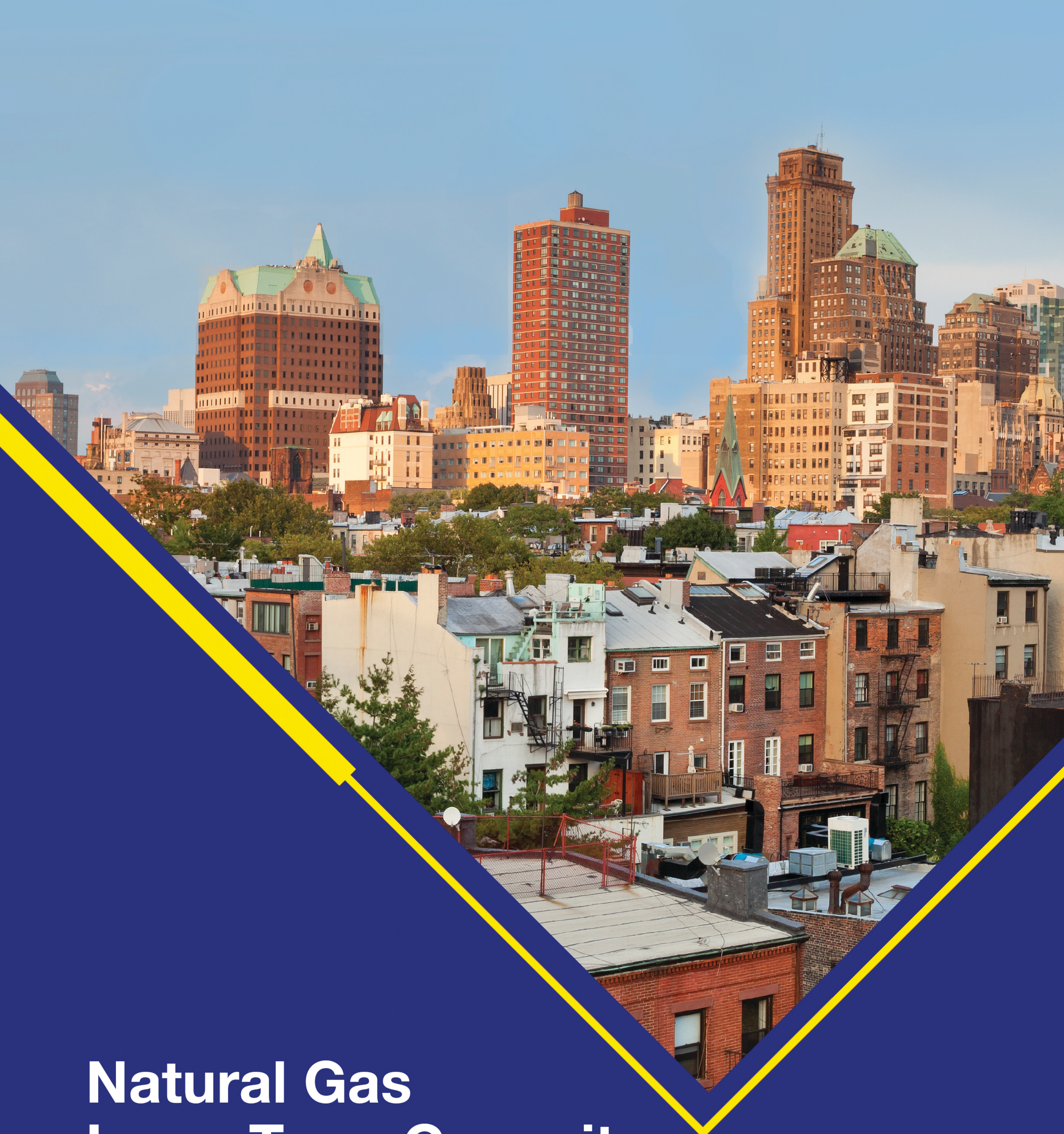

Natural Gas Long-Term Capacity Supplemental Report

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

May 2020

nationalgrid

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1. Introduction

On February 24, 2020, National Grid released the Natural Gas Long-Term Capacity Report (the "Report") for Brooklyn, Queens, Staten Island and Long Island ("Downstate NY"). This Report provided a detailed analysis of natural gas capacity constraints in the region and available options for meeting long-term demand.

Since the release of the Report, numerous activities were undertaken to provide additional content details and gather and analyze feedback, including:

- **Publications providing additional information**, including a 20-page Summary Report published to the NY PSC website and the National Grid website on March 11th; a more detailed Technical Appendix published on March 23rd and updated on April 1st; and a Customer Cost Impact Analysis published on March 23rd.[1]
- **Collection of feedback from public meetings**. Throughout March, a series of six public meetings were held to present the contents of the Report, answer questions, and hear public statements. The first meeting was held in Hicksville, NY, and the remaining five were moved to virtual meetings due to the COVID-19 pandemic. In total, there were 813 participants in these meetings and 258 public statements were collected.
- **Submitted written comments.** Through May 1, National Grid reviewed 15 filed documents and 7,385 public comments from 5,017 individuals and organizations regarding the Report submitted through the PSC web site.
- **On-line survey responses.** Through May 1, National Grid received 200 completed on-line surveys. This survey provided another avenue for the public to share their opinion on the different options presented in the Report to close the identified gap between natural gas demand and existing supply.
- **Ongoing Monitor engagement.** National Grid has continued to work with the Monitor who is overseeing the settlement agreement[2] between the Company and the state of New York, ensuring compliance with the settlement terms and responding to recommendations for improvements.

Also, since the release of the Report, the world economy in general and the Downstate NY economy in particular have undergone significant disruption due to the COVID-19 pandemic. While it is anticipated that the economy will open back up in the long-term, some near-term reduction in Design Day natural gas demand is expected, and there could also be an impact to longer term forecasts.

National Grid has reviewed all the comments and feedback from the sources cited above, and considered the potential impact of COVID-19, to create this Supplemental Report (the "Supplemental Report"). This Supplemental Report is intended to accomplish three objectives: 1) respond to the comment themes, and in some cases to specific comments, providing further data and explanation regarding National Grid's assumptions and analysis (or, where applicable, a change to assumptions or analysis); 2) utilize the feedback and additional analyses completed to update our assessment of the Downstate NY gap between natural gas demand and available supply, and the options available

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[1] These and all additional publications are available at www.ngrid.com/longtermsolutions
[2] Settlement Agreement, dated November 24, 2019, between National Grid and Department of Public Service Staff; approved by the New York State Public Service Commission in Case 19-G-0678 by order dated November 26, 2019.

to resolve this gap; and 3) recommend potential solutions – narrowing down the choices and outlining the requirements to achieve these specific solutions.

Following a summarization of comments and responses received through the public meetings, the written public comments and the on-line survey, this Supplemental Report will address updates to the Downstate NY natural gas demand forecast, National Grid's available natural gas supply, and the demand-supply gap; an update to solution options to close the gap; expanded analyses of cost, environmental and risk considerations for each of the different solution options; and finally, National Grid's recommended solution choices for consideration.

For access to the original Report and all additional related materials, please go to **www.ngrid.com/longtermsolutions**.

2. Executive Summary

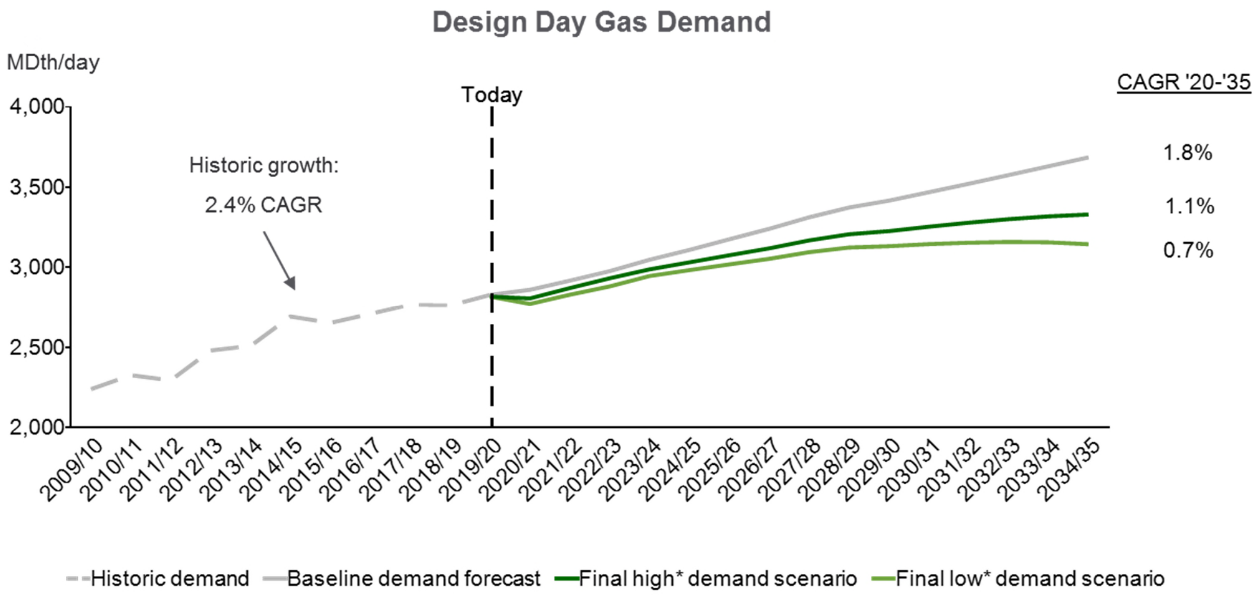
The major changes and additions that are being made in the Supplemental Report in relation to the Long-Term Capacity Report include:

- Updates to our demand forecast, available supply and the demand-supply gap;
- Addition of a new Distributed Infrastructure option (LNG Vaporization);
- Updates to our cost assumptions for the different solutions;
- Additional analysis of customer cost impact, assessment and societal cost of GHG emissions, environmental concerns, and quantification of risk impact; and
- National Grid recommendations on the preferred solutions.

Each of these items is discussed below, and in more detail in the main body of the report.

Demand reduction due to COVID-19 impact. Initial data indicates Downstate NY natural gas demand reduction of 0% to -2% in the 2-3 weeks in March that preceded a full lockdown, and -4% to -6% during the late March and April lockdown. Based on this data and further analysis of the potential impact COVID-19 will have on the number of natural gas customers and usage per customer in Downstate NY, we are adjusting our Design Day Demand forecast down by 1.4-2.5%[3] (40-70 MDth/day) for the winter of 2020/21, and by 0.3-1.0% (10-30 MDth/day) on a more permanent basis through 2034/35. Figure 1Figure 1 below shows our new Design Day demand under the High Demand and Low Demand scenarios.

Figure 1: Historic and Projected Design Day Natural Gas Demand in Downstate NY, 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.*

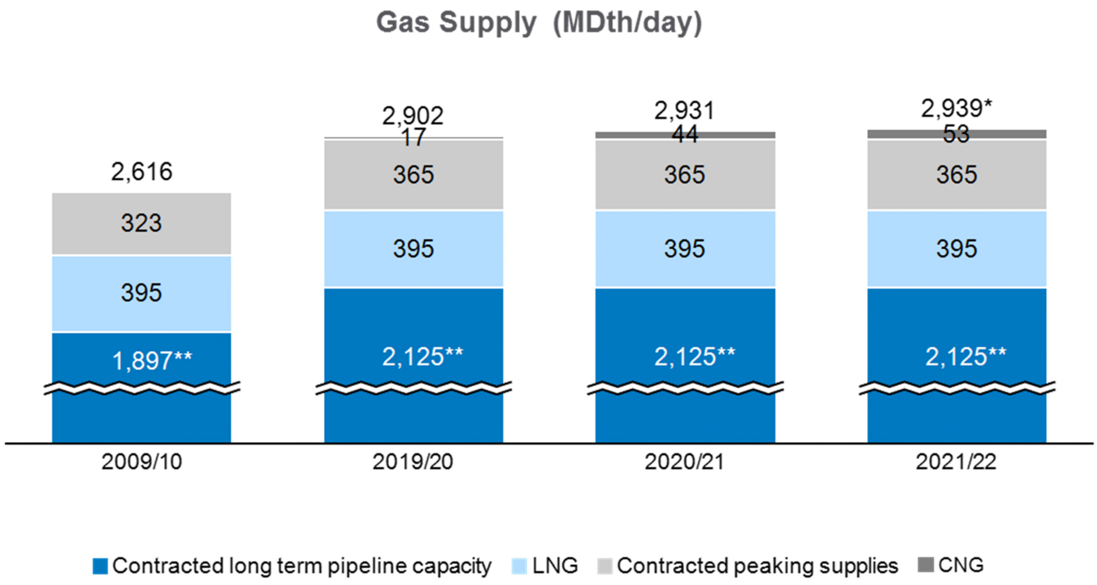
Source: National Grid analysis based on projections and data from Advanced Data Analytics team, rate case filings, New Efficiency New York Order, and Con Edison and PSEG Long Island Downstate NY electrification programs.

[3] Assuming partial or complete end of lockdown. If we remain in or return to a full lockdown in the winter of 2020/21, the design day reduction could be as high as 6%.

The numbers above are calculated using the existing Design Day standard of 0˚F in Central Park for 24 hours. As explained further in Section 4 of this Supplemental Report, it is National Grid's conclusion that there are too many factors to warrant changing the analysis without a more detailed study done in conjunction with other impacted parties and stakeholders. Going forward, National Grid believes there is an opportunity to review Design Day standards with the NY PSC as part of the recently announced natural gas supply planning proceeding.[4]

Modest supply increase based on detailed internal review. Following a detailed review of all supply capacity and agreements, including recently updated throughput results, National Grid has determined that there is an additional 14.5 MDth/day (+0.5%) of supply capacity available with its existing infrastructure (13 MDth/day through its pipelines, and 1.5 MDth/day through its LNG facilities). Figure 2 below provides an updated natural gas supply stack for Downstate NY.

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



**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*

Source: National Grid analysis

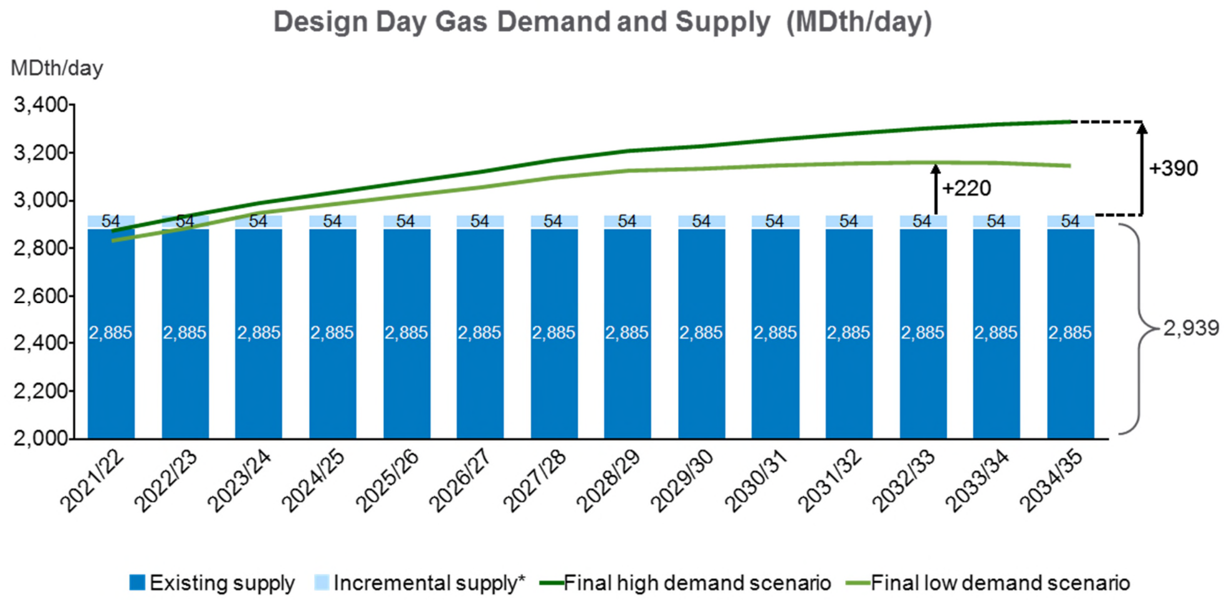
Smaller gap between demand and supply. Based on the lower demand forecast and the increase in supply described above, the Design Day demand-supply gap has been reduced by 25 – 45 MDth (0.8% - 1.5% of total). In the updated High Demand scenario, there is now a Design Day gap that

[4] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding at 2 (issued March 19, 2020). The gas utilities subject to the Order are Consolidated Edison Company of New York, Inc.; The Brooklyn Union Gas Company d/b/a National Grid NY; KeySpan Gas East Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc.; Central Hudson Gas & Electric Corporation; Niagara Mohawk Power Corporation d/b/a National Grid; New York State Electric & Gas Corporation; Rochester Gas and Electric Corporation; National Fuel Gas Distribution Corporation; St. Lawrence Gas Company, Inc.; and Corning Natural Gas Corporation.

starts in 2022/23 and grows to 390 MDth by 2034/35, whereas in the initial Report the High Demand gap started in 2021/22 and grew to 415 MDth. In the updated Low Demand Scenario, there is now a Design Day gap that starts in 2023/24 and grows to 220 MDth by 2032/33, whereas in the initial Report the Low Demand gap started in 2022/23 and grew to 265 MDth.

Figure 3 below shows the updated gap between demand and supply under the High Demand and Low Demand scenarios.

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

Based on the updated numbers above, and following assumed implementation of Low Carbon initiatives as described in Section 8 of the original Report, the Design Day demand-supply gap is reduced to 185 MDth – 375 MDth. All potential solutions are now being assessed based on their ability to close this revised gap.

Introduction of a new Distributed Infrastructure option to close the gap between demand and supply. While planning vaporization upgrades at its Greenpoint Liquefied Natural Gas (LNG) facility to increase reliability and reduce maintenance costs, National Grid identified a separate opportunity to enhance throughput at its existing facility and further leverage existing infrastructure with the addition of two more vaporizers.[5] This Greenpoint LNG Vaporization project could increase supply by 60 MDth/day and be available by November 30, 2021, with a construction cost of $59M.

Table 1 provides a summary of the Greenpoint LNG Vaporization option.

[5] This opportunity was also identified in public comments from Synapse, based on their review of recent National Grid filings.

Table 1: Summary of LNG Vaporization Option

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

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Installation of two additional Submerged Combustion Vaporizers (SCVs) at National Grid's Greenpoint LNG facility
Size	60 MDth/day	Designed to meet periods of peak demand
Safety	◕	New York City Fire Department (FDNY) and state entities to review and approve all necessary safety processes and protocols
Reliability	◕	Vaporizers are simple in design and have historically been very reliable – National Grid has extensive experience in this area
Cost	●	Total project cost to install two vaporizers is $59M, and estimated annual costs are approximately $12M
Environmental Impact	◑	The short-term ecological impact from installation will be moderate in the Greenpoint area of New York. While emissions from an LNG system are 10-15% higher than what would be expected for a pipeline solution, impact would be low due to intermittent peak usage.
Community Impact	◕	Low impact to the community – all planned construction and installation is within the existing Greenpoint LNG footprint
Permitting, Policy and Regulatory Requirements	N/A	Would require NYC Department of Buildings (DOB) and FDNY approval for construction within NYC. LNG truck station permits and LNG Trucking MoU with the City of New York are also required.
Requirements for Implementation	N/A	Assuming all approvals are attained on a timely basis, the project can be in-service by December 2021 (~1.5 years)

Updated cost numbers for all potential solutions. We have updated the cost modeling for each of the different potential solutions to close the gap between demand and available supply. The majority of the change is driven by the lower demand-supply gap, which in most options leads to lower required levels of incremental energy efficiency, demand response, and electrification.

There are two other cost changes of note. The first is related to the cost of electrification. Based on comments received, we reviewed and updated our assumptions around program design to more explicitly target existing gas customers and have tighter coordination with the electric distribution companies, avoiding costs related to overlap with NENY targets. While the exact percentages vary by year and scenario, as an example this change reduces electrification costs by 17% in the High Demand scenario for the No Infrastructure solution.

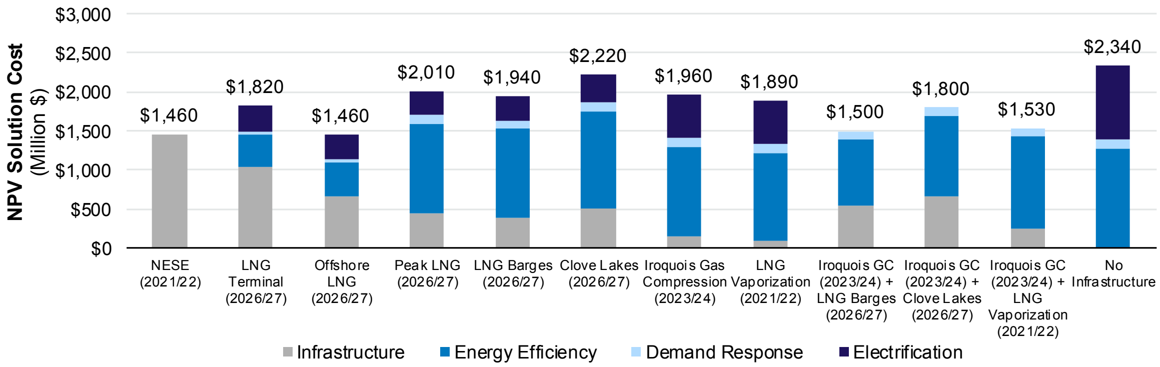
The second is the cost to operate our Compressed Natural Gas (CNG) sites. Updated information indicates this cost will be $20-$25M per year ($22.5M midpoint). For the Large Infrastructure options (Floating LNG, LNG Terminal, NESE Pipeline), our assumption is that CNG trucking can be stopped once these projects are brought online, saving $22.5M per year once this occurs. For the

Distributed Infrastructure and No Infrastructure options, we are assuming that CNG will continue through 2035 and will be included in the Supply stack as it currently stands[6].

Figures 4 and 5 below show the updated Net Present Value calculations of the cost for the different alternatives to close the gap between forecast demand and available supply under the revised High Demand and Low Demand scenarios.

[Note: For the Figures below and all subsequent analyses that compare the different options, they are being analyzed as the entire solution to close the gap between forecast demand and available supply. So, for example, "Peak LNG" represents both the construction of this distributed infrastructure solution, and the incremental demand reduction from energy efficiency, demand response and electrification that would be required to close the gap.]

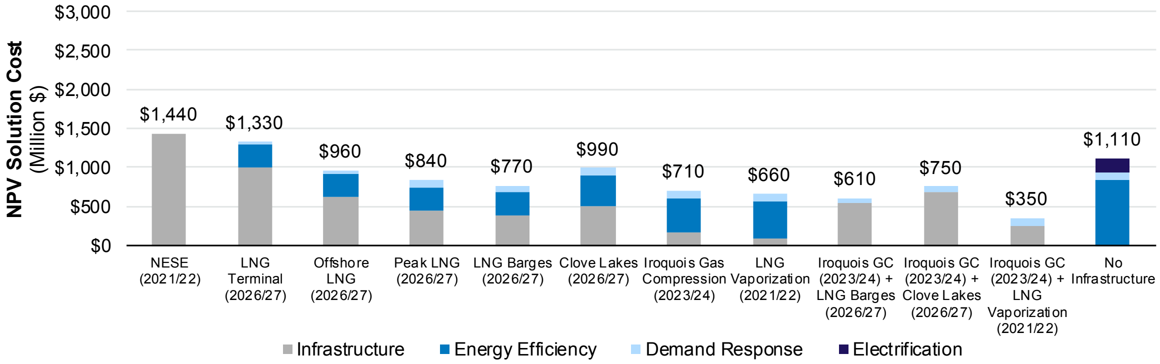
Figure 4: NPV of Net Costs for Different Solutions to Close Demand-Supply Gap – High Demand Scenario



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 between KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, which start in the listed operational year and are assumed to end in 2034/35, 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 through 2034/35.

[6] If demand reduction programs start to consistently exceed targets, and/or if incremental programs can be designed to increase penetration and demonstrate predictability and delivery in specific geographies/times of day, in future years CNG trucking could be reduced or eliminated.

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



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Additional analyses completed on customer cost impact, cost of GHG emissions, CLCPA/environmental considerations, and risk impact.

Customer Cost Impact

In addition to the total cost analysis shown above, National Grid also completed an analysis for each of the solution options to show the customer cost impact. These costs were evaluated in isolation from any other network and program costs, while taking into account forecast changes in number of customers over time. So, to the extent that % growth in number of customers is greater than the net % growth in the cost of the solution, cost impacts could in fact be negative in this analysis. Tables 2 and 3 below show a ranking of the lowest to highest monthly cost impact on customers in the revised High Demand and the Low Demand scenarios.

Table 2: Ranking of the Average Customer* Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply – High Demand Scenario

Rank	Solution Option	Mo. Cost Impact (%) **	Mo. Cost Impact ($) **
1	Northeast Supply Enhancement (NESE)	0.9%	$1.21
2	Gas Compression + LNG Vaporization	1.1%	$1.50
3	Gas Compression + LNG Barges	1.3%	$1.81
4	Gas Compression + Clove Lakes	2.3%	$3.23
5	Offshore LNG Port	2.4%	$3.34
6	LNG Barges	3.8%	$5.30
7	LNG Import Terminal	3.8%	$5.31
8	Peak LNG Facility	4.1%	$5.64
9	LNG Vaporization	4.9%	$6.79
10	Gas Compression on Iroquois GTS (ExC)	5.2%	$7.17
11	Clove Lakes Transmission Loop (CL)	5.2%	$7.23
12	No Infrastructure	8.5%	$11.71

** Weighted average customer across all customer types, which is very similar to the impacts on a residential heat customer (e.g. higher customer cost from multifamily and C&I customers are offset by lower customer cost from Residential Non-Heat)*

*** Based on 15-year average annual cost impact*

Table 3: Ranking of the Average Customer* Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply – Low Demand Scenario

Rank	Solution Option	Mo. Cost Impact (%) **	Mo. Cost Impact ($) **
1	Gas Compression + LNG Vaporization	(2.3%)	($3.19)
2	LNG Vaporization	(1.6%)	($2.18)
3	Gas Compression on Iroquois GTS (ExC)	(1.4%)	($1.95)
4	Gas Compression + LNG Barges	(1.3%)	($1.75)
5	LNG Barges	(1.0%)	($1.44)
6	Peak LNG Facility	(0.8%)	($1.07)
7	Gas Compression + Clove Lakes	(0.7%)	($1.01)
8	Offshore LNG Port	(0.3%)	($0.44)
9	Clove Lakes Transmission Loop (CL)	(0.3%)	($0.42)
10	No Infrastructure	0.5%	$0.72
11	LNG Import Terminal	1.1%	$1.49
12	Northeast Supply Enhancement (NESE)	1.2%	$1.61

** Weighted average customer across all customer types, which is very similar to the impacts on a residential heat customer (e.g. higher customer cost from multifamily and C&I customers are offset by lower customer cost from Residential Non-Heat)*

*** Based on 15-year average annual cost impact*

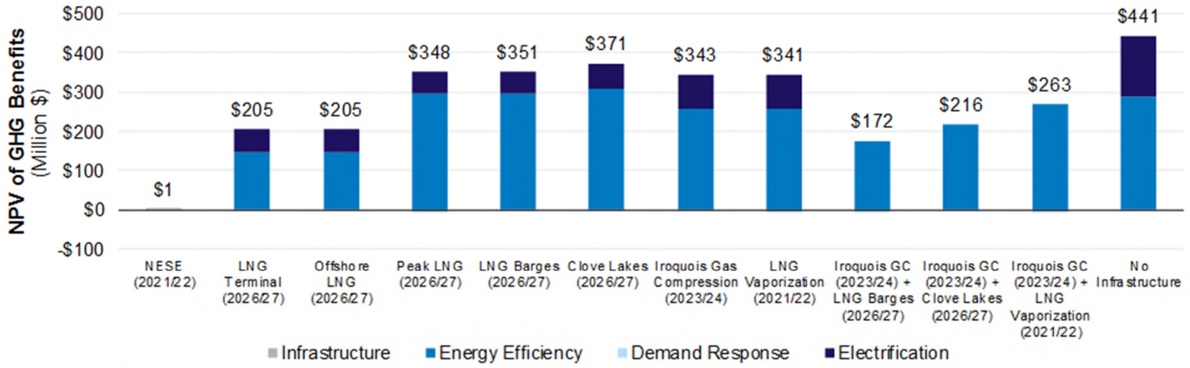
In the high demand scenario, the NESE option has the lowest impact – adding an average $1.21 per month to each customer's cost. In the low demand scenario, a combination of Gas Compression on Iroquois GTS and LNG Vaporization paired with incremental Energy Efficiency and Demand Response has the lowest impact – showing an average reduction of ($3.19) per month from each customer's cost.

This ranking is valuable to understanding the cost impact of these Supply Options, however, it is important to note that this analysis is not equivalent to an expected bill increase for each customer. This analysis isolates the overall cost of these solutions across a projected uniform customer base (i.e. it does not evaluate potentially different impacts by customer type and usage of Residential Heat, Multifamily, etc.). Other potential changes that could impact costs and customer bills, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, inflation, etc. are also not included in this analysis.

