figure 20 below shows how our Supply Capacity compares to the forecast natural gas demand.

Figure 20: A Comparison of Downstate NY Natural Gas Forecast Demand vs. National Grid's Supply Capacity, 2021-2035



** Incremental supply includes addition of CNG (53 MDth/day) and RNG (1 MDth/day) capacity*

Note: Figures above represent the entire National Grid Downstate NY network for a Design Day. Normal usage fluctuations, particularly during morning and evening hours, create Design Hour supply shortages that start in 2021/22, even after factoring in the impact of incremental CNG.

Source: National Grid analysis

As the chart above indicates, there is a gap between forecast demand and currently available supply that grows over time to a range of 265 – 415 MDth.

8. Low-Carbon Opportunities: How Renewable Natural Gas (RNG), Hydrogen and Geothermal Heat Pumps Can Help Reduce the Projected Gap Between Demand and Supply, While Significantly Reducing Greenhouse Gas (GHG)

National Grid is committed to and optimistic about the potential to develop low-carbon gas alternatives, as a means of leveraging existing natural gas infrastructure and helping New York achieve its climate goals. Several studies have outlined how cold climate heat decarbonization can be most effectively achieved by combining low carbon and renewable gases in a balanced combination with low carbon electricity. For example, a 2019 study by Navigant (now Guidehouse), "Pathways to Net-Zero: Decarbonizing the Gas Networks in Great Britain" concluded that a balanced gas-electric approach to decarbonizing the Great Britain energy system by 2050 was 11% less expensive than a high-electrification scenario. Similarly, a 2018 Poyry study "Fully Decarbonizing Europe's Energy System by 2050" concluded that "overall it is cheaper to pursue a 'Zero Carbon Gas' pathway to decarbonization than an 'All-Electric' pathway."

Two specific options that we are pursuing to add to our natural gas supply are Renewable Natural Gas (RNG) and Hydrogen. Additionally, we believe that National Grid can play an important role in building out Geothermal Heat Pumps as a targeted alternative to oil, new gas connections, and end-of-the-line Leak Prone Pipe repairs.

In addition to helping reduce the size of the gap between natural gas demand and our existing supply, these solutions can significantly contribute to reducing GHG. Each of the opportunities are profiled below, followed by a summary of estimated impact.

8.1 Renewable Natural Gas (RNG)

RNG is pipeline gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent emissions than geological natural gas. Producing renewable gas to augment supply involves the construction of plants or contracting for output of third party plants.

Currently, there are more than 85 operational RNG projects for pipeline injection across the U.S. All existing RNG projects use biomass as feedstock – sources of biomass include: landfills, wastewater treatment plants, food waste, and livestock manure. The EPA's Renewable Fuel Standard (RFS) program has been a critical driver of significant growth over the last few years, providing policy support to lower the emissions of the transportation sector.

Based on current studies, it is estimated that 12-29% of gas consumption can be supplied by RNG in the future[11]. National Grid views RNG supplies that are sourced within our service territory as incremental gas supply to serve gas demand growth. Although RNG from outside our service territory is an attractive opportunity to decarbonize our gas supply, it displaces gas that would otherwise be flowing through the limited interstate pipeline capacity serving our gas system, and therefore does not contribute toward incremental supply.

In Downstate NY, National Grid has two RNG sites – we are taking 1.6MDth/day of RNG from a plant in Staten Island, and construction is under way to enable connection of a 1.0 MDth/day plant at Newtown Creek, with an expectation that this will be live by the Winter of 2020. The volume associated with these two plants has been reflected in our existing supply stack, although it should be noted these plants are not under "firm capacity" contracts and thus do not guarantee supply during periods of peak demand.

In addition to these two plants, as of January 2020, National Grid has received 12 requests from developers who have RNG projects where they are interested in connecting to our natural gas system. Of those 12, the six referenced in Table 16 below have been initially scoped and are actively being pursued as opportunities to move forward. Three of the six have progressed to where engineering work has commenced, while the other three – including the largest two – are still in early stages of planning. If all six of these projects were to proceed, there is the potential to add 23 MDth/day of gas supply between now and 2026.

[11] American Gas Association Study prepared by ICF: Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment (2019)

Table 16: Potential Incremental Renewable Natural Gas Plants in Downstate New York

Plant Name/ Location	Estimated Year to Come On-Line	Size of RNG Plant (Design Day MDth)	Cumulative Incremental RNG Supply (MDth/day)	Status
Suffolk Food Waste	2021	1.4	1.4	Has gone through approval process; moving into construction phase
Staten Island Food Waste #1	2022	0.3	1.7	Under an Engineering Services agreement. Project in review/permitting
Staten Island Food Waste #2	2023	1.5	3.2	Under an Engineering Services agreement. Project in review/permitting
Brooklyn Food Waste	2024	0.9	4.1	Project developer submitted general inquiry to National Grid and kickoff meeting was held December 2018
Queens MSW	2025	11.3	15.4	Project developer submitted general inquiry to National Grid and kickoff meeting was held December 2018
NJ to NY Food Waste	2026	8.0	23.4	Project developer submitted general inquiry

Source: National Grid

In addition to Staten Island, Newtown Creek and the six potential RNG plants listed above, National Grid believes there is more opportunity to expand RNG in Downstate NY that can benefit from supportive policies and programs.

National Grid encourages a program equivalent to the Renewable Portfolio Standard (RPS) for the natural gas distribution system, mandating a volume of renewable fuels be blended into the distribution network. This should be done alongside programs requiring the phase out of oil heating, to ensure that customers do not convert to higher emitting fuels. To support this effort, National Grid filed a Green Gas Tariff proposal in its recent Downstate NY rate case, which would establish a tariff to allow customers to purchase RNG. The tariff will give downstate customers the choice to supplement their natural gas usage with RNG – pipeline quality gas produced from biomass, wastewater or renewable electricity with lower emissions than from fossil fuel derived natural gas.

National Grid supports further policy developments that incentivize the use of RNG at the state and federal level to decarbonize the gas network and policies that incentivize the use of RNG as a source of renewable heat. Specifically, renewable energy credits that already exist in the power generation and transmission sector are needed for the heating sector. And, it is likely that RNG will need an RPS-like program that allows National Grid to access RNG outside of state boundaries (similar to how Low Carbon Fuel Standard/Renewable Fuel Standard programs work today).

To materially increase RNG in the gas distribution system, significant effort is required by all stakeholders, including legislative action from the governments in our service territories and the building of internal capabilities at National Grid (e.g., research and design, engineering, etc.). National Grid remains committed and excited to tackle this challenge and expand the use of RNG.

8.2 Hydrogen and Power-to-Gas (P2G)

Hydrogen blending refers to the addition of hydrogen with natural gas to augment the current energy supply available to serve our customers. Modular Proton Exchange Membrane (PEM) systems are the emerging favorite to make H_2 from water and renewable electricity. Current commercial scale is small, with single units producing a heating equivalent to ~70 Dth/day. Alkaline-based systems are another option which can produce higher volume; however, they are larger and require a plant facility.

Industrial hydrogen networks have been in service for decades. In the U.S. Gulf region, high pressure storage and transmission pipelines serve pure hydrogen to oil refineries. In the United Kingdom, Europe, and Australia there are various system pilots where local gas distribution companies blend up to 20% hydrogen with the natural gas supply. And in the United States, the Hawaii Gas Company has been serving customers with natural gas containing approximately 12% hydrogen since the 1970's.

Studies estimate that 10-20% is the maximum blend allowable by most existing gas infrastructure and end-use equipment (e.g., appliances). Because hydrogen has a lower volumetric energy density than natural gas, a 20% blend could increase the available energy supply for heating by 6-7% in any local system where it is deployed. As the gas system distributes energy on a volumetric basis, there may be a need to increase capacity of the current network to support the additional volume if 20% hydrogen is blended with natural gas.

National Grid has been actively tracking the developments and reviewing the benefits and limitations of hydrogen blending. In the U.K., National Grid, as the National Gas Transmission System (NTS) operator, has been monitoring and studying blending demonstrations by our distribution network customer companies. The NTS is also engaging in a long-term study to identify requirements and processes to safely transport a blend or pure hydrogen in the transmission network. In the US, we are a member of the Center for Hydrogen Safety and have recently developed plans for a hydrogen blending study in Downstate New York.

In early 2020, National Grid proposed a hydrogen blending study to be conducted by The Institute of Gas Innovation and Technology (I-GIT) with potential support from NYSERDA over the next two years. The proposed project will assess the impact of hydrogen on New York's unique composition of natural gas infrastructure, including cast iron and unprotected steel mains, to determine acceptable blend amounts, and identify specific alterations that may be necessary to accomplish safe and cost-effective inclusion of hydrogen into gas pipelines. Filling these knowledge gaps will enable the development of hydrogen blending in NY, opening the opportunity to achieve deep decarbonization of the gas network, while also supporting further renewable deployment in the electric network.

Power-to-Gas (P2G) is also a process which could fundamentally change the energy landscape in the future. P2G involves converting excess renewable electricity to hydrogen through the electrolysis of water. Hydrogen from this process can then be blended into the gas distribution system as described above. It could also be combined with carbon dioxide to produce synthetic methane or RNG.

In the current electric system, power plants ramp down production when generation capacity exceeds demand. However, with limited ability to manage demand, difficulty curtailing nuclear base load, and increasing penetration of renewables, there will be conditions of excess supply of low-carbon electricity. Production of renewable electricity is already being curtailed in the U.S. (e.g., solar in California and wind in Colorado). As solar and wind generation is expected to grow significantly over the next 20 years, storing that variable energy will become an increasingly important challenge.

P2G can drive more investment in renewable electricity by increasing utilization of those assets and addressing the biggest weakness of solar and wind: intermittency and storage. Rather than being curtailed during cool and sunny days or windy nights, solar and offshore wind could be converted to hydrogen or methane, effectively storing that energy in the form of chemical bonds.

There are multiple studies underway that will quantify the potential of hydrogen production from P2G. Transformation of the whole energy system is required to achieve all the potential benefits. P2G offers a solution that integrates the decarbonization of the gas and electric systems, and the two decarbonized systems complement each other.

National Grid believes that a forecast Downstate NY supply of 4-16 MDth/day by 2035 from hydrogen is achievable given the current trajectory of renewable energy in Downstate NY. This goal would require approximately 100-400 MW (at 50% capacity factor) of renewable energy to achieve the required level of hydrogen production through P2G. The 50% capacity factor is typical for advanced wind turbines and conditions in New York. As stated, we believe these figures are achievable given New York's current plan to develop as much as 9,000 MW of offshore wind. Though it is achievable, it will require significant investment (e.g., gas system modernization, replacement of leak prone pipe, etc.) which will need to be investigated further.

8.3 Geothermal Heat Pumps

Geothermal heat pumps are another area where there is significant opportunity to expand a low-carbon solution. A geothermal heat pump, or ground source heat pump, is a central heating and/or cooling system that transfers heat to or from the ground. It uses the earth all the time, without any intermittency, as a heat source or a heat sink. While the installation price of a geothermal system can be several times that of an air-source system or natural gas connection, there are significant energy savings that often generate a payback over 5 to 10 years[12].

It is estimated that ~200,000 residential buildings in Downstate NY are more than 200 feet from National Grid's gas distribution system. These buildings currently are typically utilizing oil for heating and are not areas where the existing gas distribution system is likely to expand, which makes them excellent prospects for an alternative heating solution. Also, if there are customers/neighborhoods that are at the end of National Grid's distribution system and have leak-prone pipe, geothermal systems could be an effective alternate solution (e.g., it could be more cost effective and/or environmentally beneficial to install geothermal heating vs. replacing the natural gas pipes).

National Grid has pursued and wishes to expand involvement in geothermal systems in Downstate NY. In 2016, a Geothermal Demonstration Project for Downstate NY connected a total of 10 homes with shared-loop GSHP systems, representing a total heating capacity of 30 tons. The systems performed well during a period of extended cold weather in January 2018, with customers not reporting any loss in comfort. The systems achieved high coefficients of performance ("COP") in the range of 2.2 to 3.5, and customers identified comfort-related benefits, including improved air quality, quiet equipment operation, simplicity, and more even distribution of hot and cold air[13].

Building off this successful initial pilot, National Grid has proposed in its recent rate case filings a $12M program that will connect 900 homes in Downstate NY to geothermal ground loops over the next four years. The goal of this expanded program is to help scale the market for geothermal heat

---

[12] US Department of Energy
[13] National Grid Direct Testimony of the Future of Heat Panel, April 2019

pumps, reducing costs as economies of scale are achieved. National Grid would seek to collaborate with industry stakeholders to develop and adopt best practices for installing Ground-Source Heat Pump loops, with specific consideration to how to best operate these systems in an area that has a high saturation rate of natural gas infrastructure. And, for those customers switching from heating oil to geothermal systems, it is estimated they could realize average annual energy cost savings of $1,000 - $1,500 while reducing nearly 6.75 metric tons of CO_2 emissions.

8.4 Summary of Low-Carbon Opportunities

With program funding and support, we anticipate that RNG, Hydrogen and Geothermal programs can cover 15 – 35 MDth/day of the projected gap between Downstate NY gas demand and currently available supply, while also significantly increasing levels of low-carbon gas that are brought into our network and positioning our distribution network as a viable component of achieving long-term net zero carbon goals.

Table 17: Summary of Low-Carbon Opportunities

	High Demand Scenario		Low Demand Scenario	
	Description	**Size by 2034/35 (Design Day MDth)**	**Description**	**Size by 2032/33* (Design Day MDth)**
RNG (incremental to Staten Island and Newtown Creek)	Achieve 33% of 6 existing proposals that total 23.4 MDth (note: to date, we've converted 1 in 5)	8	Double size of proposal portfolio over time to 46.8 MDth, and achieve 50% of proposals	18
Hydrogen	5-10% of network accepts 5% hydrogen blend	4.2	15% of network accepts 10% hydrogen blend	12
Geothermal Heat Pumps	900 homes get connected over first 4 years (full pilot as proposed), 50% would have become our customers (50% are truly new that would have been too far off the network). Then, connect 200 customers per year thereafter, for 3,100 total (50% new, 50% reduce gas demand)	2.4	900 homes get connected over first 4 years (full pilot as proposed), 75% would have become our customers (25% are truly new that would have been too far off the network). Then, connect 400 customers per year thereafter, for 5,300 total (25% new, 75% reduce gas demand)	5
TOTAL		15		35

** When demand peaks under the Low Demand scenario. Further growth of these solutions is expected to achieve a total of 45 MDth/day by 2035.*

Table 18: Impact of RNG, Hydrogen and Incremental Geothermal Heat Pumps on Gap Between Downstate NY Projected Natural Gas Demand and National Grid's Supply Capacity

	Impact on Max Gap Demand (MDth/day)	
	Low Demand Scenario (2032/33)	High Demand Scenario (2034/35)
Gap Between Demand and Supply	265	415
RNG, Hydrogen and Incremental Geothermal Heat Pump Impact	35	15
Remaining gap	**230**	**400**

Source: National Grid analysis

In addition to these specific RNG, Hydrogen and Geothermal programs, in November 2019, National Grid and its affiliates, through shareholder funding, committed $20M towards clean energy projects and/or investments in New York-based startup energy businesses and technologies to reduce reliance on non-renewable sources. The Company has an active portfolio of opportunities it is pursuing in areas such as energy efficiency, demand response, geothermal heat pumps, and gas leak detection.

9. Assumptions for Evaluating Cost and Environmental Impact

Before moving into the individual options required to close the remaining 230-400 MDth gap between forecast demand and available supply, it is important to provide more details on the background and assumptions that will be used for evaluating cost and environmental impact.

9.1 Methodology and Assumptions for Evaluating Cost

In evaluating cost, we are considering multiple aspects of each option as follows:

- **Project Cost** – For Large Scale and Distributed Infrastructure options, we are considering all the costs of constructing and bringing the solution online. For those that are built via third parties this translates into a demand charge, and for those items we place into rate base we are calculating the revenue requirements that would result over the period of the study (2020-2035).
- **Annual Operating Cost** – We are factoring in the estimated annual costs of operations for the different infrastructure options, as well as the estimated annual costs to implement and execute different energy efficiency, demand response, and electrification programs.
- **Commodity Cost** – For each of the different options, we are evaluating the commodity cost and corresponding impact to the customer. For example, there are different prices paid for pipeline natural gas, LNG, and CNG. To get a true assessment of the different cost impacts, we need to weigh commodity cost into the equation, even though it is a pass through from National Grid, as it impacts customer bills.
- **Corresponding Savings** – Many of the options generate savings in other parts of the demand-supply equation that need to be "netted out" to get to a true bottom line assessment. For example, a large-scale infrastructure option, once implemented, would allow National Grid to eliminate CNG trucking and reduce the level of contracts for peaking supplies. Likewise, incremental EE programs would result in avoided gas commodity costs, as customers would be consuming less gas. These offsets are factored in to provide a more complete picture and allow for effective cost comparison across the different alternatives.

9.2 Methodology and Assumptions for Evaluating Environmental Impact

The evaluation of environmental impact can encompass many considerations. For this evaluation, we have divided the environmental impact assessment into two primary categories: ecological impact and climate impact.

- **Ecological impact:** Encompasses the impact from construction and operation of the solution, i.e. potential habitat disruption from building infrastructure, and the potential risk of a larger environmental incident.
- **Climate impact:** Encompasses the GHG emissions resulting from the solution, air quality impacts (which often go hand in hand with GHG emissions), and the potential of the solution to support decarbonization of the entire energy system.

The criteria for the evaluation of these two subcategories is presented in Table 19 below. It must be noted that the environmental assessment criteria attempt to identify the most critical differences between the options available to close the supply gap. At this conceptual stage these impacts can only be broadly clarified - a full assessment of environmental impact would require more detailed inputs, including building sites and clarification of supply chains, which are not available at this stage of the process for many of the options.

Table 19: Criteria for Assessing the Environmental Impact

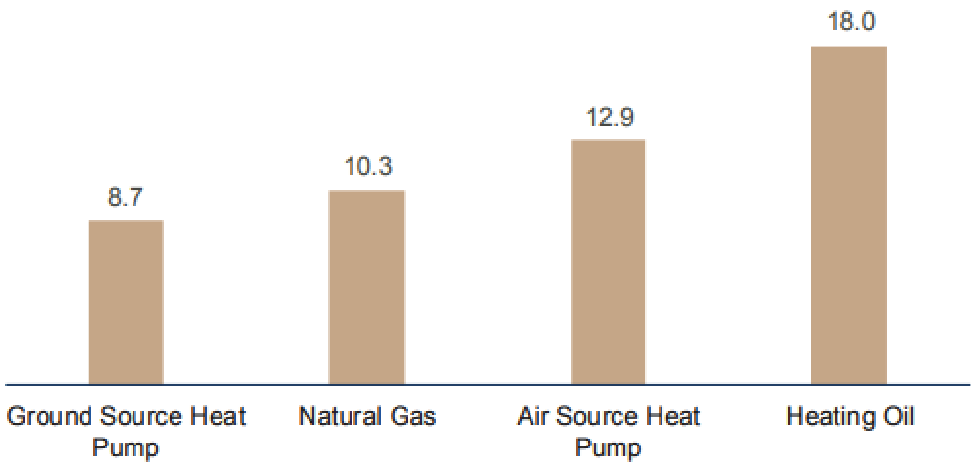
Category	Evaluation Criteria
Ecological Impact	• Development needs, completely new development or alignment with existing operations (i.e. greenfield vs. brownfield) • Design standards to which construction will conform • Operational impact (e.g., supply, servicing, etc.) • Potential for and impact of a larger environmental event (i.e. a spill or combustion)
Climate Impact	• GHG emissions intensity of the fuel supplied through each option (considering lifecycle emissions of the fuel development) • Annual GHG emissions, if any variance • Potential to increase health effects from air quality • Contribution to a decarbonization solution (i.e. build out of infrastructure that will be required/can support a decarbonized system)

Within the environmental impact category, ecological impact is defined by the evaluation criteria, but climate impact needs some additional discussion to clarify the baseline and methodology used to quantify potential impact. The options that are explored further in this Report are the available options to fill the natural gas Design Day gap between demand and supply. As such, the environmental impacts are compared to one another and not against a baseline that won’t result in a fix to this demand-supply gap.

Except for energy efficiency and certain demand response programs, all the options result in an increase in total GHG emissions from the supply of natural gas by National Grid and/or increased electricity consumption for heat electrification. However, this increase in total GHG emissions from natural gas and electricity may not result in an increase in total emissions at a statewide level – if closing this supply gap for natural gas results in fewer oil systems being installed and utilized.

It is also important that we consider both the average emissions of a solution and the marginal impact of adding more customers onto that solution, particularly as we look at the impact of customers switching from oil to gas, oil to electric and gas to electric heating. For example, when we look at the marginal impact of currently adding one more customer onto a system, natural gas enjoys a substantial advantage over air source heat pumps and heating oil in terms of emission levels (see Figure 21 below).

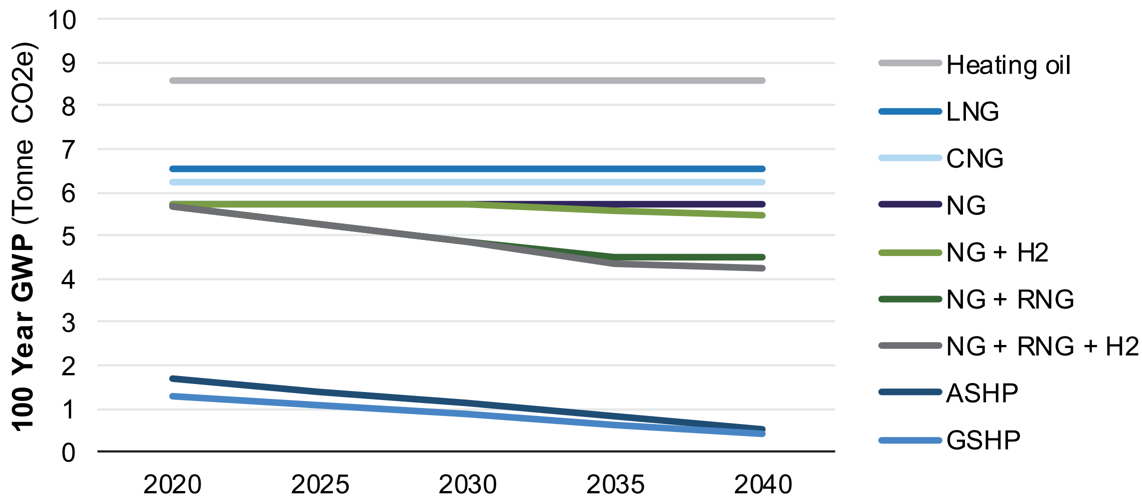
Figure 21: Estimated Life Cycle Greenhouse Gas Emissions by Energy Option for a New Single-family Home In Downstate NY (metric tons CO_2-e per year)



Source: MJ Bradley & Associates: Life Cycle Analysis of the Northeast Supply Enhancement Project, June 2019 (pg 6)

Conversely, when we look at the average emissions for power generation in Downstate NY across a solution, we see a different picture emerge – while natural gas retains a substantial advantage over heating oil, with potential to see further declines due to RNG and Hydrogen solutions, the average annual emissions – including lifecycle GHG accounting – for air source and ground source heat pumps are lower than the average annual emissions from a natural gas heating system. Figures 22 and 23 below provide a comparison of annual Greenhouse Warming Potential (GWP) emissions – both current and forecast based on decarbonization of the electricity supply and potential reductions from combining natural gas with Hydrogen or RNG – using 100 year and 20-year Global Warming Potential (GWP) emissions.

Figure 22: Estimated Annual 100 Year GWP Emissions from Space Heating, 2020 - 2040

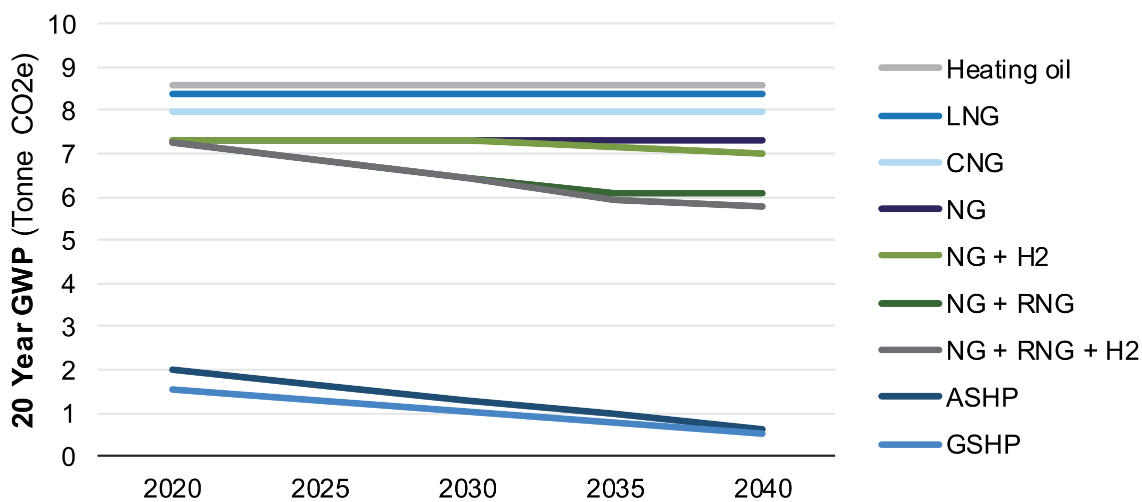


Notes: Estimated annual 100 year GWP emissions from space heating for typical single family household in downstate New York. Assumes 85% reduction from 1990 NYS emissions, ASHP CoP = 3.5, GSHP CoP = 4.5, gas efficiency of 95% with NG + RNG + H2.

Source: National Grid data, Guidehouse data and analysis

Note: NG = natural gas; H2 = Hydrogen, ASHP = Air Source Heat Pump, GSHP = Ground Source Heat Pump

Figure 23: Estimated Annual 20 Year GWP Emissions from Space Heating, 2020 - 2040



Notes: Estimated annual 20 year GWP emissions from space heating for typical single family household in downstate New York. Assumes 85% reduction from 1990 NYS emissions, ASHP CoP = 3.5, GSHP CoP = 4.5, gas efficiency of 95% with NG + RNG + H2.

Source: National Grid data, Guidehouse data and analysis

Note: NG = natural gas; H2 = Hydrogen, ASHP = Air Source Heat Pump, GSHP = Ground Source Heat Pump

Table 20: Assumptions for the Annual GWP Emissions Figures

Assumptions:
• Air Source Heat Pump (ASHP) Coefficient of performance (COE) = 3.5 • Ground Source Heat Pump (GSHP) Coefficient of Performance (COE) = 4.5 • Electricity Production Emissions based on NYISO Zone J Average Emissions in 2019 • Emissions reduction from Electricity Production over time forecast to decrease on a linear basis by 85% of 1990 GHG emissions level by 2040 • Renewable Natural Gas (RNG) assumed to increase as % of NG from 1% in 2020 to 25% in 2040 in NG+RNG case • Hydrogen (H2) assumed to be blended with natural gas starting in 2030, increasing to 15% of gas volume by 2040 in NG + H2 case • NG+RNG+H2 case assumes both 25% RNG and 15% H2 by volume by 2040

10. Description and Evaluation of Specific Options

As we move to examining specific projects and investments, the level of attractiveness for each individual option has been evaluated considering multiple factors. To make it easier to compare, each of these options is presented in a consistent format, covering the following:

- **Overview** – a description of the infrastructure that would need to get built, or the program that would need to be implemented
- **Size** – Design Day capacity (MDth/day), total volume/frequency of use (throughout the year, or just to meet peak demand), and timing of capacity availability (e.g., does it all become immediately available, or is there a build of capacity over time)
- **Safety** – requirements, risks and how the risks can be mitigated
- **Reliability (certainty of meeting demand)** – likelihood that the option will be able to deliver on its projected capacity, and the risks that it might not deliver
- **Cost** – aggregate cost to bring the capacity online, and annual costs with and without a discount rate, which includes infrastructure and/or program costs and adjustments for commodity costs, as described in Section 9 above
- **Environmental impact** – greenhouse gas (GHG) emissions; air quality considerations; potential impact from construction and operation; environmental risk; and decarbonization potential (i.e. the ability of the option to support New York's decarbonization goals), as described in Section 9 above
- **Community impact** – impact on business growth and development, and on customer convenience and choice; how components such as location of infrastructure and amount of trucking impact affected communities
- **Permitting, policy and regulatory requirements** – permits that will need to be approved, policy changes that could enable the option, and regulatory obstacles that would require approvals or changes
- **Requirements for implementation** – location siting; hiring for construction/program implementation; requirements to place equipment orders; etc.

Following the detailed description of each option, we will provide a summary to facilitate comparison of the options.

It is important to note that over the years, as part of our annual, long-term and ongoing planning processes, National Grid has considered multiple different variations and configurations of infrastructure alternatives. These have included different pipeline sizing and routing options; increased pipeline compression; and different alternatives for siting and transporting LNG and CNG. Many of these specific options were “considered and ruled out” over the years due to issues such as technical feasibility, cost, safety/reliability concerns, and/or environmental issues. To present every permutation ever considered would not be practical. We have therefore attempted to put forth the options we believe cover all types of solutions, and that are the most attractive/representative configurations worthy of consideration.

10.1 Large-Scale Infrastructure Options

10.1.1 Offshore LNG Deepwater Port

Description

The Offshore LNG Deepwater Port solution involves installation of an offshore buoy and connecting undersea lateral to an existing offshore pipeline for connection to a dedicated Floating Storage and Regassification Unit (FSRU) which can provide peak supply and has potential to help meet daily demand throughout the year. The FSRU is an LNG tank ship that delivers LNG in bulk, typically storing more than 3,000 MDth of LNG with the added capability of a fully staffed LNG peak shaving plant including vaporization equipment and a control room integrated into the ship.

Size

The key difference between this Offshore LNG Port solution and the LNG Barge solution described below is the capacities available on one vessel. A typical FSRU can replicate the daily throughput of a 400 MDth/day pipeline for a week at full capacity. There is a potential location in Long Island Sound that would enable delivery of up to 400MDth/day to Commack, NY or Hunts Point, NY.

An alternate location exists off the South Shore in the Atlantic Ocean, with a subsea interconnection on Williams’ existing subsea lateral to Floyd Bennett Field City Gate. This location would also enable incremental delivery of 400 MDth/day to National Grid’s supply capacity.

Safety

The US Coast Guard (USCG) and US Maritime Administration (MARAD) will conduct a security / safety review as part of the federal permitting process. A process safety approach will be used to identify, quantify and manage risks by these agencies with significant input from the applicant. Once in operation, the FSRU will be subject to a specifically designed USCG Security Zone per 33 CFR Part 165 Subpart D. Furthermore, the USCG manages a rigorous inspection and regulation program of all foreign and domestic flagged commercial vessels under their Port State Control program. This includes mandates to inspect ships on an annual basis for materiel condition, safety functions, operations, security programs, crew training and overall Safety Management Systems (SMS) under International Maritime Organization (IMO) standards, United Nations Safety of Life at Sea (SOLAS) conventions, US safety and environmental laws codified in CFRs, and International Ship and Port Facility Security (ISPS) code. The potential project partner has significant operational experience with all these standards and has delivered gas via FSRU for 29 years (currently operates eight active FSRUs).

Reliability

Once up and running, the FSRU would be a highly reliable source of supply. This is a proven technology that can operate in seas up to 6-8 meters. There are over 30 FSRU facilities worldwide, including three in the US - Northeast Gateway and Neptune are located offshore in Boston Harbor and Gulf Gateway in the Gulf of Mexico. FSRU maintenance is a continuous process managed by the ship's operator. With a full-time crew for maintenance and operations, the ship's staff performs all equipment maintenance and testing on a routine basis in compliance with their SMS. The ship's condition and operating reliability is inspected annually through the Port State Control program described above. Additionally, overall condition of the vessel is certified periodically by Class Society organizations such as American Bureau of Shipping (ABS). Long-term hull maintenance will be performed as necessary by the vessel owner in dry dock repair during the off season. In summary, the maritime industry is extremely competent in transport and operation of bulk storage vessels given the severe financial penalties for non-performance.

Unlike a gas pipeline solution which provides the ability to provide gas supply 365 days per year, FSRUs store a finite amount of natural gas and require replenishment via ship-to-ship transfers - this type of refill is limited to sea conditions at or below a wave size of two meters.

Cost

The cost of constructing a complete facility including the subsea equipment, the buoy and the FSRU capable of delivering 400 MDth/day is estimated at $800M. The FSRU vessel will likely be purpose built as all existing vessels are under commercial agreement worldwide. The cost to build a new FSRU is estimated at $300M. The submerged buoy is similar in nature to the FSRU where it will be designed and built on shore to connect specifically with the hull of the FSRU. The cost of the buoy is estimated at $60M while installation of the subsea lateral covers the remaining cost. Operational costs and maintenance of the FSRU, buoy and subsea equipment is typically covered under the commercial agreement with the FSRU owner/operator. A capacity charge of approximately $160M/year is expected in a commercial agreement consistent with pipeline models. The LNG commodity cost will be separately charged on a variable basis and under today's economics may be at a premium to pipeline supply. However, a combination of the peak nature of the supply used and an expected worldwide oversupply of LNG in the 2020's could mitigate the overall customer costs.

Environmental Impact

Ecological Impact: The ecological impact of an offshore LNG deepwater port will be more significant than most of the other options discussed in this analysis. Construction requires a subsea pipeline to be built and both the construction and ongoing maintenance will have an impact on the ocean floor (though a relatively small impact once the pipeline is constructed). Construction impacts, typical of marine construction work, may include decreased water quality, increased sedimentation, decreased air quality, pollution to water, noise and waste generation. Onshore, the pipeline will connect to an existing natural gas distribution pipeline, so onshore impact will be relatively limited.

Once operational, potential impacts include LNG tankers traveling to and from the offshore port, stack emissions from the FSRU for the engines and generators running while moored on the buoy and potential intake and discharge of ocean water to cool ship systems and in some cases as a carbon free heat source to vaporize the LNG cargo into the buoy. The ship will not be able to discharge oily water, sewage or garbage under Maritime Pollution laws (MARPOL) which are strictly enforced by the USCG. All these waste products will be stored on board and transferred to shore when the FSRU is at a port to be disposed of legally.

The overall environmental impact of the project from construction to operations will be reviewed under the National Environmental Protection Act (NEPA) process led by FERC with consultation and analysis by state environmental agencies, all federal agencies with jurisdiction and any interested stakeholders. The resulting report recommending approval or denial will be in the form of an Environmental Impact Statement (EIS). As an example, in the construction phase, the EIS will approve methods to minimize impact to the subsea environment describing specific trenching and burial methods that will minimize suspended sediment and impacts to benthic environments.

Climate Impact: The GHG emissions from an offshore LNG deepwater port are higher than from a typical, new pipeline due to the process of liquefaction and gasification which are energy intensive processes and may result in some leakage/losses, essentially methane escaping in the process. In addition, operation of an LNG port requires that LNG is transported by vessel to the system, resulting in additional emissions from the transport process. It is expected that GHG emissions are approximately 10-15% more on an annual basis than a pipeline solution. Longer term, an LNG tanker network could support decarbonization of the natural gas network as the tankers could be used to transport liquid hydrogen.

Community Impact

Given the distance from shore, minimal if any view shed impacts on the horizon are anticipated. Some shore-based jobs will be created to support the FSRU operation locally. FSRUs are typically contracted in 10 to 15-year increments; should the resource be no longer needed the FSRU could simply contract with another port and leave the buoy system for future emergency use only. Depending on advancements in hydrogen production technology, the system could be used to inject hydrogen from liquefied hydrogen. As an example, this year Japan built the world's first bulk liquefied hydrogen carrier using technology and materials consistent with that of an LNG ship.

Permitting, Policy and Regulatory Requirements

An offshore LNG port project would require Federal Energy Regulatory Commission (FERC) approval, as well as specific state approval (NY and CT if located in Long Island Sound; NY and NJ if located on South Shore in Atlantic Ocean). It is worth noting that NY, NJ and CT opposed two FERC-approved LNG Deepwater Port projects in 2008 and 2015. Accordingly, offshore developers are currently unlikely to take on development cost/permitting risk in this region.

Federal permits under the NEPA program would likely include issuances from the Bureau of Energy Management (BOEM), National Oceanic and Atmospheric Administration (NOAA), United States Fish and Wildlife Service (USFWS), United States Army Corps of Engineers (USACE), and the United States Environmental Protection Agency (EPA). FERC, under the National Environmental Protection Act (NEPA), would identify any other federal agencies specific to the project.

Requirements for Implementation

Permitting would need to be completed prior to placing an order with a shipyard for new FSRU vessel construction, and prior to building vessel interconnecting facilities and system upgrades. Assuming vessel construction and interconnections/upgrades can occur simultaneously, it is estimated that it will take two years following receipt of all permits for an LNG Deepwater Port facility to be operational. Based on historical timelines, total estimated implementation timeline is 6-8 years.

Summary

Table 21 below summarizes the assessment of the Floating LNG option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 21: Summary of Offshore LNG Deepwater Port Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Installation of offshore buoy and undersea infrastructure to connect a Floating Regasification and Storage Unit (FSRU) to existing on-shore gas infrastructure
Size	400 MDth/day	Can be used for daily throughput or can be used for peak supply
Safety	◕	US Coast Guard to conduct and maintain a rigorous security/ safety review and inspection program
Reliability	◕	Highly reliable source of supply – there are over 30 FSRU facilities worldwide. Replenishment is limited to sea conditions at or below a wave size of two meters.
Cost	◑	Estimated cost to construct is $800M – annual cost to the residents of Downstate NY: ~$160M
Environmental Impact	◔	The ecological impact from construction will be significant to the subsea environment, though it will be monitored by the EPA. The GHG emissions from an LNG systems are 10-15% higher than what would be expected from a standard natural gas solution.
Community Impact	◑	Minimal impact to community – FSRU would be offshore with limited visibility – typical contracted lifespan of FSRU is 10-15 years
Permitting, Policy and Regulatory Requirements	N/A	• Permits would likely include BOEM, NOAA, USFWS, USACE, EPA • NY, NJ and CT opposed two FERC approved Floating LNG projects in 2008 and 2015
Requirements for Implementation	N/A	• Considering new FSRU vessel construction required, permitting would need to be completed prior to large Capital Order • Estimating 6-8 years total to obtain permits, build vessel and interconnecting facilities, and complete system upgrades

10.1.2 LNG Import Terminal

Description

The LNG import terminal option includes construction of port infrastructure to accommodate LNG carrier ships. The infrastructure includes cargo receiving facilities, on shore storage, regasification and transportation elements. This option can be utilized to provide peak supply and can also be managed to help meet demand throughout the year. It is important to note that this project would require a change to or waiver of NY state Law 6 NYCCR 570 that limits land storage of natural gas.

Size

To date, no land area has been considered for this option. Under current NY state law, this option would require a change in law or waiver by NY State due to the requirement in 6 CRR NY 570 limiting LNG land-based storage to 70,000 gallons per facility or approximately 6 MDth. For context, LNG tankers deliver over 26 million gallons to the Everett LNG terminal (Operated by Exelon in Everett, MA) and the smallest LNG barges available hold approximately 580,000 gallons.

Safety

Any LNG import terminal facility design would be governed by FERC's LNG Division using NFPA 59A and 49 CFR 193 as codes, with consultation and operational oversight by the NY PSC and the Pipeline and Hazardous Materials Safety Administration (PHMSA) – a US DOT agency responsible for developing and enforcing regulations for the safe, reliable and environmentally sound operation of pipeline transportation. If sited successfully, a USCG security zone would be established and maintained while a vessel was unloading onsite. For the land-based facility, US LNG Operations would employ all process safety, safety, maintenance, and operating procedures similar to those used at National Grid's Greenpoint and Holtsville LNG plants.

Reliability

Once in place, the LNG import terminal would be a reliable source of supply. LNG Terminals are a proven natural gas supply option used all over the world and National Grid has extensive experience in operating LNG facilities in NY, New England and the UK. Given the weather impacts (e.g., hurricane, blizzard, etc.) on near shore energy infrastructure, this option would not be as resilient as the LNG Deepwater Port or LNG Barge options. For example, damages from a large storm like Hurricane Sandy could incapacitate the import terminal, while a floating solution could leave its station and return to operations immediately after the storm.

Cost

Estimating the cost of the proposed LNG import terminal is a difficult task. There are no comparable recent or inflight projects in North America. The Sabine Golden Pass import terminal in Port Arthur, Texas cost approximately $1B in 2003. Repsol & Irving built a 10 BCF import terminal in New Brunswick, Canada in 2009, which cost approximately $800M. Based on this evidence, it is estimated that building an LNG import terminal to service Downstate NY would cost over $1B; however, a more detailed feasibility study will be needed to better quantify the cost.

Environmental Impact

Ecological Impact: There are substantial ecological impacts in the construction phase, due to large-scale construction activities in and near the marine environment. These construction impacts would be similar or slightly higher than what would be expected for the construction of an offshore LNG deepwater port, and more than the development of a pipeline. Potential impacts include those typical to marine construction work: water quality and sediment introduced into the marine environment, decreased air quality, increased stormwater/runoff, noise, and waste generation. These impacts would be mitigated, to the extent possible, by control measures used during construction.

Once operational, the LNG import terminal would likely have a greater impact than an offshore LNG deepwater port, because LNG tankers would need to travel into the port area to offload supplies. In addition, the LNG import terminal would include a large storage tank and require trucks traveling from the storage tank to natural gas peaking stations as supplies are needed.

Climate Impact: The GHG emissions of an LNG import terminal are similar to what would be expected for an offshore LNG deepwater port – as the same process of liquification liquefaction, gasification, and vessel transport to the terminal is required for the LNG supply. It is expected that GHG emissions would be approximately 10-15% higher than a standard natural gas solution.

Community Impact

Community concerns would be greater than that of the offshore LNG options as a permanent facility would be sited in a community. Even when sited in industrial zones, significant community resistance is a common part of the siting process.

Permitting, Policy and Regulatory Requirements

Assuming current NY law could be changed or waived for this project, the LNG import terminal would require FERC approval under the NEPA process described above, as well as specific state and local government approval.

Permits will likely include USFWS, USACE, US EPA, New York Public Service Commission (NY PSC), New York State Environmental Quality Review Act (NY SEQRA), and New York State Department of Environmental Conservation (NYSDEC).

Requirements for Implementation

FERC will be the lead agency conducting a NEPA review collaborating with all federal agencies, state agencies and all stakeholder groups. A full EIS is required for import terminals. This process is typically at least two years following a required 6-month pre-filing process used to identify the scope of review. The NEPA process requires multiple stakeholder open houses and culminates in a FERC Certificate Order up to 6 months after the Final EIS is approved. Once the Order is received, the Company can begin construction, which for a terminal would be an additional 2-3 years. Total estimated implementation timeline is 5-6 years.

Summary

Table 22 below summarizes the assessment of the LNG Import Terminal option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 22: Summary of LNG Import Terminal Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Construction of port infrastructure to accommodate LNG carrier ships – to provide peak supply and daily demand
Size	400 MDth/day	Can be used for daily throughput or can be used for peak supply
Safety	◕	US Coast Guard to conduct and maintain a rigorous security / safety review and inspection program
Reliability	◕	Highly reliable source of supply; however, would be susceptible to weather / onshore events (e.g., hurricanes)
Cost	○	Based on evidence from similar projects, building an LNG import terminal to service Downstate NY would cost over $1B
Environmental Impact	◔	The ecological impact from construction will be significant; the same or slightly higher than a deepwater LNG port. The GHG emissions from an LNG system is 10-15% higher than what would be expected for a pipeline solution.
Community Impact	◔	Potential high impact to Downstate NY community – significant onshore construction/operation and siting
Permitting, Policy and Regulatory Requirements	N/A	• Permits would likely include USFWS, USACE, NY PSC, NY SEQRA, NYS DEC
Requirements for Implementation	N/A	• Would require a change in or waiver of NY law (6 CRR NY 570) • If approved, total timeline would be 5-6 years

10.1.3 Northeast Supply Enhancement (NESE) Project

Description

The NESE Project option includes construction of pipeline infrastructure to transport natural gas from Pennsylvania to New York through New Jersey via the Raritan Bay and Lower New York Bay. The pipeline would include approximately 23.5 miles (approximately 17 miles in NY) of underwater pipeline to the Rockaway Peninsula of Queens.

Size

The NESE project would be able to supply 400 MDth/day of natural gas to the baseload capacity, allowing for the elimination of less efficient, temporary supply solutions (e.g., CNG trailers.) The project would enhance system reliability and provide additional gas to Downstate NY.

Safety

NESE plans, development, operation, and maintenance would be reviewed by the Pipeline and Hazardous Materials Safety Administration (PHMSA) – a US DOT agency responsible for developing and enforcing regulations for the safe, reliable and environmentally sound operation of pipeline transportation.

Reliability

Historically, natural gas supplied by pipelines similar to NESE have been very reliable. Above ground weather events (e.g., blizzards, hurricanes, etc.) and man-made events (e.g., traffic, automobile accidents, etc.) would not impact availability of the natural gas supply. Challenges such as valve malfunctions can occur but are rare.

Cost

The total projected capital cost is approximately $1B. These costs would be incurred by Williams & Co. To utilize the pipeline, National Grid is expected to pay Williams $193M per year for a 15-year term, which includes all operations and maintenance. Variable cost of the pipeline is based on natural gas prices and is projected to be approximately an average of $3 per dekatherm.

Environmental Impact

Ecological Impact: As an underwater pipeline, the construction of NESE would have an ecological impact similar to an offshore LNG deepwater port, though larger in geographic area as it would be much longer. Both the construction and ongoing maintenance will have an impact on the ocean floor (though a relatively small impact once the pipeline is constructed). However, since the pipeline will not include active LNG terminals, the ongoing impact of NESE will be lower than the LNG deepwater port or an LNG import terminal.

Climate Impact: The GHG emissions associated with the NESE project will be a function of the natural gas transported and available for end-use. GHG emissions associated with the operation of the pipeline would be related to operations of compressor stations and any leakage (which given it is a new pipeline should be at or close to zero).

National Grid partnered with the Environmental Defense Fund and Williams to support M.J. Bradley & Associates to perform a study on greenhouse gas (GHG) impacts with and without NESE. The results demonstrate significant GHG reductions with NESE due to a reduction in the use of less environmentally friendly fuels for heating purposes. More details and a link to the full report can be found in the Appendix.

GHG for the NESE project are estimated to be 10-15% lower than the various LNG solutions, and have a reduced GHG footprint when compared to CNG trailers/trucking.

In addition, with its carbon steel infrastructure, NESE will allow hydrogen to be transported through its facilities. Our partners are also working on strategies to enable RNG supply to interconnect into midstream and interstate pipeline assets. Enabling hydrogen and RNG can significantly assist with carbon reduction goals.

Community Impact

The project is entirely offshore in NY. There is minimal impact to community land / space. There will be some onshore construction in New Jersey occurring on brownfield locations in Williams' existing footprint. Additionally, pipeline assets are not visible to the public, compared to many of the other potential supply options.

Permitting, Policy and Regulatory Requirements

The NESE project has already received FERC approval. Local county/town/village stakeholder concerns are also a key component of NEPA. The project currently has received approval in PA and is awaiting such approvals in NY and NJ where initial applications have been previously rejected.

Specifically, NY DEC rejected the project's water permit in the Spring of 2018 and Spring of 2019 based on concerns relating to water quality in the NY Harbor during construction. This permit has been resubmitted, with an expected decision scheduled for May 15, 2020.

Requirements for Implementation

Williams anticipates being able to complete this project as early as December 2021 if the environmental permits are approved in NY and NJ and the FERC approval process is completed by June 2020.