Cost of GHG Emissions

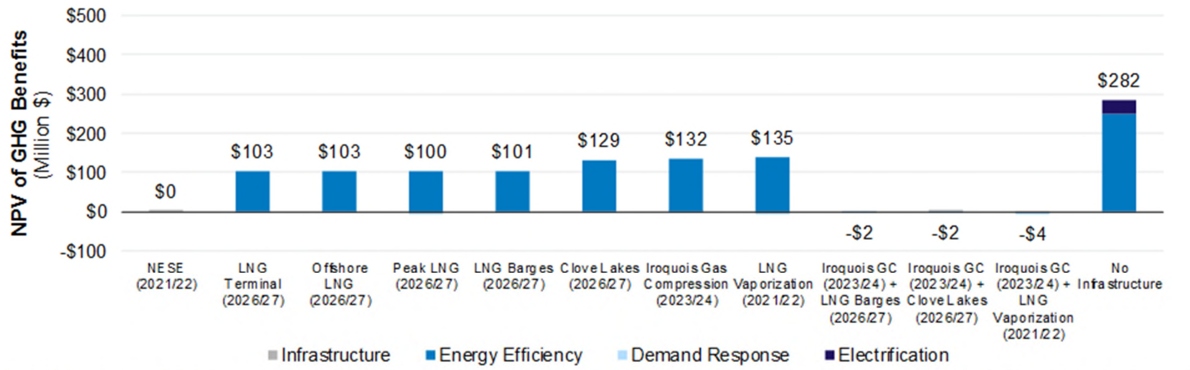
In addition to the customer cost impact analysis, we also completed additional analysis on the cost of GHG emissions and benefits of emission reductions. For each of the potential solutions, we considered the change in emissions vs. projected natural gas demand assuming incremental capacity filled by pipeline natural gas. So, for example, if a solution calls for the utilization of LNG, and LNG has 10-15% higher emissions than pipeline gas, then the incremental LNG volume used in that solution would have higher emissions and a calculated "cost of GHG penalty". And, on the other hand, if a solution reduces demand through energy efficiency, then the solution would have a "cost of GHG savings" calculated based on a reduction of pipeline natural gas. The net results of this analysis can be seen in Figure 6 below for the High Demand scenario, and Figure 7 for the Low Demand scenario.

Figure 6: GHG Cost/Benefit of Different Solutions to Close the Gap Between Projected Demand and Available Supply – High Demand Scenario



Notes: Net present value of GHG savings includes net annual emissions savings of CO2, N2O, and CH4 pollutants, monetized by the respective social cost by pollutant from the EPA at the 3% discount rate (Source: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

Figure 7: GHG Cost/Benefit of Different Solutions to Close the Gap Between Projected Demand and Available Supply – Low Demand Scenario



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We then combined the cost analysis from Figures 4 and 5 above with the GHG cost analysis from Figures 6 and 7 to show the "total societal cost impact" of the different options, which can be seen in Figures 8 and 9 for the High Demand and Low Demand scenarios.

Figure 8: Total Societal Cost NPV of Different Solutions (Factoring in Cost/Benefit of Carbon Emissions) – High Demand Scenario

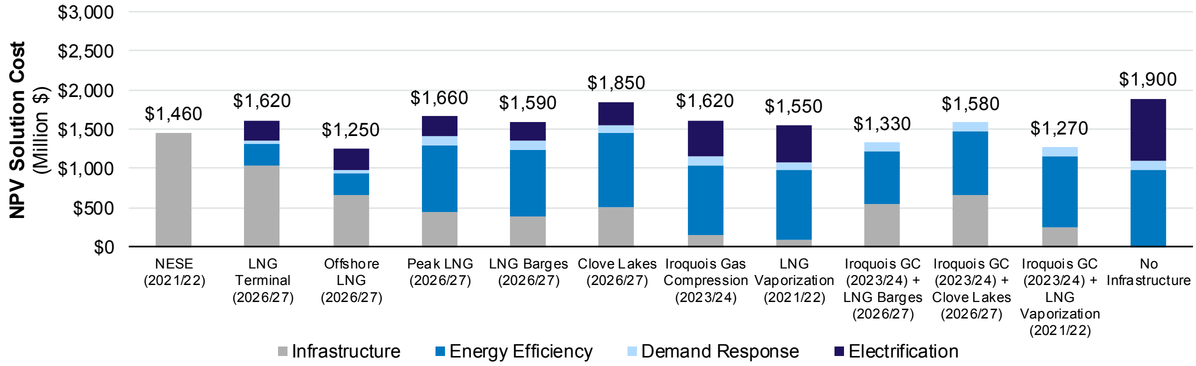

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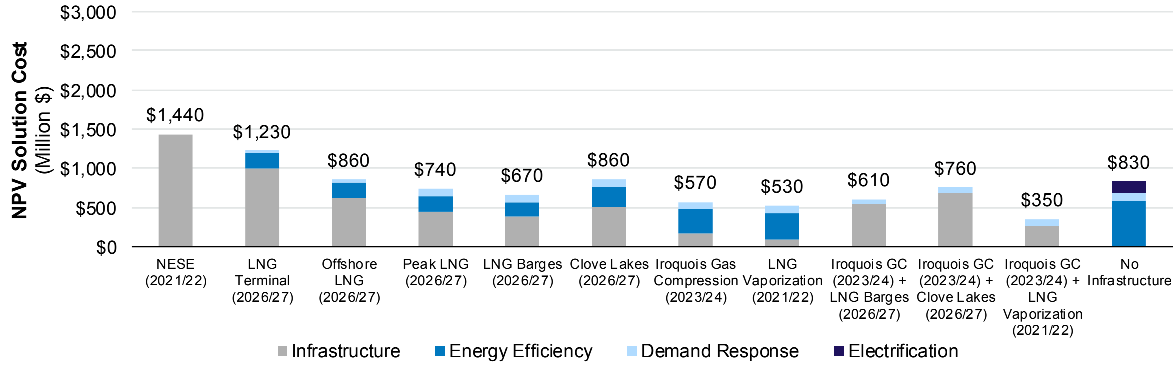
Figure 9: Total Societal Cost NPV of Different Solutions (Factoring in Cost/Benefit of Carbon Emissions) – Low Demand Scenario



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CLCPA/Environmental Considerations

National Grid also completed additional assessments of the environmental implications for each of the different options. This primarily focused on considerations and plausible pathways for achieving what is required under the CLCPA. National Grid has previously published analysis exploring some of these issues, focusing on what would be required to achieve an interim 2030 target of 40% below 1990 levels across the 7-state region of New York and New England.[7] This analysis demonstrated that continued growth in gas use is consistent with a regional 40% reduction by 2030, provided it is coupled with energy efficiency and dramatic reductions in fuel oil utilization.

[7] https://www.nationalgridus.com/News/Assets/80x50-White-Paper-Final.pdf

Looking out to 2050, while the CLCPA sets clear expectations for the magnitude and pace of electric sector decarbonization, the law is not prescriptive with regards to interim targets or 2050 endpoints for each sector such as transportation, heat, industry and land use. Such targets may be developed over time by the various Committees established by the law, which would enable such evaluation in the future. Having said that, several industry studies have concluded that gas networks can have a significant role in decarbonization, and that by avoiding overbuilding of electricity generation and networks, while minimizing invasive home equipment retrofits, these multiple-fuels pathways are more cost-effective than scenarios exclusively reliant on electrification.

Section 9 of this Supplemental Report provides more detailed considerations regarding how each option could support a pathway to carbon reduction and overall CLCPA achievement.

Risk Impact Analysis

In many of the options discussed in the Long-Term Capacity Report, National Grid referenced a potential need to restrict new customer connections if the solution did not deliver to its targets and explained under certain options how a disruption to supply could lead to service interruptions for existing customers. To better understand the potential impact of these scenarios, the Company completed a Risk Impact analysis. Table 4 below shows a summary of the results of this analysis, with the solutions listed in order from lowest risk impact to highest risk impact, based on timing of when the risk first appears and the magnitude of impact it could have over time (a more detailed analysis is included in Section 10 of this Supplemental Report).

Table 4: Potential Risk Impact by Solution – High Demand Scenario

	Potentially Halted New Customer Connections *		Customer Service Interruptions in the Event of a 2% Supply Disruption **	
Solution Option	Year that Risk First Appears	Potential # of Customers Impacted Over Time	Year that Risk First Appears	Potential # of Customers Impacted Over Time
NESE Project	N/A	0	2032-33	21,300
Iroquois + LNG Vaporization	2027-28	21,600	2025-26	82,800
LNG Vaporization	2026-27	27,500	2023-24	95,300
Iroquois Gas Compression	2026-27	26,700	2022-23	93,700
Iroquois + LNG Barges	2023-24	18,100	2022-23	75,400
Iroquois + Clove Lakes	2023-24	19,300	2022-23	78,000
Peak LNG Facility	2024-25	23,500	2022-23	87,000
LNG Barges	2024-25	23,500	2022-23	87,000
Clove Lakes	2024-25	25,200	2022-23	90,400
LNG Import Terminal	2024-25	27,200	2022-23	94,600
Offshore LNG Port	2024-25	27,200	2022-23	94,600
No Infrastructure	2024-25	32,400	2022-23	105,600

** Cumulative number of new customer connections that would need to be refused if incremental energy efficiency, demand response, and electrification missed their savings targets by 30% each year or the added infrastructure is delayed 1 year. Please see section 10 for more details.*

*** Number of customers that would need to have service interrupted in the event of an unforeseen reduction in available supply of 2%, based on a range of scenarios regarding achievement of demand management and timing of infrastructure. Please see section 10 for more details.*

Recommendations

In the initial Report, National Grid outlined a series of criteria against which it evaluated each of the options for closing the gap between projected demand and available supply. While we continue to believe these evaluation criteria are relevant, we have added some additional components. To get to our recommendations, we have considered the following (additions from the original Report in *blue*):

- **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, the risks that it might not deliver**,** *and the potential consequences (risk impact) if it does not deliver*
- **Cost** - aggregate cost to bring the capacity online, annual costs with and without a discount rate, which includes infrastructure and/or program costs and adjustments for commodity costs, *customer cost impact, and cost of GHG emissions*
- **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, *including pathways to CLCPA achievement*)
- **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
- ***Deliverability* –** which includes both permitting, policy and regulatory requirements (e.g. permits that will need to be approved, policy changes that could enable the option, and regulatory *funding vehicles* and obstacles that would require approvals or changes), as well as requirements for implementation (e.g. location siting; hiring for construction/program implementation; requirements to place equipment orders; etc.)

Based on our evaluation of the different options and potential solutions across these criteria, as explained in more detail in Section 12 below, the Company is recommending two potential solutions:

Option A: LNG Vaporization and Iroquois Gas Compression enhancements to existing infrastructure, combined with incremental Energy Efficiency (EE) and Demand Response (DR)

Option B: NESE Pipeline

Table 5 below provides a summary comparison for these options against the evaluation criteria described above.

Table 5: Comparison of Two Recommended Solutions Against Evaluation Criteria

	Option A: Enhancements to Existing Infrastructure Combined with Incremental EE and DR	Option B: NESE Pipeline
Safety	• Strong safety records exist for all infrastructure proposed for enhancement, and all programs proposed for demand management	• Strong pipeline safety record; PHMSA would enforce all regulations for safe, reliable and environmentally sound operation
Reliability (certainty of meeting demand)	• Risk impact analysis does not identify any risk to new customer connections until 2027/28, or any risk resulting from a 2% supply disruption until 2025/26, providing ample time to address issues/put programs in place to mitigate these risks	• Has the highest degree of certainty that it will meet demand, with no risk of restrictions to customer connections, and no risk of customer shut-offs with a 2% supply disruption until at least 2032/33
Cost	• The second lowest customer cost impact under the High Demand scenario, and the lowest cost impact under the Low Demand scenario • Factoring in the cost of GHG, it is the second lowest total societal cost option under the High Demand scenario and the lowest cost option under the Low Demand scenario	• The lowest cost option under the High Demand scenario; lowest total $ cost and customer cost impact • Under the Low Demand scenario, it is the highest cost option • Factoring in the cost of GHG, it is the fourth lowest total societal cost solution under the High Demand scenario and the highest cost under the Low Demand scenario • Pipeline agreement is for 15 years, which eliminates concern about customers paying for stranded assets
Environmental Impact	• Infrastructure impact on the environment is minimal, as there is no new greenfield construction – it is enhancements to existing infrastructure. • Demand reduction through energy efficiency reduces emissions in the 2020-2035 time frame and accelerates pathway to achieving CLCPA goals	• Creates ecological impact from construction to the subsea environment • Has some beneficial environmental aspects in the near term (lower current marginal emissions vs. electrification, elimination of CNG trucking) • Longer term, supports carbon reduction from expansion of Renewable Natural Gas supplies, and is hydrogen-enabled to enable hydrogen blending/transport
Community Impact	• All planned infrastructure enhancements are within existing footprints/locations • Buildout of Energy Efficiency and Demand Response contractors could add jobs in Downstate NY	• Project is entirely offshore in NY, with minimal impact to community land/space • Some onshore construction in NJ on brownfield locations
Deliverability	• Involves multiple regulatory, permitting, customer behavior, and other external dependencies, including a number of infrastructure and non-infrastructure programs requiring regulatory approvals and funding to move forward, creating some implementation complexity that will need to be managed	• Has the lowest number of dependencies with regards to permitting, regulatory, and implementation considerations*

**NESE Project rates as "most deliverable" option assuming the project can obtain a water permit. This permit decision is, in effect, binary - if it is not obtained, then the project cannot move forward.*

With a balanced assessment that weighs cost across a range of scenarios and includes the broad set of evaluation criteria, including areas of high customer feedback such as cost of GHG and pathway to CLCPA achievement, then the preferred choice is Option A (Enhancements to existing infrastructure combined with incremental EE and DR). National Grid would need to work with the State of New York and other key stakeholders to ensure Deliverability and long-term Reliability.

However, if heavier emphasis is placed on reducing risk related to Deliverability and Reliability (certainty of meeting demand), then the preferred choice is Option B (NESE Pipeline).

Table 6 below summarizes what would be required to implement each of the two recommendations described above.

Table 6: 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
LNG Vaporization and Iroquois Gas Compression enhancements to existing infrastructure, combined with incremental Energy Efficiency and Demand Response		
Distributed Infrastructure: LNG Vaporization and Iroquois Gas Compression	• Requires FERC (under NEPA) approval and state specific approval from both NY and CT for Iroquois Gas Compression project • Requires FDNY, NYDEC approvals for LNG Vaporization • Requires Memorandum of Understanding (MoU) for LNG trucking to support expanded vaporization • To ensure system reliability and manage volume/pressure across the network, requires permitting approvals for CNG sites, along with NYC and funding approvals for Metropolitan Reliability Infrastructure (MRI) Phase 4 and 5	• If all approvals are acquired in a timely fashion, LNG vaporizers are expected to be in-service by November 30, 2021, and Iroquois compression project is expected to be in-service by November 2023
No Infrastructure: Energy Efficiency (EE) and Demand Response (DR)	• Enhanced EE 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 • Requires rate case approvals and incentive programs to drive behaviors and increase adoption rates • New DR programs will require new thermostat set back programs, enhanced program for Temperature-Controlled (TC) customers, incentives for adoption and new rate structures	• Estimated timeline: Energy Efficiency will need to have impact starting in 2021/22, and continue to build over time; Starting in 2021, all TC customers will be retained; over next five years, incremental DR will reach roughly half of all residential customers • Success will require building an extensive contractor network, and close collaboration with NYSERDA and electric utilities
NESE pipeline		
Northeast Supply Enhancement (NESE) Project	• Received FERC and PA approval, but still requires state/local approvals from NY and NJ • 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

While both options are viable, each has risk and dependencies that must be managed and require action from both National Grid and other stakeholders. For the infrastructure components, the primary dependency is the need to secure various state and local permits required for construction and operation. These permitting requirements create a risk that infrastructure options will not be available on a schedule that avoids future service restrictions. For the non-infrastructure components, there are numerous dependencies required to enable the aggressive incremental levels of energy efficiency and demand response required to support customers' future energy needs, including permitting, regulatory approvals, rate funding, market and technology development, and customer adoption. If these factors do not converge in a way that reliably reduces customer demand over the next several years, there is a risk of future service restrictions.[8]

Regardless of the execution risks stemming from these dependencies, it is important to emphasize that a solution must be chosen and implemented over the next two years to enable closure of the demand-supply gap and avoid future moratoria. Accordingly, in this Supplemental Report, the Company has sought to clearly set forth the dependencies, risks, costs and environmental impacts (among other criteria) such that all stakeholders are informed as to the implications of pursuing each option and the requirements for successful execution.

3. Summary of Public Input

As stated in our original Report, National Grid feels that an important part of the process for determining natural gas long-term solutions in Downstate NY is to allow people to provide feedback on the options considered and the assumptions used in our analysis. Over the last two months, this has been accomplished through three avenues: 1) public comments delivered at a series of six public meetings (one in-person and five virtual, due to the COVID-19 pandemic); 2) submission of written comments through the NY DPS website[9,10]; and 3) completion of an on-line survey regarding the different options for closing the gap between natural gas demand and available supply.

A summary of the amount and type of feedback received in each of these three areas is included in the remainder of this section. Also, it is important to note that some of the specific comments regarding our analysis of demand, supply, environmental and cost impact, and potential solutions are included in subsequent sections of this Supplemental Report.

In reviewing Table 7 below and the remainder of the section, please note the following definitions:

- "Individuals" – Refers to the unique individuals who provided public statements during the Q&A and/or open comment portions of public meetings and/or by submitting written statements to the NY DPS website.[11]
- "Public statements" – Refers to the discrete statements made either through public meetings or submitted in writing to the NY DPS website (including reports and documents submitted to the Filed Documents tab). Since some individuals made more than one public statement via public meeting, written submission or both, the number of public statements made is greater than the number of individuals who provided comments.

[8] In the event of a potential service restriction, and to ensure appropriate notice to customers, the New York PSC must approve tariff provisions that provide for a well-defined process for implementing reasonable restrictions on new gas connections during any periods of supply constraints.

[9] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-g-0678&submit=Search

[10] "Written submissions" include statements made to Secretary to the New York State Public Service Commission via email, mail and phone. Statements made via these methods were posted on the Public Comments section of the NY DPS website for Matter Number 19-02328.

[11] If statements (e.g., a report) were made on behalf of an organization and no names of individuals associated with the statement were given, the organization is considered as an "individual."

- "Thoughts expressed" – Refers to the points made or thoughts expressed within a public statement. Many public statements provided through public meetings or submitted via written submission included several comments spanning different topics or making different points within a topic. Thus, the number of thoughts expressed is greater than both the number of public statements and the number of individuals who provided comments.

Table 7: Public Input Summary

	Written Public Statements Total	Six Public Meetings Total	Total
Individuals	5,017*	161**	5,139***
Public Statements	7,385	258	7,643
Thoughts Expressed	**28,670**	**581**	**29,251**

** Some people may have provided more than one public statement to PSC site. This is the number of unique individuals who provided public statements. This category also includes filed documents/reports (a filed document is considered one statement). Note that many individuals who made submissions on the Public Comments tab used exactly the same language in their comment as other individuals; while duplicative, they are all counted here.*

*** The total number of unique individuals who participated (i.e., spoke), rather than additive, as some individuals participated in multiple public meetings.*

**** The total number of unique individuals/commenters, rather than additive, as some individuals provided statements via multiple forums (i.e., written public statement and participated at a public meeting).*

3.1 Public Meetings and Written Public Comments

The settlement agreement between National Grid and the New York Department of Public Service provided that National Grid would conduct at least four public meetings to solicit public input on the Long-Term Capacity Report. National Grid initially planned a series of six in-person public meetings commencing on March 9, 2020, and finishing March 31, 2020. National Grid communicated with customers and other stakeholders about the opportunity to participate in the public meetings through a number of channels, including: a dedicated website for the Long-Term Capacity Report; National Grid's main customer-facing website for Downstate New York; the media release for the Long-Term Capacity Report; e-mails to all Downstate New York customers for whom National Grid has an e-mail address; bill inserts and on-bill messages to all Downstate New York customers; a call center message; posters in payment centers; social media posts; and direct outreach to local officials, large customers, and other stakeholders.

The first public meeting was held on March 9, 2020, from 6-8 pm at the Hicksville Community Center. The format for this in-person public meeting included opening remarks by National Grid New York President John Bruckner, a "trade show" session focused on the various long-term capacity options, and a public statement session.[12] The "trade show" included booths devoted to each of the options presented in the Long-Term Capacity Report. Interested members of the public had the chance to hear about the options and ask questions of National Grid subject matter experts.

The second in-person public meeting was scheduled for March 12, 2020, at the Jamaica YMCA in Queens. Given the rapid worsening of the COVID-19 situation in New York City and Long Island, National Grid decided to cancel this in-person public meeting. On March 17, 2020, National Grid announced that the five remaining public meetings (including a rescheduling of the public meeting originally planned for March 12, 2020) would be held as "virtual" public meetings given the necessity

[12] For each of the public meetings, John Bruckner's remarks and all public statements were transcribed, which can be accessed at https://ngridlongtermsolutions.com/.

for social distancing. Communications to the public regarding the change of plans included not just the media release but also the dedicated website for the Long-Term Capacity Report, a call-center upfront recorded message, updated posters at payment centers, a revised web banner for the customer-facing website, social media posts, and the Company's Downstate New York stakeholder newsletter. To best replicate the experience of the in-person public meeting, the virtual public meetings comprised opening remarks by John Bruckner, videos describing each of the long-term capacity options, a question-and-answer session with National Grid subject matter experts on each of the options, and a public statement session.[13] The five virtual public meetings were held from 6-9 pm.

Table 8 below provides a summary of attendance and participation at each public meeting.

Table 8: Public Meeting Summary

	3/09 Nassau County (In-Person)	3/23 Suffolk County (Virtual)	3/24 Brooklyn (Virtual)	3/25 Brooklyn (Virtual)	3/30 Queens (Virtual)	3/31 Queens (Virtual)	Public Meeting Total
Attendees†	76	320	136	118	142	146	938
Number of Attendees Who Attended a Prior Meeting*	0	10	32	25	25	33	125
Net Number of Unique Attendees	76	310	104	93	117	113	813
Individuals Who Participated**	19	52	35	27	31	26	161
Public Statements^	19	60	51	37	52	39	258

† The number of attendees for the Nassau County in-person public meeting is based on the meeting's sign-in sheets and public statement transcript. For the virtual public meetings, the reported number of attendees is the total number of callers reported by the audioconference provider (Verizon) net of National Grid registrants for the meeting webcasts.

** Number of participants identified from WebEx registration or identified via speaking role during virtual meetings similarly identified at any earlier meeting.*

*** The total number of unique individuals who spoke during the Q&A and/or open comment portion of each public meeting. Public meeting total will not equal the individual meeting totals, as some people participated in multiple meetings.*

^ Total number of statements made during the Q&A and/or open comment portion of each public meeting; individuals who spoke more than once are counted multiple times.

Source: Public meeting transcripts

In addition to the public meetings, written statements could be submitted through the NY DPS website, either on the Filed Documents tab or the Public Comments tab. Table 9 below provides a summary of participation in written statements for submissions posted through the end of the public comment period on May 1, 2020.

[13] The overview videos for each long-term capacity option are available here: https://ngridlongtermsolutions.com/.

Table 9: Written Public Statement Summary

	Count
Individuals Who Provided Written Statements*	5,017
Total Written Public Statements^	7,385

** Some people may have provided more than one public statement to NY DPS website. This is the number of unique individuals providing public statements. This category also includes filed documents/reports (a filed document is counted as one statement).*

^ Total number of statements submitted via the NY DPS website, including filed reports.

Source: NY DPS website

Filed documents and reports related to the Report included the following, from most recently filed to the earliest:

- "AGREE filing", Alliance for a Green Economy (AGREE), AGREE comments on National Grid capacity options report, May 1, 2020
- "Bloom Energy filing", Bloom Energy Corporation, Bloom Energy Comments, May 1, 2020
- "NY Renews filing", NY Renews, Comments of NY Renews, May 1, 2020[14]
- "EDF filing", Environmental Defense Fund (EDF), EDF Comment on National Grid's Long-Term Capacity Report, May 1, 2020
- "City of New York filing", City of New York comments submitted by Couch White, LLP, May 1, 2020
- "NRDC April 2020 filing", Natural Resources Defense Council (NRDC), Coalition comments regarding the Natural Gas Long-Term Capacity Report, April 17, 2020[15]
- "CDCLI filing", Community Development Corporation of Long Island, Long-Term Natural Gas Capacity Report feedback Comments, April 17, 2020
- "Grassroots filing", GRASSROOTS Environmental Education, Comments from Grassroots Environmental Education, April 17, 2020
- "NYC Comptroller filing", City of New York, NYC Comptroller Scott M. Stringer Comment on National Grid Gas Capacity Report, March 11, 2020
- "IEEFA report", Institute for Energy Economics and Financial Analysis (IEEFA)[16], IEEFA Analysis NESE Comments, April 2020
- "Stop the Williams Pipeline Coalition filing", Stop the Williams Pipeline Coalition, Stop Williams Coalition Comments, April 17, 2020[17]
- "Synapse report", Eastern Environmental Law Center (prepared by Synapse Energy Economics, Inc.), Assessment of National Grid's Long-Term Capacity Report, April 6, 2020

[14] NY Renews filing was on behalf of the NY Renews Steering Committee, which includes: 32BJ SEIU, ALIGN - Alliance for a Greater New York, Catskill Mountainkeeper, Center For Working Families, Citizen Action of New York, Communications Workers of America District 1, Demos, Environmental Advocates of NY, GreenFaith, Long Island Progressive Coalition, NYC Environmental Justice Alliance, Our Climate, People's Climate Movement NY, PUSH Buffalo, Sierra Club, Teamsters Joint Council 16, UPROSE.

[15] Coalition included the following organizations: NRDC, The Sallan Foundation, Alliance for Clean Energy New York, Sierra Club, Surfrider Foundation (NYC Chapter), 350Broooklyn, Clean Ocean Action, New Yorkers for Clean Power.

[16] In collaboration with Lookout Hill Public Policy Associates, Stop the Williams Pipeline Coalition, and 350Brooklyn.

[17] Coalition included 350Brooklyn, Sane Energy Project, New York Communities for Change, Surfrider Foundation/NYC Chapter, Food & Water Action, and 350.org

- "NRDC March 2020 filing", Natural Resources Defense Council (NRDC), Coalition comment letter regarding the Natural Gas Long-Term Capacity Report, March 23, 2020[18]
- "EFG report", 350.org and 350Brooklyn (prepared by Energy Futures Group), Critical Elements in Short Supply: Assessing the Failures of National Grid's Long-Term Capacity Report, March 9, 2020
- "Sara Gronim filing", Sara S. Gronim, 20 Questions for the Public Service Commission and National Grid, March 3, 2020

The above filed documents and reports are identified as public statements as were all comments filed on the Public Comments tab of the NY DPS website.

Table 10 provides a summary of viewpoints expressed across comment platforms. The primary theme representing most comments was either support for gas infrastructure (typically the NESE pipeline[19]) from ~1,300 individuals, or support for no new gas infrastructure (typically "anti-pipeline") from ~3,600 individuals. The most common examples of pro-infrastructure statements were "many options face enormous permitting hurdles and would not be completed for more than 5 years" and "several options increase NY's dependence on dirty energy sources like oil and propane", while the most common phrases from commenters who were against infrastructure included "the PSC should reject National Grid's fracked gas proposals" and "must make investments necessary to transition New York to 100% renewable energy, as mandated by the Climate Leadership and Community Protection Act". Viewpoints are summarized at the level of the individuals providing the public statements.

Table 10: Summary of Viewpoints of Feedback from Individuals to National Grid (excluding Survey)

	Unique Individuals Who Provided Written Public Statements*	Unique Individuals Who Participated During Public Meetings**	Unique Individuals Who Provided Feedback in any Forum***
Support gas infrastructure	1,358	40	1,394
Neutral^	9	4	13
Support no new gas infrastructure	3,578	108	3,651
Not applicable^^	72	9	81
Total	**5,017**	**161**	**5,139**

** Some people may have provided more than one public statement to PSC site. This is the number of unique individuals who provided public statements. This category also includes filed documents/reports (a filed document is counted as one statement here).*

*** The total number of individuals who participated (i.e., spoke) during Q&A and/or open comment portion, rather than additive, as some individuals participated in multiple public meetings.*

**** The total number of unique individuals/commenters, rather than additive, as some individuals provided statements via multiple forums (i.e., written public statement and public meeting).*

^ No position expressed.

^^ Includes Commission orders, comments on the public meeting or comment process, and Monitor comments.

Source: National Grid and Guidehouse analysis of public meeting transcripts, statements and reports posted to the NY DPS website

[18] Coalition included the following organizations: NRDC, Alliance for Clean Energy New York, Surfrider Foundation (NYC Chapter), Clean Ocean Action, Food and Water Action, New Yorkers for Clean Power, Pace Energy and Climate Center, and NY-Geothermal Energy Organization.
[19] 98% of individuals showing support for gas infrastructure expressed support specifically for the NESE pipeline.

Associated with the 258 statements made during public meetings and the 7,385 statements through written submissions, a total of 29,251 thoughts expressed were logged. Table 11 below provides a summary of the thoughts expressed by high-level topic.

Table 11: Categorization of the Thoughts Expressed by Stakeholders

	Written Public Statements^	Public Meeting Statements^	Total Thoughts Expressed
Demand Forecast	1,900	30	1,930
Supply Forecast	40	5	45
Costs and Cost-Effectiveness	330	6	336
Policy Mandates	5,800	60	5,860
Environmental and Health Impacts	2,600	50	2,650
Support for NESE	7,600	150	7,750
Opposition to Any New Gas Infrastructure	9,000	220	9,220
Other / Non-Specific*	1,400	60	1,460
Total Thoughts Expressed	**28,670**	**581**	**29,251**

* *This topic includes comments that are unrelated to National Grid's Report or that do not provide enough content to be able to assign to another topic*

^ *Counts of thoughts expressed in written public statements and public meeting statements have been rounded to two significant figures if greater than 1,000 and 1 significant figure if greater than 10. Counts less than 10 have not been rounded.*

Source: National Grid and Guidehouse analysis of public meeting transcripts, statements and reports posted to the NY DPS website

Within each comment topic, some key themes emerged. These themes reflect thoughts expressed by a large number of individual commenters or, in certain cases, comments made by a smaller number of individuals or organizations, but which National Grid believes warrant explicit reference due to their depth, specificity and relevance. The key themes are summarized below.

Demand Forecast

Public statements related to National Grid's demand forecast presented in the Report were made by 938 individuals and organizations including organizations represented by the Synapse report, the EFG report, the NRDC March 2020 filing, the NRDC April 2020 filing, the IEEFA report, the City of New York filing, and the AGREE filing. Many statements from individuals cited these reports/filings.

Points/thoughts expressed related to demand forecast generally expressed the belief that National Grid's Report overestimated forecasted gas demand. Themes within this topic are described below.