Summary

Table 23 below summarizes the assessment of the NESE Project option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 23: Summary of NESE Project Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Construction of pipeline infrastructure to expand transportation of natural gas from Pennsylvania to New York via New Jersey
Size	400 MDth/day	Baseload capacity – available year-round
Safety	◕	US Department of Transportation would review and enforce all necessary safety / security processes and protocols
Reliability	●	Pipelines have historically been very reliable and free from above-ground weather and man-made events
Cost	◕	Total project cost is estimated at $1B – annual fixed costs are $193M for the 15-year term of the contract with Williams
Environmental Impact	◑	The ecological impact from construction will be significant to the subsea environment, but ongoing operation will be less impactful than LNG terminals. GHG emissions will be 10-15% lower than LNG solutions, and lower than CNG trailers/trucking. Pipeline can transport RNG and hydrogen, enabling further GHG reductions.
Community Impact	◕	Low impact to the community – vast majority of construction is offshore – some onshore construction in NJ (brownfield sites)
Permitting, Policy and Regulatory Requirements	N/A	• Received FERC approval, but still requires state / local approvals (NY, NJ) – PA has already approved • NY DEC rejected water permits in Spring 2018 and 2019 – next review is May 15, 2020
Requirements for Implementation	N/A	• Once all approvals are attained, the project can be completed as early as December 2021

10.2 Distributed Infrastructure Options

10.2.1 Peak LNG Facility

Description

Adding fixed LNG peaking supply involves construction of a new LNG peak shaving plant and related infrastructure (e.g., tanks, structure, vaporization, liquefaction, etc.). The peak shaving plant would allow for liquefying gas during periods of higher temperatures and lower need, storing the excess supply, and vaporizing and injecting that supply for use during peak times (e.g., during colder temperatures when the base load supply cannot meet the required demand). Currently, there are two such facilities in the Downstate NY National Grid territory - our Greenpoint and Holtsville LNG plants - and this proposal is for a third. It is important to note that this project would require a change to or waiver of NY state Law 6 NYCCR 570 that limits land storage of natural gas.

Size

There has been no land area in Downstate NY considered for this project. Current NY law (6 NYCRR 570) states that no facility can store more than 70,000 gallons (approximately 6 MDth/day) of LNG on site. The plans for this option would potentially supply up to 100 MDth/day of supply. This law was recently reviewed in 2015 and upheld despite industry requests for expanding the storage levels allowed.

Safety

Construction and use of this new facility will require significant stakeholder involvement, specifically with local zoning boards as well as local fire departments similar to what is done for our Holtsville facility. Each LNG facility constructed after March 31, 2000 must comply with requirements of 49 CFR 193 subpart D and NFPA 59A, which states: a plant and site evaluation shall identify and analyze potential incidents that have a bearing on the safety of plant personnel and the surrounding public. The plant and site evaluation shall also identify safety and security measures incorporated in the design and operation of the plant considering the following: 1) Process hazard analysis, 2) Transportation activities that might impact the proposed plant, 3) Adjacent facility hazards, 4) Meteorological and geological conditions, and 5) Security threat and vulnerability analysis.

Reliability

LNG facilities are extremely reliable and in service across the country. National Grid has significant operations and maintenance experience with 12 facilities in service across the Massachusetts, Rhode Island, and Downstate NY areas.

Cost

The cost to construct and operate is dependent on the size and scale of this facility. A 1 BCF facility that can provide 100 MDth/day with liquefaction is estimated to cost $500M. Annual fixed cost for the facility is expected to be approximately $100M. Additional feasibility studies will need to be done to confirm and refine the total cost estimates.

Environmental Impact

Ecological Impact: Construction will result in moderate environmental impacts including decreased air quality, pollution to stormwater and other runoff, disruption to natural resources and habitats, noise, and waste generation. A peak LNG facility is a smaller local facility compared to an LNG import terminal or offshore LNG deepwater port and is thus expected to have smaller ecological impact during the construction phase.

Once operational there will be ongoing moderate impacts from the transportation of LNG, as LNG is delivered by vessel to an onshore facility and then trucked to the local site as needed. However, the impact will be minimal as the gasification at this facility will occur during peak days only, so limited supply will be required.

Climate Impact: The GHG emissions from a peak LNG facility would be lower overall than the other LNG options discussed, because as a peak facility the operation would be strictly limited to peak days or local operational needs only. When operational, it would have GHG emissions similar to the other LNG options and 10-15% higher than standard natural gas.

Community Impact

Community concerns would be high as a permanent facility would be sited in a community. Even when sited in industrial zones, significant community resistance is a common part of the siting process.

Permitting, Policy and Regulatory Requirements

The plant would be sited in New York for New York customers; as such, all regulatory decisions would be state jurisdictional. The construction of this facility would require a change to current New York law (e.g., 6 NYCRR 570). All permits will likely include NY PSC, NY SEQRA, NYSDEC, and NYC DOB and FDNY if in within NYC.

Requirements for Implementation

To construct this facility, there would need to be regulatory changes as discussed above. Additionally, feasibility studies and site selection would need to occur. Assuming changes or a waiver from current NY Law (6 NYCCR 570), it is estimated a new site would be operational in 5-6 years.

Summary

Table 24 below summarizes the assessment of the option to utilize a Peak LNG Facility as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 24: Summary of Peak LNG Facility Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Construction of an LNG peak shaving plant – to liquefy off peak gas, store it, and regasify for use during peak times
Size	100 MDth/day	Designed to meet periods of peak demand. Requires changes or a waiver from current NY Law (6 NYCCR 570) which restricts size.
Safety	◕	The LNG facility must comply with requirements of DOT 49 CFR 193 subpart D and NFPA 59A.
Reliability	◕	LNG facilities have historically been very reliable – National Grid has extensive experience in this area
Cost	◑	Total project cost for a 1 BCF facility is approx. $500M – annual fixed costs are approx. $100M
Environmental Impact	◑	The ecological impact from construction will be less significant than the Large Infrastructure solutions due to a smaller footprint. The GHG emissions from an LNG system is 10-15% higher than a natural gas solution, but will only occur during peak periods of demand.
Community Impact	◑	Potential high impact to Downstate NY community – significant construction/operation and siting. Project would be smaller than an LNG Import Terminal or LNG Port.
Permitting, Policy and Regulatory Requirements	N/A	• Requires specific state / local approvals – and requires a change / waive to existing NY law (6 NYCCR 570) • Permits: NY PSC, NY SEQRA, NYC DOB, and FDNY
Requirements for Implementation	N/A	• Would require a change to or waiver of NY law [6 CRR NY 570] • If approved, total timeline estimated at 5-6 years

10.2.2 LNG Barges

Description

The LNG Barge option would include the purchase and construction of one (or more) specialty LNG Barge(s). When vaporization equipment is integrated into the design, these are referred to as Floating Storage and Regassification Barges (FSRB). FSRBs are further categorized as either tow barges where a tugboat tows the vessel or an Articulated Tug/Barge Unit (ATB) where the tugboat connects with pinions to a notch in the FSRB stern. There are a few potential locations to place these barges where a combination of water access, pier capacity, and gas system takeaway are favorable. The potential sites include some National Grid Generating assets that have high pressure gas laterals serving gas turbine peakers such as Glenwood Landing, Port Jefferson, Northport and Shoreham. Utilizing an FSRB is a new concept for the U.S. market; however, one such barge was delivered in 2018 and is currently transporting LNG from the U.S. gulf to Puerto Rico to "bunker" or fuel ships. Two other barges are in construction in U.S. shipyards. New York could model the solution based on these projects.

The limiting factor to this market has been the US Jones Act Law (1920) that requires coastwise trade to be on ships or vessels built in the U.S., owned by U.S. companies (i.e. US Flagged) and operated by U.S. crew. Since all worldwide LNG trade is on non-Jones Act ships, LNG cannot be legally moved from one U.S. port to another without an emergency waiver as is used during national emergencies. To date, the market for U.S. owned/operated barges is small, but this is changing as the U.S. industry continues to grow. For Downstate NY, a compliant Jones Act barge is needed. There are three potential types of U.S. sources of LNG under consideration: 1) US or Canadian east coast terminals such as Cove Point, MD and Elba Island, GA, 2) from a passing LNG tanker at sea, or 3) by LNG truck. Additionally, as an emerging alternative, new LNG by rail terminals are being proposed in the NJ/PA region.

Size

National Grid is reviewing barges which can each provide up to 50 MDth/day. If two barges were deployed in tandem the total supply would be up to 100 MDth/day. These barges would be utilized for peaking capacity. Limitations include size of pier facilities and water depth near shore.

Safety

US Coast Guard (USCG) and US Maritime Administration (MARAD) will conduct a security / safety review as part of the federal permitting process. A process safety approach will be used to identify, quantify and manage risks by these agencies. Once in operation, the FSRB will be subject to a specifically designed USCG Security Zone per 33 CFR Part 165 Subpart D. Furthermore, the USCG manages a rigorous barge inspection and regulation program codified by US safety codes under 33 CFR Section 83. This includes mandates to inspect barges on an annual basis for material condition, safety functions, operations, security programs, and crew training.

Reliability

Assuming availability, these types of barges could be moored together to increase capacity and enhance reliability and contingency. These barges could also be strategically placed in multiple locations assuming permit success. The integrated systems on the FSRB are very similar to those used by LNG Operations at Greenpoint and Holtsville LNG plants. From a supply standpoint, barged LNG provides a near coast supply without the climate risks associated with Hurricane Sandy-type events. With advanced notice of a storm, the FSRB can be easily transported away from shore and returned to supply gas immediately after the storm without the risk of damage to the FSRB. In some respects, an FSRB offers more reliability than a coastal facility.

Cost

Based on preliminary estimates and discussions with industry experts, the total cost for deploying one barge system is ~$210M. Assumptions include a US-built barge approximate cost of $50M, interconnecting facilities and pier construction approximate cost of $100-150M depending on site, and upgrades to the current shoreside gas system of $10M. Further refinement of the costs is dependent on the final site and size/capacity of the barge. We are currently reviewing the feasibility of multiple sites. For two barges, the total cost would be approximately $410M if both barges feed into the same port (there would only be one charge for shoreside piping upgrades).

Environmental Impact

Ecological Impact: The ecological impacts of the LNG barges would be similar to the offshore LNG port solution but at a smaller scale. Instead of constructing a buoy and lateral at sea, the only construction that would be required is a new pier and short pipeline connection to a shore connection point, assuming the existing pier facilities are incompatible. The resulting facility will be smaller than an onshore terminal and will have flexibility in the siting because it is served by barges.

The construction would still result in impacts including decreased water quality and sediment introduced into the marine environment, decreased air quality, increased stormwater / runoff, noise, and waste generation. These impacts would be mitigated by control measures during construction.

Once operational, there would be limited impacts from the transport of LNG by barges. While these vessels would disrupt ecological habitat, most of their operation would occur in well-used marine space.

Climate Impact: The GHG emissions from an LNG Barge would be similar to a peak LNG facility. This would also be lower than the other LNG options discussed, because as a peak facility the operation would be limited to peak days or local operational needs only. When operating, GHG emissions would be like other LNG solutions, and 10-15% higher than standard natural gas. Like the LNG deepwater port, an LNG barge network could support longer-term decarbonization of the natural gas network, as the barges could be used to transport liquid hydrogen in the future.

Community Impact

Since the barge would need to be docked close to the shore, there would be visual impacts to water views during the winter. Additionally, there may be potential loss of waterside recreation use in immediate area due to the size of the barge system and the security perimeter developed during the siting process.

Permitting, Policy and Regulatory Requirements

Permitting the barge would be similar to the other LNG options discussed above. It is believed that there will likely be a strong market for a US built barge system if there comes a time when New York no longer needs this capacity. If sold, the proceeds from the barge could benefit the customers of New York. Permits will likely include USFWS, USACE, NY SEQRA, NYSDEC.

Requirements for Implementation

Currently, the total lead time for delivery is approximately two years. Additionally, dock facilities and interconnecting gas systems may require FERC EA or EIS, which would take approximately 3-4 years to go through the permitting process. Pier construction and barges could be completed in parallel. Total estimated implementation timeline is 5-6 years.

Summary

Table 25 below summarizes the assessment of the option to use LNG Barges as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 25: Summary of LNG Barges Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Purchase / construction of near-shore LNG barges to provide natural gas supply during peak demand
Size	100 MDth/day	Two barges in tandem could provide up to 100 MDth/day of peaking capacity
Safety	◕	US Coast Guard to conduct and maintain a rigorous security / safety review and inspection program
Reliability	◕	Barges are a reliable source of supply – can be moved in the event of large weather events to avoid risk of damage
Cost	◕	Total cost per barge is estimated at $210M ($50M for construction, $150M for interconnecting facilities, $10M for shoreside piping). Assuming two barges, total cost is estimated at $410M (do not need to replicate shoreside piping)
Environmental Impact	◑	The ecological impact from construction would be like an offshore LNG port but at a smaller scale. GHG emissions from an LNG system are 10-15% higher than what would be expected for a pipeline solution, but will only occur during peak periods of demand.
Community Impact	◑	The barge(s) would be visible from shore during the winter months – this would also impact any waterside recreation. The project would be smaller than an LNG Terminal or LNG Port
Permitting, Policy and Regulatory Requirements	N/A	• Permits would likely include USFWS, USACE, NY PSC, NY SEQRA, NYS DEC
Requirements for Implementation	N/A	• Limited by the US Jones Act (1920) • If approved, total timeline would be 5-6 years

10.2.3 Clove Lakes Transmission Loop Project

Description

The Clove Lakes Transmission Loop Project would consist of the construction of approximately 8 miles of new 30-inch steel transmission main across the borough of Staten Island to facilitate National Grid's ability to take more gas through the TETCO Goethals Take Station and ultimately move this gas across National Grid's system to supply constrained areas.

The Clove Lakes Transmission Loop would essentially remove a "bottleneck" and enable more gas to flow to the National Grid system, without requiring an upstream pipeline. Currently, our natural gas supply from the Goethals delivery point across Staten Island is limited by the capacity of the existing gas main that runs from Goethals to Brooklyn. By completing the Cloves Lakes project, we would add additional capacity to deliver supply to our NYC territory. The project can be likened to adding an additional lane to a roadway - it adds additional capacity to move gas.

Size

It is estimated that the Clove Lakes Transmission Main would bring incremental Design Day capacity of approximately 80 MDth/day (potential range of 70-100 MDth/day) and would support annual volume as it would be used year-round.

Safety

A detailed feasibility study and engineering analysis would be conducted prior to progressing this project to development and construction. If feasible, construction of this project would involve installation of new gas main across sections of a heavily populated urban environment and would possibly impact multiple highways and/or small water crossings during installation. Plans would be developed to ensure its safe installation with minimal impact to workers and the surrounding community.

Pipelines are historically a very safe method of transporting natural gas. National Grid follows and will continue to follow best practice in process safety and operational safety methods in the design, installation and operation of all its pipeline assets. Once installed, National Grid will actively patrol, monitor, and control the assets to minimize the potential for incidents.

Reliability

Historically, underground pipelines have been extremely reliable. Above ground weather events (e.g., blizzards, hurricanes, etc.) and man-made events (e.g., traffic, automobile accidents, etc.) would not impact availability of the natural gas supply through this line.

Cost

Initial estimates for the cost of bringing the Transmission Main online are $320M, which includes the following components: engineering design and development, material, permits, and construction labor. Additionally, it is estimated that a yearly fixed demand charge of approximately $48M is required to procure additional natural gas. This demand charge does not include the commodity cost of natural gas.

Environmental Impact

Ecological Impact: As the Clove Lake Transmission Loop project will connect existing points that are constrained on the system, bypassing the existing constrained infrastructure, most ecological impacts will be related to construction. These impacts will be limited compared to interstate pipelines as most of the construction will occur in areas that are already developed. Once operational, the ecological impacts will be minor as little ongoing maintenance will be required.

Climate Impact: The GHG emissions associated with the development of this project will be minimal and comparable to similar gas mains in the current distribution system. Once operational, natural gas through the new main will have lower emissions than LNG options or CNG trailers/trucking.

Community Impact

The project would consist of installation of new gas main across sections of a heavily populated urban environment and possibly impact multiple highways and/or small water crossings during installation. Mitigation plans would need to be developed to minimize disruption to residents, businesses and traffic as is typically created during utility below grade construction.

Permitting, Policy and Regulatory Requirements

The project would require NYC DOT and NYC DOB approval for construction within NYC. Permitting also includes, but is not limited to, all federal, state and local NYC (e.g., NYC DEP and NYS DEC) environmental permit requirements.

Requirements for Implementation

National Grid has requested funding to conduct feasibility and engineering studies to provide a more detailed cost and timing estimate, and to better understand the details regarding feasibility of construction. Initial estimates indicate that the transmission main could be in service by November of 2025, at the earliest. Total timeline for implementation could take 5+ years.

Summary

Table 26 below summarizes the assessment of the Clove Lakes Transmission Loop option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 26: Summary of Clove Lakes Transmission Loop Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Construction of new transmission main across the borough of Staten Island to increase Downstate NY gas supply
Size	80 MDth/day	This option would add incremental supply to the Downstate NY baseload and would support daily demand
Safety	◕	A detailed feasibility study should be conducted to identify safety / security risks associated with urban construction
Reliability	●	Pipelines have historically been very reliable and free from above-ground weather and man-made events
Cost	◔	Cost for engineering design and development, material, permits, and construction labor is estimated at $320M. Additionally, there is an annual demand charge of $48M.
Environmental Impact	◑	The ecological impact from construction will be relatively small, as this project is occurring in areas that have already been developed. Ongoing operations will have very small ecological impact. The GHG emissions will be comparable to similar gas mains in the current distribution system, and less than LNG options or CNG trailers/trucking.
Community Impact	◔	Construction would involve installation of new gas main in heavily populated areas - potentially impacting highways, water crossings, etc. for a period of time
Permitting, Policy and Regulatory Requirements	N/A	Would require NYC DOT and NYC DOB approval for construction within NYC. Permitting also includes, but is not limited to all federal, state and local NYC (e.g., NY DEP and NYS DEC) environmental permit requirements.
Requirements for Implementation	N/A	National Grid has requesting funding to conduct a detailed feasibility and engineering study to assess requirements for implementation and overall timeline – total timeline could take 5+ years

10.2.4 Iroquois Enhancement by Compression ("ExC") Project

Description

The ExC Project option involves construction of additional compression facilities to increase capacity on the Iroquois Gas Transmission System's (IGTS) existing infrastructure, to transport natural gas from the U.S./Canadian border at Waddington, NY through the existing Iroquois system located in New York and Connecticut to the existing interconnection with National Grid's gas distribution system at South Commack, NY. The 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.

Size

ExC will provide a total additional 125 MDth/day of supply which will be split evenly by National Grid and Con Edison. National Grid will receive 62.5 MDth/day of natural gas to the baseload capacity. The project would 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.

Safety

To date, the IGTS has a long-standing excellent safety record. The proposed facilities will be designed, built and operated in a safe and environmentally responsible manner.

All phases of construction and operation are monitored by various government agencies such as the Department of Transportation, the Connecticut Department of Public Utility Control and the New York Department of Public Service. As part of Iroquois' ongoing Public Awareness Education Program, collaboration and training with local emergency responders will be maintained. During operation, safety inspectors will monitor the sites and security personnel will be onsite, as required.

Reliability

Historically, natural gas supplied by pipelines similar to ExC have been very reliable. Above ground weather events (e.g., blizzards, hurricanes, etc.) and man-made events (e.g., traffic, automobile accidents, etc.) would not impact availability of the natural gas supply.

Cost

The projected capital cost is approximately $272 million. This figure reflects the total cost to provide 125 MDth/day, which will be split evenly by National Grid and Con Edison. Additionally, an annual recourse demand charge of approximately $24.7M is expected - which equates to a unit rate of $1.06 per Dth. The recourse charge is a demand charge and does not include the commodity cost of additional natural gas.

Environmental Impact

Ecological Impact: Construction of the compressor station will have moderate ecological impact. As this compressor station will be constructed on an existing line the ecological impact will be focused on locations that are already developed. The ExC Project will be subject to an extensive environmental review as part of the regulatory process. Iroquois will collect and analyze site-specific environmental information to understand potential impacts, develop mitigation plans, and prepare environmental reports for review by the FERC and other permitting agencies. Construction will not commence until these agencies are satisfied that the ExC Project can be constructed without significant impacts to the environment.

In addition, as part of the ExC Project, Iroquois plans to further reduce methane and overall emissions at project sites. Iroquois is proposing to install low Nitrogen Oxide (NOx) turbine units which will reduce NOx emissions by 40% over standard turbine units, as well as adding oxidation catalysts on the newly installed turbines which will reduce Carbon Monoxide (CO) emissions by approximately 90%.

Climate Impact: Potential GHG emissions are related to the operation of compressors and potential leakage at these sites. However, at each project site, Iroquois is proposing to install methane recovery systems to capture released natural gas from station operations and thereby reduce methane emissions.

To more fully assess the environmental impacts, National Grid is supporting M.J. Bradley & Associates to perform a study on greenhouse gas (GHG) impacts with and without the ExC project.

Community Impact

ExC will be completed entirely within the IGTS existing footprint. All facilities will be constructed entirely within Iroquois' existing compressor station properties. No new pipeline is proposed as part of this project. Additionally, these assets are not visible to the public, unlike many other supply options.

Permitting, Policy and Regulatory Requirements

Iroquois will be required to comply with the regulations of the Federal Energy Regulatory Commission (FERC) and other appropriate federal, state and local agencies (e.g., air permits for new compression at existing sites in NY and CT). The ExC Project filed a formal application with the FERC in February 2020 and is expecting a decision on approval by early 2021.

FERC, as lead federal agency, will assess the project from an environmental standpoint and will issue a determination of whether the proposed project is within the public convenience and necessity.

Requirements for Implementation

Assuming timely receipt of required permits and other authorizations, the ExC project is expected to be in-service by November 2023.

Summary

Table 27 below summarizes the assessment of the option to use Gas Compression on the IGTS as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 27: Summary of Gas Compression on the IGTS Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Construction of additional compression facilities to facilitate transport of gas through the existing IGTS
Size	63 MDth/day	National Grid to evenly split 125 MDth/day with Con Edison. This volume would be available to baseload capacity.
Safety	◕	US Department of Transportation and state entities to review and enforce all necessary safety processes and protocols
Reliability	●	Pipelines have historically been very reliable and free from above-ground weather and man-made events
Cost	●	The projected capital cost of the total project is estimated at $272M for 125 MDth/day. National Grid portion is $136M for 62.5 MDth/day, with a $24.7M annual recourse demand charge
Environmental Impact	◑	The ecological impact from construction will be moderate, focused on locations that are already developed. Iroquois is proposing installing methane recovery systems to capture released natural gas and reduce NOx and CO emissions.
Community Impact	◕	Low impact to the community – all planned facilities are within existing Iroquois footprint; no new pipelines needed
Permitting, Policy and Regulatory Requirements	N/A	• Must comply with FERC and other appropriate federal, state and local agencies • Formal application has been filed with FERC in February 2020
Requirements for Implementation	N/A	• Assuming all approvals are attained on a timely basis, the project can be in-service by November 2023 (~3 years)

10.3 No-Infrastructure Options

10.3.1 Methodology and Assumptions for No-Infrastructure Solutions

There are three major elements that compose the no-infrastructure option: Energy Efficiency (EE), Demand Response (DR) and electrification. Incremental EE programs will expand upon and accelerate the efforts included within base and NENY targets and include programs and measures that would not necessarily have achieved cost-effectiveness standards unless they were part of an approach to drive more aggressive natural gas savings. A major focus of these incremental EE initiatives will be intensive weatherization programs, focused on Design Day thermal savings. Similarly, the DR program will build on efforts identified as part of the Downstate NY projected demand and will include new programs that target incremental Design Day gas savings. In addition, KEDNY and KEDLI (along with Con Edison, PSEG Long Island and NYSERDA) will target electrification incentives to existing natural gas customers or oil heating customers who are within 100 feet of gas main. These are customers that might otherwise switch to gas heating when they are replacing or upgrading their systems. These efforts will enable reductions in the forecasted Design Day gas demand. Each element is further described in the sections that follow.

10.3.2 Incremental Energy Efficiency

Description

KEDNY and KEDLI will build upon and expand the base and incremental NENY EE programs with a more aggressive program offering that reduces annual energy consumption and Design Day demand. The nature of this initiative will emphasize robust and aggressive natural gas efficiency savings, with a key focus on a set of intensive weatherization measures. The incremental program will also implement efficiency upgrades of heating, hot water systems, and many other efficiency opportunities.

The magnitude of the gap between Design Day demand and natural gas supply in the near- and medium-term will require extensive customer and trade ally engagement and training, door-to-door neighborhood campaigns, and customer concierge and financial and contractor coordination services to help facilitate whole house and commercial facility intensive weatherization measures such as air-sealing and maximized insulation. These measures save energy regardless of whether the customer's heating fuel is natural gas or whether they are converting to electric heat.

The intensive weatherization approach is patterned after the Deep Energy Retrofit pilot deployed by National Grid in Massachusetts and Rhode Island about 10 years ago. That pilot featured maximizing building shell weatherization (ceiling and wall insulation, air sealing) and heating equipment upgrades.[14] It is also similar to the weatherization education approach being piloted by NYSERDA in its Comfort Home program. These measures would be the core elements of what will be necessary for Downstate New York to drive the highest level of Design Day energy savings possible.

Size

The intensive weatherization and more robust efficiency program would include all Downstate NY customers, and prioritized to gas heating customers. National Grid has approximately 1.1 million residential heating customers; 23,000 multi-family customers; and 112,000 commercial customers within the region.

Table 28: Existing Downstate NY Gas Heating Customers (January, 2020)

Customer Segment with Gas Heating	KEDNY	KEDLI	Downstate NY
Residential Heating Customers	630,000	460,000	1,090,000
Multi-family Customers	21,000	2,000	23,000
Commercial & Industrial Customers	52,000	60,000	112,000

New York State and New York City have enacted laws to reduce building sector emissions. In the years ahead, these buildings will need to reduce their energy use significantly. This program would accelerate the adoption of intensive weatherization measures for natural gas heating customers, to target significant space heating savings for participating customers.

Assuming the programs achieve approximately 20% Design Day savings, and that there are roughly 30% adoption rates by 2035, the impact on Design Day demand could be as much as 216 MDth/day.[15] To meet the near-term supply gap and get to this level by 2035, the program will need

[14] "Building America Case Study Whole-House Solutions for Existing Homes: National Grid Deep Energy Retrofit Pilot," U.S. Department of Energy, March 2014 https://www.nrel.gov/docs/fy14osti/61172.pdf.
[15] Based on the forecasted High Demand scenario, which has Design Day demand in 2035 of roughly 2,000 MDth for Residential Heat, 680 MDth for Multi-family, and 700 MDth for Commercial & Industrial.

to ramp up to 40 MDth/day impact by 2024/25 and 142 MDth/day impact by 2029/30. This will require aggressive development of a network of building contractors, building supply companies, financing partners, and marketing firms to engage and encourage customers to adopt these measures.

To achieve the incremental demand reduction described above, Downstate NY would have to increase its level of EE achievement from 0.4% of gas sales today, to 1.3% of sales by 2025. This would be a level comparable to Rhode Island and Massachusetts, and significantly higher than Connecticut and New Jersey, despite Downstate NY having 16-28% less heating degree days than all these states and thus being more challenged to derive high percentage benefits from EE programs such as weatherization. Table 29 below shows how this level of EE achievement compares to other states in the area.

Table 29: A Comparison of Energy Efficiency (EE) Achievement Relative to Annual Heating Needs (2017 actual unless otherwise noted)

State/Location	EE as a % of Annual Gas Sales	Annual Heating Needs ('000 heating degree days)
Rhode Island	1.6%	5.6
Massachusetts	1.3%	6.0
Connecticut	0.7%	5.8
Downstate NY		4.3
- **Estimated 2019**	0.4%	
- **NENY 2025**	0.8%	
- **Incremental EE Under No Infrastructure 2025**	1.3%	
New Jersey	0.2%	5.1

Note: Massachusetts 2019-2021 is also projected at 1.3%

Source: American Council for an Energy Efficient Economy (ACEEE); National Oceanic and Atmospheric Administration (NOAA), National Grid analysis

Safety

Like any customer service offering, safety is increased with proper participant and trade ally education, awareness, and training. Only contractors licensed by the State of New York can install equipment or provide services offered through the EE programs. Downstate NY will need to expand the existing trade ally network and include extensive trade ally training. In addition, as part of intensive weatherization projects, it will be important to develop safety and quality control procedures and review a statistically valid sample of projects to ensure safety and quality standards are being met.

Reliability

The intensive weatherization program will lead to passive energy and Design Day savings. Like other EE programs, KEDNY and KEDLI will need to verify measures are installed and savings are achieved. In addition, information from evaluation, measurement, and verification (EM&V) efforts will inform changes to program design to tailor the selection of which measures are installed and the targeted number of homes and buildings in Downstate NY to realize the targeted design day savings[16].

[16] The EM&V will need to consider each customer as savings may not be readily apparent in aggregated company statistics because of weather variability or the initial scale of the program compared to the entire customer population. With quality EM&V, annual and peak day savings estimates can be adjusted periodically, providing stakeholders with a high confidence in the reliability of the efficiency measures.

A key challenge for achieving the targeted savings will be the ability of KEDNY and KEDLI to ramp up quickly and start realizing impact by the winter of 2021/22. This will require efforts to start as soon as possible to design, market, and rapidly expand programs.

The number of customers who agree to participate in EE programs, and/or the impact of these programs on those who do participate, may not meet projections. This creates risk of not achieving the full projected potential on peak days. Reliability could improve over time as programs mature.

Cost

The program will require funding to incentivize the intensive efficiency and weatherization measures (the utility may reimburse 50+% of the measure cost), expand the contractor network, and ensure a robust EM&V effort is deployed. It is estimated that EE costs will increase to $9.30-$9.60 per therm on average across customer segments. To achieve the maximum projected level of participation across all customer segments, the program funding amounts ramp quickly to $100+ million per year by 2022 and increase to $240 million per year by 2027, with total investment by 2035 of $1.1B-$2.4B. Note that this is in addition to the existing base and incremental NENY energy efficiency program budgets for Downstate NY.

Environmental Impact

Ecological Impact: The ecological impact of the energy efficiency program will be minimal, as work will only be completed on existing structures. The program will not result in new potential for risk that may harm the environment; in fact, it may reduce risks as new equipment replaces existing, and as efficiency improves the health, comfort and safety of buildings. Materials selected for the efficiency and weatherization activities will be compliant with all state and local environmental regulations and contractor training will include environmental considerations.

Climate Impact: As the primary goal of an intensive EE program is to reduce energy use, the direct result will be GHG emissions reduction through less gas consumption. GHG emissions will be reduced further through electricity savings. The goals of the EE program are in direct alignment with larger state-wide decarbonization efforts and regardless of source, energy demand will need to be reduced to meet mid-century decarbonization targets.

Community Impact

The intensive incremental efficiency and weatherization effort will further develop the ecosystem that includes a wide range of contractors and suppliers who will need to hire additional employees to support the spending over the duration of the program. A significant portion of these investments will go directly into the downstate economy. In addition, bill savings from the energy efficiency measures will allow consumers to spend some portion of this savings within the local economy.

Permitting, Policy and Regulatory Requirements

National Grid will require NY PSC approval for the enhanced efficiency and weatherization programs, incentives and total investments before these can commence. Once approved and implemented, KEDNY and KEDLI will need to provide updated cost and benefit estimates for the magnitude of these programs to the NY PSC as part of future regulatory reporting and approval processes.

The magnitude of the energy efficiency program envisioned will impact permitting, policy, and regulatory activities at the local and state level. At the local level, contractors will be responsible for obtaining local permits for the retrofits of homes and businesses. Local permitting authorities will need to prepare for the increased volume of permit applications to address the weatherization efforts. Work will be required to streamline these application and approval processes to achieve program targets.

Requirements for Implementation

Because of the size of the near-term gap between natural gas demand and available supply, the implementation of an incremental EE program will require a significant increase in the level of effort across the entire energy efficiency network. For reference, the EE program would have to scale by 2025 to become similar in size to the current program in MA. There will need to be growth in the number of qualified contractors for the design and installation of the measures, staff in local permitting offices, and increases in the number of program staff at KEDNY and KEDLI. There will also be a need for more investment in marketing, education and training as these new programs are launched and efforts are accelerated to increase adoption.

In addition, there will need to be a high level of coordination of agencies and utilities to manage program design and implementation in the most effective manner possible. For example, New York State and local governments should consider approaches that focus attention on building energy efficiency through home energy ratings, further updating of building codes, and implementation of effective mechanisms for landlords of multifamily buildings to encourage comprehensive weatherization of all units in a building. National Grid will also coordinate with its existing programs, NYSERDA's pilots and income-qualified programs, and electric utilities' efficiency programs.

Summary

Table 30 below summarizes the assessment of the incremental Energy Efficiency option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 30: Summary of Incremental Energy Efficiency Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Intensive efficiency and weatherization programs are rapidly established for Downstate NY and grow to offset otherwise increasing forecasted Design Day demand.
Size	111 - 216 MDth/day	Success will require: • An incremental 20,000 – 40,000 customers per year starting in 2021 to complete energy efficiency programs (50% annual increase vs. current baseline plus NENY) • Program to ramp by 2025 to become similar in size to current program in MA (1.3% of sales), despite Downstate NY having significantly less heating degree days
Safety	●	Only licensed contractors will be able to participate in the program and KEDNY and KEDLI will administer training programs for the EE efforts
Reliability	◔	Design Day savings will be certain once implemented as intensive weatherization measures are passive and have a >15-year measure life; however, National Grid and Downstate NY's ability to aggressively scale the programs to the level and size required poses significant challenge and uncertainty. Reliability could improve over time as programs mature.
Cost	◔	Investment totals estimated at $1.1B - $2.4B through 2035
Environmental Impact	●	There will be significant reductions in GHG emissions from weatherization and other EE measures
Community Impact	●	Investments in EE will create jobs in Downstate NY and local spending
Permitting, Policy and Regulatory Requirements	N/A	Requires alignment of state and local policies and regulatory outcomes across multiple areas.
Requirements for Implementation	N/A	To support the deployment of these programs, the ecosystem of licensed contractors and vendors would need to significantly increase.

10.3.3 Demand Response

Description

Compared to the other non-infrastructure options, natural gas Demand Response (DR) is more cost effective and can be ramped up more quickly, as DR will typically leverage existing equipment at customer premises. This option encompasses two types of programs – 1) DR for commercial customers and multi-family buildings, and 2) thermostat direct load control programs for residential heating customers. The limitation in expanding these programs is related to the overall number of potential customers available to participate, and the challenges that multi-family and commercial customers have of maintaining a backup source of heat - typically fuel oil – for use in Temperature Control (TC) or non-firm programs.

There is already a program in place for some C&I and large multi-family buildings on non-firm rates. However, the number of customers on these rates is declining, as many of these customers switch to firm gas rate programs. Stemming or halting this decline would create a significant Design Day savings that could be sustained in the future. This would require new rate design programs that encourage these customers to remain on non-firm rate programs and maintain their alternate fuel source heating systems.

In parallel, thermostat setback programs can be used to reduce thermostat set points to reduce consumption of residential heating customers on peak load days. With available incentives in New York, the adoption of connected thermostats continues to grow. An incremental program would augment those incentives with an enrollment incentive and participation incentive, based on performance when called upon during peak usage events.

Size

There are currently about 2,400 large C&I and MF customers on non-firm rates in Downstate NY. These customers represent 130-140 MDth of Design Day savings. As these customers consider switching to firm rates, an incremental program would establish incentives or other mechanisms that encourage these customers to remain on non-firm rates.

Today, approximately 10% of residential customers have connected thermostats and the penetration of this technology is expected to continue to grow as the technology is incentivized by programs to somewhere between 30% to 50% of the total residential customers. National Grid has successfully demonstrated that thermostat direct load control programs can reduce peak summer electricity demand for air conditioning. We conservatively estimate a winter DR program could achieve a 2% load reduction on the Design Day, leading to additional savings in 2035 of around 13 MDth/day.

In total, it is estimated that the programs described above can generate Design Day demand reduction of 81 – 108 MDth.

Safety

For the non-firm rate customers, the main safety concern is in relying on fuel oil for heating on peak days. This requires having a minimum of a10-day supply of fuel oil on-site, and potentially for risks associated with transportation of fuel oil on peak days in the event of prolonged cold spells.

For the residential customers participating in the direct load control program, there are not expected to be any significant safety issues. National Grid has successfully worked with its partners to administer summer DR programs and winter Temperature Control programs.

Reliability

Customers on non-firm rates must sign affidavits that they have 10 days of alternative available fuel to participate in the C&I and multifamily program. As LL97 and other constraints encourage a transition to natural gas away from fuel oil as a secondary option, National Grid can provide incentives or support the procurement of alternative fuels, such as biofuels, to ensure the non-firm customers have the necessary reserves and can achieve broader environmental objectives.

Demand response can be an attractive way to reduce peak day consumption, given that non-firm rates are already offered, and thermostat setback programs have been performed by National Grid for years. However, in both cases customers can override the event and use gas, and the number of customers who agree to participate can fluctuate or not meet projections. Therefore, there is risk of not achieving the full projected potential on peak days. Reliability could improve over time as programs mature.

Cost

DR programs would have relatively low costs for reducing forecasted Design Day therms. For both types of demand response programs, the costs would be annual implementation and evaluation costs as well as performance incentives. For the TC (non-firm) customers these would likely be in the form of lower rates, which is an attractive benefit.

In addition to program costs, TC customers incur the cost of maintaining alternate fuel systems that they can call upon when the temperature drops and they switch from natural gas.

Total incremental DR program investment is estimated at $164M - $364M through 2035.

Environmental Impact

Ecological Impact: The demand response program will have little or no ecological impact, as little new equipment will be installed and the program only reflects a behavior change for existing customers.

Climate Impact: Implementing a demand response program will have a limited climate impact – it will reduce energy use during peak periods, but some of this displaced energy use will swing to non-peak periods.

For TC customers, switching from natural gas to fuel oil on peak days for C&I and multifamily customers results in higher GHG emissions. In the future fuel oil could be transitioned to renewable fuels, such as biofuels, which would help reduce environmental impact.

Community Impact

The community impact is limited for the demand response programs. As TC customers are largely multi-family, it is important that these customers have adequate available alternative fuel supplies and functioning equipment for when they need to switch away from natural gas.

Permitting, Policy and Regulatory Requirements

At the state level, KEDNY and KEDLI will provide updated cost and benefit estimates for the magnitude of these programs to the NY PSC as part of a future regulatory approval process.

Requirements for Implementation

Temperature Control (TC) and interruptible (IT) customers were migrated to non-firm service classes which were recently established. Resolution of the ongoing rate cases will establish rate discounts for customers in this service class, as discussed in Section 5 and considered in the High and Low demand scenarios. Incremental programs as discussed above will need to be reviewed and approved.

Thermostat setback programs of the size contemplated will require continued aggressive adoption of smart thermostats by residential customers.

Summary

Table 31 below summarizes the assessment of the incremental Demand Response option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 31: Summary of Incremental Demand Response Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Demand response programs are rapidly established for Downstate NY and grow to offset otherwise increasing forecasted Design Day demand.
Size	81 - 108 MDth/day	Success will require: • All Temperature Controlled customers will be retained (vs. current trend of 140/year moving to firm service) • Incremental Demand Response will reach roughly half of all residential customers in the next five years
Safety	◕	For TC (non-firm) customers, the main safety concern is relying on fuel oil for heating on peak days. This requires having a 10-day supply of fuel oil on-site, and has risks associated with transportation of fuel oil in the event of prolonged cold spells. For residential customers in the direct load control program, there are not expected to be any significant safety issues.
Reliability	◔	If the targeted number of customers do not enroll in the program, there is risk to falling short of projected impact. Also, in both non-firm rates and thermostat setback programs, customers can override the event and use gas. This also creates risk of not achieving the full potential on peak days. Reliability could improve over time as programs mature.
Cost	●	Demand Response is attractive from a cost perspective. Annual program costs and customer incentives in total are less expensive on a $/therm basis of Design Day demand reduction than other options. Total investment through 2035 estimated at $164 - $364M.
Environmental Impact	◕	Thermostat setback programs can result in reduced emissions. Other DR programs will have limited impact – they will reduce energy use during peak periods, but some of this displaced energy use will swing to non-peak periods. For TC customers, switching from natural gas to fuel oil on peak days results in higher GHG emissions.
Community Impact	◕	The community impact is limited for DR programs. As TC customers are largely multi-family, it is important they have adequate available alternative fuel supplies and functioning equipment when they need to switch from natural gas.
Permitting, Policy and Regulatory Requirements	N/A	Requires alignment of state and local policies and regulatory outcomes across multiple areas.
Requirements for Implementation	N/A	Resolution of the ongoing rate cases will establish rate discounts for TC and interruptible (IT) customers. Thermostat setback programs of the size contemplated will require continued aggressive adoption of smart thermostats by residential customers.

10.3.4 Electrification

Description

Another opportunity for reducing Design Day natural gas consumption is by converting customers' space heating energy source from natural gas to electricity. This could be achieved using cold-climate heat pumps, which operate efficiently even at low outdoor temperatures. If they are sized correctly, these cold-climate heat pumps may be installed and operated without a fossil fuel backup heating system in residential, commercial, and multi-family properties. Advances in technology over the past decade have led to the development and successful implementation of cold climate heat pumps across the United States, even in climates that are colder than Downstate NY, such as Maine. For this initiative, KEDLI/KEDNY (working in conjunction as appropriate with NYSERDA and the Downstate NY electric utilities) will provide incremental incentives and coordinate customer and trade ally awareness, education, marketing, and promotion of cold climate heat pumps focused on our current customers and those customers within 100 feet of the gas main, who might otherwise consider switching to gas for heating.

Size

Electrification can be an option for all Downstate NY customers, although typically only those that are within 100 feet of the gas main would be considered as customers that are substituting away from switching to gas – those that are more than 100 feet from the gas main are not generally considered for oil to gas conversions. National Grid assumes that once a customer switches from natural gas to electric, 100% of the customer's Design Day demand will be reduced. Assuming a robust incentive program, incremental electrification can yield a range of 52 - 86 MDth/day of Design Day demand reduction.

Safety

Like any customer service offering, safety is increased with proper participant and trade ally education, awareness, and training. Only contractors licensed by the State of New York can install equipment or provide services offered through the electrification program. Downstate NY will need to expand the existing trade ally network and include extensive trade ally training. In addition, as part of incremental electrification, it will be important to develop safety and quality control procedures and review a statistically valid sample of projects to ensure safety and quality standards are being met.

Reliability

Total electrification of customers will reliably reduce forecasted Design Day gas demand. However, if customers retain their natural gas service for non-heating end uses (e.g., cooking, water heating) or as a back-up heating source, the Design Day savings will be less than anticipated. In addition, uptake of electrification may be slower than necessary to achieve the target gas savings if the projected levels of incentives required to drive customer adoption are not approved, or if customers do not see electrification as an attractive and viable alternative at the pace required to achieve timely adoption. There is also risk of achieving the desired levels of savings if the required contractor network is not developed soon enough to support installations. Reliability could improve over time as programs mature.

Performance reliability of electric heat will be dependent on the reliability of the electric utility network, and its ability to manage additional volume from incremental heat pump adoption.

Cost

The biggest drawback for electrification in Downstate NY is the cost – both upfront cost and ongoing operating cost. The upfront cost of a heat pump and installation is often twice as high as the typical natural gas unit heating for which it would substitute. And although heat pumps are very efficient, electric prices are relatively high in Downstate NY. This means that switching from gas heating to electric heating is likely to lead to an overall increase in a customer's annual utility bills, even when accounting for the increased efficiency of electric heat pumps.[17] For heat pumps to be economic in this region, electric prices would need to be 25%-50% lower, or heat pump efficiency would need to increase by 20%-40%.[18]

While there are other factors that contribute to the current levels of heat pump adoption in Downstate New York, driving levels of adoption high enough to meet targeted gas savings requires overcoming these economic barriers with a combination of upfront and ongoing incentives. As a program matures and electric and natural gas prices change, the upfront and ongoing incentives necessary to encourage the targeted adoption rates will likely need to be adjusted. At this time, it is assumed an upfront incentive equivalent to 50% of incremental installed costs along with an ongoing incentive enough to create a payback period for customers of 5 to 10 years would be necessary to drive enough adoption to achieve the targeted level of heat pump adoption and the associated gas savings. At these incentive levels there will likely also be some level of free ridership. This means that many of the customers that are expected to organically adopt heat pumps in Downstate NY (e.g., they would install a heat pump even if there was not an incentive available) would now participate in the program, somewhat reducing the program cost-effectiveness.

Total incremental electrification program investment is estimated at $0.7B - $1.1B through 2035.

Environmental Impact

Ecological Impact: The ecological impact of the electrification program, like the energy efficiency program, will be minimal. Air source heat pumps to be installed as replacements to existing systems will be compliant with all state and local environmental regulations and contractor training will include environmental considerations. Implementing an electrification program will have slight benefits from an air quality perspective, as it will result in fewer homes and businesses in Downstate NY combusting fossil fuels onsite.

Climate Impact: The reduction in annual gas consumption due to electrification will largely be offset by an increase in electricity consumption. In fact, given that marginal electric power in Downstate NY has in some analyses shown higher current emissions than natural gas, in the short-term emissions from incremental electrification could be higher than natural gas.

However, due to the forecasted decarbonization of NY's electric supply, incremental electrification will eventually result in decreased emissions. Emissions are expected to further decline for heat pumps, to the point where NY is targeting net zero GHG from the electric sector (85% direct carbon reduction and 15% offsets).

Community Impact

The intensive incremental electrification program will create an entire ecosystem that will include a wide range of contractors and suppliers who will need to hire additional employees to support the

[17] In recent months in Downstate NY, the ratio of electric to gas prices in New York City is 20% to 25% higher than the United States average.
https://www.bls.gov/regions/midwest/data/averageenergyprices_selectedareas_table.htm#ro5xgenergy.f.1

[18] This comparison assumes typical heating season heat pump and natural gas furnace performance for typical weather in Downstate NY.

spending over the duration of the program. A significant portion of these investments will go directly into the Downstate NY economy.

Due to the increased adoption of heat pumps for heating in Downstate New York, there would be a growth in total electric customers and electric demand.

Permitting, Policy and Regulatory Requirements

The magnitude of the electrification envisioned will impact permitting, policy, and regulatory issues at the local and state level. At the local level, contractors will be responsible for obtaining local permits for the retrofits of homes and businesses. Local permitting authorities will need to prepare for the increased volume of permit applications to address electrification efforts. Work will be required to streamline these application and approval processes to achieve program targets.

The design and magnitude of the incentive program that would be required to drive this high level of heat pump adoption would require policy initiatives beyond the current level of NENY or LL97. This policy change could provide a mechanism for National Grid to offer the high level of both first cost and ongoing cost incentives to drive the target level of heat pump adoption. National Grid will require NY PSC approval for these programs, incentives and total investments before they can commence. At the state level, KEDNY and KEDLI will provide updated cost and benefit estimates for the magnitude of these programs to the NY PSC as part of a future regulatory approval process.

Requirements for Implementation

Because of the size of the near-term gap between demand and supply, the implementation of the program will require significant startup costs and resources. For example, there will need to be growth in the number of qualified contractors for the design and installation of the heat pumps, an increase in staff in local permit offices, and increases in the number program staff at KEDNY and KEDLI. In addition, this type of program would require investments in marketing, training and broad on-going support to sustain the level of targeted program growth.

In addition, there would need to be a high level of coordination between agencies and utilities to manage program design and implementation in the most effective manner possible. For example, New York State and local governments should consider approaches that focus attention on building HVAC design through home energy ratings, further updating of building codes, and implementation of effective mechanisms for landlords of multi-family buildings to encourage adoption of heat pumps for application to all types of buildings.