The EFG and IEEFA reports, along with around 250 points/thoughts expressed from individuals, recommended that National Grid consider a gas demand forecast created by the U.S. Energy Information Administration that predicted an increase in gas demand, nationally, of 1.6% over the next decade. Additionally, the Synapse report noted an inconsistency between gas demand forecasts included in the Report and those included by National Grid in a rate case proceeding in 2019.

The IEEFA report stated that National Grid's demand forecast was inconsistent with Con Edison's gas demand forecast for the same period and that the Report does not account for the differences. This report also noted that National Grid's demand forecasts do not factor in the long-term impacts of climate change on gas demand projections.

Similarly, the Synapse and IEEFA reports and several statements from individuals asserted that the conditions upon which National Grid's Design Day demand forecasts are based may result in unduly conservative estimates of demand and may warrant reconsideration. In particular, commenters suggested that the Design Day condition of 0ºF in Central Park, which last occurred in 1934, was too low and could be adjusted to a higher temperature.

The Synapse and IEEFA reports and around 150 points/thoughts expressed from individuals asserted that National Grid's Report overestimates the pace of oil-to-gas conversions going forward, particularly since New York City regulations (NYC Clean Heat Program) mandated the phase-out of No. 6 fuel oil by the end of 2015. The Synapse report put forth that the Report overestimated fuel conversion rates for the multifamily buildings sector.

The NRDC March 2020 filing, the NRDC April 2020 filing, and the Synapse and IEEFA reports stated that National Grid's base case demand forecasts do not adequately account for the impact of policy mandates on gas demand including Climate Leadership and Community Protection Act (CLCPA), New Efficiency: New York (NENY) and Local Law 97. The Synapse report asserted that NYSERDA's contribution to the NENY gas efficiency targets should be included in National Grid's base case demand forecasts. Additionally, this report asserted that the impact of Local Law 97 and NENY on heat pump adoption was underestimated by National Grid in its base case gas demand.

Finally, a few public statements, including the AGREE filing and the City of New York filing, urged National Grid to contemplate the potential long-term impacts of COVID-19 on the future projections of gas demand.

Supply Forecast

Public statements addressing the topic of National Grid's supply forecast assumptions were made by 35 individuals and organizations including organizations represented by the Synapse report and the NRDC April 2020 filing.

The Synapse report made several assertions relating to National Grid's base case supply forecast assumptions in the Report. This report stated that National Grid's Report was overly conservative in its assumptions regarding the availability of delivered peaking gas supplies. The Synapse report states that, although National Grid says that it is operationally constrained to accept only up to 300 MDth, National Grid contracted for 415 MDth of short-term peaking supplies for the 2019-20 winter season. Additionally, the Synapse report notes that National Grid's Report claims that Con Edison relies on 400 MDth of the 700 MDth available on the market despite that fact that Con Edison contracted only for 345 MDth of delivered peaking supply for the 2018-2019 winter season.

The Synapse report noted that National Grid's Report does not account for plans to add 60 MDth from an expansion of daily vaporization capacity at its Greenpoint LNG facility.

The NRDC April 2020 filing noted skepticism relating to the amount of Renewable Natural Gas (biomethane) available for use in Downstate New York and maintained that the available biomethane should be reserved for hard-to-electrify sectors rather than the buildings sector. Statements from individuals made general assertions that hydrogen and renewable gas are not plausible or meaningful solutions.

Costs and Cost-Effectiveness

Public statements addressing the topic of National Grid's assumptions around costs and/or the cost-effectiveness of different options were made by 271 individuals and organizations including organizations represented by the Synapse report, the NYC Comptroller filing, the Grassroots filing, the NRDC March 2020 filing, the NRDC April 2020 filing, the EDF filing, as well as Rocky Mountain Institute (RMI).[20]

Related to the No Infrastructure option, the Synapse report asserts that National Grid's assumption on the per-unit cost of saved energy (COSE) per therm is overestimated.

The Synapse report and NRDC April 2020 filing, along with several other commenters, believe that the value of carbon emission reductions needs to be incorporated into National Grid's cost comparisons across the options evaluated. They assert that the value of carbon has been recognized by the PSC and should be included. Relatedly, EDF asserts that National Grid's benefit-cost analysis should account for upstream methane impacts.

The Synapse report and commentary by RMI also question the validity of National Grid's use of a 15-year time horizon in cost-benefit calculations.

The Synapse report, and the filings by the NYC Comptroller, Grassroots, NRDC March 2020, NRDC April 2020, along with around 300 points/thoughts from individuals, expressed the belief that any new gas infrastructure (including the NESE pipeline) could become a stranded asset. They asserted that the CLCPA and its mandated targets to reduce greenhouse gas production would render new infrastructure useless before the end of the infrastructure's useful life. The NRDC filings explicitly urged National Grid to account for this issue in its assessment of cost-effectiveness of each solution considered, including the impact of CLCPA on depreciation schedules.

Policy Mandates

Statements related to New York City and New York State policy mandates were made by 1,315 individuals and organizations, including organizations represented by the Synapse report, the EFG report, the NRDC March 2020 filing, the NRDC April 2020 filing, the IEEFA report, the Stop the Williams Pipeline Coalition filing, the EDF filing, the City of New York filing, the NY Renews filing, the AGREE filing, and RMI.

Around 2,600 points/thoughts expressed by these organizations and individuals asserted that any proposal involving investment in new gas infrastructure goes against the CLCPA climate targets and New York City's commitment against new fossil fuel infrastructure. Some statements noted specifically that CLCPA mandates that the state emit no more than 35 million metric tons of CO_2 equivalents by 2050, yet the gas National Grid supplied to its customers in 2015 yielded 70 million metric tons of CO_2 equivalents when burned, and NESE would increase the gas supply in New York by 14%. Stakeholders indicated they want to understand how the options that were presented in the Report address the CLCPA.

Environmental and Health Impacts

Statements that focused on the environmental and health impacts of NESE and other gas infrastructure solutions were made by 2,823 individuals and organizations, including organizations represented by the IEFFA report, the EDF filing, and RMI.

[20] Source: https://rmi.org/new-york-can-meet-its-energy-needs-without-a-new-pipeline/; RMI did not submit commentary contained in this blog post to the NY DPS website.

Approximately 2,600 points/thoughts expressed support NESE for environmental reasons. Many of these expressed the belief that NESE will result in lower GHG emissions by allowing more people to switch to gas from oil and propane. Many other points asserted that other options that depend on trucking in compressed natural gas (CNG) from Pennsylvania would cause disproportionate impacts on traffic and air quality and would increase the burden on environmental justice communities in New York.

Over 500 points/thoughts expressed, including from the IEEFA report, focused on concerns about the environmental potency of methane associated with the NESE pipeline. Many of these points address assumptions within the MJ Bradley & Associates report[21] that was cited in the Report.

Around 1,200 points/thoughts expressed, including from RMI, the Stop the Williams Pipeline Coalition filing, and the Grassroots filing, were general statements expressing disproval of “fracking”, “fracked gas” or fossil fuels and the associated contribution to climate change, pollution, and contaminated air and ground water.

Around 750 points/thoughts expressed focused on radon[22] and radioactivity of fracked gas, particularly gas derived from the Marcellus Shale in Pennsylvania. These points noted that, during its current rate case, National Grid testified that a growing percentage of the gas it delivers was produced through fracking in the Marcellus Shale.

Around 850 points/thoughts expressed asserted that the NESE pipeline will be highly detrimental to the oceans, including fragile animal and plant life, and, by consequence, will negatively impact coastal communities including Staten Island, Coney Island, and the Rockaways. Many comments cited conclusions of the New York Department of Environmental Conservation (DEC) that the NESE pipeline would significantly impact critical benthic communities and release toxins, such as mercury and copper, into the water.

Approximately 150 points/thoughts expressed focused on the risk of gas leaks and ruptured pipelines on environment and health and also commented on National Grid’s safety record.

Support for NESE

Points/thoughts expressing support of the NESE pipeline solutions were made in public statements made by 1,315 individuals.

In addition to comments previously noted related to environmental impacts, around 3,000 points/thoughts expressed supported the NESE pipeline solution over other options because these other options do not provide enough gas to meet demand and are not as reliable or because NESE is the only option, comments assert, that does not face extensive permitting hurdles and delays.

Around 1,800 points/thoughts supported NESE due to concerns about equity and affordability of heating, with some asserting that low- and moderate-income populations cannot afford electric heating/heat pumps. Many points assert that NESE is the best option from a ratepayer and/or cost-effectiveness perspective.

Close to 700 points/thoughts assert that NESE will help to revitalize and spur economic activity in certain areas. Several assert that NESE will contribute to post-COVID-19 economic recovery.

[21] “Life Cycle Analysis of the Northeast Supply Enhancement Project”, June 2019.

[22] These comments also assert that radon is the leading cause of lung cancer in non-smokers in the U.S.

Finally, close to 300 additional points are general expressions of support for the NESE pipeline solution.

Opposition to Any New Gas Infrastructure, Including NESE

Around 9,000 points/thoughts express opposition towards any new gas infrastructure in ways other than those previously outlined. These points were made in public statements made by 2,934 individuals or organizations. The majority of these points are general statements calling for the PSC to reject all of National Grid's fracked gas proposals and fund 100% renewable solutions. Some statements point to prior pipeline disapprovals as a reason to reject the NESE pipeline. Several statements, including those in the NRDC April 2020 filing and from RMI, assert that no-infrastructure investments will create local jobs and boost local economies.

In summary, points/thoughts expressed opposing any new gas infrastructure, including those described under Policy Mandates, Environmental and Health Impacts and those mentioned above in this section, most typically cite the following reasons: 1) opposition to fracking; 2) new gas infrastructure goes against CLCPA and New York City climate targets, perpetuating the climate crisis and likely resulting in costly stranded assets; 3) the NESE pipeline will adversely impact the air, drinking water, and the ocean; 4) prior disapprovals of pipeline projects.

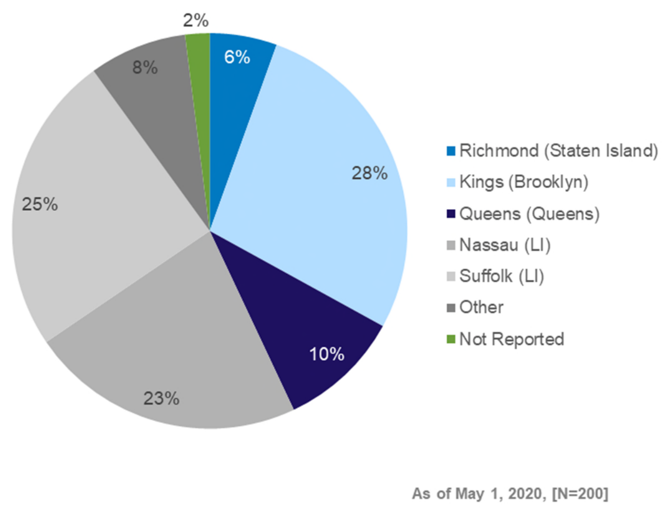
3.2 On-Line Survey

To offer the public multiple means of providing feedback, National Grid created a survey that asked respondents about their views on the Downstate New York capacity options. The survey was available on National Grid's dedicated Long-Term Capacity Report website at any time and was also offered at the in-person public meeting at an iPad kiosk and via paper survey forms. The purpose of the survey was to provide a relatively easy way to capture the sentiment from members of the public who could not attend one of the six public meetings, who did attend a public meeting but preferred not to offer an oral public statement, or who did not want to submit written comments. The survey was also open to members of the public who did make public statements or submit written comments. The survey was intended to solicit structured public input that was both readily quantifiable and that provided insights into the relative importance of decision-making criteria for selecting a Downstate New York capacity option and the relative attractiveness of the different options to the public.

As of May 1, 2020, 200 people completed the survey. 88% of survey respondents indicated at the time of taking the survey that they had not attended a public meeting. 84% of respondents reported that they get natural gas from National Grid for their home or for their home and business, while 7% get natural gas from National Grid for their business only and 9% of survey respondents are not natural gas customers.

Close to 50% of survey respondents live in the Long Island counties of Nassau and Suffolk, while 28% live in Brooklyn.

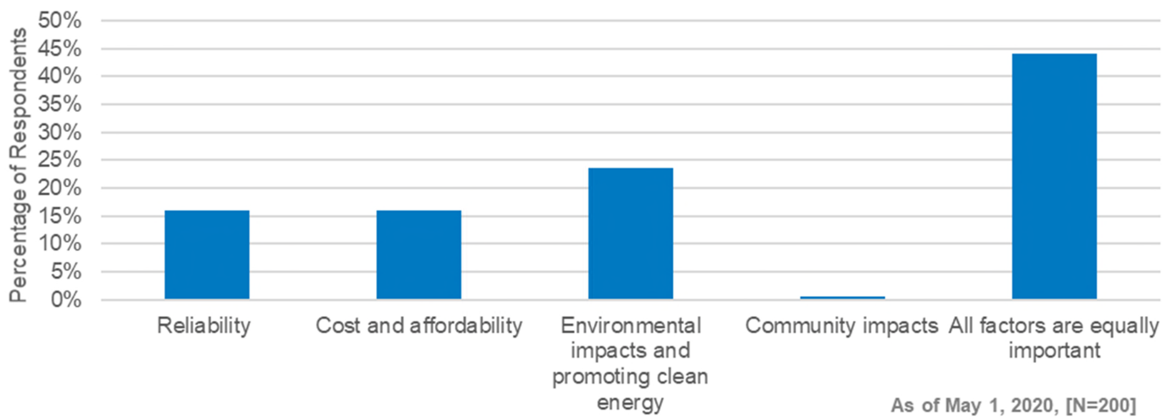
Figure 10: Survey Respondents by County Based on Self-Reported Zip Code



Source: Guidehouse analysis of National Grid Survey data

44% of respondents view all factors (reliability, affordability, environmental impacts, community impacts) as equally important when considering options for addressing gas capacity constraints.

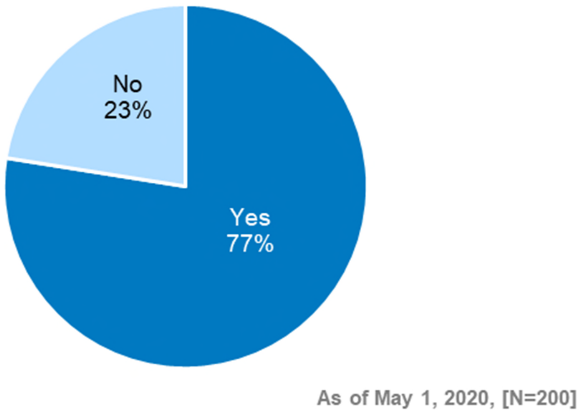
Figure 11: Which ONE do you think is most important when choosing options to address the natural gas capacity constraint (assuming all options are safe) or do you think they are all equally important?



Source: Guidehouse analysis of National Grid Survey data

77% of respondents agree that a long-term solution should allow for the connection of new natural gas customers and avoid moratoriums on new customer connections.

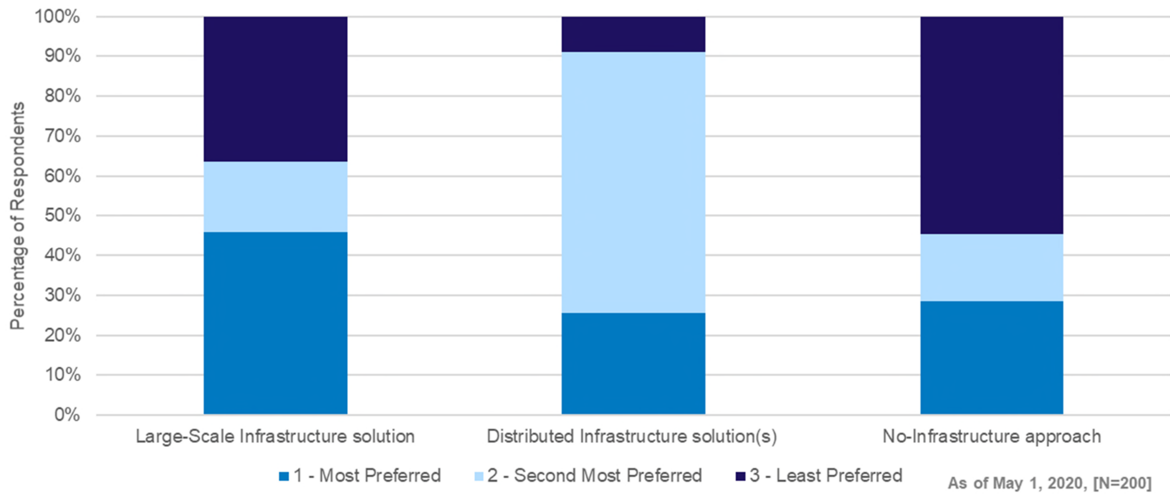
Figure 12: Do you agree that a long-term solution to the natural gas capacity constraint for Brooklyn, Queens, and Long Island should allow for the connection of new natural gas customers and avoid any future need for a moratorium on new customer connections?



Source: Guidehouse analysis of National Grid Survey data

Large-Scale Infrastructure solutions had the highest percentage of most preferred. Distributed Infrastructure solutions had the highest combined percentage of most and second most preferred.

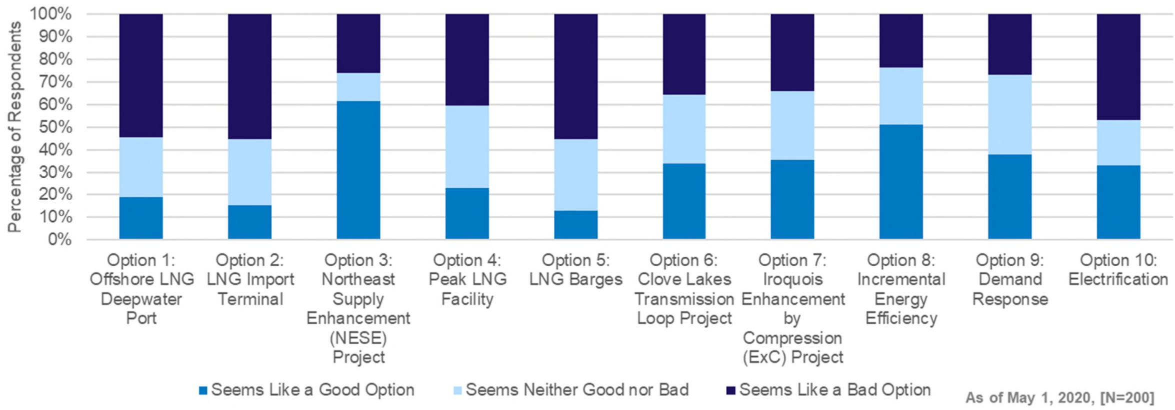
Figure 13: Please rank the following approaches to creating a comprehensive solution to solve the gap between natural gas supply and demand in Brooklyn, Queens, and Long Island from 1 (most preferred) to 3 (least preferred).



Source: Guidehouse analysis of National Grid Survey data

Option 3 (NESE project) and Option 8 (Incremental EE) had the highest percentage of survey respondents reporting it is a good option.

Figure 14: How do you feel about each of the options below as part of an approach to solving the gas supply and demand gap?*



**Note, the Supplemental Report introduces a new Distributed Infrastructure option, LNG Vaporization, that was not considered in the survey.*

Source: Guidehouse analysis of National Grid Survey data

4. Demand Forecast

4.1 Demand Assumptions

Many comments were received, both in writing and through the public meetings, challenging National Grid's demand forecast and the assumptions used in creating the Low and High Demand scenarios. These comments can be generally categorized into the following areas:

The general level of anticipated natural gas growth. Multiple comments stated a belief that National Grid is overstating the expected level of natural gas growth. In particular, multiple comments cited the Energy Information Administration (EIA) natural gas forecasts as a reason to question and potentially lower our demand forecast. These comments pointed to forecasts from EIA showing total expected natural gas growth of 1.6% between 2019 and 2030, for an annual growth rate of 0.1%.

We have examined the EIA forecast and believe there are two problems with this comparison. First, it is for the entire United States, and is therefore not specific or directly comparable to Downstate NY. Second, it is a forecast that includes all usage of natural gas – both for electricity generation and other uses in addition to gas that is consumed by homes and businesses for space heating, cooking, clothes drying etc.

Table 12 shows the EIA forecast in total, and the same forecast once gas utilized for electricity generation is excluded. While this still is for the US in total and may include gas used in other sectors (such as transportation), it is a step closer to being comparable to what National Grid has included in its Downstate NY demand forecast. What this shows is that natural gas for all sectors minus electricity is projected to grow at a rate of 0.8% per year across the US.

Table 12: EIA Natural Gas Demand Projections, total US

Source: EIA AEO 2020	2019	2030	2040	2050	2019-2030 Cumulative Growth	2019-2030 CAGR
USA Natural Gas, All Sectors (TCF)	31.03	31.54	34.09	36.92	1.6%	0.1%
USA Natural Gas, All sectors minus electricity (TCF)	19.63	21.34	22.63	24.72	8.7%	0.8%

For comparison purposes, natural gas Design Day demand over the past ten years in Downstate NY has grown at an annual rate of 2.4%, and National Grid has projected that this demand growth will slow down in the 2020-2035 time period to a range of 0.8% - 1.1% per year. Based on our analysis of the EIA forecast, we did not find any reason to adjust our forecast.

National Grid also received several comments pointing out that in our historic Design Day demand growth, the growth rate appears to be higher in the earlier years and lower in the most recent time period. A review of this data does show that Design Day demand growth was 2.9% from 2009/10 to 2015/16, and then slowed to 1.6% from 2015/16 to 2019/20. Over the last four years, the growth has been 2.1%, 2.1%, -0.1% and 2.4%. National Grid does not view this as inconsistent with its demand forecast that starts at 1.8% per year from a Baseline perspective and is adjusted to 0.8% - 1.1% per year based on assumptions around increased energy efficiency, demand response and electrification.

Finally, some commenters pointed out that it appears Con Edison has different, and perhaps lower, estimates of natural gas growth in its nearby service territory. They reference Con Edison's January 2019 Gas Long-Range Plan, which states that they have forecast growth of 1.1% per year over five years, and 0.5% per year over a 20-year period.

It is important to note that the Con Edison forecast numbers assume "increased energy efficiency, smart solutions, as well as a temporary moratorium for most of Westchester County for firm gas service.[23]" Also, while National Grid's forecast of 0.8% - 1.1% is higher than Con Edison's 0.5%, our forecast is only for 15 years and shows a substantial reduction in growth or, in the Low Demand scenario, a modest net decline in the later years. While not a 20-year forecast, if we were to take a simple extrapolation of the declining growth/net decline trends out to years 16-20, our 20-year annual growth rates would range from 0.3% in the Low Demand scenario to 0.8% in the High Demand scenario. Based on this comparison to the Con Edison forecast, we would not see any reason to change our demand forecast.

The treatment of NENY targets in our demand forecast. Another area where there were a substantial number of comments related to our demand forecast pertained to our treatment of the New Efficiency: New York (NENY) projections. Specifically, commenters pointed out we were estimating that in order to achieve 100% of NENY targets, energy efficiency efforts will have to

[23] Con Edison, Gas Long Range Plan, January 2019, page 26

increase to 0.8% of gas sales by 2025, whereas the NENY order indicated that achievement will require energy efficiency to be equal to 1.3% of gas sales.

The Long-Term Capacity Report uses the same savings targets for Downstate NY as listed in the NENY order to develop the demand forecast. However, in communicating those savings targets as a "percent of sales" the Report used the total sales forecasted in 2025 as a denominator while the NENY order uses the 2018 SBC sales net of cumulative EE savings through 2025. Table 13 shows the savings as a percent of sales for the No Infrastructure Solution in the High Gap scenario using these two approaches.

Table 13: NENY Savings as a % of Total Forecasted Sales in 2025

EE Source	2025 Target Savings (Dth)	Total Forecasted Sales in 2025 (Dth)	Total Savings as Percent of Total Forecasted Sales (%)	2018 SBC Sales Net of Cumulative EE through 2025 (Dth)	Total Savings as Percent of Net 2018 SBC Sales (%)
Base EE	449,561	308,101,936	0.15%	232,679,973	0.19%
NENY	2,028,000	308,101,936	0.80%	224,330,168	1.10%
Incremental EE	1,517,417	308,101,936	1.30%	211,098,609	1.89%

As can be seen above, the 0.8% NENY achievement excluding NYSERDA referenced in the Long-Term Capacity Report is equivalent to 1.1% when utilizing the same denominator as the statewide NENY target. In addition, our demand forecast includes all historic levels and rates of change of NYSERDA Downstate NY activity. For reference, NYSERDA's impact across the state of New York is calculated as 0.19% of sales in 2018 and 0.16% of sales in 2019.[24] Assuming a proportional allocation to Downstate NY, this would mean that National Grid is accounting for at least 1.26% - 1.28% of sales through NENY energy efficiency in its demand forecast assumptions, and to the extent that there has been a growing historic trend in NYSERDA activity, the forecast would be accounting for more than this level (i.e. it would be continuing the growth trend in its projections). As such, any difference between National Grid's forecast and the proposed 1.3% would be considered de minimis.

Other specific components of demand, such as the rate of oil-to-gas conversions and the impact of Local Law 97. Several commenters pointed out that the rate of oil-to-gas conversions can be expected to slow given that there has already been a concerted effort to convert many buildings from fuel oil, in particular no. 4 and no. 6 oil, supported under the NYC Clean Heat Program.

In National Grid's Baseline forecast we expect oil-to-gas conversions to continue at a similar rate as in the past, due to the following factors:

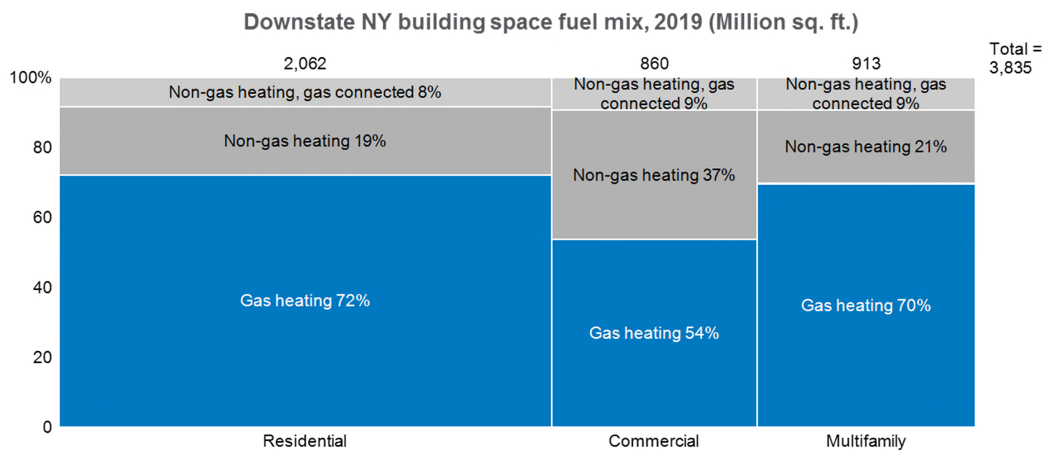
- Though there have been many oil-to-gas conversions over the years there are still many potential customers remaining, with 27% of Residential, 46% of C&I and 30% of multifamily building space in the Downstate NY area still heated with non-gas sources (please see Figure 15 below for details)
- An estimated 56% (7,000 out of 12,400 per year) of our "oil-to-gas conversions" are from customers who already have gas connections for non-heat purposes and are adding gas

[24] State of New York Public Service Commission, Case 18-M-0084 "Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025", Appendix B

heat. In these circumstances we are not adding customer count, but we are adding usage per customer as they use gas for heating purposes. This continues to be an attractive value proposition as connections already exist for customers to capture significant advantages over oil when it comes to commodity cost, convenience and lower emissions.

- There has been a continuous flow of National Grid customers (mostly multifamily) switching from non-firm/temperature controlled gas rates to firm gas rates. In our Baseline forecast, this trend is expected to continue, accounting for 140 new firm customers per year and incremental 8 MDth/day Design Day demand growth per year (16% of total Design Day demand growth per year in baseline scenario).[25]
- NYC's efforts to convert away from No. 4 and No. 6 heating fuels (2012 NYC Clean Heat program) to reduce soot pollution supported oil-to-gas conversions over 2012-2019. However, its effect on the total number of conversions was relatively small - only 1% of buildings in NYC were heated by No.4 and No.6 oil prior to this program, and National Grid converted 800 buildings heated by these oils during the 2012-2018 time period. Moreover, although No. 6 heating fuel customers had to convert by 2015, No. 4 heating fuel customers need to convert by 2030, which continues to support future oil-to-gas conversions.

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

With regards to Local Law 97, several commenters challenged whether National Grid's assumptions were too conservative regarding the level of adoption/conversion to heat pumps. In particular they questioned whether the impacts to natural gas demand due to Local Law 97 compliance through electrification during the first ten years (2020-2030) may be greater than what National Grid has in its High Demand and Low Demand scenarios.