Summary

Table 32 below summarizes the assessment of the incremental electrification option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 32: Summary of Incremental Electrification Option

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	An incremental on-main electrification program is rapidly established for Downstate NY and grows to offset otherwise increasing forecasted Design Day demand.
Size	52 - 86 MDth/day	Success will require: • 5,000 to 15,000 incremental customers per year starting 2021 to move to electric heat/cooking/industrial use
Safety	◕	Only licensed contractors will be able to participate in the program and will have appropriate training programs for the electrification efforts
Reliability	◔	Design Day savings will be certain once implemented as electrification measures are passive and have a >15-year measure life; however, National Grid and New York's ability to aggressively scale the programs to the level and size required will pose a significant challenge. Also, if customers retain natural gas service for non-heating uses (e.g., cooking, water heating) or as a back-up heating source, Design Day savings will be less than anticipated. Reliability could improve over time as programs mature.
Cost	○	The necessary incentive programs to achieve the required incremental electrification ramp is more expensive than alternative options. Total investment through 2035 is estimated at $0.7B - $1.1B.
Environmental Impact	◕	There will ultimately be significant reductions in GHG emissions from electrification measures. In the short-term, some analyses show that there are higher marginal emissions from air source heat pumps vs. natural gas
Community Impact	◕	Investments in electrification will create jobs in Downstate NY
Permitting, Policy and Regulatory Requirements	N/A	Requires alignment of state and local policies and regulatory outcomes across multiple areas
Requirements for Implementation	N/A	The ecosystem of licensed contractors and vendors would need to significantly increase to meet the program requirements

10.4 Summary of Options

Tables 33 and 34 below provide a summary of the evaluation of options completed above, including the level of attractiveness of each option across a number of criteria, as well as corresponding permitting, policy, regulatory, and implementation requirements.

Table 33: Level of Attractiveness of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

● = highly attractive; ◕ = attractive; ◑ = neutral; ◔ = unattractive; ○ = highly unattractive

OPTION	SIZE (MDth/ day)	LEVEL OF ATTRACTIVENESS				
		SAFETY	RELIABILITY	COST	ENVIRONMENT	COMMUNITY
Large-Scale Infrastructure Options						
Offshore LNG Port	400	◕	◕	◑	◔	◑
LNG Import Terminal	400	◕	◕	○	◔	◔
Northeast Supply Enhancement (NESE) Project	400	◕	●	◕	◑	◕
Distributed Infrastructure Options						
Peak LNG Facility	100	◕	◕	◑	◑	◑
LNG Barges	100 (2 barges)	◕	◕	◕	◑	◑
Clove Lakes Transmission Loop Project	80	◕	●	◔	◑	◔
Gas Compression on the Iroquois Gas Transmission System	63	◕	●	●	◑	◕
No Infrastructure Options						
Incremental Energy Efficiency*	Up to 216	●	◔***	◔	●	●
Incremental Demand Response**	Up to 108	◕	◔***	●	◕	◕
Incremental Electrification*	Up to 86	◕	◔***	○	◕	◕

**In excess of Local Law 97, 80-100% of NENY targets and Downstate NY electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, all of which are assumed in Demand forecasts*

*** In excess of planned demand response programs that are assumed to reduce Demand by up to 53 MDth by 2035*

**** Reliability could improve over time as programs mature*

Table 34: Permitting, Policy, Regulatory and Implementation Requirements for Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

OPTION	PERMITTING, POLICY, REGULATORY	IMPLEMENTATION REQUIREMENTS
Large-Scale Infrastructure		
Offshore LNG Deepwater Port ("Offshore LNG")	• Requires FERC (under NEPA) approval and state specific approval (e.g., NY, NJ, etc.) • NY, NJ and CT opposed two FERC approved Floating LNG projects in 2008 and 2015 • Requires NYS DEC and FDNY (if within NYC jurisdiction) approval • Permits would likely include BOEM, NEPA, NOAA, USFWS, USACE, US EPA	• Estimated timeline: 6-8 years • Considering new FSRU vessel construction required, permitting would need to be completed prior to placing construction order • Estimating two years post-permitting to build vessel interconnecting facilities, and system upgrades • Offshore LNG developers may be unwilling to take on development cost/permitting risk in the region
LNG Import Terminal	• Requires a change or waiver to NYS Law 6 NYCCR 570 that limits any on land storage to less than 70,000 gallons – this law was reviewed in 2015 and upheld • Requires FERC (under NEPA) approval and state specific approval (e.g., NY, NJ, etc.) • Permits will likely include USFWS, USACE, US EPA, NY PSC, NY SEQRA, NYSDEC.	• Estimated timeline: 5-6 years • Requires a change or waiver from current NY Law (6 NYCCR 570) – current filing process takes ~3 years, acceleration would reduce timeline • No land area considered yet – could consider an adjacent state (NJ) to accelerate timeline, which would likely require additional infrastructure improvements • Once the Order is received, the Company can begin construction, which would take 2-3 years • The process would require a full Environmental Assessment and EIS (required for import terminals)
Northeast Supply Enhancement (NESE) Project	• Received FERC approval, but still requires state / local approvals (NY, NJ) – PA has already approved • Requires NYS DEC approval • NYSDEC rejected water permit in 2018 and 2019 based on concerns relating to water quality in the NY Harbor during construction	• Estimated timeline: ~2 years • Anticipate completion date as early as December 2021, assuming all permitting and approvals are secured by June 2020 • Project is entirely offshore in NY, while work in NJ is at brownfield locations
Distributed Infrastructure		
Peak LNG Facility	• Requires a change or waiver to NYS Law 6 NYCCR 570 that limits any on land storage to less than 70,000 gallons – this law was reviewed in 2015 and upheld • All approvals are within NY jurisdictions • Permits will likely include NY PSC, NY SEQRA, NYSDEC, NYC DOB, and FDNY (if within NYC) • May require new regulations for fire departments to address storage and other safety issues	• Estimated timeline: 5-6 years • Assuming a changes or waiver from current NY Law (6 NYCCR 570) and all required regulatory changes are completed, feasibility and site selection studies would need to occur
LNG Barges	• Permits would likely include USFWS, USACE, NY SEQRA, NYSDEC • Dock facilities and interconnecting gas systems may require FERC EIA; at a minimum NY DEC WQC is needed	• Estimated timeline is 5-6 years • Total permitting process estimated to take 3-4 years; acceleration would reduce timeline • Pier construction and barge order to delivery could be done in parallel in 2 years

OPTION	PERMITTING, POLICY, REGULATORY	IMPLEMENTATION REQUIREMENTS
Distributed Infrastructure, continued		
Clove Lakes Transmission Loop	• Requires permits from NYC DEP/DOB, NYS DEC, and EPA • State / local (e.g., NYC DOT) specific approval for urban construction	• Estimated timeline is 5+ years • Feasibility and engineering studies are being planned to confirm timing and requirements
Gas Compression on the Iroquois Gas Transmission System	• Requires FERC (under NEPA) approval and state specific approval • Air permits required in NY and CT for new compression at existing sites. • Formal application with FERC was submitted in February 2020 and decision on approval is anticipated in early 2021	• Estimated timeline is ~3 years • If all approvals are acquired in a timely fashion, the project is expected to be in-service by November 2023
No Infrastructure		
Incremental Energy Efficiency*	• Enhanced energy efficiency will require policies that support programs that exceed current cost tests by including value of carbon reduction and mechanisms to support increased use of renewable and clean energy sources. • Rate case approvals and incentive programs to drive behaviors and increase adoption rates will be required to implement new programs	• Estimated timeline: will need to have impact starting in 2021/22, and continue to build over time • Success will require a >3x increase in Energy Efficiency (EE) from 0.4% of total sales currently to 1.3% of total sales by 2025 (vs. 0.8% NENY target) • Success will require an incremental 20,000 – 40,000 customers per year starting in 2021 to complete energy efficiency programs (50% annual increase vs. current baseline plus NENY)
Incremental Demand Response**	• New demand response programs will require new thermostat set back programs, enhanced program for Temperature-Controlled (TC) customers, incentives for adoption and new rate structures	• Estimated timeline: starting in 2021, all TC customers will be retained; over next five years, incremental demand response will reach roughly half of all residential customers
Incremental Electrification*	• More aggressive electrification will require policies and incentives to drive behaviors to increase customer adoption	• Estimated timeline: starting in 2021, will need 5,000 to 15,000 incremental customers per year to move to electric heat/cooking/industrial use • Electric power generation and transmission/ distribution infrastructure buildout may be required to satisfy increased electric demand driven by electrification

**In excess of Local Law 97, 80-100% of NENY and Downstate NY electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, all of which are assumed in Demand forecasts*

*** In excess of planned demand response programs that are assumed to reduce Demand by up to 53 MDth by 2035 Note:*

Please see Section 13 of the Report for a full list of Acronyms

11. Approaches to Close the Remaining Projected Gap Between Demand and Supply

11.1 Overview

Creating a comprehensive solution requires looking at how the options described in Section 10 can be individually or collectively utilized to solve the gap between demand and supply. Not all options are large/scalable enough to individually solve the issue. And, the timing of when an option can be implemented may also necessitate that it be combined with others to meet more immediate customer needs.

While there are many details to consider, in summary there are three possible approaches:

- Build out **Large-Scale Infrastructure**, capable of providing ~400 MDth of Design Day supply.
- Combine a **Distributed Infrastructure solution(s) with incremental No-Infrastructure solutions**.
- Fully rely on **incremental No-Infrastructure solutions**, where demand is reduced through incremental energy efficiency, demand response and building/appliance electrification to the point where existing National Grid gas supply will meet customer needs.

Each of these approaches are reviewed below, followed by a summary comparing across the approaches.

11.2 Build Out Large-Scale Infrastructure

This approach would require moving forward with one large-scale project – either an Offshore LNG Deepwater Port, an LNG Import Terminal, or the Northeast Supply Enhancement (NESE) Project. Once operational, a Large-Scale Infrastructure option would enable termination of CNG trucking, reduce the need for many of our Multi-Family and C&I customers to switch to burning fuel oil during cold weather events, and would create some short-term contingency supply (consistent with guidance provided by the NY PSC (Case 19-G-0678)) should challenges occur with upstream pipelines or LNG tank maintenance.

To the extent that Large Scale Infrastructure cannot be implemented by the start of the 2021/22 winter season, incremental action will be required to reduce demand. In Table 35 below, we have estimated the required incremental Energy Efficiency (EE), Demand Response (DR) and electrification efforts under the Low Demand and High Demand scenarios that would close the gap between demand and available supply, assuming a Large Infrastructure solution is deployed in 2026/27.

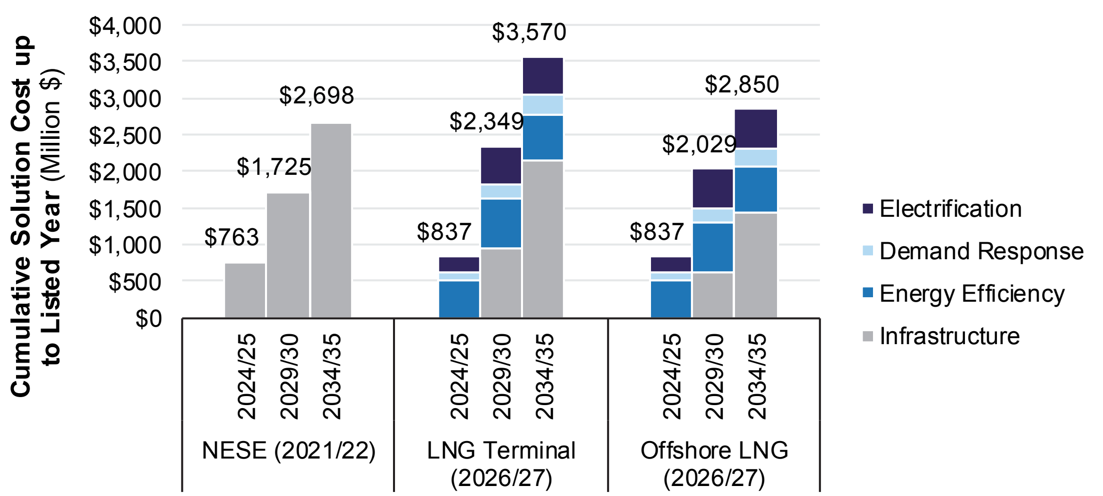
Table 35: Incremental EE, DR and Electrification Requirements to Close Gap Between Demand and Supply if Large Scale Infrastructure Comes On-Line in 2026/27

	Program Requirements
Large Infrastructure Deployed 2021/22	None required. Infrastructure is deployed in time to effectively close the demand-supply gap without incremental investments in EE, DR, and electrification. EE/DR/electrification is focused on achievement of what is in forecast Demand: NENY, Local Law 97, Downstate NY electric utility electrification programs, and organic electrification adoption
Large Infrastructure Deployed in 2026/27	In addition to what is contained in forecast Demand as described above: The three major elements that compose the no-infrastructure approach are Energy Efficiency (EE), Demand Response (DR) and electrification. To address the gap in supply until a large infrastructure project is on-line will require a portfolio of incremental activities from all three areas, including: 1) an intensive efficiency and weatherization program to be executed in 65,000 – 95,000 homes served by 2025; 2) an additional electrification program in Downstate NY to switch 16,000 – 25,000 homes to electric heat pumps by 2025; and 3) Two separate DR programs: Customers currently on non-firm rates will be kept on non-firm rates by offering an incentive of double the current annual bill savings, and a thermostat setback program that seeks to enroll over 450,000 residential heating customers by 2025 to help reduce Design Day usage.

Note: ranges of program achievement are estimated based on Low Demand and High Demand scenarios

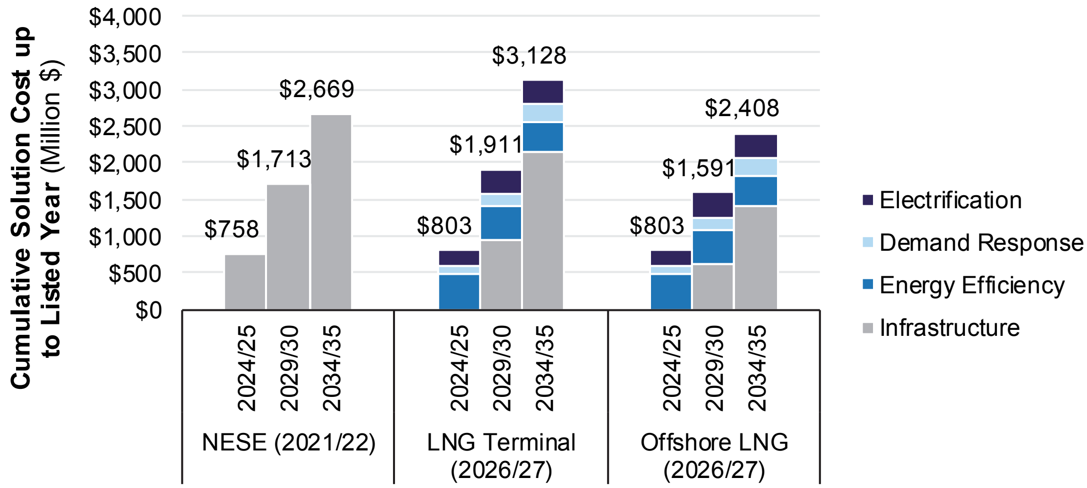
The total cost of the different options under the Large-Scale Infrastructure approach is summarized in Figures 24 and 25 below.

Figure 24: Large Infrastructure Cumulative Costs – High Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. High gap scenario is described in Section 5.

Figure 25: Large Infrastructure Cumulative Costs – Low Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, as applicable. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. Low gap scenario is described in Section 5.

11.3 Combine Distributed Infrastructure Solution(s) with Incremental No-Infrastructure Solutions

On their own, none of the Distributed Infrastructure options will close the gap between forecast demand and available supply. Incremental EE, DR and electrification will be required in the short-term, until one of the options can come online. And, given these infrastructure options range in size from 63 – 100 MDth/day and there is a projected gap of 230 – 400 MDth/day, even if two options were pursued there would still be an ongoing need for incremental demand reduction.

In Table 36 and Figures 26 and 27 below, we have outline the required incremental EE, DR and electrification efforts and projected costs under the Low Demand and High Demand scenarios that would close the gap between demand and available supply, assuming 1) a 100 MDth option (LNG Barges, Peak LNG, or Clove Lakes) comes online in 2026/27, and 2) a 63 MDth option (gas compression on the IGTS) comes online in 2023/24.

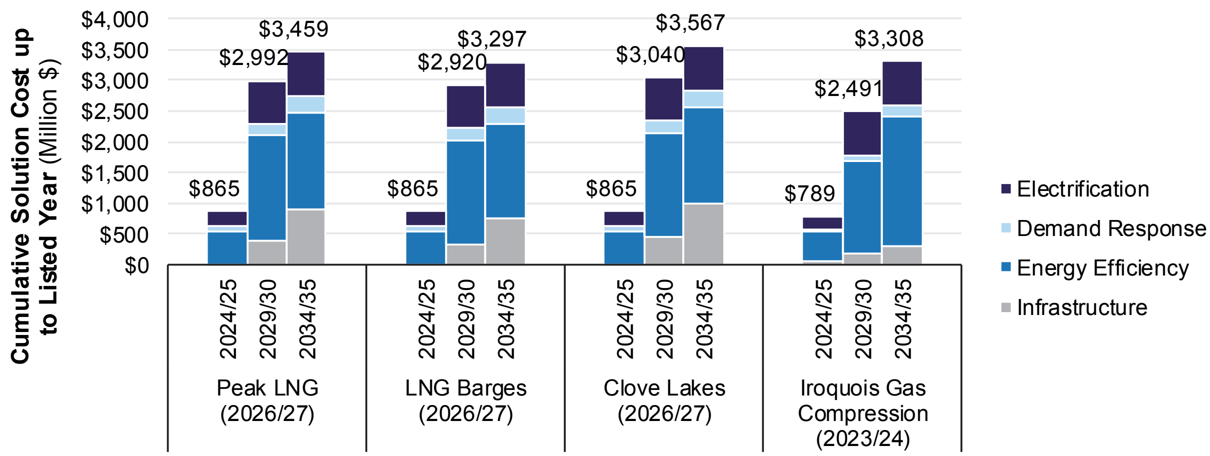
Under this approach, CNG trucking would have to remain and short-term contingency supply would not be available, unless EE, DR and electrification exceeded projections and further reduced demand.

Table 36: Incremental EE, DR and Electrification Requirements to Close Gap Between Demand and Supply Under Different Distributed Infrastructure Solutions

	Requirements
LNG Barge, Peak LNG, or Clove Lakes Deployed 2026/27 (80-100 MDth)	Addressing the Demand-Supply gap in conjunction with a 100 MDth Distributed Infrastructure solution coming online in 2026/27 will require a portfolio of EE, DR and electrification activities. In addition to NENY targets, Local Law 97, Downstate NY electric utility electrification programs, and organic electrification adoption as outlined in the demand forecast, incremental programs/ requirements are estimated to include: 1) an intensive efficiency and weatherization program to be completed in 65,000 - 90,000 homes and businesses by 2025, with requirements to weatherize an additional 130,000 homes and businesses by 2035; 2) two separate DR programs: Customers currently on non-firm rates will be kept on non-firm rates by offering an incentive of double the annual bill savings, and a thermostat setback program will be offered that seeks to enroll over 450,000 residential heating customers by 2025 to help reduce peak usage; and 3) an additional electrification program in Downstate New York to switch roughly 16,000 – 40,000 homes to electric heat pumps by 2026.
Iroquois Gas Compression Deployed 2023/24 (63 MDth)	Addressing the Demand-Supply gap in conjunction with a 63 MDth Distributed Infrastructure solution coming online in 2023/24 will require a portfolio of EE, DR and electrification activities. In addition to NENY targets, Local Law 97, Downstate NY electric utility electrification programs, and organic electrification adoption as outlined in the demand forecast, incremental programs/ requirements are estimated to include: 1) an intensive weatherization program to be completed in 80,000 homes and businesses by 2025, with requirements to weatherize an additional 80,000 – 200,000 homes and businesses by 2035; 2) a DR program where customers currently on non-firm rates will be kept on non-firm rates by offering an incentive of double the annual bill savings; and 3) an additional electrification program in downstate New York to switch roughly 40,000 homes to electric heat pumps by 2026.

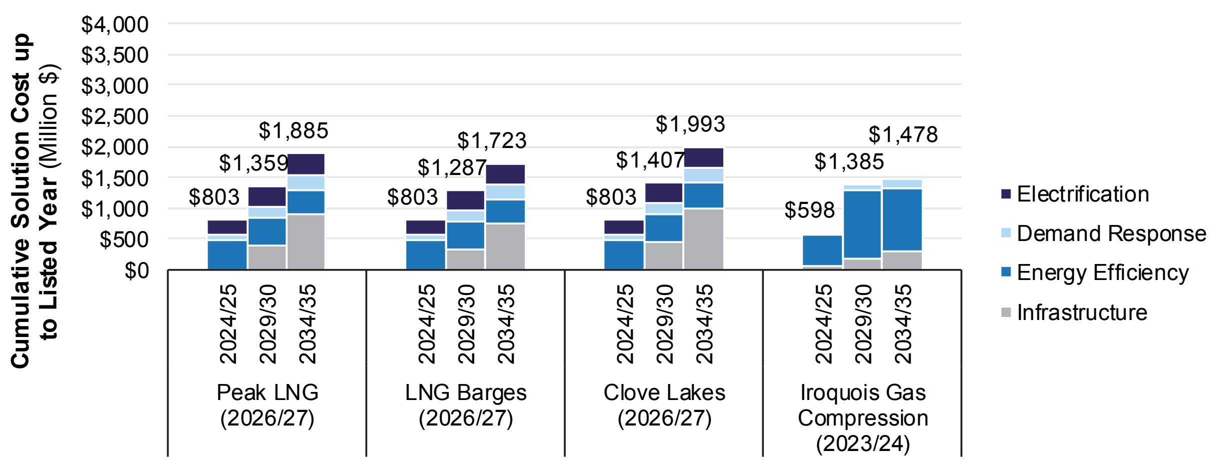
Note: ranges of program achievement are estimated based on Low Demand and High Demand scenarios

Figure 26: Distributed Infrastructure Cumulative Costs – High Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. High gap scenario is described in Section 5.

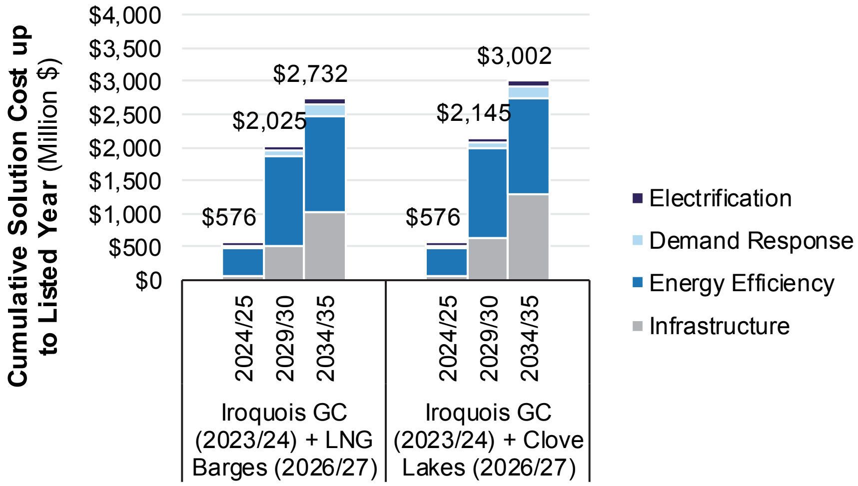
Figure 27: Distributed Infrastructure Cumulative Costs – Low Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. Low gap scenario is described in Section 5.

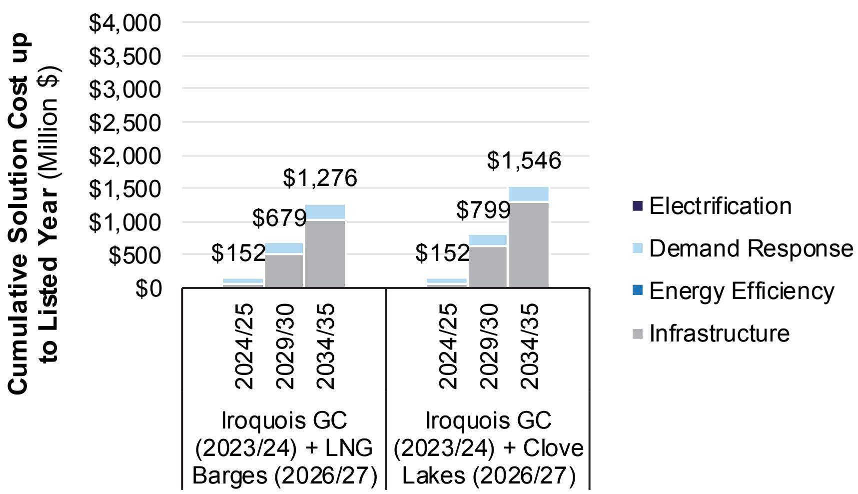
In addition, we could consider combinations of distributed infrastructure options, where two or more infrastructure efforts are put in place along with a smaller amount of incremental EE, DR, and electrification to close the gap between projected demand and available supply. As examples, we have included in Figures 28 and 29 below two possible combinations – Iroquois Gas Compression with LNG Barges (the two lowest cost options from above), and Iroquois Gas Compression with Clove Lakes (the lowest and highest cost option from above).

Figure 28: Cumulative Costs Under Possible Combinations of Distributed Infrastructure – High Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. High gap scenario is described in Section 5.

Figure 29: Cumulative Costs Under Possible Combinations of Distributed Infrastructure – Low Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. Low gap scenario is described in Section 5.

11.4 Execute A No-Infrastructure Approach

The third approach to addressing the forecasted Design Day gap between demand and supply is to significantly invest in an incremental portfolio of demand-side programs for Downstate NY, referred to here as the "No Infrastructure Approach". This would require Downstate NY to make industry leading investments in additional customer and trade ally incentives to rapidly achieve the aggressive gas savings targets required to offset future demand growth. Correspondingly, high levels of investment in program design, implementation, marketing and customer education, and regional/statewide coordination with the electric utilities and NYSERDA would have to be core features and building blocks for the required no-infrastructure solution.

Satisfying the full future need for growth in gas demand exclusively with incremental demand-side resources requires a high level of investment in energy efficiency, demand response, and electrification. A rapid ramp-up of these investments is also necessary to drive enough demand reduction to meet the need in the near term. Key elements of the portfolio of programs for closing the demand-supply gap include:

- **Demand response – Non-firm, TC rates** - all current non-firm customers would need to be kept on new non-firm rates,
- **Demand response**, **residential thermostat setback program** would need to reach roughly half of all residential customers in the next five years,
- **Energy efficiency - intensive weatherizatio**n would need to be completed for roughly a third of Downstate NY customers over the next fifteen years, and
- **Electrification** - a robust electrification incentive program would need to be implemented to drive electrification of new construction and oil conversions, and to overcome the challenging economics for gas to electric fuel switching enough to drive enough adoption to close the remaining gap.

Table 37: Summary of No Infrastructure Solution to Have Impact Starting in 2021/22

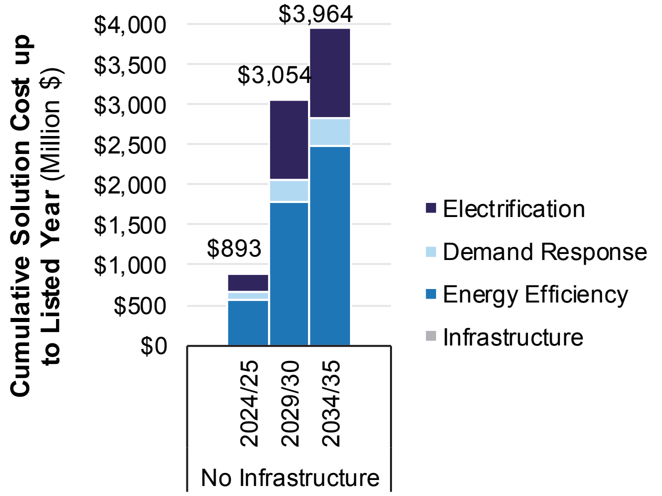
	Requirements
No-Infrastructure Solution	Addressing the Demand-Supply with no incremental infrastructure will require a very aggressive portfolio of EE, DR and electrification activities. In addition to NENY targets, Local Law 97, Downstate NY electric utility electrification programs, and organic electrification adoption as outlined in the demand forecast, incremental programs/requirements are estimated to include: an intensive efficiency and weatherization program to be completed in roughly 90,000 homes and businesses by 2025, which continues to weatherize another 80,000 – 240,000 homes and businesses by 2035; an additional electrification program in downstate New York to switch 35,000 – 60,000 homes to electric heat pumps by 2028; and, finally, two DR programs: 1) customers currently on non-firm rates will be kept on non-firm rates by offering and incentive of double the annual bill savings, and 2) a thermostat setback DR program will also be offered that seeks to enroll nearly 500,000 residential heating customers by 2025 to help reduce peak usage.

In all, the investment to accomplish a no infrastructure solution is expected to range from $2.0 billion - $4.0 billion over 15 years, with annual costs peaking in 2026 at over $400 million.

At this level of investment, the savings from the different resources begin to interfere with each other. For example, intensive weatherization would reduce the effective Design Day usage per average residential customer by around 5% in 2030, which thereby reduces the impact of a residential demand response program. These interactions further increase the cost of any incremental no-infrastructure investment.

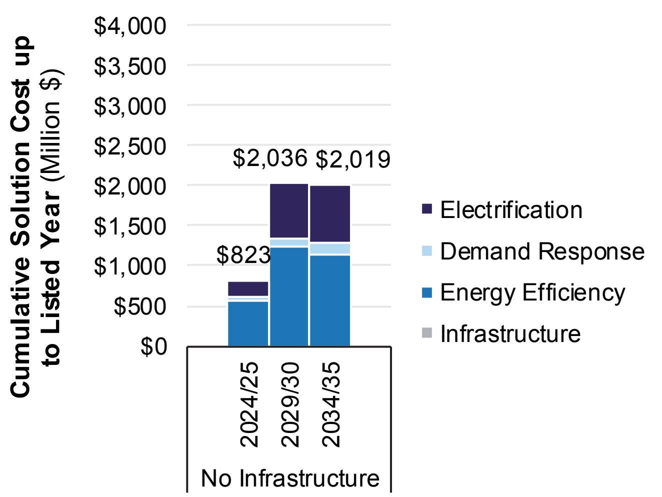
Figures 30 and 31 below show the cumulative investment in the No Infrastructure approach through 2034/35 required to close the gap between demand and supply under the High and Low demand scenarios.

Figure 30: No Infrastructure Cumulative Costs – High Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. High gap scenario is described in Section 5.

Figure 31: No Infrastructure Cumulative Costs – Low Demand Scenario



Notes: Sum of annual costs up to and including listed year with no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies. Demand side resource costs include program administration and incentive costs, net of gas commodity savings. Low gap scenario is described in Section 5.

11.5 Summary of the Different Approaches

Table 38: Summary of Supply and Demand Approaches and Implications (note: ranges are a function of the timing and scale of the options, and the differences between Low and High Demand forecasts)

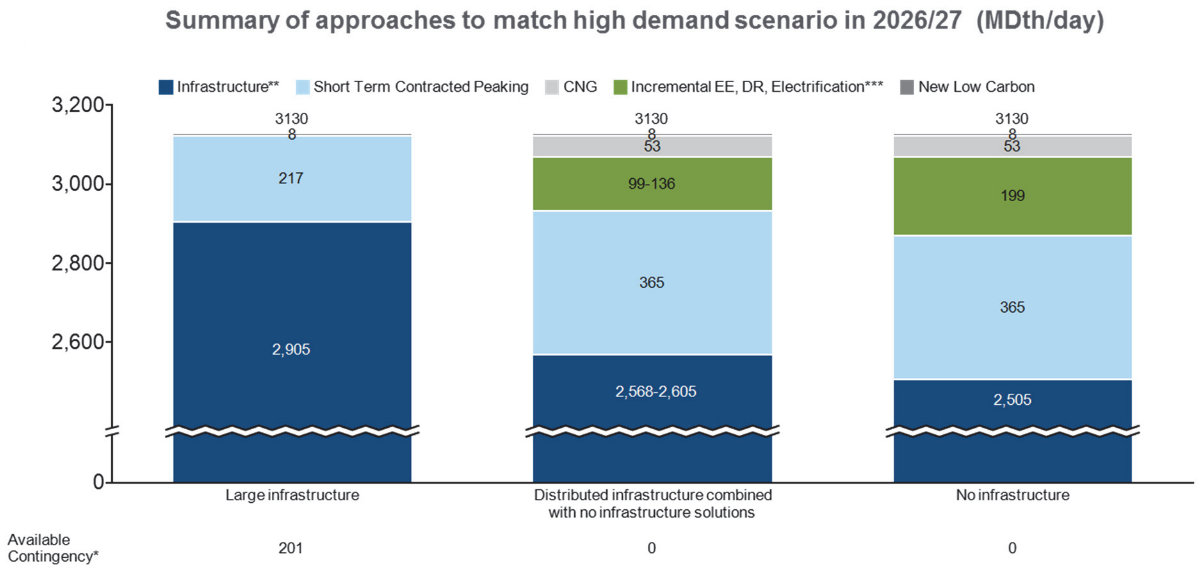
	Impact from Infrastructure (MDth/day)	Required Impact from Incremental EE/DR/ Electrification (MDth/day)*		Impact to National Grid Supply Stack	
		2026/27	2034/35	2026/27	2034/35
Large-Scale Infrastructure	400	0	0	• No CNG trucking • Contracted peaking supplies flex down to 166 – 217 MDth • 201 – 252 MDth short-term contingency available • Temperature Controlled (TC) customers continue to move to firm gas and away from burning fuel oil at peak • Need for incremental EE/DR/electrification if infrastructure not in place by 2021/22	• Under High Demand scenario, CNG trucking required again starting in 2031/32 • Contracted peaking supplies flex down to 223 – 365 MDth • 0 – 195 MDth short-term contingency available • TC customers continue to move to firm gas and away from burning fuel oil at peak
Distributed Infrastructure Combined with No-Infrastructure Solutions	63-100	48-136	130-337	• Contracted peaking supplies continue at 100% of available to meet planned needs • TC customers do not move to firm gas, continue to burn fuel oil at peak • If projected or incremental EE/DR/electrification targets to close the gap are exceeded, reduces/eliminates CNG trucking and creates some short-term contingency • If targets are met, CNG trucking continues and zero short-term contingency available • If targets are not met, will have to restrict new gas customer connections	
Incremental Portfolio of No-Infrastructure Solutions	0	148-199	230-400	• Contracted peaking supplies continue at 100% of available to meet planned needs • TC customers do not move to firm gas, continue to burn fuel oil at peak • If projected or incremental EE/DR/electrification targets to close the gap are exceeded, reduces/eliminates CNG trucking and creates some short-term contingency • If targets are met, CNG trucking continues and zero short-term contingency available • If targets are not met, will have to restrict new gas customer connections	

Source: National Grid analysis

**Required amounts in excess of Local Law 97 achievement, 80-100% achievement of NENY targets and electric utility electrification program targets, and 25-49% organic electrification of heat in retrofit buildings by 2035, all of which are already assumed in Demand forecasts*

Examples of how the approaches would evolve by 2026/27 to meet the projected High and Low demand forecasts can be found in Figures 32 and 33 below.

Figure 32: How Potential Approaches Will Match High Demand Scenario in 2026/27



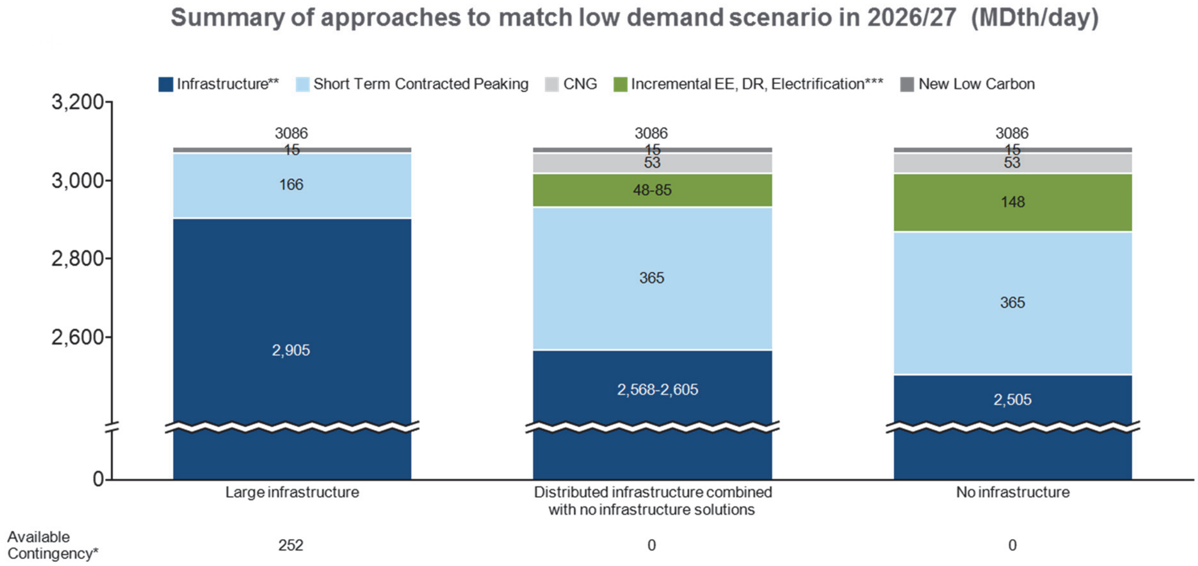
Source: National Grid analysis

**additional available short-term supply that could be contracted for or put in place if there are any interruptions to pipeline or LNG capacity, or if EE/DR/electrification targets fall short of forecast [note: if EE/DR/electrification exceeds targets in distributed infrastructure and no infrastructure scenarios, could reduce/eliminate need for CNG trucking and create available contingency of up to 53 MDth]*

***includes fixed third-party pipeline and LNG infrastructure assets*

****incremental EE/DR/Electrification reflects required amounts in excess of Local Law 97 compliance, 80% achievement of NENY targets and electric utility electrification program targets, and 15-29% organic electrification of heat in retrofit buildings by 2035 – all of which are already assumed in the "High Demand" scenario.*

Figure 33: How Potential Approaches Will Match Low Demand Scenario in 2026/27



Source: National Grid analysis

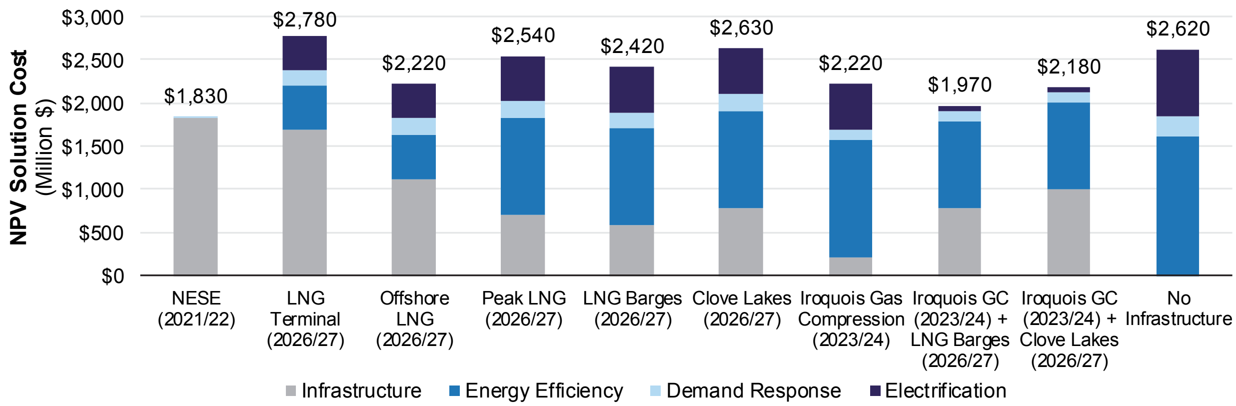
**additional available short-term supply that could be contracted for or put in place if there are any interruptions to pipeline or LNG capacity, or if EE/DR/electrification targets fall short of forecast [note: if EE/DR/electrification exceeds targets in distributed infrastructure and no infrastructure scenarios, could reduce/eliminate need for CNG trucking and create available contingency of up to 53 MDth]*

***includes fixed third-party pipeline and LNG infrastructure assets*

***incremental EE/DR/Electrification reflects required amounts in excess of 100% achievement of NENY targets, electric utility electrification program targets, Local Law 97, and 25-49% organic electrification of heat in retrofit buildings by 2035 – all of which are already assumed in the “Low Demand” scenario.

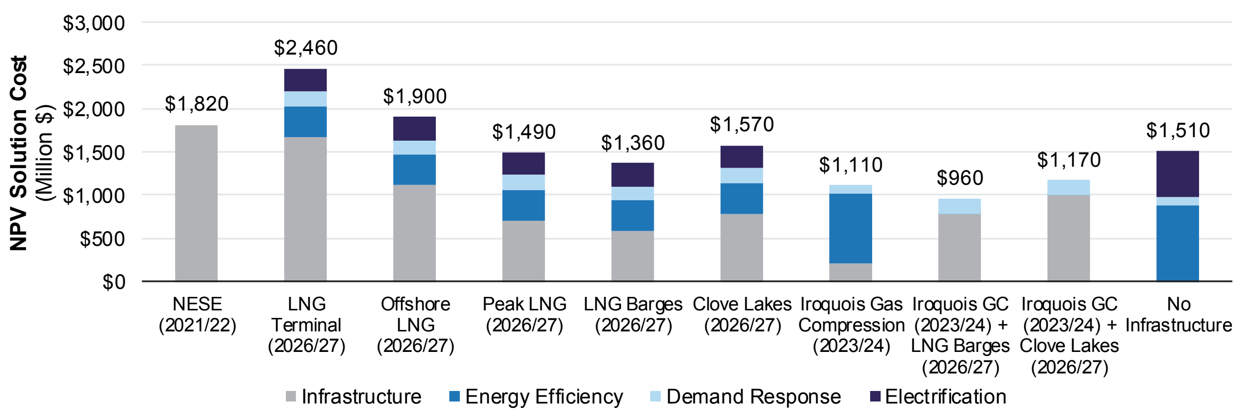
With regards to cost, we have developed a comparison of the different approaches, based on detailed assumptions on capital costs and timing of infrastructure, annual costs of operations, and one-time and annual costs to implement programs. Looking at the total cost package that would impact customers from 2020-2035, Figures 34 and 35 below provide a cost comparison across the different alternatives.

Figure 34: NPV of Net Costs for Different Alternatives to Close Demand-Supply Gap – High Demand Scenario



Notes: Net present value of costs over contracted lifetime of resources, using a 6.3% discount rate (average after-tax Weighted Average Cost of Capital betw een KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, w hich are assumed to have a 15 year life that starts in the listed operational year, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. High gap scenario is described in Section 5.

Figure 35: NPV of Net Costs for Different Alternatives to Close Demand-Supply Gap – Low Demand Scenario



Notes: Net present value of costs over contracted lifetime of resources, using a 6.3% discount rate (average after-tax Weighted Average Cost of Capital betw een KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, w hich are assumed to have a 15 year life that starts in the listed operational year, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap scenario is described in Section 5.

12. Long-Term Capacity Report Conclusions and Summary

National Grid's goal with the Long-Term Capacity Report is to provide readers with more information on the Downstate NY energy situation as it pertains to natural gas distribution and end-use consumption, and the potential options and approaches for evolving its network to best meet customer needs. We are fully aligned to finding solutions that:

- **Close the gap between existing supply and forecast demand.** Our detailed modeling, after accounting for the impacts of NENY, Local Law 97, electrification programs from Con Edison and PSEG Long Island, and organic electrification adoption, indicate a gap between customer demand and available supply that starts in 2021/22 and grows to 265 – 415 MDth by 2032-2035. To ensure customers can be connected and properly served, it is important to have plans in place that can address these ongoing needs.
- **Make delivery safe and reliable, with appropriate contingencies.** It is not just a matter of having the appropriate volume of solutions to meet the demand-supply gap. Solutions must also be designed in an integrated fashion with all appropriate safety considerations and must consider the likelihood that they will achieve their estimated contribution when needed most. There needs to be careful evaluation of potential risks to supply disruption and what contingencies will be available to cover these challenges should they occur.
- **Are environmentally friendly and reduce Greenhouse Gas (GHG) emissions**. Options and approaches should be considered in terms of their ability to help the state of New York achieve its CLCPA goals. There could be multiple pathways to achieving these goals, as many technologies continue to evolve, and in fact there is continued debate amongst experts regarding the "best" pathway to achieve low and eventually net zero carbon emissions. It is important to drive progress on multiple fronts in this area, taking advantage of different pathways that continue to emerge and evolve.
- **Are cost effective and minimize impact to customer bills.** It is critically important to consider affordability throughout the evaluation of alternatives. While investments for a clean and secure energy future need to be made, it cannot be done by asking customers to shoulder rapid bill increases. Programs and projects need to show strong returns and be done in a way that minimizes impact to customer bills.
- **Are feasible and timely.** Many of the options presented have a number of permitting and regulatory hurdles that need to be addressed, and/or require significant funding and a fast ramp-up if they are going to effectively address demand-supply challenges. The feasibility of executing each option or approach, and a realistic assessment of the timing and implementation requirements, is another important aspect of determining the optimal path forward.

We look forward to receiving feedback on the Report contents and the different options and approaches outlined. This Report will also serve as the basis for presentation and discussion during our public meetings, which will be held in March in various locations through Downstate NY. For more information on those meetings, and to submit written comments on the report, please go to **www.ngrid.com/longtermsolutions**.

13. Acronyms

ABS	American Bureau of Shipping
ATB	Articulated Tug Barge
BCF	Billion Cubic Feet
BNY	Brooklyn Navy Yard
BOEM	Bureau of Ocean Energy Management
Btu	British Thermal Unit
CNG	Compressed Natural Gas
C&I	Commercial & Industrial
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide Equivalent
ConEd, Con Edison	Consolidated Edison
COP	Coefficient of Performance
CT	Connecticut
DR	Demand Response
DOT	Department of Transportation
Dth	Dekatherms
Dth/day	Dekatherms per Day
EE	Energy Efficiency
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EM&V	Evaluation Measurement and Verification
EPA	Environmental Protection Agency
ExC	Enhancement by Compression
FDNY	New York City Fire Department
FERC	Federal Energy Regulatory Commission
FSRB	Floating Storage Regasification Unit
FSRU	Floating Storage Regasification Barge
GHG	Greenhouse Gas
GHP	Geothermal Heat Pump
HVAC	Heating, ventilation, and air conditioning
I-GIT	Institute of Gas Innovation and Technology
IGTS	Iroquois Gas Transmission System
IMO	International Maritime Organization
ISPS	International Ship and Port Facility Security
IT	Interruptible
KEDLI	KeySpan Energy Delivery Long Island
KEDNY	KeySpan Energy Delivery New York
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LDC	Local Distribution Company
LI	Long Island
LL	Local Law (of New York)
LNG	Liquefied Natural Gas
MA	Massachusetts
MARAD	United States Maritime Administration
MARPOL	International Convention for the Prevention of Pollution from Ships
MDth	Thousands of Dekatherms
MDth/day	Thousands of Dekatherms per Day

MMBtu	Million British Thermal Units
MRI	Metropolitan Reliability Infrastructure Project
MW	Megawatt
NCP	Nissequogue Cogen Partners
NENY	New Efficiency New York
NEPA	National Environmental Policy Act
NESE	Northeast Supply Enhancement
NGUSA	National Grid USA
NJ	New Jersey
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NTS	National Gas Transmission System
NY	New York
NYC	New York City
NYCCR	New York Codes, Rules and Regulations
NY PSC	New York Public Service Commission
NYC DEP	New York City Department of Environmental Protection
NYC DOB	New York City Department of Buildings
NYS DEC	New York State Department of Environmental Conservation
NYSEQRA	New York State Environmental Quality Review Act
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations & Maintenance
PA	Pennsylvania
P2G	Power to Gas
PEM	Proton Exchange Membrane
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEG	Public Service Enterprise Group
RI	Rhode Island
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SMS	Safety Management System
SOLAS	Safety of Life at Sea
TC	Temperature Controlled
TETCO	Texas Eastern Transmission
Transco	Transcontinental Pipeline / Williams
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USFWS	United States Fish and Wildlife Service
WQC	Water Quality Certification

14. Appendix

14.1 Compressed Natural Gas (CNG) Trucking / Trailers Detail

Description

The Compressed Natural Gas (CNG) Trucking / Trailers effort includes the continued use and expansion of existing CNG facilities and the addition of new facilities to support system growth and supply demand during the coldest days of the winter heating season. Under this plan, CNG supply is secured upstream of our system, transported via tractor trailer to National Grid CNG sites in New York, and connected to equipment (i.e. decompression skids) to inject the natural gas into National Grid's transmission and distribution systems. The CNG sites are mobilized and operated under temperature thresholds requiring supplemental supply to maintain system reliability for our customers during peak periods of demand. National Grid's 2019/20 Winter Operations Plan includes operation of CNG sites in Glenwood Landing and Riverhead requiring up to 42 total trucks of CNG per day to reliably support minimum system pressures to all firm customers on the downstate New York systems. These Long Island sites support NYC shortfalls through gas displacement.