Clearly there is a level of uncertainty regarding how achievement of Local Law 97 will occur, e.g. the mix of building efficiency, electric efficiency and fuel source changes deployed to achieve targets. National Grid acknowledges that the number of heat pump installations could be greater than what it

[25] National Grid is designing programs to incentivize customers to stay on non-firm/temperature-controlled rates in the future

has forecast in the Long-Term Capacity Report. However, there are several important points that should be considered when assessing different assumptions, including:

- Local Law 97 is designed to help buildings of 25,000 sq. ft. or more reduce their carbon emissions vs. 2005 baseline: 40% reduction by 2030 (which is a 26% reduction vs. 2018 levels) and 80% reduction by 2050
- There are ~50,000 buildings in NYC that are covered by Local Law 97[26]. According to our estimates based on review of internal data, ~9,000 of them are National Grid Downstate NY customers
- "The building emissions limits for 2024-2029 are designed to impact the top 20% of emitters, which means that most NYC buildings are already compliant.[27]" This gives most customers some time to assess their situation, consider options and develop strategies to come into compliance for 2030 and beyond.
- Emission limits become more stringent for the 2030-2034 compliance period with an estimated 75% of all covered buildings requiring some form of action in order to comply, based on the current emission coefficients. This implies that ~6,750 buildings in National Grid Downstate NY territory will need to act to comply with Local Law 97.
- Local Law 97 provides several ways to ensure compliance:
    - Reduce building emissions (e.g., perform energy efficiency, oil-to-gas conversions, heat electrification)
    - Acquire credits from other sources (e.g., renewable energy credits, greenhouse gas offsets, carbon trading to be defined by 2021)
    - Adjust targets or pursue alternative compliance pathways (e.g., complete prescriptive energy efficiency measures) for some categories of buildings (e.g., hospitals, rent-regulated buildings)
- Given these flexible ways to ensure compliance there are multiple pathways for each covered building depending on their particular situation and preferences, for example:
    - Many building owners could achieve their targets by relying on energy efficiency and leveraging NENY Energy Efficiency programs
    - Some building owners could pursue aggressive energy efficiency retrofits (e.g., insulation, controls, lighting) and purchase renewable energy credits to cover the rest of the gap to target
    - Other building owners could pursue both energy efficiency and "partial electrification" whereby customers install heat pumps to operate during typical conditions but retain their gas connection and use natural gas for cooking and on the coldest parts of the winter when heat pumps are less efficient, which leads to significantly less or no reduction to Design Day demand. In National Grid's model, we assumed all customers moving to electrification are doing so completely - our electrification numbers do not account for these customers who also retain gas.
    - Some building owners may even choose to install distributed renewable or low-emitting generation in their buildings, subject to permitting and space constraints.
- There are several uncertainties related to Local Law 97 and the ways covered buildings will pursue compliance:
    - While greenhouse gas coefficients have been established for 2020-2024 (showing natural gas with 30% lower emissions than oil), coefficients for 2030-2034 will not be

[26] Urban Green Council, NYC building emissions law summary-Local Law 97
[27] Jahnavi Sajip, ny-engineers.com, November 14, 2019

published until January 1, 2023. One of the key areas of uncertainty is the underlying emissions of electric power generation. Currently, only 30%[28] of electric energy comes from clean energy resources (renewable and nuclear)[29] in Downstate New York. Historic data shows that although renewable resources have been gaining share, gas generation was expanding at an even greater pace. Moreover, the upcoming planned retirement of Indian Point nuclear power plant (~37% of all nuclear power capacity in the state) by April 2021 could considerably increase the emission intensity of electricity generation in the short to medium-term (e.g., 2021-2030). This complicates the story that switching to heat pumps will necessarily be the solution of choice for customers to achieve emission reduction goals.

- There is considerable opposition to the law among certain types of customers, particularly condo and co-op owners who feel they are being singled out to shoulder the necessary upgrades to meet emissions limits. Some of them have already undergone costly heating retrofits to convert from No. 6 heating oil to gas and might not be able to afford further building updates. This could lead to readjustment of Local Law 97 targets.

In our forecast we assumed that depending on the demand scenario ~4,300-8,900 multifamily and Commercial customers in KEDNY (out of a total customer base of 73,000) will fully switch to electric heating by 2035. These customers will decrease total multifamily and Commercial customer natural gas Design Day demand by 6-12%, of which 4-10% is due to Local Law 97 and the remaining 2-3% is due to organic heat pump adoption. The reductions driven by Local Law 97 (4-10% of the demand) correspond to 700-1,500 complete electrifications of large buildings (>25,000 sq. ft.), which represents 10-22% of 6,750 National Grid Downstate NY customers that would need to act in order to comply with Local Law 97. National Grid believes these are reasonable assumptions to include in its Design Day demand forecasts and that no further adjustment for Local Law 97 is necessary.

4.2 The Design Day Standard

A number of commenters have challenged our Design Day standard. Specifically, they raised the question as to why we are using the standard of 0˚F for 24 hours in Central Park, when the last time there was such an occurrence was in 1934.

In response to these comments, we looked even more extensively at the Design Day standard. There is no one "set standard" in the natural gas industry regarding Design Day. In many geographies, it is similar to Downstate New York in that it is a set temperature and not based on a probabilistic "once-in-x years" methodology. We do use probabilistic methodology in Massachusetts, where the Design Day standard is based on once-in-33 years. And, when we look at annual volumes, it is done with probabilistic models that look at once-in-40-years. Based on this assessment, it is reasonable to consider once-in-30 years or once-in-40 years as a potential standard[30].

[28] While overall across New York state 60% of electric energy is generated from clean resources, this number is currently substantially lower in Downstate NY. Source: NY ISO, 2019 Power Trends Report

[29] NY ISO, 2019 Power Trends Report

[30] It is also worth considering population density and the corresponding level of risk. For example, in a geography such as upstate NY or western MA, the impact and ability to respond to a supply outage would be much different than if such an outage were to occur in a high-density area such as New York City, which may lead to a desire for a lower temp/higher year standard in more urban areas. The Massachusetts standard is actually derived from a Benefit-Cost Analysis that considers cost and risk of outage compared to levels of investment in infrastructure and other solutions.

To conduct additional analysis, we started by going back and looking at the weather data to determine the coldest period over the last 30 years. While the Company does not have ready access to the full 30-year database of hourly temperatures for Central Park, NY (KNYC), the official weather station used by the Company for its Downstate NY weather data, it does have daily weather data for KNYC going back to 1948. In looking at the last 30 years, Jan 19, 1994 was the coldest observed day in the time period, with a gas day (10am – 10am) average reading of 61 Heating Degree Days (HDD) or approximately 4ºF. Knowing that the gas day is a time period selected to align with the operations of the natural gas industry, and not necessarily the coldest consecutive 24-hour period, the Company acquired the hourly temperature readings from LaGuardia International Airport (KLGA) for 18-20 January 1994. Reviewing the hourly air temperatures over that 72-hour time period, the coldest 24-hour period occurred between 05:00 19 January – 04:00 20 January, where the average was 2.8˚F.

We also created a probability distribution using the 151-day period from November-March of each winter and looking at both 30 and 40 years of data. Using thirty winters of data, the probability model indicates a 1-in-30-year event would be an average of 62 HDD or 3˚F. Using a rolling 40-year time-period of data, which is what we typically use, a once-in-30-year peak day would be one HDD greater at 63 or 2˚F. This 40-year analysis also defines our current 65 HDD or 0˚F Design Day as a once-in-71-year event.

Given the analyses described above, we believe that it would be appropriate to characterize a once-in-30-year event as 3˚F or 62 HDD[31].

We then modeled the impact of change in Design Day temperature on Design Day demand levels. Based on this analysis, a one HDD change in temperature equates to approximately 1.25% of demand, so a 3 HDD change would imply an approximate 3.75% Design Day demand reduction.

It is important to note that a change of Design Day from 0˚F to 3˚F, without any other considerations, would add significant risk to Downstate NY natural gas delivery. As explained in the Long-Term Capacity Report, there are also Design Hour considerations that require a higher level of gas need during periods of highest gas usage, typically during early morning and evening hours and/or as temperature fluctuate on the Design Day. And, these Design Day calculations are done with no supply contingency or operating margin – in other words, it assumes that forecasts are 100% accurate (even though we know and have shown by comparing previous forecasts to actuals that the range of forecast error is +/-2%) and assumes that all available supply will be operating at 100% with no disruption to total capacity (while pipeline capacity is generally highly reliable, limitations can arise due to interstate pipeline problems at compressor stations, integrity issues etc. that reduce what we can get from our contracted capacity).

Given the above, to provide more context around the Design Day standards, we created a more detailed model that quantifies the impact on Design Hour and considers as one option a 2% contingency for supply disruption/forecasting error. Said another way, if we want to look at the impact of moving the Design Day standard from something that is likely to occur once every 71-86 years (0˚F that our probability model says is 1 in 71 years, and that last occurred in 1934), to something that is likely to occur once every 26-30 years (a 1-in-30 probability model that last

[31] All of this analysis has been completed based on temperature and temperature fluctuations. In some states such as Massachusetts, wind and wind chill is also included as a factor in the analysis. This additional variable could change the standard that gets set and the corresponding level of supply capacity required. For example, an above-average wind chill day with a Design Day temperature of 2˚F may trigger usage equivalent to a 0˚F day with average wind.

occurred in 1994), we should also consider the actual Design Hour needs during that event, and consider a scenario where 2% of our supply may not be available due to disruption or higher demand may occur due to forecast accuracy.

To model Design Hour, we started by looking at demand. Historically, based on previous analysis we have used a conversion rate of 5% to go from Design Day demand to Design Hour (i.e. Design Hour is 5% or 1/20th of the total Design Day demand). We looked at several different data sets to test this assumption, and every analysis yielded a range of 4.96% - 5.00%, thus validating 5% as an acceptable Design Hour demand assumption.

For Supply, we looked at each component of our supply stack to understand its ability to "flex" and provide more on an hourly basis vs. a steady 1/24th of Design Day demand. For example, some of our pipeline contracts will allow us to take more on a Design Hour, as long as the total for the day does not exceed Design Day capacity, while other contracts do not allow this flexibility. And, while LNG cannot be increased beyond 1/24th of Design Day, our CNG capacity is designed such that it can deliver all its Design Day capacity over eight hours (two four-hour windows).

The results of this detailed analysis are shown in Table 14 below, using the High Demand Scenario from the Long-Term Capacity Report as an example.

Table 14: A Comparison of Different Design Standards on Required Natural Gas Capacity

Design Day Gap Between Demand and Supply by Year (MDth)															
Design Standard	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
0 Degree Design Day - Currently Used	(68)	(29)	17	72	115	157	199	248	285	303	330	353	375	390	400
0 Degree Design Hour	27	58	105	161	206	250	293	344	382	401	429	453	475	492	502
3 Degree Design Day	(175)	(137)	(93)	(41)	0	41	82	128	164	182	207	230	250	265	274
3 Degree Design Hour	(84)	(54)	(9)	46	88	131	172	221	258	276	303	326	347	363	373
3 Degree Design Hour w/2% contingency	(25)	4	50	104	147	189	231	279	316	335	361	385	406	422	432

This modeling shows that at a 3°F Design Day, meeting Design Hour needs would require slightly less capacity (373 MDth/day in 2034/35 vs. 400 MDth/day under current standard), while factoring in a 2% forecasting/operating contingency would require slightly more supply capacity than what we currently plan for on a 0°F Design Day (432 MDth/day in 2034/35 vs. 400 MDth/day).

When considering all of these potential impacts – temperature, wind chill, Design Day vs. Design Hour, and any potential considerations for forecast error or operating margin/contingency – it is National Grid's conclusion that there are too many factors to warrant changing the analysis without a more detailed study done in conjunction with other impacted parties and stakeholders. Therefore, our analysis considering the gap between demand and supply and comparing different options for closing that gap and meeting the needs of Downstate NY continues with the 0°F Design Day standard.

Going forward, National Grid believes there is an opportunity to review Design Day standards with the NY PSC as part of the recently announced natural gas supply planning proceeding. We believe any such effort should be conducted in conjunction with Con Edison, who as we pointed out in the Long-Term Capacity Report shares the same Design Day standard and coordinates planning with National Grid due to some of our shared upstream infrastructure.

4.3 Reforecast of demand based on preliminary estimated COVID-19 impact

Following the publication of our initial Report, the world economy in general and the Downstate NY economy in particular have undergone significant disruption due to the COVID-19 pandemic. While it is anticipated that the economy will open back up over the long-term, some near-term reduction in Design Day natural gas demand is expected, and there could also be an impact to longer term forecasts.

In the time frame of producing this Supplemental Report, and given a constantly changing COVID-19 landscape, National Grid does not have the ability to complete an in-depth, econometrically driven reforecast of demand. However, we also do not believe it is prudent to assess our long-term options as if nothing has changed. We therefore have completed a reforecast of demand based on preliminary estimated COVID-19 impact.

To provide some context, we created a model utilizing a “backcasting” methodology. Briefly, we used the last three years of March data, including load and actual weather information, to build a daily load model. We then fed the actual weather of March 2020 into the model to create an estimate of counterfactual load for each day of March 2020. We were then able to compare the counterfactual load with the actual load we metered, to get a directional estimate of what we believe the COVID-19 impact might have been. We also separated the data between the first three weeks of March (when activity had slowed, but there was not a full lockdown) and the late March through mid-April time frame (when a more complete lockdown was in place). The results of this analysis are shown in Table 15 below.

Table 15: High-Level Estimate of Potential COVID-19 Impact on Downstate NY Natural Gas Demand in March-April 2020 (% Difference Between Actual Natural Gas Usage and Counterfactual Usage per National Grid Backcasting Model)

	Pre-Lockdown			Lockdown				
Geography	Feb 29 -March 6	March 7-13	March 14-20	March 21-27	March 28 - April 3	April 4-10	April 11-17	Total Since Lockdown
New York City (KEDNY)	0.1%	-0.9%	-1.3%	-0.9%	-3.5%	-4.3%	-6.8%	-3.7%
Long Island (KEDLI)	-0.9%	-1.8%	-6.5%	-3.2%	-8.6%	-4.1%	-7.8%	-5.8%

We believe that this data provides useful context – e.g. in a time of reduced economic activity such as that seen in the first 2-3 weeks of March, we might expect natural gas usage to decline a couple/few percentage points, whereas in a severely or completely restricted environment such as what was experienced at the end of March and into April, reductions may be more in the 4-6% range, or even as high as 8% in certain time periods and locations. However, it does not answer how this might translate into Design Day demand on the coldest of winter days, nor does it answer what things might look like if there is a return over time to relatively normal personal and business activity (e.g., with some limited new restrictions vs. what we were used to prior to COVID-19).

To get to a more specific range of estimates for utilization in our demand forecast, we believe there are three drivers that must be considered to get to a preliminary estimated COVID-19 impact:

- Lower demand due to a reduction in the number of customer connections. During the lockdown period, National Grid is only connecting new customers through an exception process, and new applications are coming in at about 40% of our typical rate. We would anticipate that even when more economic activity resumes, the pace of new customer connections may be slower than normal for a period of time.

- Lower demand due to a reduction in natural gas usage per customer. While 85% of Design Day demand is for space heating, which fluctuates more on weather than economic activity, it is expected that there will be some impact to customers on the amount of natural gas that is utilized. For example, there would be an expected impact to any assumptions of utilization growth due to increases in building square footage.
- Higher demand due to a reduction in the level of energy efficiency, demand response, and electrification activity levels. During the lockdown period, most of these activities have been suspended, and even when more economic activity resumes, the pace of these activities may be slower than normal for a period of time.

Table 16 below provides a summary of the assumptions used under the Low Demand and High Demand scenarios for estimating the range of potential COVID-19 impacts.

Table 16: Assumptions Used in Creating Estimated COVID-19 Impact on Downstate NY Natural Gas Design Day Demand

Variable Impacted	Assumption – High Demand Scenario	Assumption – Low Demand Scenario
Number of Customers	• Zero customer connection activity for three months • Connections resume for four months at a reduced pace (50% of normal for Residential and multifamily, 25% of normal for Commercial & Industrial) • Total customers lost for 2020/21 of (4,306) • Regain +1,140 customers in each of 2021/22 and 2022/23; 2,026 customers remain "lost forever"	• Zero customer connection activity for five months • Connections resume for four months at a reduced pace (40% of normal for Residential and multifamily, 20% of normal for Commercial & Industrial) • Total customers lost for 2020/21 of (7,063) Regain +570 customers for 2021/22 - 2023/24; 5,353 customers remain "lost forever"
Usage Per Customer*	• For 2020/21, Residential Heat usage growth per customer goes from 0.2% to 0.05%, C&I from 0.6% to -0.5%, and multifamily from 1.2% to 0.3% • Over 2021-2023, Residential Heat growth goes back to 0.19%, C&I to 0.5% and multifamily 1.05%	• For 2020/21, Residential Heat usage growth per customer goes from 0.2% to 0%, C&I from 0.6% to -2.0%, and multifamily from 1.2% to 0% • Over 2021-2024, Residential Heat growth goes back to 0.18%, C&I to 0% and multifamily 0.9%
Energy Efficiency/Demand Response/Electrification Activity	• Activity is reduced by 50% in the time leading up to and including 2020/21 • Programs are 95% caught up by 2022/23 and resume growth path going forward	• Activity is reduced by 40% in the time leading up to and including 2020/21 • Programs are 100% caught up by 2022/23 and resume growth path going forward

**Baseline growth prior to any reductions that occur because of NENY and Local Law 97*

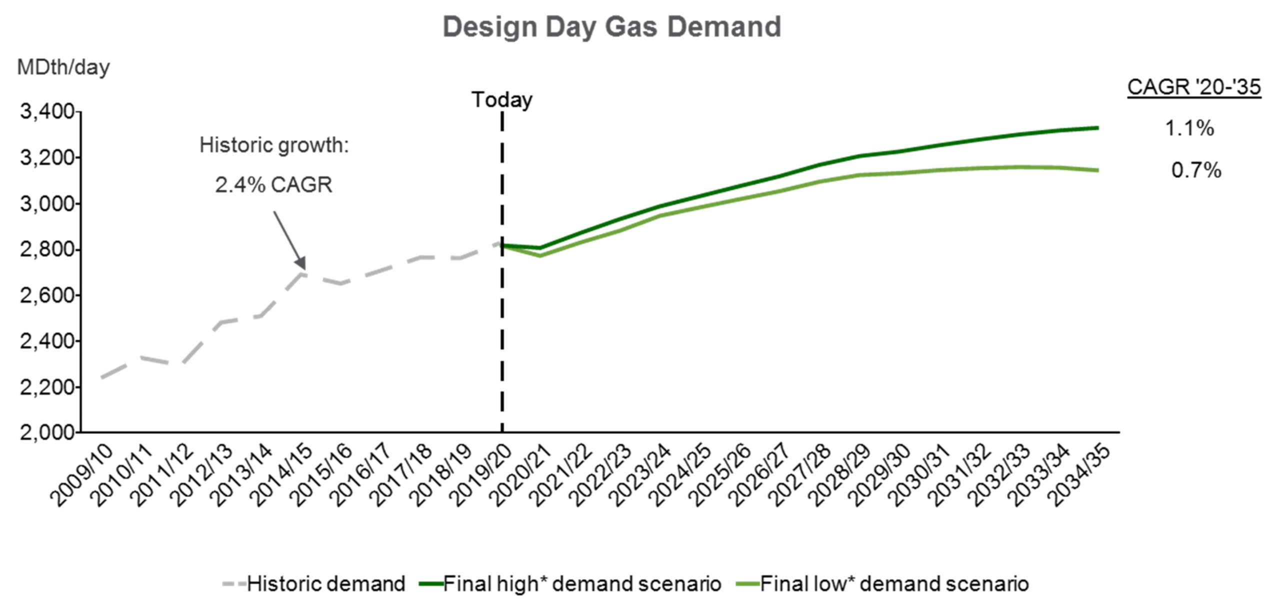
Based on the assumptions outlined above, Table 17 below provides the estimated impact of COVID-19 to Design Day demand under the High and Low Demand scenarios.

Table 17: Estimated Impact of COVID-19 to Design Day Demand Under the High and Low Demand Scenarios (MDth)

Design Day Demand Change From…	High Demand Scenario			Low Demand Scenario			
	2020/21	2021/22	2022/23 + Beyond	2020/21	2021/22	2022/23	2023/24 + Beyond
# of Customers	(16)	(11)	(7)	(26)	(23)	(21)	(19)
Usage Per Customer	(32)	(18)	(4)	(50)	(37)	(24)	(11)
Rate of new EE/ DR/Elec. Programs	7	6	2	6	5	0	0
Total (% of forecast)	(40) (-1.4%)	(24) (-0.8%)	(10) (-0.3%)	(70) (-2.5%)	(56) (-1.9%)	(46) (-1.6%)	(30) (-1.0%)

Applying these reductions results in new projections for Downstate NY natural gas demand growth. Figure 16 below shows this updated projected demand under the High Demand and Low Demand scenarios.

Figure 16: Projected 2020-2035 Downstate NY Natural Gas Demand Curve Factoring in Increases in Energy Efficiency, Customer Demand Response and Electrification, and Estimated Impact of COVID-19



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

Source: National Grid analysis

National Grid acknowledges that a lockdown that extends through the winter of 2020/21 could reduce near-term demand even further than what it has projected. As there is currently no projected gap between forecast demand and available supply for the winters of 2020/21 or 2021/22, any such increase in short-term impact is not expected at this time to have a material impact on long-term forecasts or potential solutions.

National Grid has created this updated demand forecast to the best of its abilities utilizing the data available through late April of 2020. As part of its standard annual forecasting process, the Company will issue an updated demand forecast in June of this year to reflect data from this past winter and additional information on the impacts of COVID-19.

5. Available Supply

Several commenters raised questions regarding our available supply capacity. These questions related to our existing pipeline and LNG capacity, our peak contracting capacity, and additional capacity available through further development of our LNG infrastructure. Additionally, while not part of our assessment on supply capacity, some questions and comments were received regarding National Grid's MRI project. These items are addressed below.

5.1 Existing pipeline and LNG capacity

In the initial Report, National Grid represented total pipeline Design Day capacity of 2,112 MDth. While these pipeline contracts are long term in nature and essentially "fixed" in terms of volume, there are some variations on the margin related to fuel loss (typically from operators utilizing some gas to operate the pipeline and associated facilities). As such, the "gross to net" calculations that are observed and used for forecasting can cause some minor changes in capacity – typically less than 1% of the total.

National Grid has gone back and reviewed all of its pipeline agreements, its observed throughput for 2019/20, and its modeling assumptions. Based on this analysis, the Company believes that there is an additional 13 MDth/day that can be assumed as supply capacity from its pipeline network, bringing the total to 2,125 MDth/day. This 13 MDth/day is coming from slightly lower observed and projected fuel losses on the IGTS and Rockaway pipelines. While there is no guarantee that in the future this 13 MDth/day will be available due to changing conditions on the interstate pipelines, it is our best estimate based on current conditions to include it in our supply capacity.

We also reviewed our assumptions on LNG Design Day capacity from our existing Holtsville and Greenpoint facilities. Our Design Day available capacity is 394.5 MDth, vs. the 393 MDth that was erroneously listed in the original version of the Report. This 0.4% difference adds 1.5 MDth of Design Day capacity.

The total impact of these updated assumptions on existing pipeline and LNG capacity is to increase National Grid's available Design Day supply by 14.5 MDth. This increase will be included in our updated charts/analyses on available supply, the demand-supply gap, and the cost of the different options, as shown in Figure 17 below and throughout the rest of the Supplemental Report.

5.2 Peak contracting capacity

Some commenters asserted that there are additional peak contracting supplies available, and that National Grid is thus underestimating its available supply in this category. National Grid acknowledges that peak contracting supply capacity is a complex issue and has provided further explanation below regarding its assumptions. With that said, having extensively reviewed our modeling and assumptions, we are comfortable with our projected levels of peak contracting capacity as shown in the original Report.

There are two main factors driving our peak contracting capacity: 1) the amount and location of what is available in the market; and 2) National Grid's operational constraints – its ability to utilize what is available. As these are short term contracts, the amount and location of what is available can change from year to year. And, while operational capacity and constraints do not tend to fluctuate as much, there can still be significant changes to that aspect of the equation.

An example of how these factors interact with each other can be seen in this most recent winter of 2019/20. In the fall of 2019, Enbridge notified National Grid that there could be a delivery shortfall through their pipeline network estimated at 106 MDth/day. While we had already contracted for the maximum amount of supply that our system could accept under normal supply circumstances at the Goethals station, due to the hydraulic limitations on our Staten Island infrastructure, this Enbridge shortfall now meant that we would have to go out and seek contracts to make up for this shortfall.

Fortunately, we were able to find available "contingency" supplies to make up for the Enbridge shortfall, and with NY PSC agreement we entered into contracts for the winter of 2019/20. It is important to note, however, that if the Enbridge situation had not occurred, these additional contracted supplies would not have been able to increase our supply capacity due to operational constraints that limit the total volume our system can accept.

While it is true that depending on the year, the location, and our operational constraints, there could be additional supply available that we have not taken into consideration, the opposite is also true – there could be short term contracts that we currently have that no longer become available, or while the "total amount" of what is available in the market may satisfy what is needed, operational constraints could limit our practical ability to utilize what is available in order to keep or increase supply capacity. National Grid has extensively reviewed its existing contracts, what it knows about the marketplace, and its operational constraints, and has concluded that its assumptions as utilized in the original Report provide a balanced estimate of what it believes can be counted on with regards to peak contracting capacity.

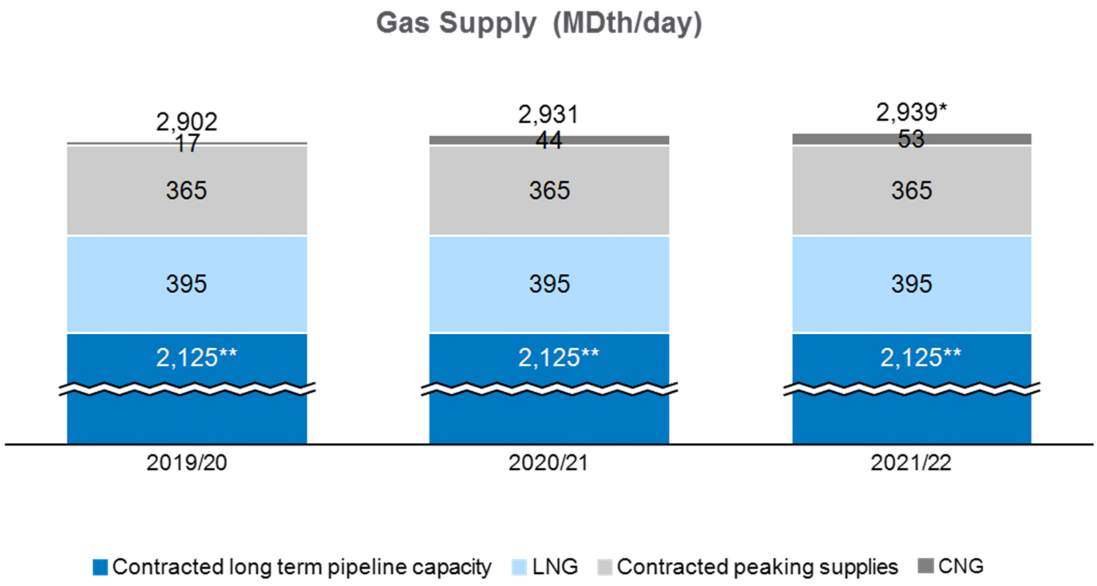
5.3 Additional capacity through further development of our LNG infrastructure

National Grid received comments that there is additional supply capacity of up to 60 MDth/day available through enhancements to LNG vaporization at its Greenpoint location. National Grid agrees that this is an opportunity – while we would not include it in our firm existing and projected supply stack, we have included this potential project as an additional option explained further in Section 6 below and in subsequent comparisons of solution alternatives to close the gap between projected demand and available supply.

5.4 Summarizing changes to National Grid's Downstate NY natural gas supply capacity

Figure 17 and Table 18 provide an updated view and explanation of National Grid's existing and projected supply stack.

Figure 17: 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 18: 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	2,125	• 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)	395	• 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	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	**2,902 – 2,939**	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	

**National Grid may install and operate up to 62 MDth of capacity, however the difference between 53 MDth/day and 62 MDth/day is a result of hydraulically modeling for pressure support in specific geographies and time periods, and as such this difference cannot be assumed as incremental supply capacity.*

Source: National Grid

5.4 National Grid's MRI Project

National Grid's Metropolitan Reliability Infrastructure Project (MRI) is being undertaken to improve Brooklyn's natural gas system by increasing the system's safety, reliability, and operational flexibility, providing critical improvements to the circulation and reliability of the Company's existing transmission system for the benefit of all customers. The project has five Phases of execution. Phases 1-3 are complete and Phase 4 is well underway with work having begun on Phase 5 before all work being halted due to the COVID-19 pandemic. Restart plans are being actively evaluated with a likely restart in May. Commenters, in particular New York City, pointed out that the final phase of this project is not yet approved and wanted to better understand why it was necessary.

Under any of the options considered to close the gap between forecast demand and available supply, MRI Phase 5 completes the effort to effectively manage gas pressures across the system in the KEDNY territory. It provides much-needed system reliability and flexibility to move supply across the borough in a safe and efficient manner to meet the energy needs of new and existing customers.

Without the completion of this project, we are challenged in maintaining and operating an aging and constrained infrastructure that puts existing customers at risk of losing service during the coldest days of the year. The Jamaica, Queens area is at greatest risk of seeing below design pressures at the gate stations that serves over 30,000 customers who potentially could have pressure (safety) problems.

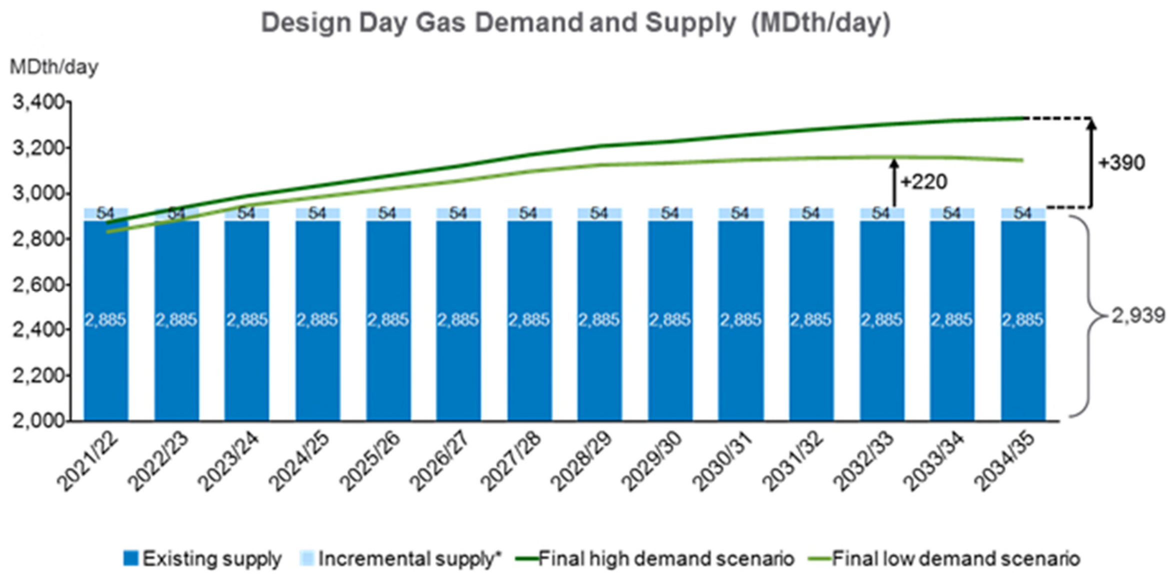
Additionally, under the LNG Vaporization opportunity that is described in Section 7 below, MRI Phase 5 is an important requirement to enable this incremental capacity, as it completes the reliability looping to our Greenpoint LNG facility.