Size

The Glenwood Landing site has been operational since the 2016/17 winter. Last winter's gas contingency operations contract with a third-party operator was extended for this winter. All third-party operations occur under the supervision of National Grid onsite personnel, including during a cold weather event requiring mobilization and injection into National Grid's transmission system. A second CNG site in Riverhead was newly established, recently tested, and is operational to support Winter 2019/20 system needs. This site is contracted with a different third-party operator but is also overseen by National Grid onsite personnel during a cold weather event. Each site will be supplied from a fleet of CNG trucks contracted with the respective third-party vendor/operator, delivering CNG supply from upstream of National Grid's system to the contracted site. At any time, roughly half of the fleet will be connected to the CNG decompression facility while the other half will be in transit to support CNG replenishment requirements.

For the 2019/20 winter, the Glenwood site supplies 1,000 Dth/hr (peak), utilizing 10 CNG trailers over ~ 4 hours (operating 20 trucks in total to support morning and evening peak demand periods). There are plans to expand the Glenwood site next year to 2,200 Dth/hr utilizing 22 CNG trailers over ~ 4 hours (operating 44 trucks in total to support morning and evening peak demand periods). The Riverhead site will supply 1,100 Dth/hr (peak) utilizing 11 trailers over ~ 4 hours (operating 22 trucks in total to support morning and evening peak demand periods). Additionally, National Grid is in the process of identifying a third site which will be commissioned to support increased demands in the Winter of 20/21; this site is planned to supply 2,200 Dth/hr (peak) utilizing 22 CNG trailers over ~ 4 hours (operating 44 trucks in total to support morning and evening peak demand periods).

The total peak supply from these sites is approximately 5,500 Dth/hr (44 MDth/day) operating a total fleet of 110 CNG trucks for each cold weather event. An additional site with 20 trucks could be developed for 2021/22.

Safety

Operation of the CNG sites for Winter 2019/20 is contracted with firms specializing in CNG operations. National Grid will staff each site with qualified personnel to oversee the operation including temperature and pressure regulation of the gas at the injection point, monitor flows and pressures on site and communicate with Gas Control. Like any satellite operation, difficult operating conditions (weather) for equipment and personnel will add to the risk of operations.

Multiple process safety reviews were conducted to identify, quantify and manage risks to employees as well as to members of the public in the nearby areas of each site. This included facility siting assessments to understand and reduce the potential risk associated with the particular location. It also included process hazard analyses of the injection stations' design to understand and reduce the potential risks that could occur during the unloading and injection process. Additionally, a third party independent assurance assessment is being performed for each site to review design, construction, CNG filling operations, transportation and CNG site operation and injection into National Grid's systems.

Reliability

It is important to note that this supply option has historically been viewed as a contingency operation to augment baseload supply in the event of an unplanned shortage. As a contingency, this supply option is reliable. However, as an option for natural gas baseload supply, this option is medium to low in reliability.

Due to the transportation-focused nature of this option, CNG supply from upstream of National Grid's system could be impacted by multiple events (e.g., road/bridge closures due to automobile accidents or construction, high winds, and inclement weather). Additionally, future CNG supply issues may arise as demand for CNG supply and transportation increases over time. Scalability of this option also impacts its viability as a long-term solution for Downstate NY. As the number of locations and trucks continue to grow, the complexity of operating multiple CNG sites will outweigh the supply capacity provided.

Cost

There are three components to the cost of constructing, testing and operating each CNG site:

- **Capital Investment** – Includes engineering and design, development, real estate acquisition, material procurement, site preparation, construction of the CNG assets, testing and commissioning.
- **Operating and maintenance expenses** – Includes contracts with CNG vendors, decompression skids (i.e. onsite equipment) and operation for each cold weather event. Internal labor costs to support operations and maintenance associated with these activities.
- **Gas supply costs** – Variable commodity cost of approximately $12.75/Dth; this covers commodity and road transportation including reservations of trucking volumes.

The fixed cost per site is approximately $800k/year.

Environmental Impact

In the construction phase, there are low potential impacts due to construction activities. Potential impacts include those typical to construction work such as air quality, stormwater, natural resources (if present depending on location), noise, and waste generation. These impacts would be mitigated by control measures used during construction.

Once operational, this option would not result in a reduction in regional GHG emissions if used for peak only (assumes limited oil to gas conversions) and could add to emissions if new construction heat uses oil; operationally, GHG emissions associated with operations would be higher than NESE due to emissions from CNG handling and transport to the facilities (based on number of trucks and distance travelled). As the capacity from this option increases, so does the need for transportation, which will continue to increase GHG emissions.

Community Impact

As described above, cold weather events necessitating supply to ensure system reliability will require a volume of CNG tractor trailer trucks traveling on the interstate highways, over bridges, and on local roads to access each site to support site operations. The existing sites are located in industrial and commercial areas in an effort to minimize the impact of operations to abutters and residential neighborhoods.

Permitting, Policy and Regulatory Requirements

All necessary permitting for the siting and operation at Glenwood Landing, Riverhead, and the new CNG facility will be managed by National Grid. The location of the new site (Site #3) has not been determined, however, National Grid is pursuing permits in multiple locations to reduce schedule risk.

Requirements for Implementation

As discussed above, multiple sites are under review for engineering design, system take-away capabilities and constructability to meet peak hour demand needs for the winters of 2020/21 and 2021/22.

14.2 MJ Bradley & Associates: Life Cycle Analysis of the Northeast Supply Enhancement Project, June 2019

B. Jones, et al., June 2019, Life Cycle Analysis of the Northeast Supply Enhancement Project <https://www.mjbradley.com/reports/life-cycle-analysis-northeast-supply-enhancement-project>

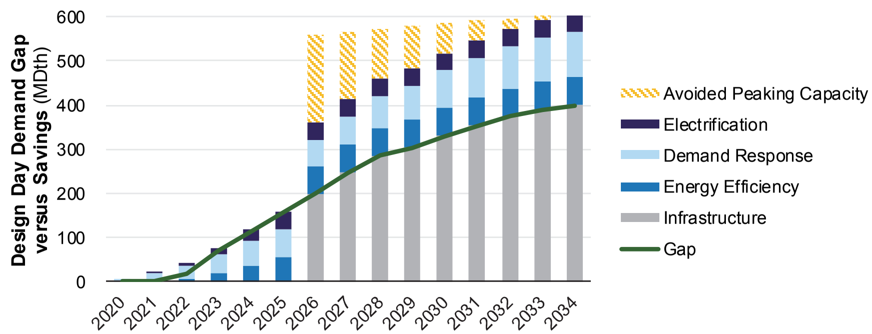
Description:

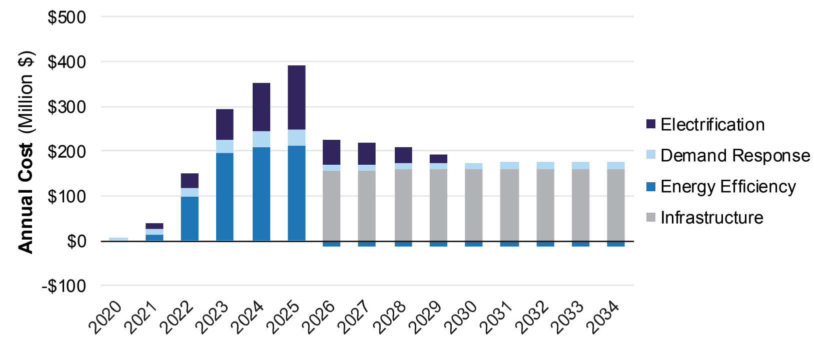
The study was prepared by M.J. Bradley & Associates (MJB&A) to assess the life cycle greenhouse gas impacts associated with the Northeast Supply Enhancement Project (NESE)—a project to provide additional gas supply to downstate New York. MJB&A compared the life cycle emissions from natural gas use for space heating, water heating, and other purposes (e.g., cooking and clothes drying) to the life cycle emissions from meeting the same energy demand with heating oil and electricity

14.3 Alternatives to Close Demand-Supply Gap: Detailed Cost Analysis

14.3.1 Offshore LNG Deepwater Port (2026/27)

Figure A-1: Offshore LNG Deepwater Port – High Demand Scenario

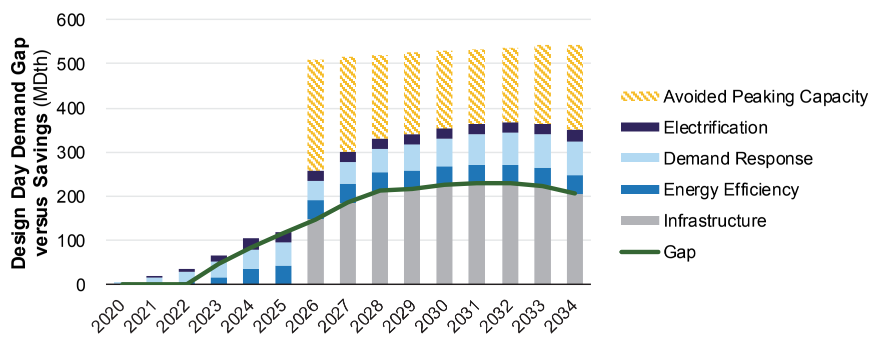


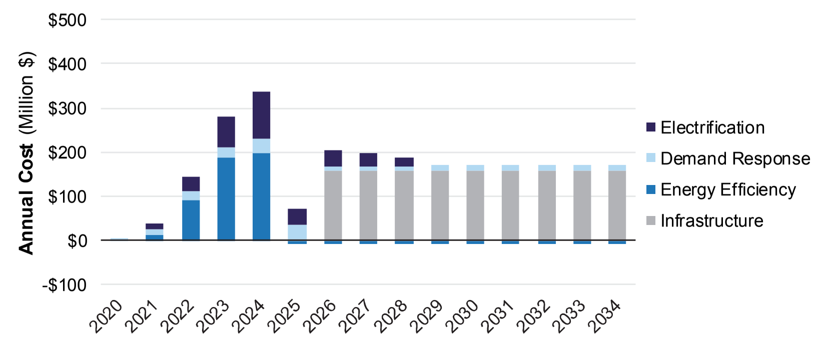


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-2: Offshore LNG Deepwater Port – Low Demand Scenario



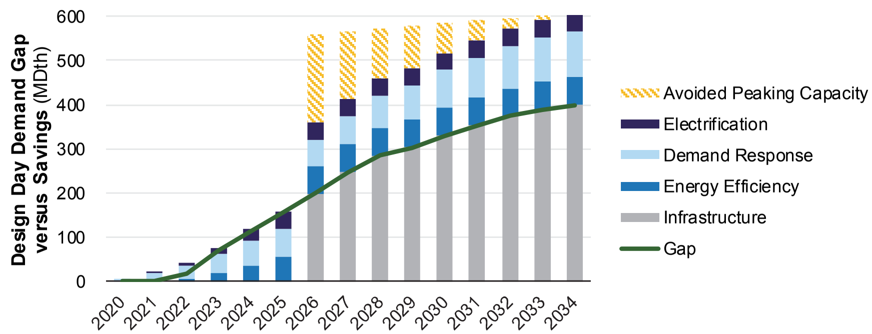


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

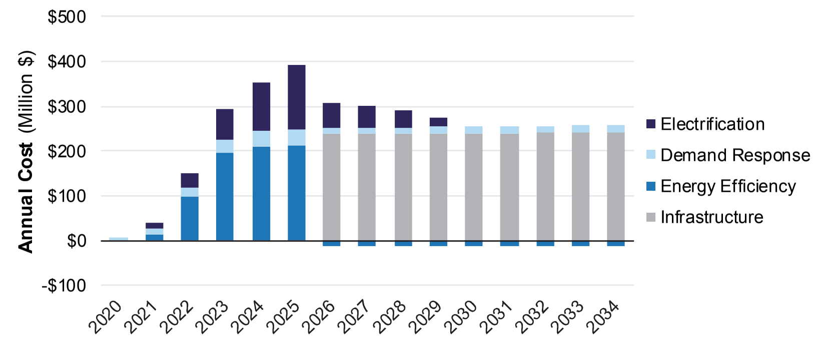
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.2 LNG Import Terminal (2026/27)

Figure A-3: LNG Import Terminal – High Demand Scenario

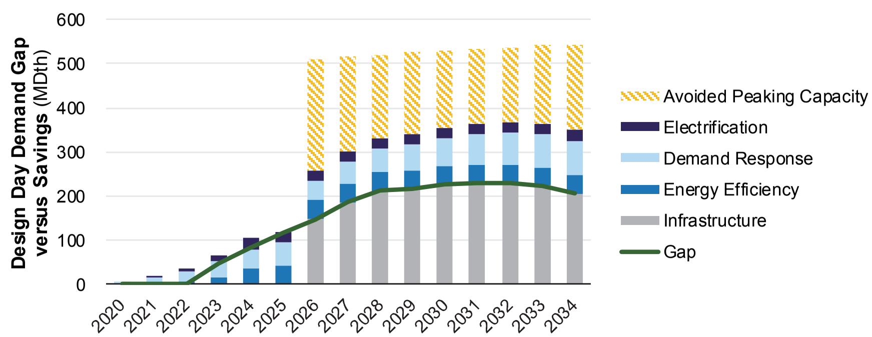


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

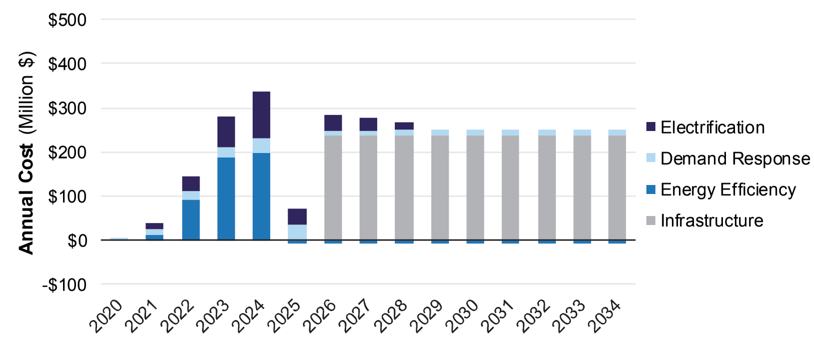


Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-4: LNG Import Terminal – Low Demand Scenario



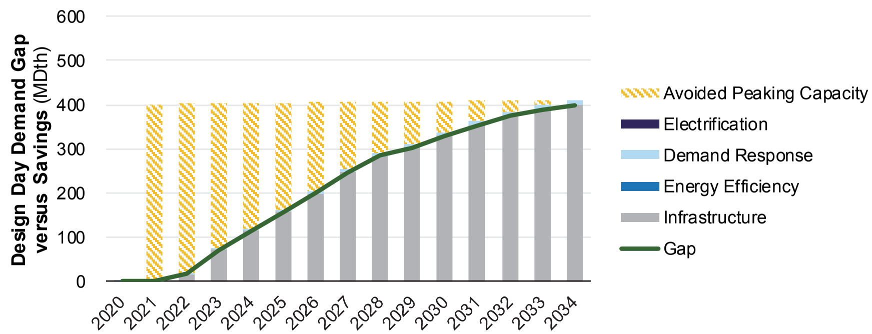
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



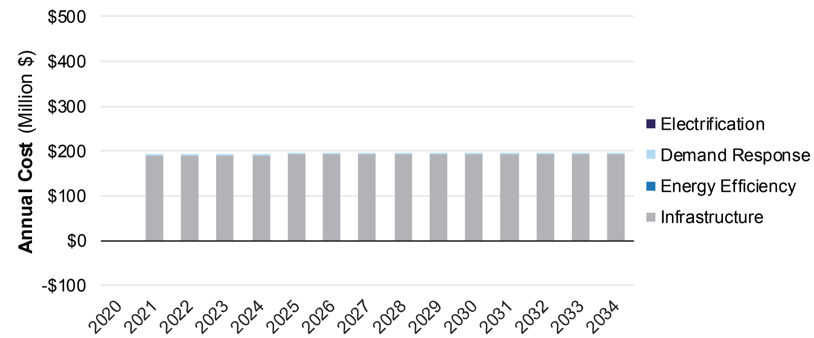
Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.3 Northeast Supply Enhancement (NESE) (2021/22)

Figure A-5: Northeast Supply Enhancement (NESE) – High Demand Scenario

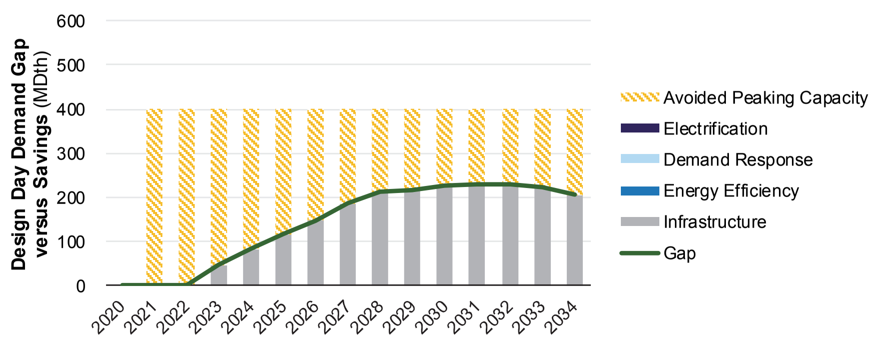


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

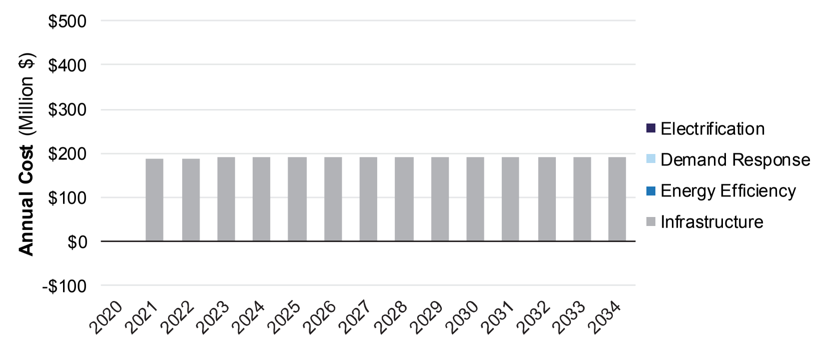


Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-6: Northeast Supply Enhancement (NESE) – Low Demand Scenario



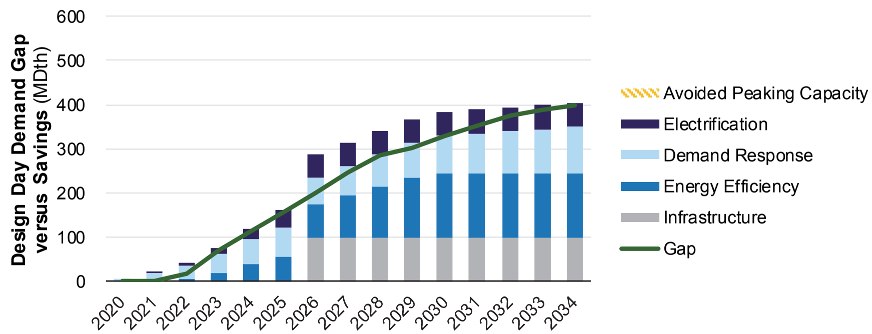
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



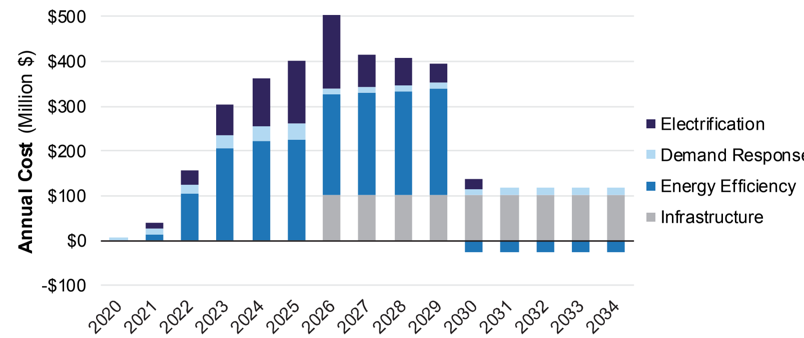
Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.4 Peak LNG Facility

Figure A-7: Peak LNG Facility – High Demand Scenario

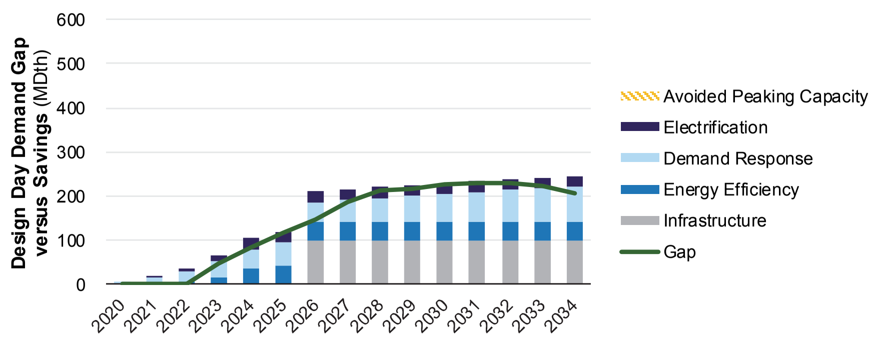


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

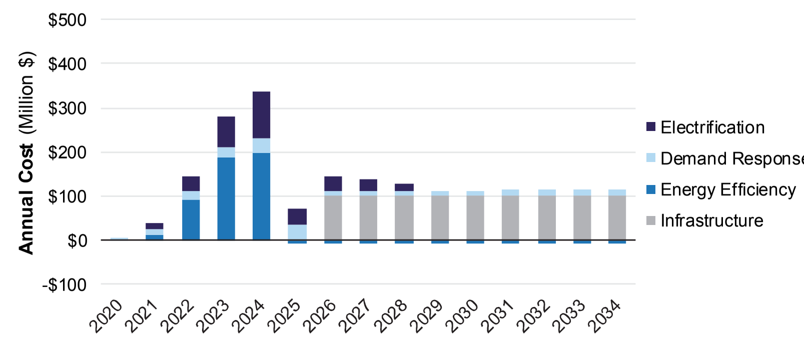


Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-8: Peak LNG Facility – Low Demand Scenario



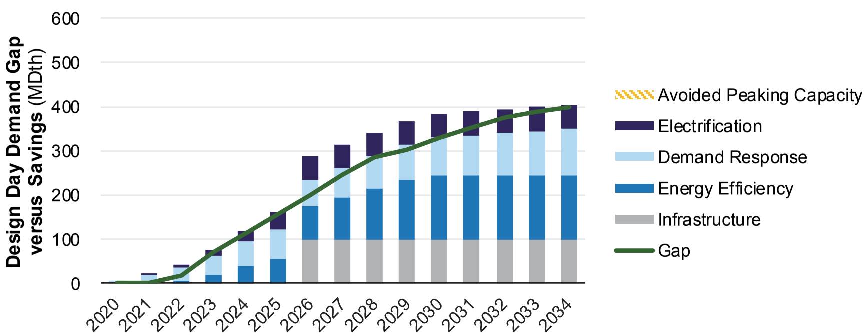
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



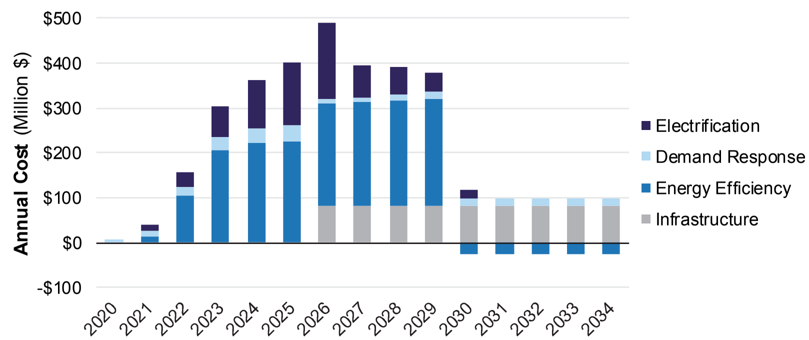
Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.5 LNG Barges (2026/27)

Figure A-9: LNG Barges – High Demand Scenario

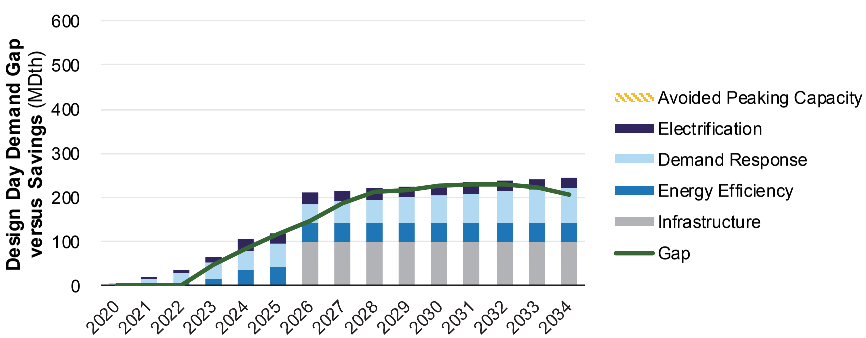


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

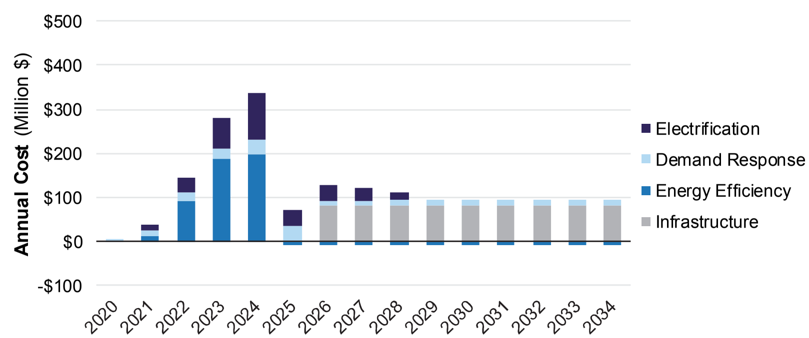


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-10: LNG Barges – Low Demand Scenario



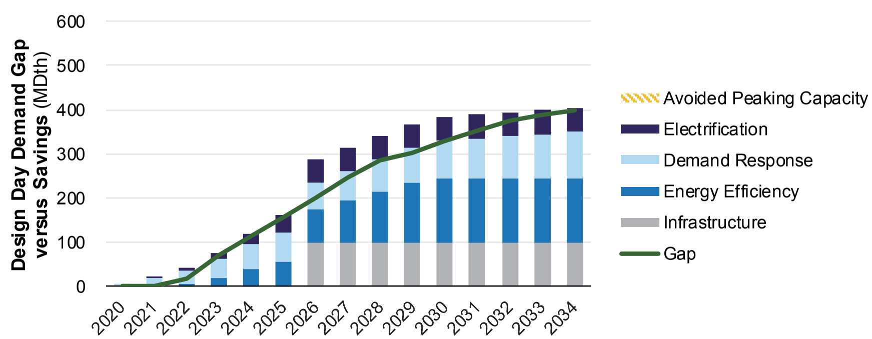
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

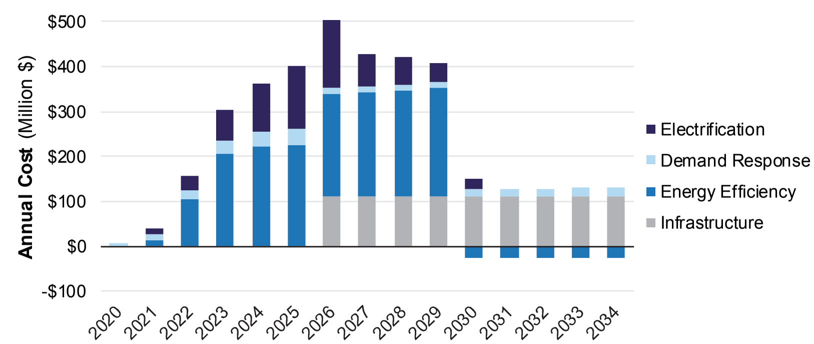


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.6 Clove Lakes Transmission Loop Project (2026/27)

Figure A-11: Clove Lakes Transmission Loop Project – High Demand Scenario

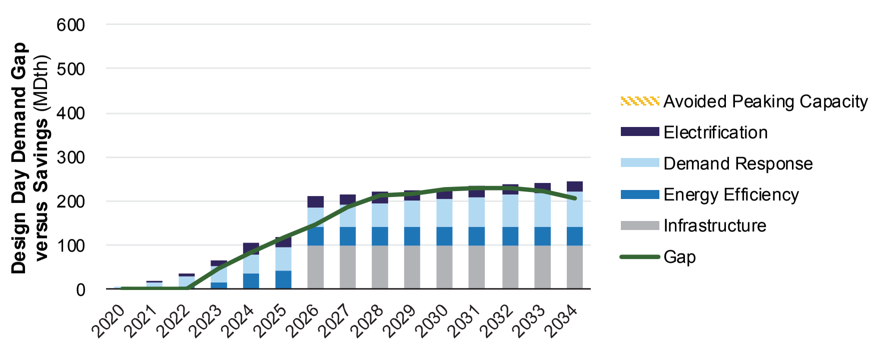


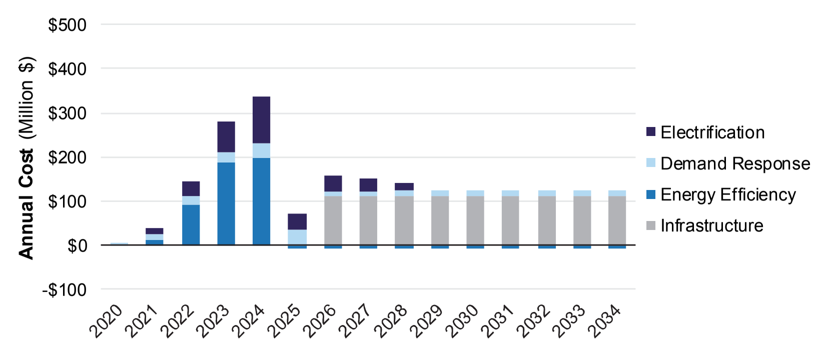


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-12: Clove Lakes Transmission Loop Project – Low Demand Scenario



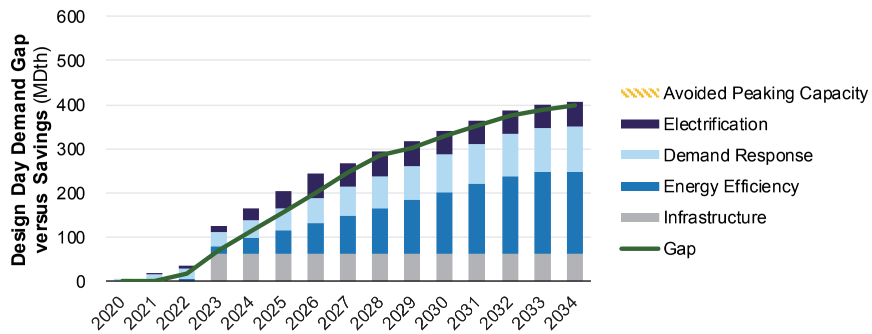


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

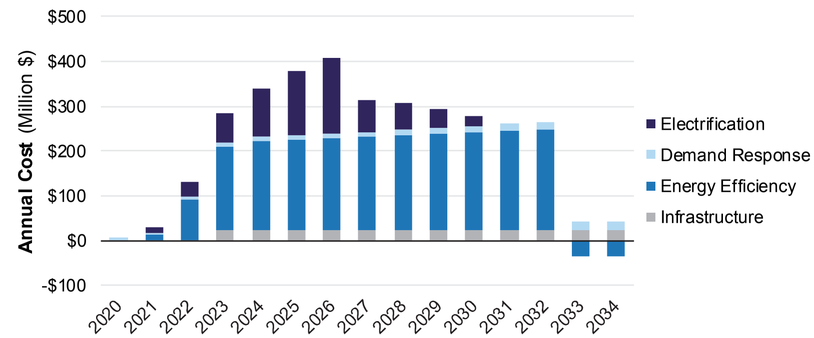
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.7 Iroquois Enhancement by Compression (EXC) (2023/24)

Figure A-13: Iroquois Enhancement by Compression (EXC) – High Demand Scenario

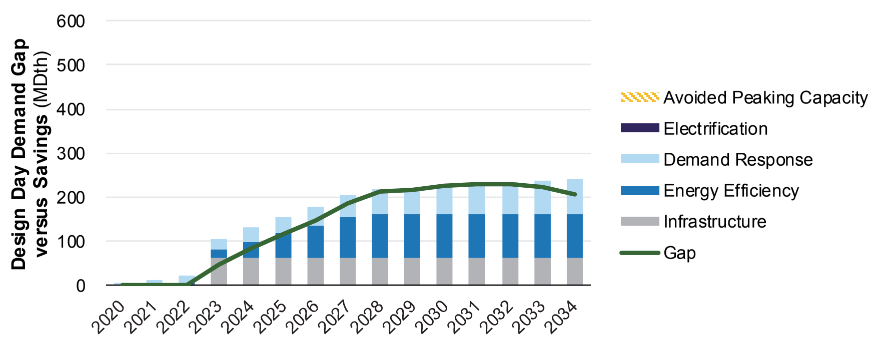


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

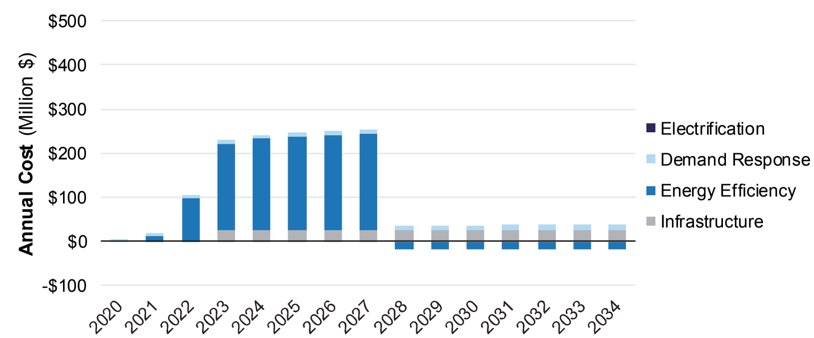


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-14: Iroquois Enhancement by Compression (EXC) – Low Demand Scenario



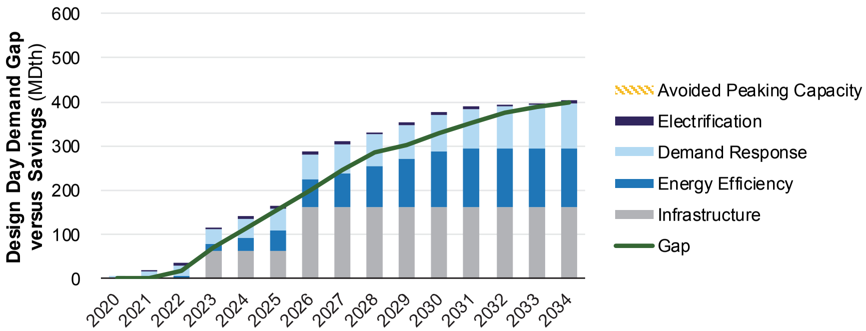
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



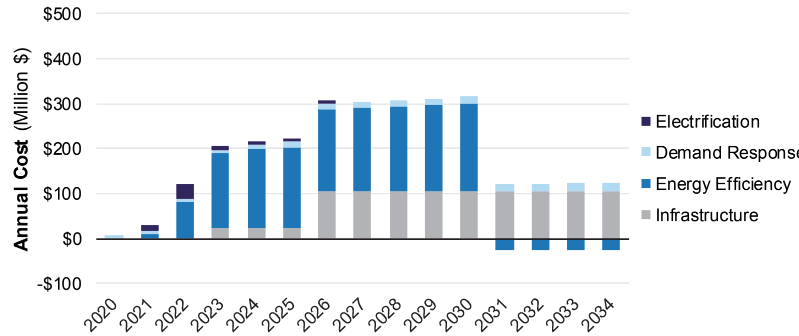
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.8 Iroquois ExC (2023/24) plus LNG Barges (2026/27)

Figure A-15: Iroquois ExC plus LNG Barges – High Demand Scenario

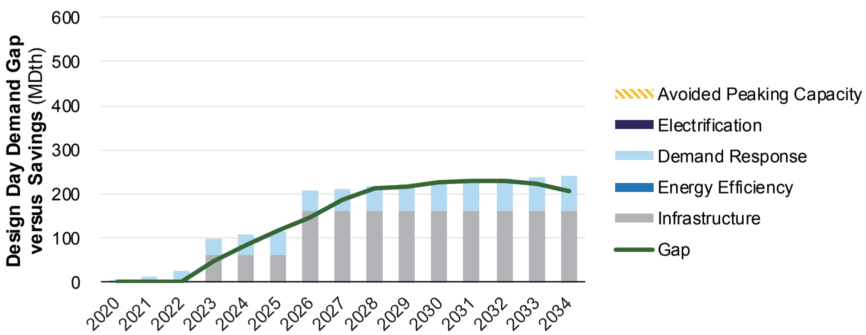


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

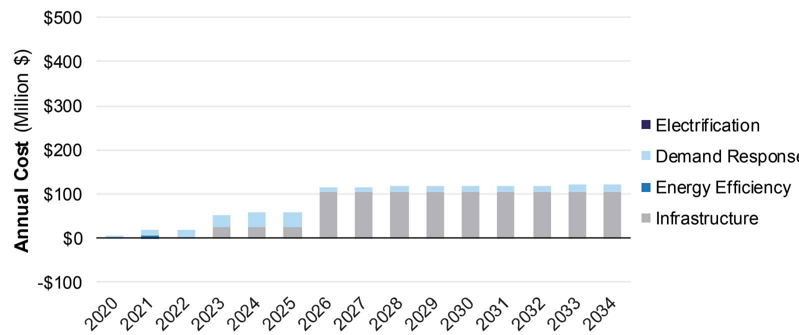


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-16: Iroquois ExC plus LNG Barges – Low Demand Scenario



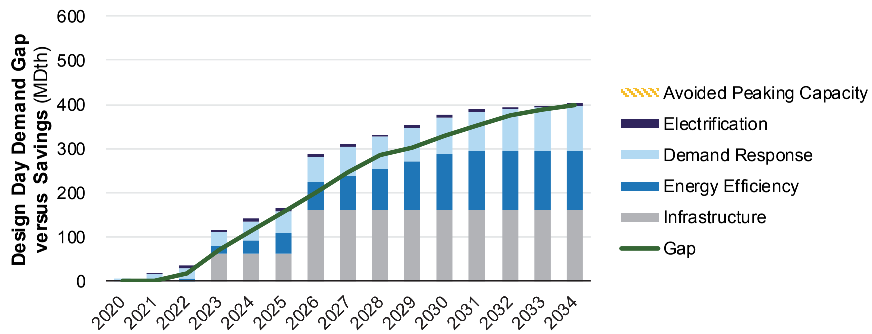
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



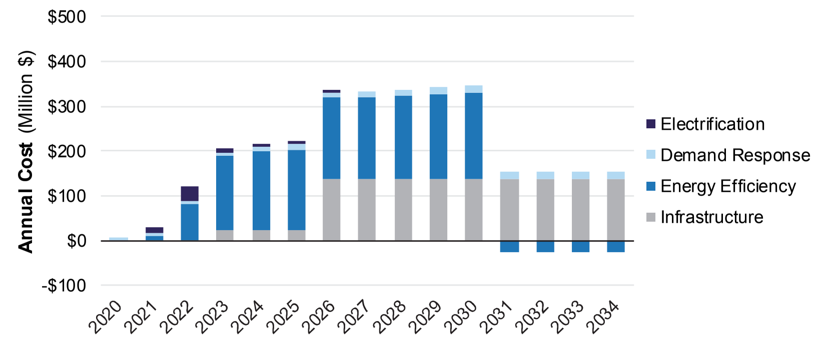
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.9 Iroquois ExC (2023/24) plus Clove Lakes Transmission Loop (2026/27)

Figure A-17: Iroquois ExC plus Clove Lakes Transmission Loop – High Demand Scenario

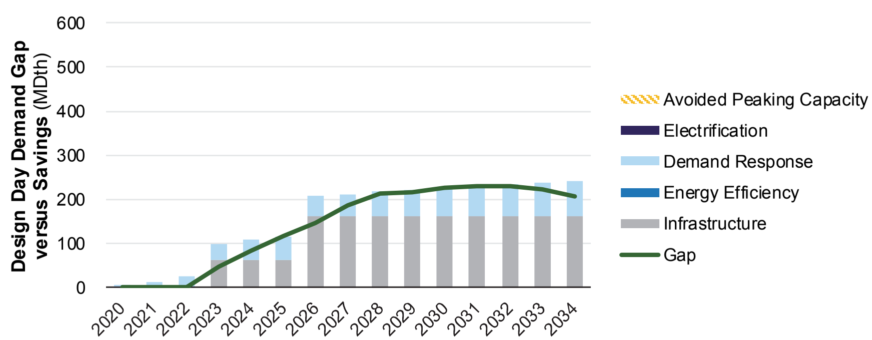


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

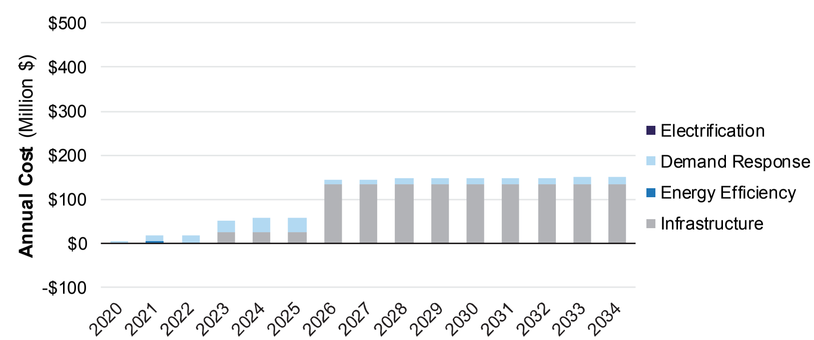


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-18: Iroquois ExC plus Clove Lakes Transmission Loop – Low Demand Scenario



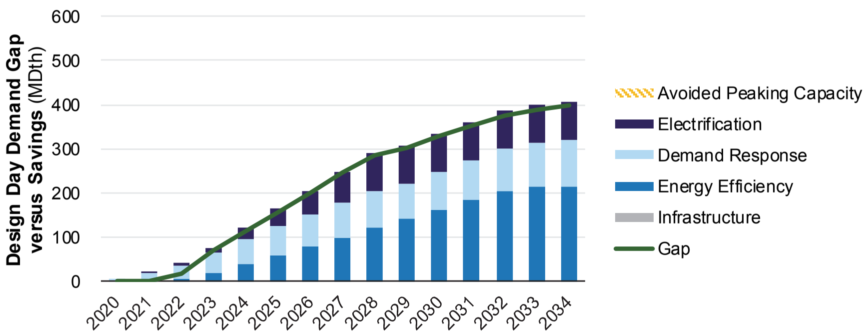
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



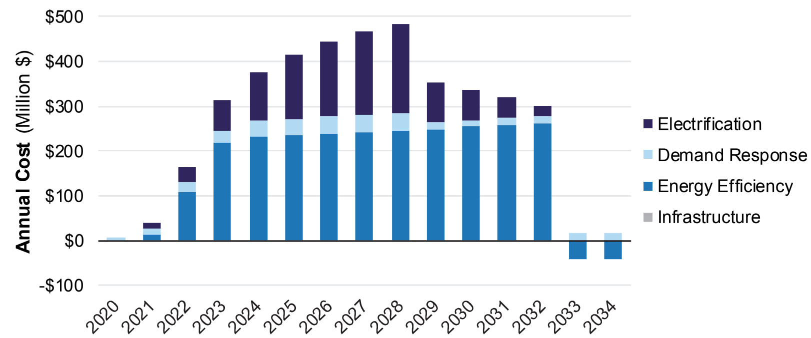
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

14.3.10 No Infrastructure

Figure A-19: No Infrastructure – High Demand Scenario

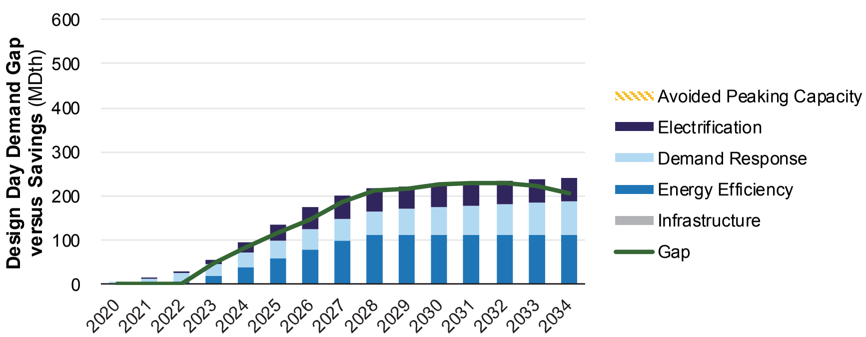


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

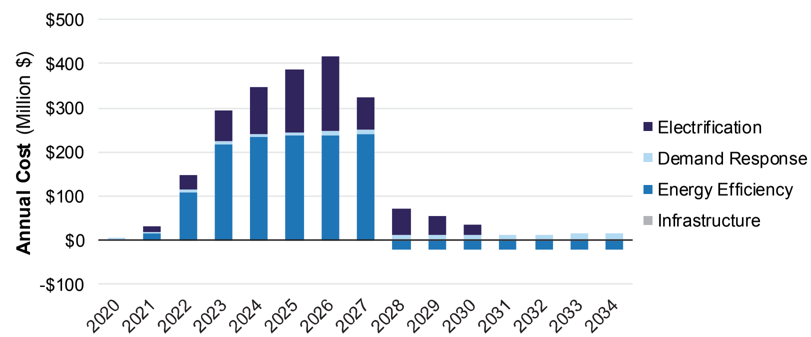


Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A-20: No Infrastructure – Low Demand Scenario



Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.