National Grid has not identified any other projects or solutions that could bring the reliability benefits of MRI to the Brooklyn system as discussed above. These benefits can only be provided by the looping of the backbone that is the intent and design of the MRI project.

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

Having constructed an updated Low Demand and High Demand forecast for 2020-2035 in Section 4, and compiled National Grid's updated Supply Capacity in Section 5, we can now bring these two components together. Figure 18 shows how our Supply Capacity compares to the forecast natural gas demand.

Figure 18: 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 220 – 390 MDth. Furthermore, our projected impact from Low-Carbon Opportunities – which we expect to pursue under any scenario – has not changed and continues to grow to 15 MDth/day in the High Demand scenario and 35 MDth/day in the Low Demand scenario. Applying these projected impacts, as shown in Table 19 below, results in a remaining Design Day gap of 185 MDth in the Low Demand Scenario and 375 MDth in the High Demand Scenario.

Table 19: 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	220	390
RNG, Hydrogen and Incremental Geothermal Heat Pump Impact	35	15
Remaining gap	**185**	**375**

Source: National Grid analysis

7. Update on the Options

7.1 LNG Vaporization

As part of the on-going process to identify and scope out potential options to meet our customer needs, we present an additional potential distributed infrastructure supply option to close the demand gap. This option consists of installing two additional LNG Vaporizers at our existing National Grid Greenpoint facility. Details on the option can be found below. As a reminder from the Long-Term Capacity Report, each supply option is evaluated against multiple factors. To make it easy to compare this new option against the others presented in the Long-Term Capacity report, this new option 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
- **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.

Following the detailed description of this new option, we will provide a summary to facilitate comparison against the options presented in the Long-Term Capacity Report.

Description

The LNG Vaporization option includes installation of two LNG Vaporizers at National Grid's Greenpoint LNG Facility in Brooklyn, New York. The facility currently includes two LNG storage tanks, a liquefaction train, LNG truck unloading, and six LNG Vaporizers. The first tank and original vaporizers have been in service since 1968. This option would install two more vaporizers designated as "13 and 14" bringing the total number of vaporizers at this facility to eight.

LNG Vaporizers are heat exchangers that regasify liquefied natural gas. The vaporizers that are currently at the Greenpoint LNG site are Submerged Combustion Vaporizers (SCVs). This option would add two additional SCVs. In the SCVs, LNG is pumped into a heat exchanger that lies in a water bath where it is heated and turned back into a vapor state. The water is heated through the submerged combustion unit, a process that sparges hot combustion gas under water resulting in a very efficient exchange of heat energy.

Size

Vaporizers 13 and 14 will provide an additional approximate 60 MDth/day of supply capacity. These vaporizers can be operated intermittently and will be used for peaking capacity.

Safety

SCVs are a safe and proven technology – they are installed all over the world and have been used for decades. Since all combustion takes place under water at relatively low temperatures (water baths typically operate at 120˚F), there is minimal risk of exposure to operations personnel. National Grid will work closely with FDNY on approvals and will ensure facility siting meets or exceeds all applicable codes. National Grid follows best practice in process safety and operational safety methods in design, installation, and operation of all assets. Once installed, National Grid will actively patrol, monitor, and control the assets to minimize the potential for incidents. In particular, a safety instrumented system will be installed that automatically brings the process into a safe state when abnormal process conditions are detected.

Reliability

SCVs have a simple design that allows for easy scheduled and unscheduled maintenance. Additionally, all materials will be made with corrosion resistant and long-lasting materials, such as stainless steel. National Grid is also undertaking efforts to upgrade the LNG tanks at the Greenpoint facility by 2027. These upgrades will ensure the reliability of all LNG operations at the Greenpoint facility, including the newly installed SCVs.

Cost

The projected capital cost to install two vaporizers is approximately $59M. National Grid will capitalize these costs and will pass along these costs to its customers through rate cases. Additionally, an incremental annual cost of approximately $50K is anticipated for additional inspections, calibration, and maintenance of these two vaporizers.

Environmental Impact

Ecological Impact: Installation will result in modest short-term environmental impacts related to decreased air quality, pollution to storm water and other runoff, disruption to natural resources and habitats, noise, and waste generation. SCVs are relatively small in nature compared to larger LNG facilities (e.g., LNG deepwater port) and thus expected to have smaller ecological impact during the construction phase.

Once operational there will be ongoing moderate impacts due to emissions from the vaporizer combustion process. 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 overall GHG emissions from SCVs would be lower than other LNG options, because operation of the vaporizers would be strictly limited to peak days or local operational needs. When operational, there would be GHG emissions similar to other LNG options and 10-15% higher than standard natural gas.

Community Impact

The vaporizers will be installed entirely within the Greenpoint LNG facility existing footprint. The installation process does not require a large amount of excavation and drilling, and these additional assets are not visible to the public, therefore it is anticipated there will be low impact on the neighboring communities.

Permitting, Policy and Regulatory Requirements

The project would require NYC DOB, and FDNY 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.

Additionally, since the added vaporization capacity occurs without an increase in storage capacity, LNG truck station permits and an LNG Trucking Memorandum of Understanding (MoU) with the City of New York are required to enable a refill process. The current truck unloading station has not been operated since 1977 when FDNY granted temporary use due to extreme cold weather and gas supply curtailments. Further, when the Company received the variance for the installation and operation of the LNG liquefier train at Greenpoint in 2006, FDNY required that the location of the truck station be moved (i.e. operation of a truck station at this specific location was disallowed). As such, consent from FDNY and the City of New York is needed to build a new trucking station and ensure trucking operations can occur.

Requirements for Implementation

Assuming timely receipt of required permits and other authorizations, construction could begin as early as July 2020 with project completion by the beginning of December 2021.

Summary

Table 20 summarizes the assessment of the LNG Vaporization option as a means of closing the gap between projected Downstate NY natural gas demand and available supply.

Table 20: Summary of LNG Vaporization Option

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

Area of Assessment	Evaluation	Rationale/Description
Overview	N/A	Installation of two additional submerged combustion vaporizers at National Grid's Greenpoint LNG facility
Size	60 MDth/day	Designed to meet periods of peak demand
Safety	◕	FDNY and state entities to review and approve all necessary safety processes and protocols
Reliability	◕	Vaporizers are simple in design and have historically been very reliable – National Grid has extensive experience in this area
Cost	●	Total project cost to install two vaporizers is $59M, and estimated annual costs are approximately $12M
Environmental Impact	◑	The short-term ecological impact from installation will be moderate, focused on the Greenpoint area of New York. Emissions impact would be low due to intermittent peak usage.
Community Impact	◕	Low impact to the community – all planned construction and installation are within existing Greenpoint LNG footprint
Permitting, Policy and Regulatory Requirements	N/A	Would require NYC DOB and FDNY approval for construction within NYC. LNG truck station permits and LNG Trucking MoU with the City of New York are also required.
Requirements for Implementation	N/A	Assuming all approvals are attained on a timely basis, the project can be in-service by December 2021 (~1.5 years)

7.2 Other Updates to Assumptions on the Different Options

Cost Impact and Ongoing Operation of CNG

In the original Report, we referenced CNG operating costs in the Appendix. We have since undertaken a more comprehensive assessment of these costs, including gathering a significant amount of additional information from our potential supplier partners. Based on this information, it is estimated that the cost to operate the four planned CNG sites will have an annual range of $20M - $25M (midpoint $22.5M).

In the scenarios that involve Large Infrastructure (Floating LNG, LNG Terminal, NESE Pipeline), our assumption is that CNG trucking can be stopped once these large infrastructure projects are brought online, thus saving $22.5M per year once this occurs. For all the Distributed Infrastructure and No Infrastructure options, we are assuming that CNG will continue to support our operations through 2035 and will be included in the Supply stack as it currently stands[32].

[32] If demand reduction programs start to consistently exceed targets, and/or if incremental programs can be designed to increase penetration and demonstrate predictability and delivery in specific geographies/times of day, in future years CNG trucking could be reduced or eliminated.

We continue to estimate that, for supply capacity planning purposes, we will scale up to four sites, 130 trucks and 53 MDth/day of capacity. It is possible that we could run up to 154 trucks across the four locations, as additional trucks may be needed for pressure support/balance in specific geographies and time periods. This support would not necessarily or uniformly provide supply capacity that could be counted on to close the gap between projected demand and available supply – thus we have not included capacity from these additional 24 potential trucks.

Cost Impact of Electrification

In the original Report we assumed that the incremental electrification program would have a significant level of overlap with electrification attributable to organic adoption and NENY targets, which is included in the demand forecast. However, through proper program design that exclusively targets existing gas customers and coordination with the electric distribution companies, this overlap with the NENY targets could be avoided. We have updated this assumption accordingly. Since there is virtually no overlap of organic residential electrifications in the demand forecast with the assumed incremental electrification program, it is now assumed each incentivized customer contributes incremental design day savings. This results in lowering the estimated cost of incremental electrification, which is reflected in our updated analyses throughout the Supplemental Report.

While the exact percentages vary by year and scenario, as an example this change reduces electrification costs by 17% in the High Demand scenario for the No Infrastructure solution.

Incremental Residential Thermostat Direct Load Control Demand Response Program

In the original Report we assumed that a large residential thermostat direct load control program would be required for some solutions to address the Design Day capacity constraint. Given updates to the supply and demand forecasts this program is no longer assumed to be necessary for any of the solutions. However, to the extent that a program like this may address Design Hour constraints it may still warrant consideration in future solutions.

Cost of NESE

In the original Report we assumed a full year cost in 2021 for the NESE project. Upon further review, it was deemed more accurate to assume that there would only be six months of charges to National Grid in 2021. As such, the cost modeling is updated to reflect a 50% reduction in the 2021 NESE project cost.

Size of Clove Lakes Infrastructure

In the original Report, we estimated the size of Clove Lakes at a range of 70 – 100 MDth/day in parts of the report, 80 MDth/day in other parts, and used 100 MDth/day in our cost analysis. We have confirmed that 80 MDth/day is the most appropriate estimate. All analyses have been updated reflecting the size of the project as 80 MDth/day.

8. Update on Approaches and Cost Implications to Close the Remaining Projected Gap Between Demand and Supply

In Section 11 of the original Report, National Grid described how a comprehensive solution requires looking at how options can be individually or collectively utilized to solve the gap between demand and supply, outlined those solution approaches, and presented cost information to compare across the different solutions. Given that the gap between forecast demand and available supply has been reduced, and the LNG Vaporization option has been introduced as described above, we felt it was prudent to update this entire section of the Report. This is presented below, followed by an additional analysis that has been completed regarding Customer Cost Impact.

8.1 Overview

Creating a comprehensive solution requires looking at how different options can be individually or collectively utilized to close 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**. These include both enhancements to existing infrastructure (LNG Vaporization, Iroquois Gas Compression) and development of new infrastructure (Peak LNG, LNG Barges, Clove Lakes).
- 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.

8.2 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 multifamily 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 2022/23 winter season, incremental action will be required to reduce demand. In Table 21, 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.

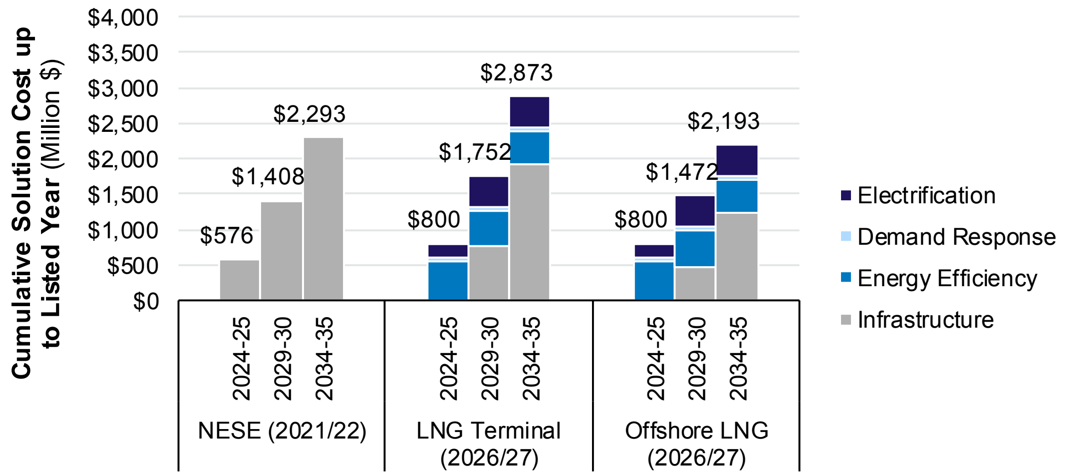
Table 21: Incremental EE, DR and Electrification Requirements to Close Gap Between Demand and Supply if Large Scale Infrastructure Comes On-Line in 2026/27

	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 70,000 – 100,000 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) a DR program where customers currently on non-firm rates will be kept on non-firm rates by offering an incentive of double the current annual bill savings.

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

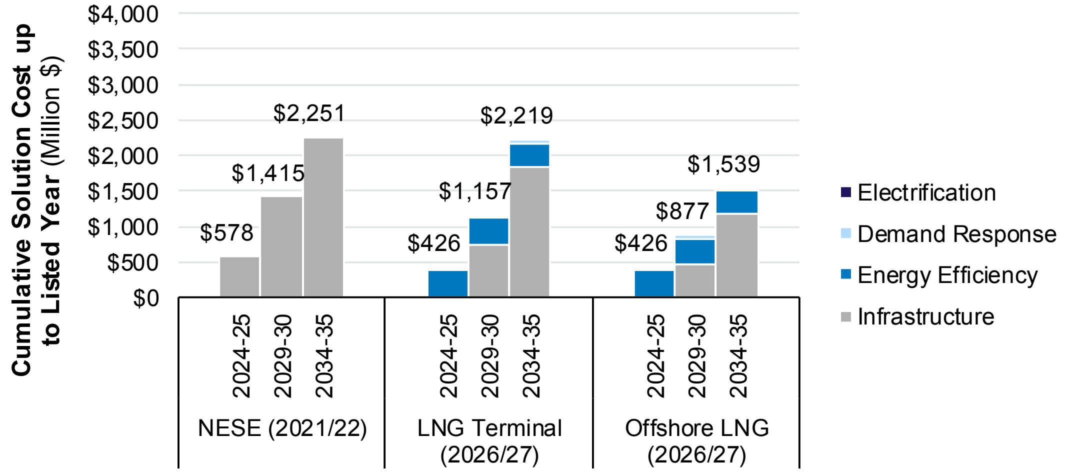
The total cost of the different options under the Large-Scale Infrastructure approach is summarized in Figures 19 and 20 below.

Figure 19: 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.

Figure 20: 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.

8.3 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 60 – 100 MDth/day and there is a projected gap of 185 - 375 MDth/day, even if two options were pursued there would still be an ongoing need for incremental demand reduction.

In Table 22 and Figures 21 and 22, 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 80 - 100 MDth infrastructure development option (Clove Lakes, LNG Barges, or Peak LNG) comes online in 2026/27, and 2) a 60 - 63 MDth enhancement option (LNG Vaporization, or Gas Compression on the IGTS) comes online in 2021/22 - 2023/24.

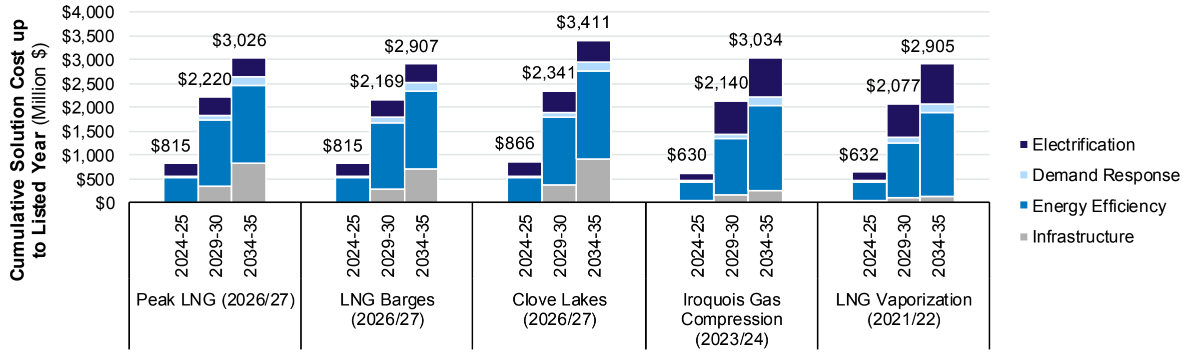
Under this approach, CNG trucking would remain and short-term contingency supply would not be available, unless EE, DR and electrification exceeded projections and further reduce demand.

Table 22: Incremental EE, DR and Electrification Requirements to Close Gap Between Demand and Supply Under Different Distributed Infrastructure Solutions

	Program Requirements
LNG Barges (100 MDth), Peak LNG (100 MDth), or Clove Lakes (80 MDth) Deployed 2026/27	Addressing the Demand-Supply gap in conjunction with a 80 - 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 70,000 - 100,000 homes and businesses by 2025, with requirements to weatherize an additional 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 20,000 – 25,000 homes to electric heat pumps by 2026.
Iroquois Gas Compression Deployed in 2023/24 (63 MDth) or LNG Vaporization Deployed in 2021/22 (60 MDth)	Addressing the Demand-Supply gap in conjunction with a 60 - 63 MDth Distributed Infrastructure solution coming online in 2021/22 - 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 50,000 – 75,000 homes and businesses by 2025, with requirements to weatherize an additional 60,000 – 225,000 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 45,000 homes to electric heat pumps by 2028.

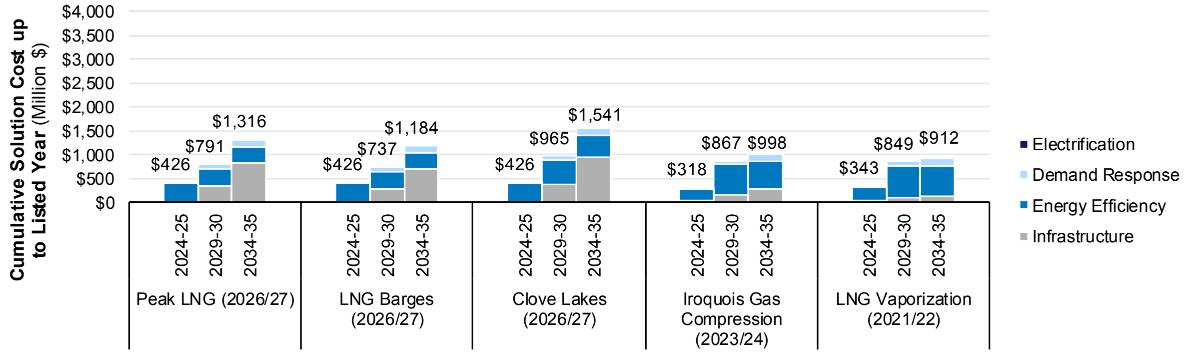
Note: ranges of program achievement are estimated based on Low Demand and High Demand scenarios

Figure 21: Distributed Infrastructure Cumulative Costs – High Demand Scenario



Notes: Sum of annual costs up to and including listed year w 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. Demand side resource costs include program administration and incentive costs, net of gas commodity savings.

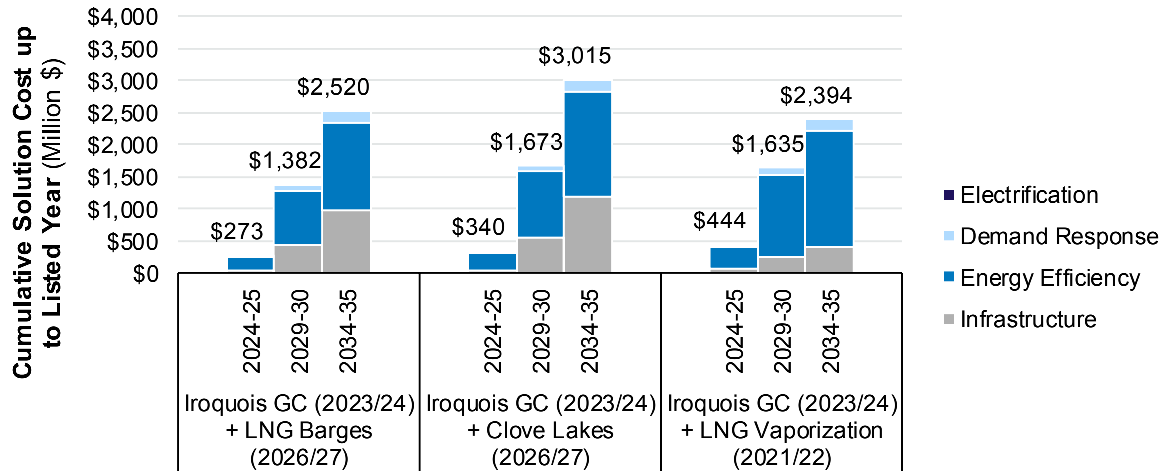
Figure 22: Distributed Infrastructure Cumulative Costs – Low Demand Scenario



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.

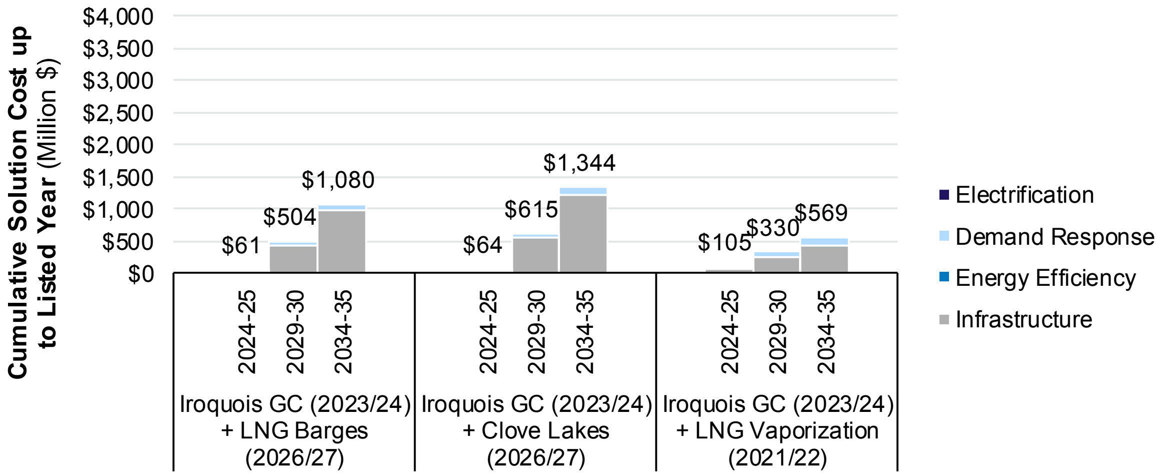
In addition, we could consider combinations of distributed infrastructure options, where two or more infrastructure efforts are put in place along with a smaller amount of incremental demand management to close the gap between projected demand and available supply. As examples, we have included in Figures 23 and 24 below three possible combinations – Iroquois Gas Compression with LNG Barges, Iroquois Gas Compression with Clove Lakes, and Iroquois Gas Compression with LNG Vaporization.

Figure 23: 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.

Figure 24: Cumulative Costs Under Possible Combinations of Distributed Infrastructure – Low Demand Scenario



Notes: Sum of annual costs up to and including listed year w 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. Demand side resource costs include program administration and incentive costs, net of gas commodity savings.

8.4 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,
- **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 23: Summary of No Infrastructure Solution to Have Impact Starting in 2021/22

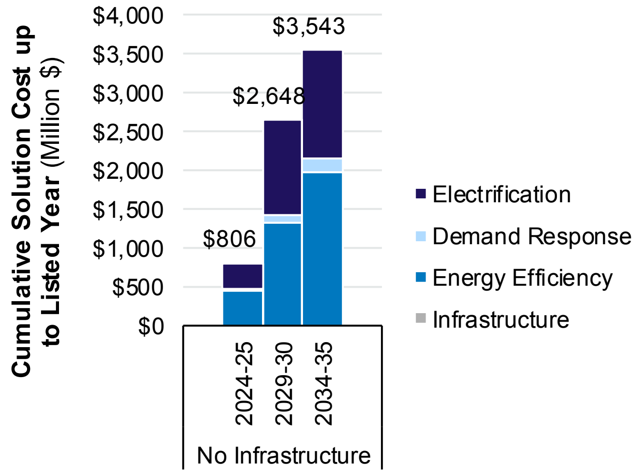
	Program Requirements
No-Infrastructure Solution	Addressing the Demand-Supply with no incremental infrastructure will require a very aggressive portfolio of EE, DR and electrification activities. In addition to NENY targets, Local Law 97, Downstate NY electric utility electrification programs, and organic 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 100,000 homes and businesses by 2025, which continues to weatherize another 100,000 – 240,000 homes and businesses by 2035; an additional electrification program in downstate New York to switch 15,000 – 75,000 homes to electric heat pumps by 2028; and, finally, 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.

In all, the investment to accomplish a no infrastructure solution is expected to range from $1.6 billion - $3.8 billion over 15 years, with annual costs peaking in 2027 at over $400 million in the high gap scenario.

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 2035 in the High Demand scenario, which thereby reduces the impact of a residential demand response program. These interactions further increase the cost of any incremental no-infrastructure investment.

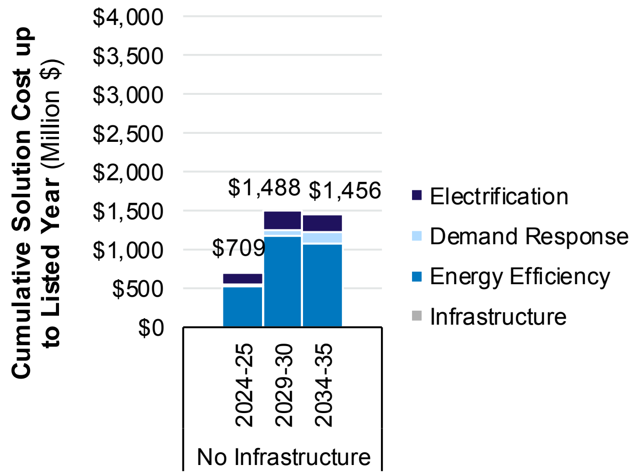
Figures 25 and 26 show the cumulative investment in the No Infrastructure approach through 2034/35 required to close the gap between demand and supply under the High and Low demand scenarios.

Figure 25: 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.

Figure 26: 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.

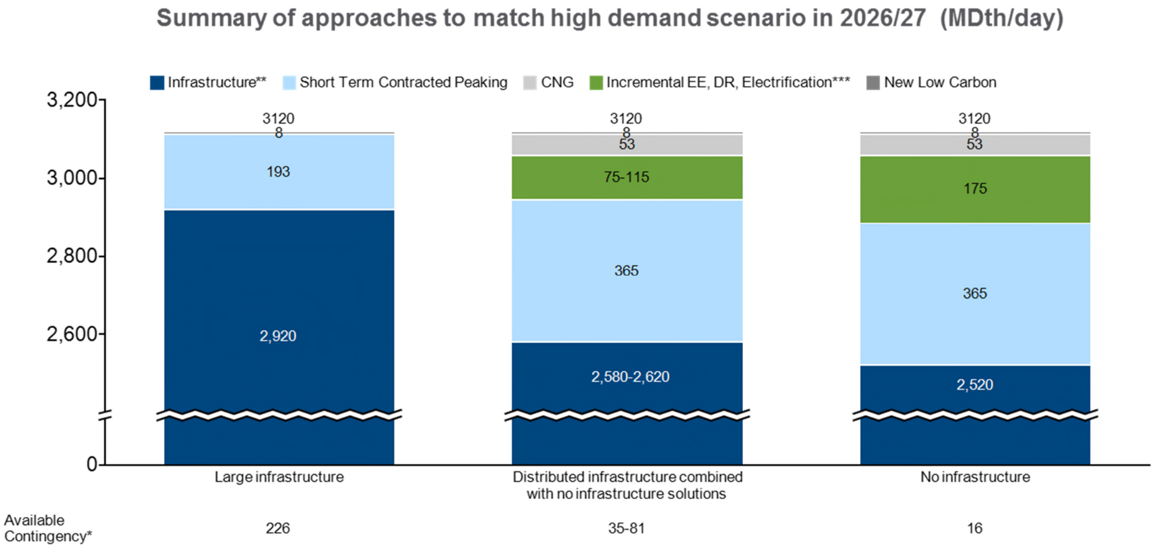
8.5 Summary of the Different Approaches

Table 24: 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)

<table>
<tr><th rowspan="2"></th><th rowspan="2">Impact from Infrastructure (MDth/day)</th><th colspan="2">Required Impact from Incremental EE/DR/ Electrification (MDth/day)*</th><th colspan="2">Impact to National Grid Supply Stack</th></tr>
<tr><th>2026/27</th><th>2034/35</th><th>2026/27</th><th>2034/35</th></tr>
<tr><td>Large-Scale Infrastructure</td><td>400</td><td>0</td><td>0</td><td>• No CNG trucking
• Contracted peaking supplies flex down to 121-193 MDth
• 226 – 297 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</td><td>• Under High Demand scenario, CNG trucking required again starting in 2032/33
• Contracted peaking supplies flex down to 178 – 340 MDth
• 25 – 240 MDth short-term contingency available
• TC customers continue to move to firm gas and away from burning fuel oil at peak</td></tr>
<tr><td>Distributed Infrastructure Combined with No-Infrastructure Solutions</td><td>60-100</td><td>3-115</td><td>85-315</td><td colspan="2">• 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</td></tr>
<tr><td>Incremental Portfolio of No-Infrastructure Solutions</td><td>0</td><td>103-175</td><td>185-375</td><td colspan="2">• 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</td></tr>
</table>

**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*

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



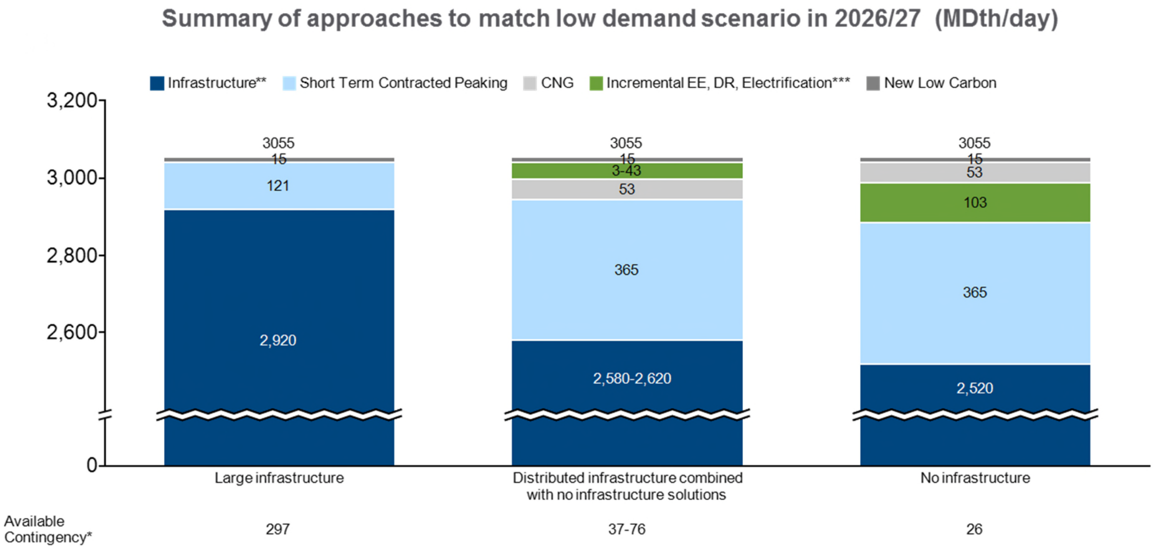
**Additional available short-term supply that could be contracted for or put in place if there are any interruptions to pipeline or LNG capacity, or if EE/DR/electrification targets fall short of forecast [if EE/DR/electrification exceeds targets in distributed infrastructure and no infrastructure scenarios, 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.*

Source: National Grid analysis

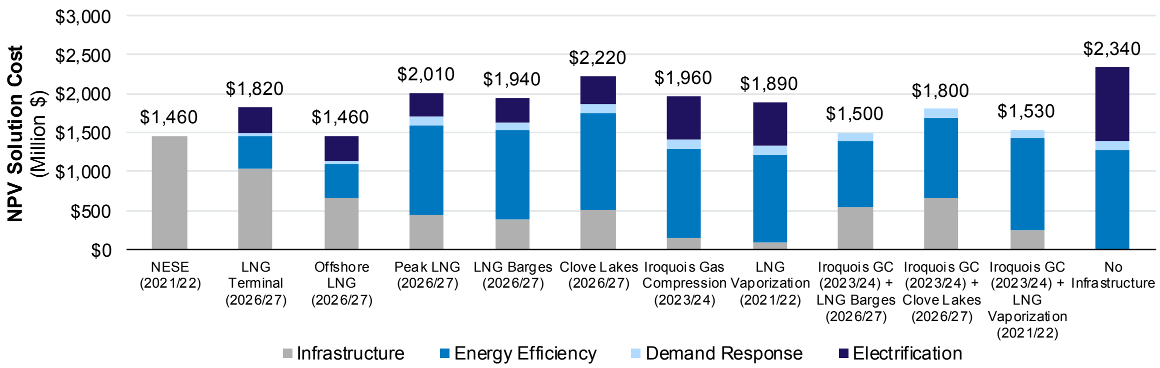
Figure 28: How Potential Approaches Will Match Low Demand Scenario in 2026/27



Same notes as figure 27; except 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

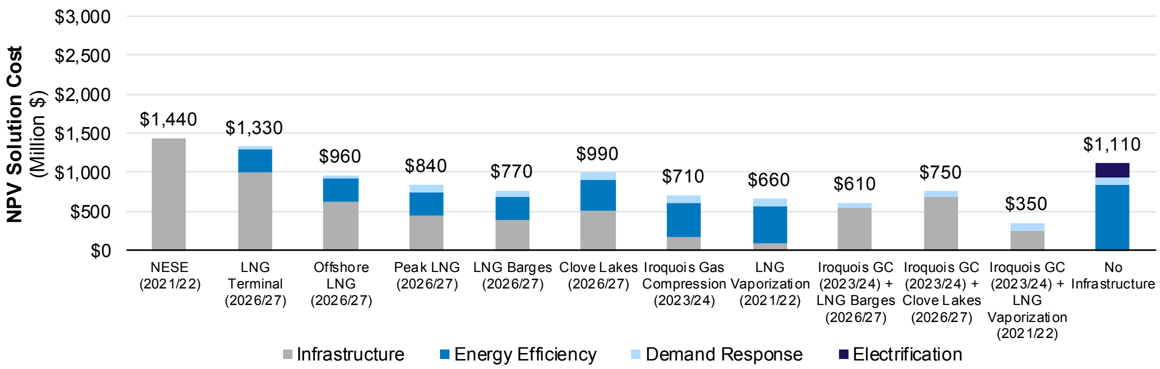
With regards to cost, we have developed a comparison of the different approaches, based on detailed assumptions on capital costs and timing of infrastructure, annual costs of operations, and one-time and annual costs to implement programs. Looking at the total cost package that would impact customers from 2020-2035, Figures 29 and 30 below provide a cost comparison across the different alternatives.

Figure 29: 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 between KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, which start in the listed operational year and are assumed to end in 2034/35, 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 through 2034/35.

Figure 30: 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 between KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, which start in the listed operational year and are assumed to end in 2034/35, 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 through 2034/35.

8.6 Customer Cost Impact

On March 23rd, we published a supplement to the Long-Term Capacity Report which estimated the customer cost impact of the different supply options presented in the Report. The supplement demonstrated how the Net Present Value (NPV) analysis presented in the Long-Term Capacity Report would translate to impact on average customer cost. This analysis has been updated to reflect the latest data as presented in this Supplemental Report and is summarized below.

Step 1: Calculating Cost Increase Percentages Over Time

In the first step of our supplemental analysis, we looked at the average annual non-discounted cost of each option in five-year time periods (2020/2021 – 2024/2025, 2025/2026 – 2029/2030, and 2030/2031 – 2034/2035), and compared that to the Baseline KEDNY/KEDLI costs (operating revenue)[33] to calculate the total cost increase % resulting from each option.

So, for example, the NESE pipeline is estimated to cost $193M per year. Therefore, over a five-year period, the average cost per year would be $170M ($193M cost of NESE minus the cost of unneeded CNG trucking). Dividing this by the total baseline revenue of $3.1B, we arrive at a 5.4% cost increase for the second five-year period for this option. The first five-year period for NESE is lower for two reasons: 1) since NESE would go operational in 2021/22, the first five-year period would only include four years of additional cost, and 2) we have assumed that in 2021/22 (i.e. NESE's first year in service), the incremental cost would be $74M, since NESE would not be operational for the full year.

The results of this analysis for each of the different options is included in Table 25 below.

Table 25: Total Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

Solution Option	High Demand Scenario				Low Demand Scenario			
	5yr avg 2024/25	5yr avg 2029/30	5yr avg 2034/35	**15 Year Average**	5yr avg 2024/25	5yr avg 2029/30	5yr avg 2034/35	**15 Year Average**
Offshore LNG Port	5.2%	4.4%	4.7%	**4.7%**	2.8%	2.9%	4.3%	**3.3%**
LNG Import Terminal	5.2%	6.2%	7.3%	**6.2%**	2.8%	4.7%	6.8%	**4.8%**
Northeast Supply Enhancement (NESE)	3.7%	5.4%	5.7%	**4.9%**	3.7%	5.4%	5.4%	**4.8%**
Peak LNG Facility	5.3%	9.1%	5.2%	**6.5%**	2.8%	2.3%	3.4%	**2.8%**
LNG Barges	5.3%	8.7%	4.8%	**6.3%**	2.8%	2.0%	2.9%	**2.5%**
Clove Lakes Transmission Loop (CL)	5.6%	9.5%	6.9%	**7.3%**	2.8%	3.5%	3.7%	**3.3%**
Gas Compression on Iroquois GTS (ExC)	4.1%	9.8%	5.8%	**6.5%**	2.1%	3.5%	0.8%	**2.1%**
LNG Vaporization	4.1%	9.3%	5.3%	**6.3%**	2.2%	3.3%	0.4%	**2.0%**
Gas Compression + LNG Vaporization	2.9%	7.7%	4.9%	**5.2%**	0.7%	1.5%	1.6%	**1.2%**
Gas Compression + LNG Barges	1.8%	7.2%	7.3%	**5.4%**	0.4%	2.9%	3.7%	**2.3%**
Gas Compression + Clove Lakes	2.2%	8.6%	8.7%	**6.5%**	0.4%	3.6%	4.7%	**2.9%**
No Infrastructure	5.2%	11.9%	5.8%	**7.6%**	4.6%	5.0%	-0.2%	**3.1%**

The percentage increases above are all calculated as changes from the Baseline. For example, if we are looking at the No Infrastructure option and the High Demand scenario, it indicates that costs would be 5.2% higher for the first five-year time period, then would increase another 6.7% to a total of 11.9% over Baseline for the next five-year period, then would go back to a level that is 5.8% higher than the Baseline for the final five-year period.

[33] Baseline revenue from 2018 annual reports: KEDNY $1.85B, KEDLI $1.24B, Downstate NY total $3.1B

This analysis isolates the cost impact of each alternative and does not consider other potential changes that could impact costs and customer bills, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, etc.

Step 2: Factoring in Projected Changes in Number of Customers to Calculate Average Cost Per Customer

Having calculated the cost changes over the five-year time periods for each of the different options, in Step 2 we factor in the changes in the number of customers over time to derive an average estimated customer cost impact. Again, we are using the same data on the cost of each option, but now take into account the expected growth in number of customers over time, taken from our High Demand and Low Demand scenarios as described in the Report and subsequently updated in Section 4 of the Supplemental Report.

The results of this analysis for each of the different options is included in Table 26 below.

Table 26: Average Customer Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply

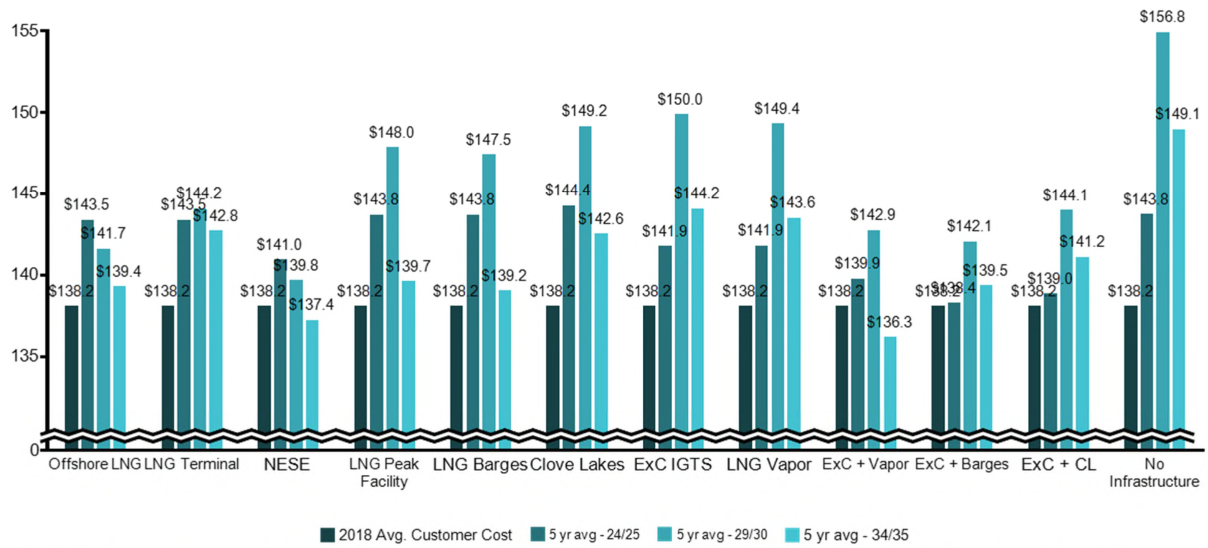
Solution Option	High Demand Scenario				Low Demand Scenario			
	5yr avg 2024/25	5yr avg 2029/30	5yr avg 2034/35	15 Year Average	5yr avg 2024/25	5yr avg 2029/30	5yr avg 2034/35	15 Year Average
Offshore LNG Port	3.8%	2.6%	0.9%	**2.4%**	1.3%	-0.9%	-1.4%	**-0.3%**
LNG Import Terminal	3.8%	4.3%	3.4%	**3.8%**	1.3%	0.9%	1.1%	**1.1%**
Northeast Supply Enhancement (NESE)	2.1%	1.2%	-0.6%	**0.9%**	2.2%	1.5%	-0.3%	**1.2%**
Peak LNG Facility	4.1%	7.1%	1.1%	**4.1%**	1.3%	-1.4%	-2.2%	**-0.8%**
LNG Barges	4.1%	6.8%	0.7%	**3.8%**	1.3%	-1.8%	-2.7%	**-1.0%**
Clove Lakes Transmission Loop (CL)	4.5%	8.0%	3.2%	**5.2%**	1.3%	-0.3%	-1.9%	**-0.3%**
Gas Compression on Iroquois GTS (ExC)	2.7%	8.5%	4.3%	**5.2%**	0.6%	-0.2%	-4.6%	**-1.4%**
LNG Vaporization	2.7%	8.1%	3.9%	**4.9%**	0.8%	-0.5%	-5.0%	**-1.6%**
Gas Compression + LNG Vaporization	1.2%	3.4%	-1.4%	**1.1%**	-0.8%	-2.3%	-3.9%	**-2.3%**
Gas Compression + LNG Barges	0.1%	2.9%	0.9%	**1.3%**	-1.0%	-0.9%	-1.9%	**-1.3%**
Gas Compression + Clove Lakes	0.6%	4.3%	2.2%	**2.3%**	-1.0%	-0.2%	-0.9%	**-0.7%**
No Infrastructure	4.1%	13.5%	7.9%	**8.5%**	3.4%	2.5%	-4.3%	**0.5%**

In all scenarios, the number of customers is expected to increase, which drives the cost impact on a per-customer basis lower when compared to the total cost impact (i.e. the percentages are lower in Table 26 than they are in Table 25 across the board). In the options that require No Infrastructure programs as a significant component of the solution, the number of new customers grows at a slower pace as programs such as Electrification of heat move customers off the gas system.

Again, as in Table 25, this analysis does not consider changes in customer mix or any other changes to cost such as changes in capital investment, operating cost increases, etc. It is an attempt to isolate to overall average impact to costs of the different options. To further illustrate the estimated impact, we have included Figures 31 and 32 that show the average customer cost over the different five-year time periods for each of the different options under the High Demand and Low Demand scenarios.

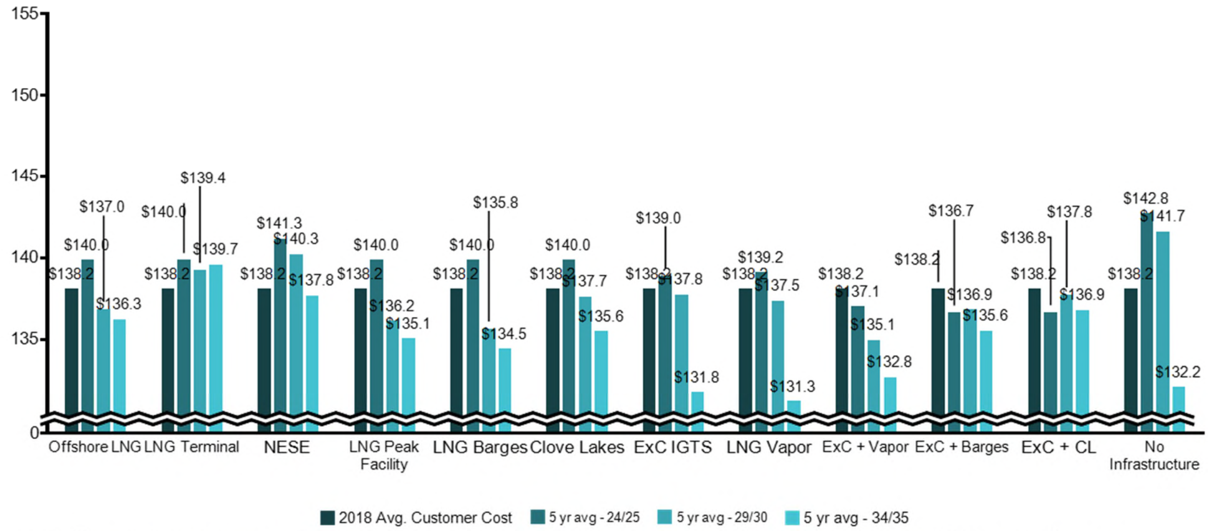
This analysis includes data from all customer types. Further segmented analysis accounting for multiple other factors would have to be conducted to arrive at projected customer bill impacts by customer class and across KEDNY and KEDLI. Based on our high-level analysis we have found that this average numbers presented here are closely aligned to the average cost of a Residential Heating customer – the higher costs associated with multifamily and C&I customers are offset by the lower costs associated with Residential Non-heating customers. For simplicity, we will continue to use the average customer cost in this analysis.

Figure 31: Option Impact on Average Monthly Customer Cost in High Demand Scenario



Note: Represents average monthly cost to DNY customers and does not reflect actual "Customer Bill Impact". Assumes the same impact for every customer type (e.g., residential heat, multi-family, etc.); actual impact would differ for each type and be impacted by other capital investments and other operating cost changes/increases

Figure 32: Option Impact on Average Monthly Customer Cost in Low Demand Scenario



Note: Represents average monthly cost to DNY customers and does not reflect actual "Customer Bill Impact". Assumes the same impact for every customer type (e.g., residential heat, multi-family, etc.); actual impact would differ for each type and be impacted by other capital investments and other operating cost changes/increases

Based on this analysis, we can rank the Solution Options from the lowest impact (i.e. lowest cost increase to the average customer) to the highest impact (i.e. highest cost increase to the average customer). In the High Demand scenario, the NESE option has the lowest impact – adding an average $1.21 per month to each customer's cost, which can be seen in Table 27 below. In the Low Demand scenario, a combination of Gas Compression on Iroquois GTS and LNG Vaporization has the lowest impact – removing an average of $3.19 per month from each customer's cost, which can be seen in Table 28 below.

Table 27: Ranking of the Average Customer Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply – High Demand Scenario

Rank *	Solution Option	Mo. Cost Impact (%) **	Mo. Cost Impact ($) **
1	Northeast Supply Enhancement (NESE)	0.9%	$1.21
2	Gas Compression + LNG Vaporization	1.1%	$1.50
3	Gas Compression + LNG Barges	1.3%	$1.81
4	Gas Compression + Clove Lakes	2.3%	$3.23
5	Offshore LNG Port	2.4%	$3.34
6	LNG Barges	3.8%	$5.30
7	LNG Import Terminal	3.8%	$5.31
8	Peak LNG Facility	4.1%	$5.64
9	LNG Vaporization	4.9%	$6.79
10	Gas Compression on Iroquois GTS (ExC)	5.2%	$7.17
11	Clove Lakes Transmission Loop (CL)	5.2%	$7.23
12	No Infrastructure	8.5%	$11.71

* *Ranking is from lowest impact on average monthly cost to customers to highest impact on average monthly cost to customers*

** *Based on 15-year average cost impact – this analysis isolates the cost impact of each alternative and does not take into account other potential changes that could impact customer costs, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, etc.*

Table 28: Ranking of the Average Customer Cost Impact (% Change from Baseline) of Different Options to Close the Gap Between Downstate NY Gas Demand and Supply – Low Demand Scenario

Rank *	Solution Option	Mo. Cost Impact (%) **	Mo. Cost Impact ($) **
1	Gas Compression + LNG Vaporization	(2.3%)	($3.19)
2	LNG Vaporization	(1.6%)	($2.18)
3	Gas Compression on Iroquois GTS (ExC)	(1.4%)	($1.95)
4	Gas Compression + LNG Barges	(1.3%)	($1.75)
5	LNG Barges	(1.0%)	($1.44)
6	Peak LNG Facility	(0.8%)	($1.07)
7	Gas Compression + Clove Lakes	(0.7%)	($1.01)
8	Offshore LNG Port	(0.3%)	($0.44)
9	Clove Lakes Transmission Loop (CL)	(0.3%)	($0.42)
10	No Infrastructure	0.5%	$0.72
11	LNG Import Terminal	1.1%	$1.49
12	Northeast Supply Enhancement (NESE)	1.2%	$1.61

* *Ranking is from lowest impact on average monthly cost to customers to highest impact on average monthly cost to customers*

** *Based on 15-year average cost impact – this analysis isolates the cost impact of each alternative and does not take into account other potential changes that could impact customer costs, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, etc.*

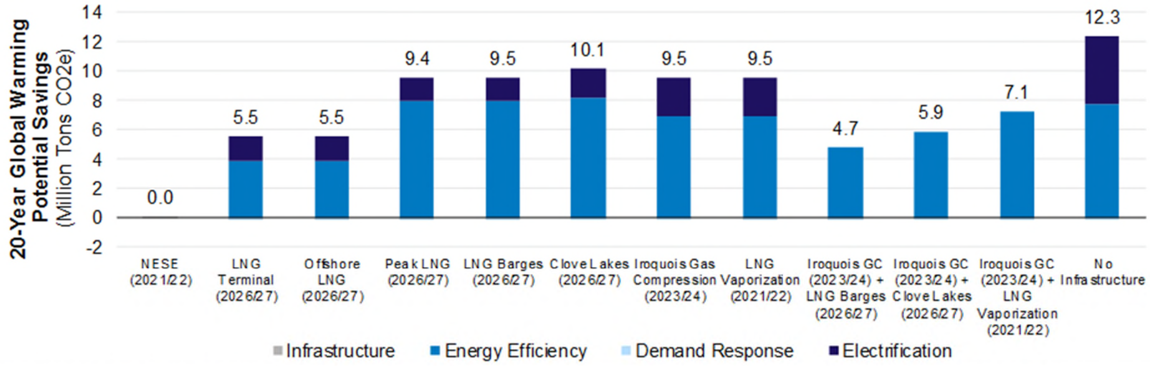
As a final point of emphasis, it must be noted that this analysis is not equivalent to a projected customer bill impact by customer class and across KEDNY and KEDLI. This analysis isolates the overall cost of these solutions across a projected uniform customer base (i.e. it does not contemplate the different customer types and usage of Residential Heath, Multifamily, etc.). Other potential changes that could impact costs and customer bills, such as changes to customer mix and volume, other changes in capital investment, operating cost increases, inflation, etc. are also not included in this analysis.

9. Cost of GHG Emissions

GHG Emissions Impact

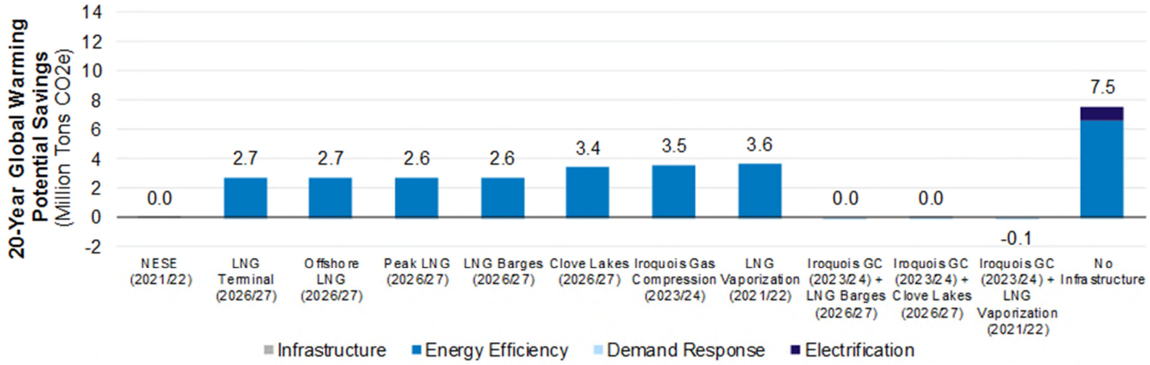
Following publication of the initial Report, and review of comments, we undertook an additional analysis to consider the cost of GHG emissions and benefits of emission reductions. For each of the options, we considered the change in emissions vs. projected natural gas demand assuming incremental capacity filled by pipeline natural gas. So, for example, if a solution calls for the utilization of LNG, and LNG has higher emissions than pipeline gas, then the LNG solution would have higher emissions and a calculated "cost of GHG penalty". And, on the other hand, if a solution reduces demand through energy efficiency, then the solution would have a "cost of GHG savings" calculated based on a reduction of pipeline natural gas. Calculations were done looking at both 20-Year and 100-Year Global Warming Potential (GWP). The results of this analysis can be seen in Figures 33 and 35 for the High Demand scenario, and Figures 34 and 36 for the Low Demand scenario.

Figure 33: 20-Year GWP Savings by Resource by Solution – High Demand Scenario



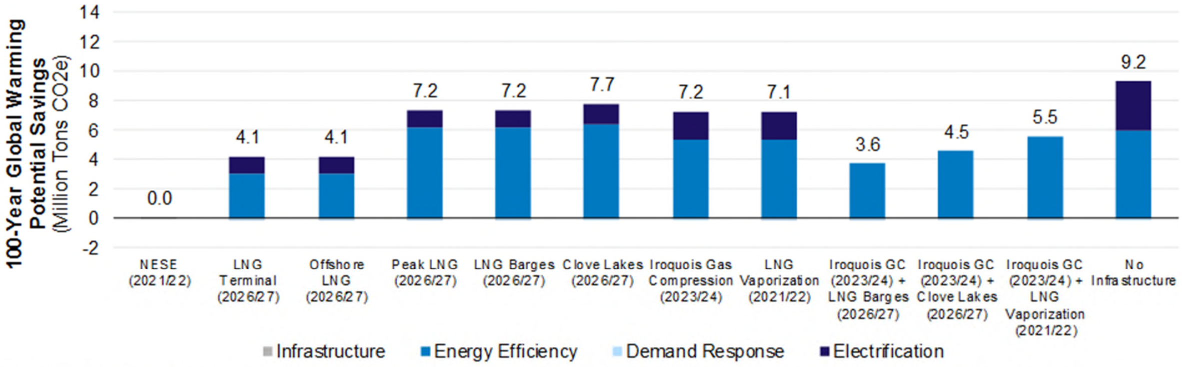
Notes: Global warming potential savings includes CO2, N2O, and CH4 pollutants, which have 100-year GWP factors of 1, 264, and 84, respectively (Source: https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

Figure 34: 20-Year GWP Savings by Resource by Solution – Low Demand Scenario



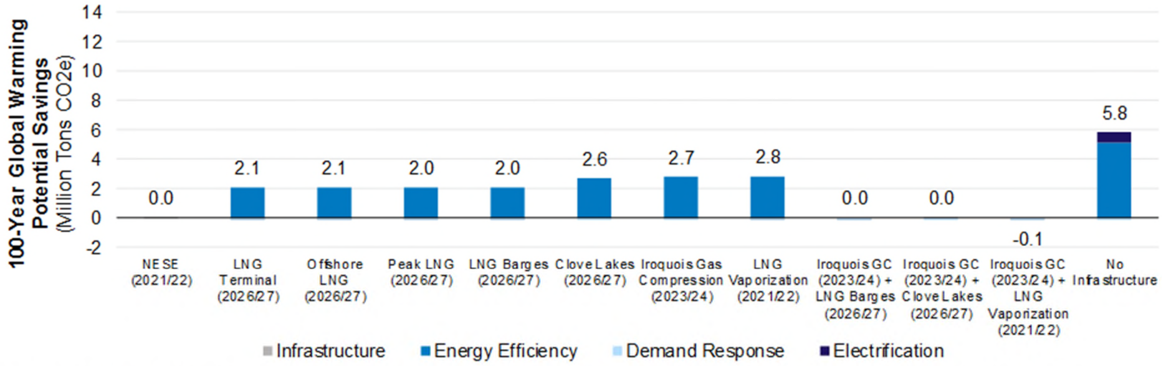
Notes: Global warming potential savings includes CO2, N2O, and CH4 pollutants, which have 100-year GWP factors of 1, 264, and 84, respectively (Source: https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

Figure 35: 100-Year GWP Savings by Resource by Solution – High Demand Scenario



Notes: Global warming potential savings includes CO2, N2O, and CH4 pollutants, which have 100-year GWP factors of 1, 265, and 28, respectively (Source: https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

Figure 36: 100-Year GWP Savings by Resource by Solution – Low Demand Scenario

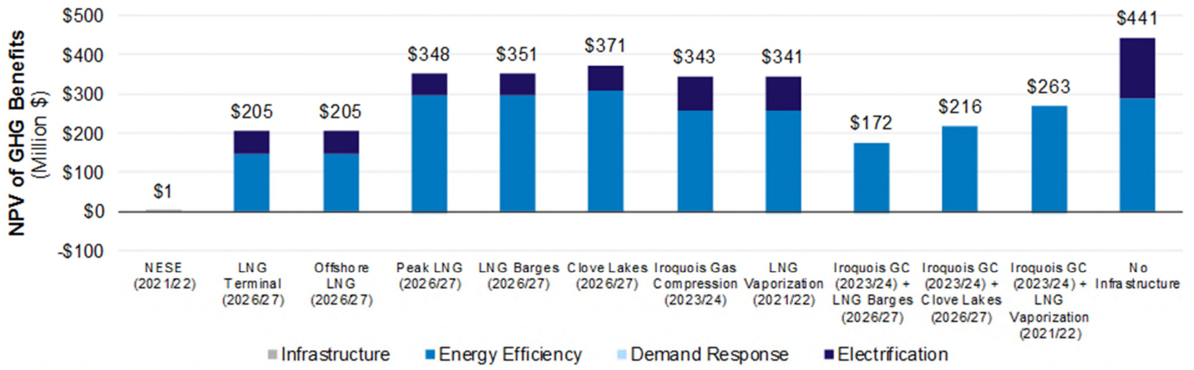


Notes: Global warming potential savings includes CO2, N2O, and CH4 pollutants, which have 100-year GWP factors of 1, 265, and 28, respectively (Source: https://www.ipcc.ch/site/assets/uploads/2018/02/SYR_AR5_FINAL_full.pdf). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

These emissions savings can then be monetized using the EPA's social cost of pollutants[34]. The net present value to society for these savings is shown in Figure 37 for the High Demand scenario and Figure 38 for the Low Demand scenario.

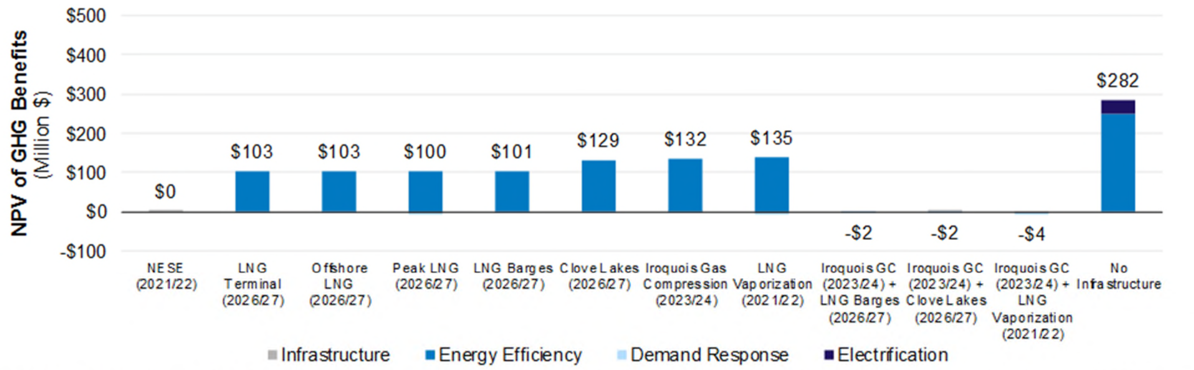
[34] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon.html

Figure 37: NPV of GHG Savings by Solution – High Demand Scenario



Notes: Net present value of GHG savings includes net annual emissions savings of CO2, N2O, and CH4 pollutants, monetized by the respective social cost by pollutant from the EPA at the 3% discount rate (Source: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

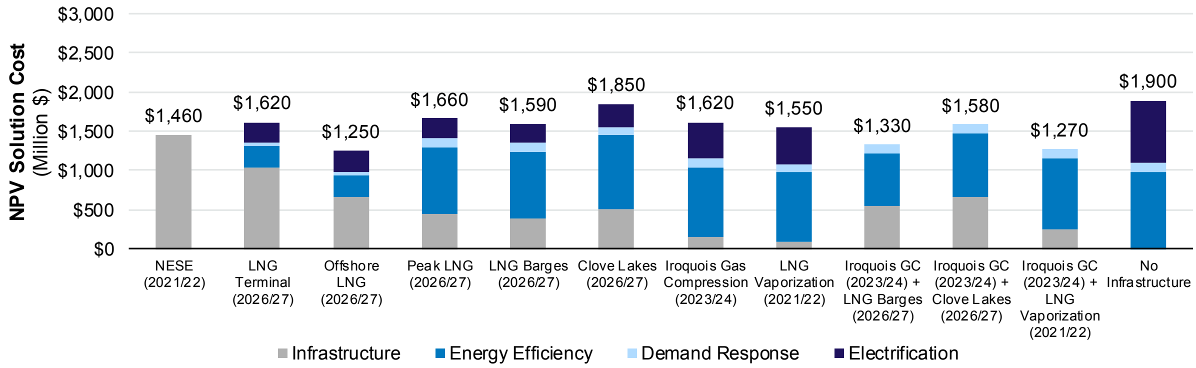
Figure 38: NPV of GHG Savings by Solution – Low Demand Scenario



Notes: Net present value of GHG savings includes net annual emissions savings of CO2, N2O, and CH4 pollutants, monetized by the respective social cost by pollutant from the EPA at the 3% discount rate (Source: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html). Net emissions from infrastructure assumes a baseline of excess demand being met by pipeline gas, which may be replaced along with CNG trucking and short-term contract peaking supplies by infrastructure; net emissions from energy efficiency includes annual savings of gas that's assumed to emit at the rate of pipeline gas; net emissions from retention of non-firm customers assumes on average 2 design days worth of gas consumption per year being replaced with fuel oil consumption for customers otherwise forecasted to switch to firm rates; net emissions from electrification includes annual savings of gas assumes to emit at the rate of pipeline gas, net of added electric emissions from increased winter electric consumption.

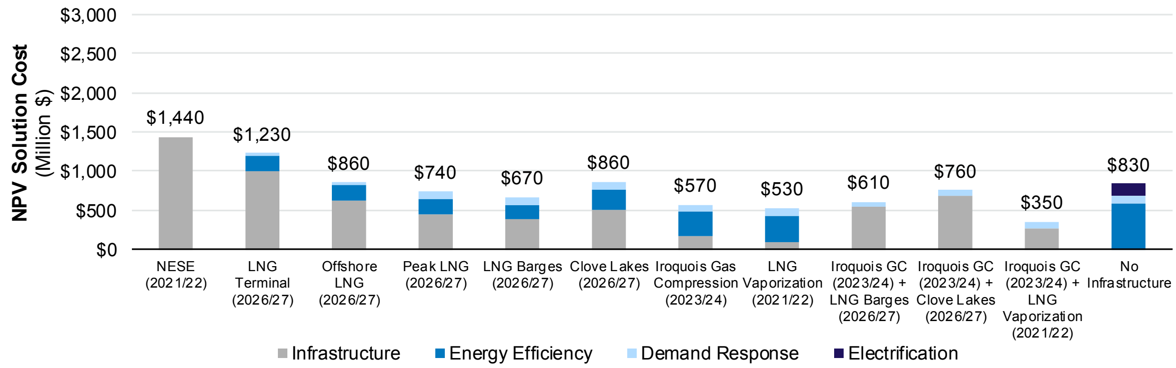
Finally, we combined the cost analysis from Figures 29 and 30 above with the GHG cost analysis from Figures 37 and 38 to show the "total societal cost impact" of the different options, which can be seen in Figures 39 and 40.

Figure 39: Total NPV of Different Solutions Factoring in Cost/Benefit of GHG Emissions – 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 between KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, which start in the listed operational year and are assumed to end in 2034/35, 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 and the value of GHG through 2034/35 (where GHG emissions are monetized at the EPA's 3% average values).

Figure 40: Total NPV of Different Solutions Factoring in Cost/Benefit of GHG Emissions – 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 between KEDNY and KEDLI established in the last rate case under Case 16-G-0059). Infrastructure costs include fixed and commodity costs, which start in the listed operational year and are assumed to end in 2034/35, 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 and the value of GHG through 2034/35 (where GHG emissions are monetized at the EPA's 3% average values).

10. CLCPA and Other Environmental Considerations for the Potential Solutions

In addition to considering the cost of GHG emissions, National Grid received extensive comments regarding how we treated environmental considerations for the potential solutions. In general, these comments focused on two themes: 1) how are the different solutions consistent/in compliance with the CLCPA; and 2) other environmental considerations regarding infrastructure construction and natural gas emissions. Each of these items is addressed in more detail below.

10.1 CLCPA

A number of commenters have asked how the different options presented in the Report can support meeting the CLCPA requirements. While the CLCPA time horizon out to 2040 for interim goals and

2050 for final goals was beyond the scope of our analysis, National Grid is committed to supporting achievement of the CLCPA and is actively working to balance the needs of our customers and the CLCPA targets.

It is important to note that there are a multitude of infrastructure pathways to deliver a net-zero energy system for New York. In fact, there is a growing consensus in pathways analysis that achieving 2050 decarbonization targets is more cost-effective and resilient through tighter integration of electric and gas, especially in cold climates. As noted on pages 43 and 44 of the original Report, these studies conclude that low carbon and renewable gases can have a significant role, and that by avoiding overbuilding of electricity generation and networks, while minimizing invasive home equipment retrofits, these multiple-fuels pathways are in fact more cost-effective than scenarios exclusively reliant on electrification. For example:

- In Imperial College's 2018 study "Analysis of Alternative UK Heat Decarbonisation Pathways" their conclusion is that a 'hybrid' pathway based on high-efficiency heat pumps coupled with gas for peak heating demand conditions or low renewable output would be the least-cost option for the UK.
- In Navigant's 2019 study "Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain," their conclusion is that "a balanced combination of low carbon gases and electricity is the optimal way to decarbonize the GB energy system and reach net-zero emissions by 2050."
- Guidehouse's 2020 study "Gas Decarbonisation Pathways 2020–2050" finds that across Europe, gas and electric network integration is a crucial element to decarbonization: "a smart energy system integration means that renewable and low carbon gases are transported, stored, and distributed through gas infrastructure and are used in a smart combination with the electric grid to transport increasing amounts of renewable electricity."

National Grid has previously published analysis exploring some of these issues, focusing on what would be required to achieve an interim 2030 target of 40% below 1990 levels across the 7-state region of New York and New England. This analysis was published in June 2018,[35] and found that three big shifts would be required by 2030:

- Accelerating the zero-carbon electricity transition, by ramping up renewable electricity deployment to achieve 67% zero-carbon electricity supply;
- A transformation of the transport sector, by reaching more than 10 million electric vehicles on Northeast roads (roughly 50% of all vehicles); and
- A transformation of the heat sector, by doubling the rate of efficiency retrofits and converting nearly all the region's five million oil-heated buildings to electric heat pumps or natural gas

This analysis demonstrated that ***continued growth in gas use is consistent with a regional 40% reduction by 2030, provided that it is coupled with energy efficiency and dramatic reductions in fuel oil utilization.***

This finding highlights two important facets of New York's decarbonization challenge: its ongoing reliance on delivered fuel oil for heat, and its need to dramatically reduce transportation emissions. Natural gas infrastructure has historically played a role in both, through oil-to-gas conversions and through electricity generation to charge electric vehicles. Demand from both of these sources remains robust, adding uncertainty to the pathway that New York will take to achieve the CLCPA.

[35] https://www.nationalgridus.com/News/Assets/80x50-White-Paper-Final.pdf

On the specific question of whether the various options presented in the Report meet CLCPA requirements, the CLCPA as enacted does not provide bright-line rules for evaluating achievement. While the CLCPA sets clear expectations for the magnitude and pace of electric sector decarbonization (zero-carbon by 2040), the law is not definitive with regards to interim targets and 2050 endpoints for other major sectors of the economy – transportation, heat, industry and land use. The law targets an 85% reduction below 1990 levels by 2050 and allows for any remaining emissions to either be directly reduced or offset through projects that remove greenhouse gases from the atmosphere. The law does not specify how the 15% residual emissions will be apportioned between transportation, heat, industry and land use.

Research on specific CLCPA pathways will likely be undertaken by the various Committees established by the CLCPA. Such research would enable a more targeted evaluation of the options to close the gap between forecast natural gas demand and available supply. Having said that, Table 29 below provides high-level considerations regarding how the different options presented in the Report could support a pathway to significant carbon reduction and CLCPA achievement:

Table 29: Analysis of How Each Option Presented in the Long-Term Capacity Report Could Support a Pathway to Carbon Reduction and CLCPA Achievement

Solution Option	How it Can Contribute to Carbon Reduction in 2020-2035	How it Can Contribute to Carbon Reduction by 2040 and 2050
ALL OPTIONS	• Low carbon RNG projects can be brought online in the Downstate NY region • Geothermal electrification can be utilized as an alternative in certain locations (e.g. far away from gas main; to replace leak-prone pipe at end of distribution lines)	• Low carbon RNG could constitute up to 29% of gas supply (national estimates of RNG 12-29%) • Geothermal expansion • Hydrogen blending of up to 20% could contribute to carbon reduction of the gas network
LNG Deepwater Port	• Once online (6-8 years), eliminates need for CNG trucking, and reduces need for temperature-controlled (TC) customers that switch to fuel oil during peak periods • Until infrastructure comes online, incremental investments in energy efficiency (EE) and certain demand response (DR) programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 34-49 MDth/day and Electrification contributes up to 0-35 MDth/day depending on Low or High demand scenario	• LNG Port can be gradually decommissioned or moved to another location outside of Downstate NY (e.g. no negative impact to achieving carbon reduction goals)
LNG Import Terminal	• Once online (5-6 years), eliminates need for CNG trucking, and reduces need for temperature-controlled (TC) customers that switch to fuel oil during peak periods • Until infrastructure comes online, incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97	• The tankers that would be brought into the terminal would not be stranded infrastructure • The terminal itself could be decommissioned, and repurposed for alternative waterfront use or development

Solution Option	How it Can Contribute to Carbon Reduction in 2020-2035	How it Can Contribute to Carbon Reduction by 2040 and 2050
LNG Import Terminal (con't)	• Incremental EE contributes up to 34-49 MDth/day and Electrification contributes up to 0-35 MDth/day depending on Low or High demand scenario	
NESE Project	• Pipeline gas has lower emissions than oil, LNG or CNG • Eliminates need for CNG trucking • Eliminates need to have TC customers switch to burning fuel oil during peak periods • Analysis shows current marginal emissions from a new natural gas connection is 20% lower than an air source heat pump in Downstate NY • In addition to low carbon RNG projects brought online in the region, gas brought onto pipeline can be RNG • Hydrogen-enabled pipeline may enable expanded pilots • EE and DR pursued through recently approved and enacted NENY and Local Law 97 programs, settlement	• Pipeline contract is for 15 years; does not need to be in place and could be decommissioned in 2040-50 if need is not there (e.g. no negative impact to achieving carbon reduction goals) • Could reduce higher emissions LNG if demand declines • Supports options to utilize a hydrogen blend of up to 20%, or move to full hydrogen with updated downstream/appliance infrastructure – may replace other infrastructure that is not hydrogen enabled • Could also be used to move RNG from rural, farmland areas to the NY region.
Peak LNG Facility	• Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 34-146 MDth/day and Electrification contributes up to 0-31 MDth/day depending on Low or High demand scenario	• Creates lower gas demand starting point than large-scale infrastructure options • Further reductions in demand could eliminate need for CNG trucking • Older LNG tanks could be decommissioned to avoid stranded infrastructure
LNG Barges	• Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 34-146 MDth/day and Electrification contributes up to 0-31 MDth/day depending on Low or High demand scenario	• Creates lower gas demand starting point than large-scale infrastructure options • Further reductions in demand could eliminate need for CNG trucking • No stranded infrastructure - LNG Barges can be decommissioned or moved to another location outside of Downstate NY (e.g. no negative impact to achieving carbon reduction goals)

Solution Option	How it Can Contribute to Carbon Reduction in 2020-2035	How it Can Contribute to Carbon Reduction by 2040 and 2050
Clove Lakes Trans-mission Loop	• Pipeline gas has lower emissions than oil, LNG or CNG • Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 45-160 MDth/day and Electrification contributes up to 0-37 MDth/day depending on Low or High demand scenario	• Creates lower gas demand starting point than large-scale infrastructure options, due to higher quantities of demand reduction solutions • Further reductions in demand could eliminate need for CNG trucking
Gas Compression on Iroquois GTS	• Pipeline gas has lower emissions than oil, LNG or CNG • Methane recovery systems to capture released natural gas and reduce NOx and CO emissions • Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 55-149 MDth/day and Electrification contributes up to 0-66 MDth/day depending on Low or High demand scenario	• Creates lower gas demand starting point than any option other than no infrastructure, due to higher quantities of demand reduction solutions • Further reductions in demand could eliminate need for CNG trucking
LNG Vaporization	• Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 58-149 MDth/day and Electrification contributes up to 0-66 MDth/day depending on Low or High demand scenario	• Creates lower gas demand starting point than large-scale infrastructure options due to higher quantities of demand reduction solutions • Further reductions in demand could eliminate need for CNG trucking
No Infrastructure	• Incremental investments in EE and certain DR programs (e.g. thermostat rollback) lower emissions beyond what is achieved with NENY and Local Law 97 • Incremental EE contributes up to 102-168 MDth/day and Electrification contributes up to 18-110 MDth/day depending on Low or High demand scenario	• Creates lowest starting point of all the options for gas demand due to highest quantities of demand reduction solutions • As electric network reduces carbon emissions, benefits of incremental electrification will follow

10.2 Other Environmental Considerations

We received a number of comments regarding the impact of natural gas (many referring to “upstream” extraction and pipeline subsea impacts), as well as comments challenging the MJ Bradley report and 20-year vs. 100-year global warming potential impacts. The existing Report does not draw definitive conclusions – it presents the MJ Bradley data comparing Greenhouse Gas Emissions by Energy Option, 20-year GWP data, and 100-year GWP data, and ranks the solutions relative to each other. This Supplemental Report provides further analysis of the major contributions to net greenhouse gas emissions by solution from additional infrastructure and from incremental demand side management, as shown in Section 9. These values are discussed in terms of both 20-year and 100-year global warming potential and are monetized using the EPA's latest social cost of pollutants. While this analysis largely captures the relative effect of GHG emissions for each solution, National Grid recognizes that this does not constitute a comprehensive environmental study, which should be pursued for a short list of preferred solutions.

11. Additional Information on Risks Under Each Solution Scenario

In our original Report, for many of the scenarios we referenced that "if projected or incremental EE, DR and electrification targets are not met, there would have to be restrictions on new customer connections." We also referenced that the Design Day standard we plan towards and the resulting supply stack does not have any contingency/operating margin to consider any disruption to available supply or possible forecasting error. Also, for all the different options, we described the permitting, policy, regulatory and implementation requirements and related risks. However, in the initial Report we did not quantify the potential impact of these risks. As such, we have undertaken additional analysis to quantify some of these risks under each solution scenario.

As a starting point, we conducted an analysis to quantify the risks of restricting new customer connections. In this analysis, we looked at two items for each solution scenario: 1) what if incremental EE, DR and electrification targets fell short of what they were projected to achieve, and 2) what if there was a one-year delay to the projected date that an infrastructure project were to come online. The analysis calculates the shortfall under different levels of achievement and based on an average blended customer usage rate across all customer classes, and calculates the number of new customer connections that would have to be stopped in order to bring the demand-supply equation back into balance. The results of this analysis under the High Demand and Low Demand scenarios are shown in Tables 30 and 31.

Table 30: Cumulative New Customer Connection Refusals Required by Situation – High Demand Scenario

Solution Option	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2034-35
Incremental Demand Management Achieves 70% of Targets								
NESE Project	0	0	0	0	0	0	0	0
LNG Import Terminal	0	4,500	11,500	0	0	0	0	0
LNG Deepwater Port	0	4,500	11,500	0	0	0	0	0
Peak LNG Facility	0	3,700	11,800	0	0	6,500	7,600	23,500
LNG Barges	0	3,700	11,800	0	0	6,500	7,600	23,500
Clove Lakes (CL)	0	2,400	10,500	0	4,500	11,200	12,300	25,200
IGTS Compression (ExC)	0	0	0	2,200	9,900	13,900	15,400	26,700
LNG Vaporization	0	0	0	3,000	10,700	14,700	16,200	27,500
ExC + LNG Barges	0	0	6,000	0	0	3,400	5,200	18,100
ExC + CL	0	0	4,500	0	0	6,500	8,000	19,300
ExC + LNG Vaporization	0	0	0	0	2,700	9,100	9,900	21,600
No Infrastructure	0	4,000	8,100	12,300	18,500	21,400	22,500	32,400
Infrastructure is Delayed One Year								
NESE Project	0	0	0	0	0	0	0	0
LNG Import Terminal	0	0	0	27,200	0	0	0	0
LNG Deepwater Port	0	0	0	27,200	0	0	0	0
Peak LNG Facility	0	0	0	5,800	0	0	0	0
LNG Barges	0	0	0	5,800	0	0	0	0
Clove Lakes (CL)	0	0	0	4,000	0	0	0	0
IGTS Compression (ExC)	0	0	0	0	0	0	0	0
LNG Vaporization	0	0	0	0	0	0	0	0
ExC + LNG Barges	1,700	0	0	7,300	0	0	0	0
ExC + CL	900	0	0	4,300	0	0	0	0
ExC + LNG Vaporization	0	0	0	0	0	0	0	0
No Infrastructure	0	0	0	0	0	0	0	0

Table 31: Cumulative New Customer Connection Refusals Required by Situation – Low Demand Scenario

Solution Option	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2034-35
Incremental Demand Management Achieves 70% of Targets								
NESE Project	0	0	0	0	0	0	0	0
LNG Import Terminal	0	0	5,900	0	0	0	0	0
LNG Deepwater Port	0	0	5,900	0	0	0	0	0
Peak LNG Facility	0	0	5,900	0	0	1,400	1,600	0
LNG Barges	0	0	5,900	0	0	1,400	1,600	0
Clove Lakes (CL)	0	0	4,700	0	0	5,000	5,200	0
IGTS Compression (ExC)	0	0	0	0	2,900	8,300	8,500	1,300
LNG Vaporization	0	0	0	0	4,500	9,300	8,600	1,400
ExC + LNG Barges	0	0	0	0	0	0	0	0
ExC + CL	0	0	0	0	0	0	0	0
ExC + LNG Vaporization	0	0	0	0	0	1,800	2,000	0
No Infrastructure	0	0	0	3,800	11,100	14,700	13,400	6,200
Infrastructure is Delayed One Year								
NESE Project	0	0	0	0	0	0	0	0
LNG Import Terminal	0	0	0	20,400	0	0	0	0
LNG Deepwater Port	0	0	0	20,400	0	0	0	0
Peak LNG Facility	0	0	0	7,300	0	0	0	0
LNG Barges	0	0	0	7,300	0	0	0	0
Clove Lakes (CL)	0	0	0	3,900	0	0	0	0
IGTS Compression (ExC)	0	0	0	0	0	0	0	0
LNG Vaporization	0	0	0	0	0	0	0	0
ExC + LNG Barges	0	0	0	5,300	0	0	0	0
ExC + CL	0	0	0	2,000	0	0	0	0
ExC + LNG Vaporization	0	0	0	0	0	0	0	0
No Infrastructure	0	0	0	0	0	0	0	0

In addition to this analysis on potential restriction of customer connections, we also looked at the potential impact of a supply disruption. This analysis looks at a 2% supply disruption and calculates the minimum number of existing customers that would have to have their gas service interrupted in order to bring the demand-supply equation back into balance.

These are minimum numbers because in an actual operating scenario you would not be able to target an exact number of customers – these situations require shutting off sections of the network and entire streets/ neighborhoods, likely leading to a higher total number of impacted customers. National Grid is analyzing its current ability to adequately sectionalize the gas distribution system for local geographic gas load shedding purposes necessary to react to Emergency Supply interruption events or Supply shortfall. Through planned outages of specific localized sections of the gas distribution system, larger overall (and more uncontrollable) customer outages can be avoided. This will likely require installation of additional valves over and above current sectionalizing procedure guidelines.

The results of this supply disruption analysis under different scenarios is shown in Tables 32 and 33.

Table 32: Minimum Service Interruptions Required Given a 2% Supply Disruption by Situation – High Demand Scenario

Solution Option	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2034-35
2% Supply Disruption and Incremental Demand Management Achieves 70% of Targets									
NESE Project	0	0	0	0	0	0	0	0	21,300
LNG Import Terminal	13,500	34,700	46,700	61,400	0	0	0	0	0
LNG Deepwater Port	13,500	34,700	46,700	61,400	0	0	0	0	0
Peak LNG Facility	12,900	33,700	45,100	62,000	15,600	36,800	50,900	53,300	87,000
LNG Barges	12,900	33,700	45,100	62,000	15,600	36,800	50,900	53,300	87,000
Clove Lakes (CL)	12,100	32,100	42,400	59,300	25,500	46,700	60,800	63,200	90,400
IGTS Compression (ExC)	16,000	700	15,700	29,300	41,900	58,200	66,600	69,700	93,700
LNG Vaporization	0	2,300	17,300	30,900	43,500	59,800	68,200	71,300	95,300
ExC + LNG Barges	19,900	8,900	29,600	49,800	5,900	28,900	44,400	48,200	75,400
ExC + CL	19,400	7,800	27,700	46,800	14,200	36,100	50,900	54,000	78,000
ExC + LNG Vaporization	0	0	0	5,900	22,600	43,000	56,400	58,100	82,800
No Infrastructure	13,200	34,500	45,600	54,400	63,100	76,300	82,400	84,800	105,600
2% Supply Disruption and Incremental Demand Management Achieves 100% of Targets									
NESE Project	0	0	0	0	0	0	0	0	21,300
LNG Import Terminal	5,500	21,100	26,600	36,100	0	0	0	0	0
LNG Deepwater Port	5,500	21,100	26,600	36,100	0	0	0	0	0
Peak LNG Facility	4,700	19,700	24,300	36,900	0	3,400	13,500	11,800	33,900
LNG Barges	4,700	19,700	24,300	36,900	0	3,400	13,500	11,800	33,900
Clove Lakes (CL)	3,600	17,400	20,400	33,000	0	12,200	22,200	20,600	33,400
IGTS Compression (ExC)	9,100	0	0	7,000	13,800	23,900	25,800	25,200	33,400
LNG Vaporization	0	0	900	8,600	15,400	25,400	27,400	26,800	35,000
ExC + LNG Barges	14,700	1,200	19,200	36,300	0	9,000	21,100	21,500	34,300
ExC + CL	14,000	0	16,400	32,100	0	14,000	25,100	24,400	32,600
ExC + LNG Vaporization	0	0	0	0	2,300	18,400	27,500	24,800	34,000
No Infrastructure	5,100	20,800	25,000	26,000	27,100	32,700	31,400	29,800	33,400
2% Supply Disruption and Incremental Demand Management Achieves 130% of Targets									
NESE Project	0	0	0	0	0	0	0	0	21,300
LNG Import Terminal	0	7,600	6,600	10,700	0	0	0	0	0
LNG Deepwater Port	0	7,600	6,600	10,700	0	0	0	0	0
Peak LNG Facility	0	5,800	3,600	11,700	0	0	0	0	0
LNG Barges	0	5,800	3,600	11,700	0	0	0	0	0
Clove Lakes (CL)	0	2,700	0	6,700	0	0	0	0	0
IGTS Compression (ExC)	2,300	0	0	0	0	0	0	0	0
LNG Vaporization	0	0	0	0	0	0	0	0	0
ExC + LNG Barges	9,500	0	8,700	22,900	0	0	0	0	0
ExC + CL	8,600	0	5,200	17,300	0	0	0	0	0
ExC + LNG Vaporization	0	0	0	0	0	0	0	0	0
No Infrastructure	0	7,200	4,400	0	0	0	0	0	0
2% Supply Disruption and Infrastructure is Delayed One Year									
NESE Project	0	0	0	0	0	0	0	0	21,300
LNG Import Terminal	5,500	21,100	26,600	36,100	94,600	0	0	0	0
LNG Deepwater Port	5,500	21,100	26,600	36,100	94,600	0	0	0	0
Peak LNG Facility	4,700	19,700	24,300	36,900	49,500	3,400	13,500	11,800	33,900
LNG Barges	4,700	19,700	24,300	36,900	49,500	3,400	13,500	11,800	33,900
Clove Lakes (CL)	3,600	17,400	20,400	33,000	45,600	12,200	22,200	20,600	33,400
IGTS Compression (ExC)	9,100	29,000	0	7,000	13,800	23,900	25,800	25,200	33,400
LNG Vaporization	0	0	900	8,600	15,400	25,400	27,400	26,800	35,000
ExC + LNG Barges	14,700	40,700	19,200	36,300	52,500	9,000	21,100	21,500	34,300
ExC + CL	14,000	39,100	16,400	32,100	46,400	14,000	25,100	24,400	32,600
ExC + LNG Vaporization	0	0	0	0	2,300	18,400	27,500	24,800	34,000
No Infrastructure	5,100	20,800	25,000	26,000	27,100	32,700	31,400	29,800	33,400

Table 33: Minimum Service Interruptions Required Given a 2% Supply Disruption by Situation – Low Demand Scenario

Solution Option	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2034-35
2% Supply Disruption and Incremental Demand Management Achieves 70% of Targets									
NESE Project	0	0	0	0	0	0	0	0	0
LNG Import Terminal	0	19,700	33,700	49,700	0	0	0	0	0
LNG Deepwater Port	0	19,700	33,700	49,700	0	0	0	0	0
Peak LNG Facility	0	19,700	33,700	49,700	4,300	26,200	40,300	40,800	25,900
LNG Barges	0	19,700	33,700	49,700	4,300	26,200	40,300	40,800	25,900
Clove Lakes (CL)	0	19,700	33,700	47,200	11,900	33,800	47,900	48,400	33,500
IGTS Compression (ExC)	0	0	0	14,100	26,900	43,400	54,800	55,300	40,400
LNG Vaporization	0	0	500	15,100	28,800	46,800	56,900	55,500	40,600
ExC + LNG Barges	0	0	13,800	33,700	0	12,600	27,700	29,300	18,600
ExC + CL	0	0	10,300	29,500	0	19,800	34,400	35,500	22,700
ExC + LNG Vaporization	0	0	0	0	5,100	27,000	41,100	41,600	26,700
No Infrastructure	0	12,700	22,000	34,100	45,300	60,800	68,400	65,700	50,800
2% Supply Disruption and Incremental Demand Management Achieves 100% of Targets									
NESE Project	0	0	0	0	0	0	0	0	0
LNG Import Terminal	0	11,800	22,300	36,100	0	0	0	0	0
LNG Deepwater Port	0	11,800	22,300	36,100	0	0	0	0	0
Peak LNG Facility	0	11,800	22,300	36,100	0	10,500	23,600	23,200	4,700
LNG Barges	0	11,800	22,300	36,100	0	10,500	23,600	23,200	4,700
Clove Lakes (CL)	0	11,800	22,300	32,500	0	16,000	29,100	28,700	10,200
IGTS Compression (ExC)	0	0	0	2,100	11,700	25,000	34,300	33,800	15,400
LNG Vaporization	0	0	0	2,800	13,800	29,100	36,600	33,400	14,900
ExC + LNG Barges	0	0	10,800	30,100	0	7,900	22,600	23,800	11,300
ExC + CL	0	0	5,800	24,100	0	12,900	26,800	27,100	11,600
ExC + LNG Vaporization	0	0	0	0	0	17,800	30,900	30,500	12,000
No Infrastructure	0	1,700	5,600	13,700	21,100	32,900	36,800	31,700	13,300
2% Supply Disruption and Incremental Demand Management Achieves 130% of Targets									
NESE Project	0	0	0	0	0	0	0	0	0
LNG Import Terminal	0	3,800	11,000	22,400	0	0	0	0	0
LNG Deepwater Port	0	3,800	11,000	22,400	0	0	0	0	0
Peak LNG Facility	0	3,800	11,000	22,400	0	0	7,000	5,600	0
LNG Barges	0	3,800	11,000	22,400	0	0	7,000	5,600	0
Clove Lakes (CL)	0	3,800	11,000	17,700	0	0	10,300	8,900	0
IGTS Compression (ExC)	0	0	0	0	0	6,500	13,700	12,300	0
LNG Vaporization	0	0	0	0	0	11,400	16,300	11,200	0
ExC + LNG Barges	0	0	7,800	26,500	0	3,300	17,500	18,200	3,900
ExC + CL	0	0	1,300	18,700	0	5,900	19,100	18,800	600
ExC + LNG Vaporization	0	0	0	0	0	8,500	20,800	19,300	0
No Infrastructure	0	0	0	0	0	4,900	5,200	0	0
2% Supply Disruption and Infrastructure is Delayed One Year									
NESE Project	0	0	0	0	0	0	0	0	0
LNG Import Terminal	0	11,800	22,300	36,100	80,200	0	0	0	0
LNG Deepwater Port	0	11,800	22,300	36,100	80,200	0	0	0	0
Peak LNG Facility	0	11,800	22,300	36,100	52,700	10,500	23,600	23,200	4,700
LNG Barges	0	11,800	22,300	36,100	52,700	10,500	23,600	23,200	4,700
Clove Lakes (CL)	0	11,800	22,300	32,500	45,600	16,000	29,100	28,700	10,200
IGTS Compression (ExC)	0	16,800	0	2,100	11,700	25,000	34,300	33,800	15,400
LNG Vaporization	0	0	0	2,800	13,800	29,100	36,600	33,400	14,900
ExC + LNG Barges	0	30,400	10,800	30,100	48,500	7,900	22,600	23,800	11,300
ExC + CL	0	26,500	5,800	24,100	41,600	12,900	26,800	27,100	11,600
ExC + LNG Vaporization	0	0	0	0	0	17,800	30,900	30,500	12,000
No Infrastructure	0	1,700	5,600	13,700	21,100	32,900	36,800	31,700	13,300

12. Recommendation(s)

In the initial Report, National Grid outlined a series of criteria against which it evaluated each of the options for closing the gap between projected demand and available supply. While we continue to believe these evaluation criteria are relevant, we have added some additional components. To get to our recommendations, we have considered the following (additions from the original Report in *blue*):

- **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, the risks that it might not deliver, *and the potential consequences (risk impact) if it does not deliver*
- **Cost** - aggregate cost to bring the capacity online, annual costs with and without a discount rate, which includes infrastructure and/or program costs and adjustments for commodity costs, *customer cost impact, and cost of GHG emissions*
- **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, *including pathways to CLCPA achievement*)
- **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
- ***Deliverability*** **–** which includes both permitting, policy and regulatory requirements (e.g. permits that will need to be approved, policy changes that could enable the option, and regulatory *funding vehicles* and obstacles that would require approvals or changes), as well as requirements for implementation (e.g. location siting; hiring for construction/program implementation; requirements to place equipment orders; etc.)

Table 34 provides an updated summary of National Grid's evaluation of the different options, including the addition of the LNG Vaporization option described in Section 6 above. Green indicates that based on our supplemental analysis, we have raised the rating by ¼ (so for example, for Energy Efficiency we have raised the cost attractiveness level from ¼ to ½). Red indicates that based on our supplemental analysis, we have lowered the rating (seen only in the second half of the NESE Cost rating).

Table 34: Updated 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	◕	●	●	◑	◕
LNG Vaporization	60	◕	◕	●	◑	◕
No Infrastructure Options						
Incremental Energy Efficiency**	Up to 168	●	◔****	◑	●	●
Incremental Demand Response***	Up to 104	◕	◔****	●	◕	◕
Incremental Electrification**	Up to 110	◕	◔****	◔	◕	◕

** Lowest cost in the High Demand scenario, but highest cost in the Low Demand scenario.*

***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*

Based on our evaluation of the different options and potential solutions across these criteria, as explained in more detail in Section 12, the Company is recommending two potential solutions:

Option A: LNG Vaporization and Iroquois Gas Compression enhancements to existing infrastructure, combined with incremental Energy Efficiency (EE) and Demand Response (DR)

Option B: NESE Pipeline

Table 35 below provides a summary comparison for these options against the evaluation criteria described above.

Table 35: Comparison of Two Recommended Solutions Against Evaluation Criteria

	Option A: Enhancements to Existing Infrastructure Combined with Incremental EE and DR	Option B: NESE Pipeline
Safety	• Strong safety records exist for all infrastructure proposed for enhancement, and all programs proposed for demand management	• Strong pipeline safety record; PHMSA would enforce all regulations for safe, reliable and environmentally sound operation
Reliability (certainty of meeting demand)	• Risk impact analysis does not identify any risk to new customer connections until 2027/28, or any risk resulting from a 2% supply disruption until 2025/26, providing ample time to address issues/put programs in place to mitigate these risks	• Has the highest degree of certainty that it will meet demand, with no risk of restrictions to customer connections, and no risk of customer shut-offs with a 2% supply disruption until at least 2032/33
Cost	• The second lowest customer cost impact under the High Demand scenario, and the lowest cost impact under the Low Demand scenario • Factoring in the cost of carbon, it is the second lowest total societal cost option under the High Demand scenario and the lowest cost option under the Low Demand scenario	• The lowest cost option under the High Demand scenario; lowest total $ cost and customer cost impact • Under the Low Demand scenario, it is the highest cost option • Factoring in the cost of carbon, it is the fourth lowest total societal cost solution under the High Demand scenario and the highest cost under the Low Demand scenario • Pipeline agreement is for 15 years, which eliminates concern about customers paying for stranded assets
Environmental Impact	• Infrastructure impact on the environment is minimal, as there is no new greenfield construction – it is enhancements to existing infrastructure. • Demand reduction through energy efficiency reduces emissions in the 2020-2035 time frame and accelerates pathway to achieving CLCPA goals	• Creates ecological impact from construction to the subsea environment • Has some beneficial environmental aspects in the near term (lower current marginal emissions vs. electrification, elimination of CNG trucking) • Longer term, supports GHG reduction from expansion of Renewable Natural Gas supplies, and is hydrogen-enabled to enable hydrogen blending/transport
Community Impact	• All planned infrastructure enhancements are within existing footprints/locations • Buildout of Energy Efficiency and Demand Response contractors could add jobs in Downstate NY	• Project is entirely offshore in NY, with minimal impact to community land/space • Some onshore construction in NJ on brownfield locations

	Option A: Enhancements to Existing Infrastructure Combined with Incremental EE and DR	Option B: NESE Pipeline
Deliverability	• Involves multiple regulatory, permitting, customer behavior, and other external dependencies, including a number of infrastructure and non-infrastructure programs requiring regulatory approvals and funding to move forward, creating some implementation complexity that will need to be managed	• Has the lowest number of dependencies with regards to permitting, regulatory, and implementation considerations* •

**Rates as "most deliverable" option assuming the project can obtain a water permit. This permit decision is, in effect, binary - if it is not obtained, then the project cannot move forward.*

With a balanced assessment that weighs cost across a range of scenarios and includes the broad set of evaluation criteria, including areas of high customer feedback such as cost of carbon and pathway to CLCPA achievement, then the preferred choice is Option A (Enhancements to existing infrastructure combined with incremental EE and DR). National Grid would need to work with the State of New York and other key stakeholders to ensure Deliverability and long-term Reliability.

However, if heavier emphasis is placed on reducing risk related to Deliverability and Reliability (certainty of meeting demand), then the preferred choice is Option B (NESE Pipeline).

Tables 36 and 37 below show the Deliverability requirements, including permitting, policy, regulatory and implementation requirements, to ensure timely and complete execution of the two recommended options.

Table 36: Permitting, Policy, Regulatory and Implementation Requirements for Option A (LNG Vaporization and Iroquois Gas compression enhancements, combined with incremental EE and DR)

Components		Permitting, Policy, Regulatory and Implementation Requirements
Infrastructure	Iroquois Gas Compression	• Receive approvals: FERC 7C Certificate by Q1 2021, New York State Department of Environmental Conservation by Q3 2021, Connecticut State permits by Q3 2021, FERC Notice to Proceed by Q3 2021, In service by Q4 2023
	LNG Vaporization	• Obtain FDNY approval of Vaporizers 13 and 14 plans by 2/1/2021 (mechanical) and by 5/1/2021 (fire protection), Greenpoint T2 Modernization by 4/1/2022, and Vaporizer 11 and 12 siting by 10/1/2020 • NYDEC consent to allow temporary LNG storage at Holtsville by 7/1/2020 • Sign Greenpoint truck unloading station MoU by 7/14/20, obtain permit for truck unloading station

Components		Permitting, Policy, Regulatory and Implementation Requirements
Infrastructure (con't)	CNG Trucking	• Receive permitting approvals to support construction timeline and commissioning of CNG sites for Winter 20/21 (Expansion of Site #1 and Site #3) and Winter 21/22 (Site #4) • Finalize engineering design by 6/15. Fabrication and receipt of (4) CNG decompression skids by 11/3 to meet Winter 20/21 Operations readiness. Receipt of (2) CNG decompression skids by 12/15 to meet Winter 21/22 Operations readiness • Secure supply contracts for filling the trucks; make commitments to suppliers by 5/1/2020 (compression, supply and trucking service)
	Metropolitan Reliability Infrastructure Project	• Obtain NYC (applicable permit) approvals to facilitate construction schedule necessary to achieve connection to the Brooklyn Backbone (Phase 4) before Winter 2020/21, with MRI project full scope (Phase 5) in-service before Winter 2021/22 • Able to restart construction of phase 4 (after COVID-19 interruption) by 5/15/2020 and ability to complete phase 4 by winter 20/21, and phase 5 by winter 21/22 • Receive approval of funding in pending rate case
	Sectionalizing	• Secure resources and funding to perform detailed engineering review, analysis and recommendations • Secure Engineering and Construction resources, and funding to design, procure and install required distribution system valving
No infrastructure and low carbon	Energy Efficiency	• Establish new regulatory framework for EE measures that are operated as part of a Non-Pipe Alternative and secure funding for the programs • Build effective customer marketing/acquisition mechanism • Build contractor network to enable delivery/installations • Establish close collaboration with NYSERDA and electric utilities
	Demand Response	• Secure funding • Develop efficient and flexible incentive payment mechanisms
	RNG/ Hydrogen	• Engage a broad coalition to shape appropriate policy framework and regulation that support the vision to decarbonize the gas network • Build up the Regulatory Strategy, Gas Engineering and Customer teams needed to support RNG interconnection and RNG/Hydrogen program development • Develop supportive programs that can reduce interconnection costs for RNG project developers/provide long-term offtake certainty • Coordinate and collaborate with utilities, producers, and other stakeholders to support R&D and align around the role of hydrogen
	Geothermal	• Receive the regulatory approval to move forward with proposed projects

Table 37: Permitting, Policy, Regulatory and Implementation Requirements for Option B (NESE Pipeline)

<table>
<tr><th colspan="2">Components</th><th>Permitting, Policy, Regulatory and Implementation Requirements</th></tr>
<tr><td>Infrastructure</td><td>NESE Pipeline</td><td>Permitting, Policy and Regulatory
• Received FERC and PA approval, but still requires state/local approvals from NY and NJ
• 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
Implementation
• 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</td></tr>
<tr><td rowspan="2">Low Carbon</td><td>RNG/ Hydrogen</td><td>• Engage a broad coalition to shape appropriate policy framework and regulation that support the vision to decarbonize the gas network
• Build up the Regulatory Strategy, Gas Engineering and Customer teams needed to support RNG interconnection and RNG/Hydrogen program development
• Develop supportive programs that can reduce interconnection costs for RNG project developers/provide long-term offtake certainty
• Coordinate and collaborate with utilities, producers, and other stakeholders to support R&D and align around the role of hydrogen</td></tr>
<tr><td>Geothermal</td><td>• Receive the regulatory approval to move forward with proposed projects</td></tr>
</table>

While both options are viable, each has risk and dependencies that must be managed and require action from both National Grid and other stakeholders. For the infrastructure components, the primary dependency is the need to secure various state and local permits required for construction and operation. These permitting requirements create a risk that infrastructure options will not be available on a schedule that avoids future service restrictions. For the non-infrastructure components, there are numerous dependencies required to enable the aggressive incremental levels of energy efficiency and demand response required to support customers' future energy needs, including permitting, regulatory approvals, rate funding, market and technology development, and customer adoption. If these factors do not converge in a way that reliably reduces customer demand over the next several years, there is a risk of future service restrictions.

Regardless of the execution risks stemming from these dependencies, it is important to emphasize that a solution must be chosen and implemented over the next two years to enable closure of the demand-supply gap and avoid future moratoria. Accordingly, in this Supplemental Report, the Company has sought to clearly set forth the dependencies, risks, costs and environmental impacts (among other criteria) such that all stakeholders are informed as to the implications of pursuing each option and the requirements for successful execution.

Acronyms

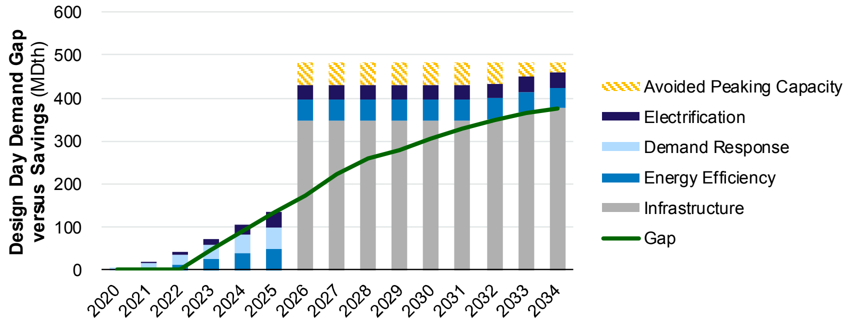
AEO	Annual Energy Outlook
BNY	Brooklyn Navy Yard
Btu	British Thermal Unit
CAGR	Compound Annual Growth Rate
CNG	Compressed Natural Gas
C&I	Commercial & Industrial
CDCLI	Community Development Corporation of Long Island
CL	Clove Lakes Transmission Loop
CLCPA	Climate Leadership and Community Protection Act
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide Equivalent
ConEd, Con Edison	Consolidated Edison
COVID-19	Coronavirus Disease 2019
CT	Connecticut
DNY	Downstate New York
DR	Demand Response
Dth	Dekatherms
Dth/day	Dekatherms per Day
EE	Energy Efficiency
EELC	Eastern Environmental Law Center
EFG	Energy Futures Group
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ExC	Enhancement by Compression
FDNY	New York City Fire Department
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GHP	Geothermal Heat Pump
GWP	Global Warming Potential
HDD	Heating Degree Days
HVAC	Heating, ventilation, and air conditioning
IEEFA	Institute for Energy Economics and Financial Analysis
IGTS	Iroquois Gas Transmission System
IT	Interruptible
KEDLI	KeySpan Energy Delivery Long Island
KEDNY	KeySpan Energy Delivery New York
kg	Kilogram
KLGA	LaGuardia International Airport
KNYC	Central Park, NY
LI	Long Island
LL	Local Law (of New York)
LNG	Liquefied Natural Gas
MA	Massachusetts
MDth	Thousands of Dekatherms
MDth/day	Thousands of Dekatherms per Day
MoU	Memorandum of Understanding
MRI	Metropolitan Reliability Infrastructure Project
NCP	Nissequogue Cogen Partners

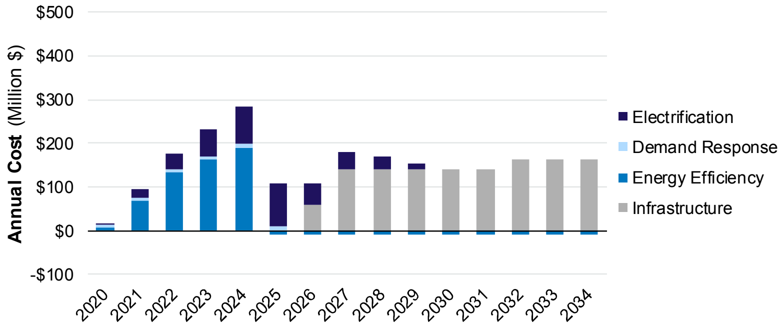
NENY	New Efficiency New York
NEPA	National Environmental Policy Act
NESE	Northeast Supply Enhancement
NGUSA	National Grid USA
NJ	New Jersey
NOx	Nitrogen Oxides
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NTS	National Gas Transmission System
NY	New York
NYC	New York City
NYCCR	New York 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
PA	Pennsylvania
PSEG	Public Service Enterprise Group
Q&A	Question and Answer
RI	Rhode Island
RNG	Renewable Natural Gas
SCV	Submerged Combustion Vaporizer
SMS	Safety Management System
TC	Temperature Controlled
TETCO	Texas Eastern Transmission
Transco	Transcontinental Pipeline / Williams

Appendix A – Annual Costs and Savings

Offshore LNG Deepwater Port (2026/27)

Figure A1: Offshore LNG Deepwater Port – High Demand Scenario

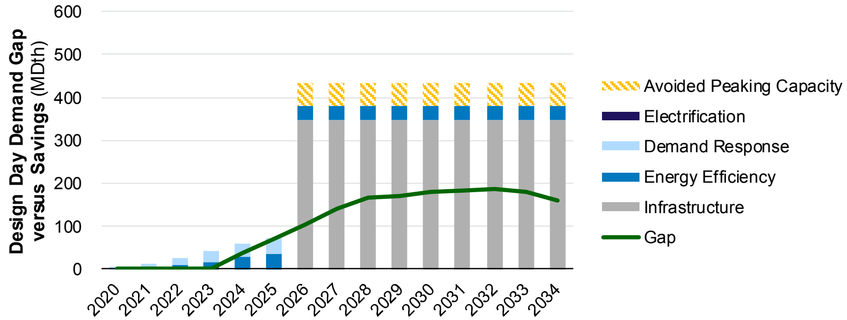


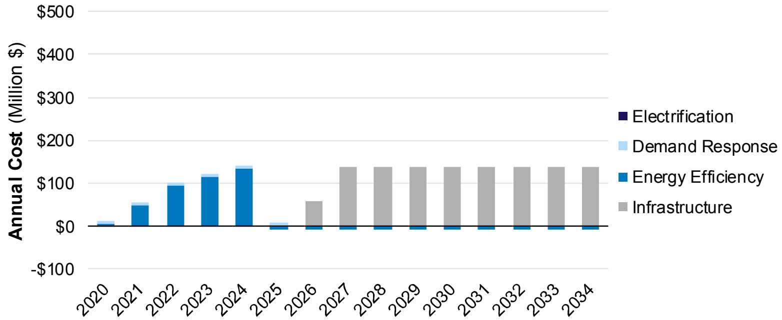


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

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 A2: Offshore LNG Deepwater Port – Low Demand Scenario



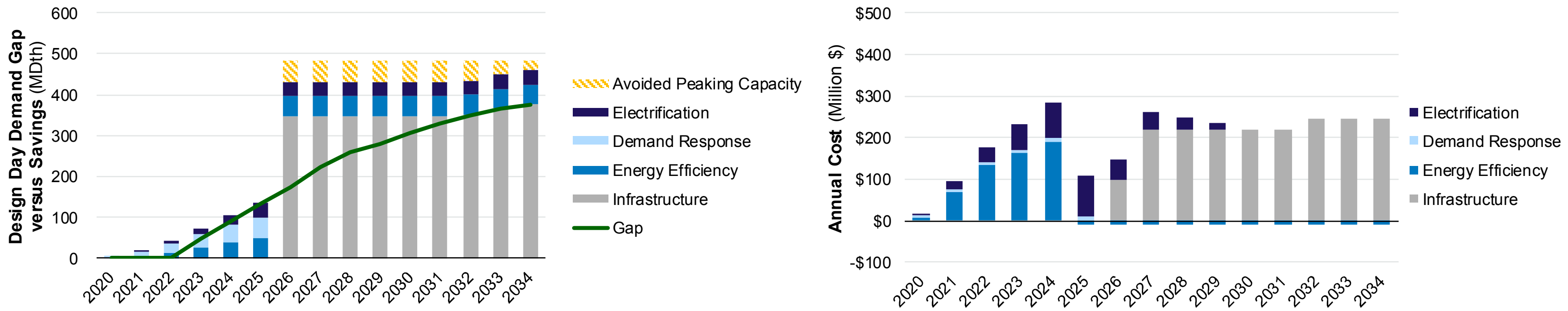


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

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.

LNG Import Terminal (2026/27)

Figure A3: 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.

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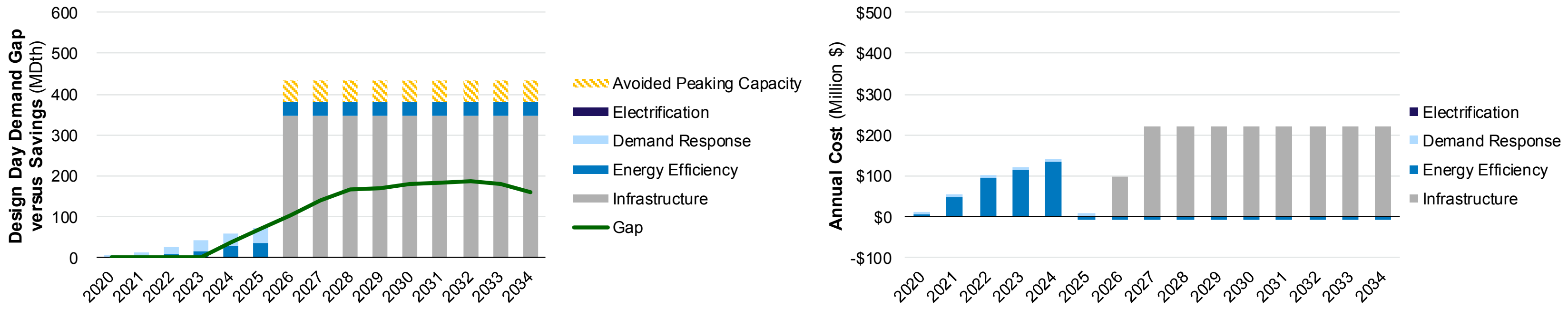
Figure A4: LNG Import Terminal – Low Demand Scenario

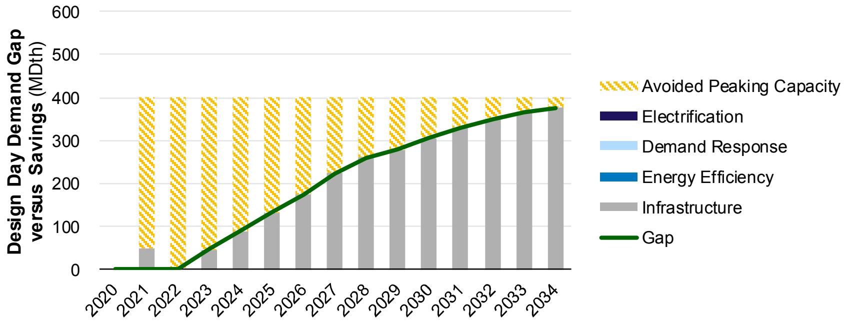


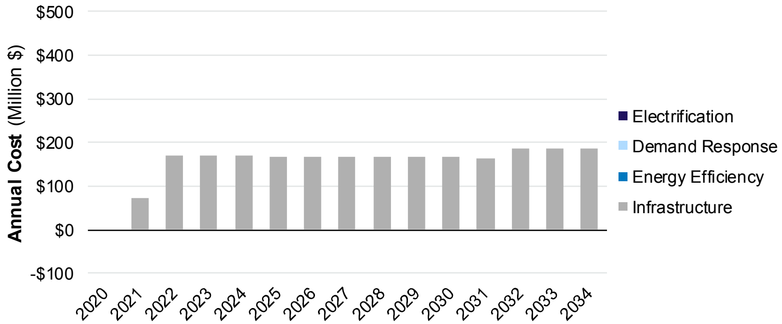
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

Notes: Annual 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.

Northeast Supply Enhancement (NESE) (2021/22)

Figure A5: Northeast Supply Enhancement (NESE) – High Demand Scenario

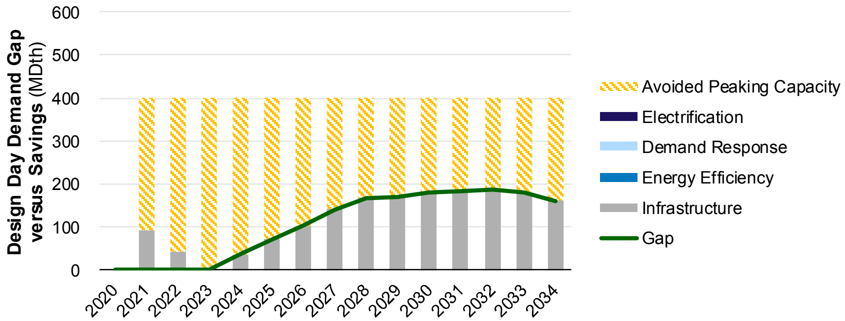


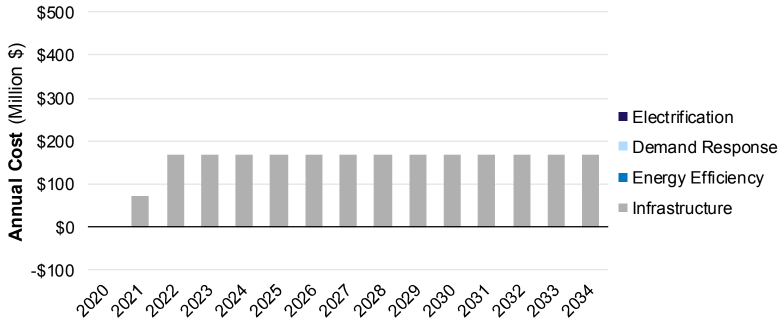


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

Notes: Annual 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 A6: Northeast Supply Enhancement (NESE) – Low Demand Scenario



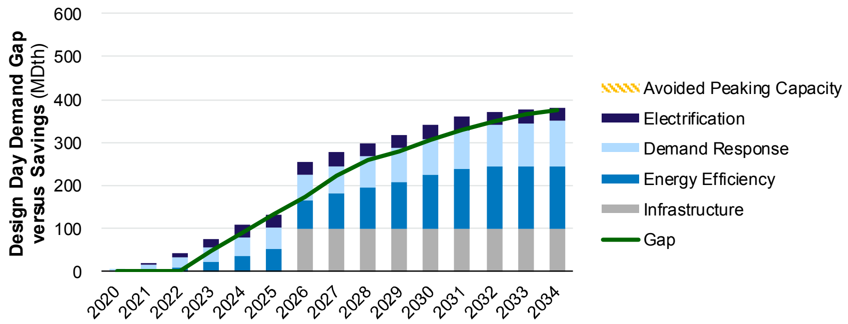


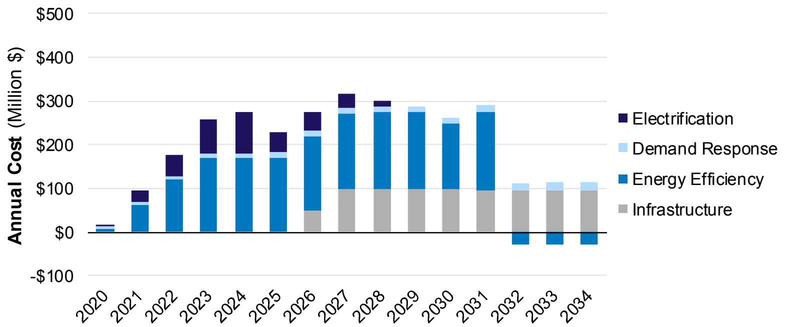
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

Notes: Annual 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.

Peak LNG Facility (2026/27)

Figure A7: Peak LNG Facility – High Demand Scenario





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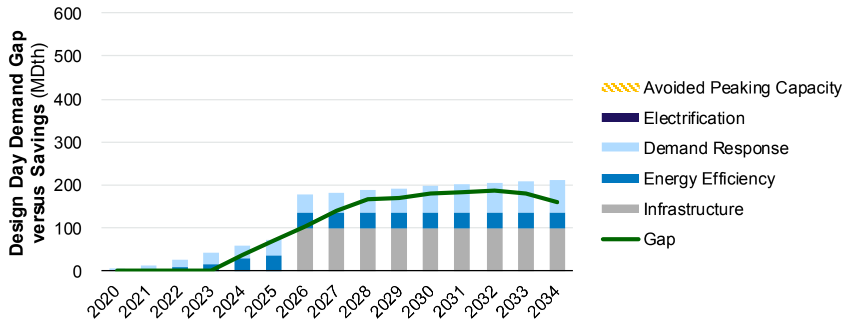
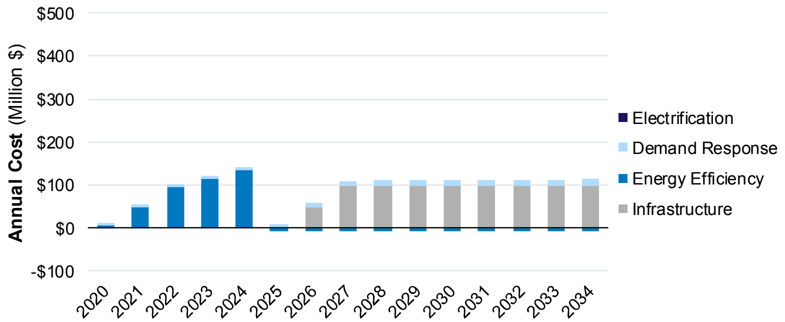
Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

Figure A8: Peak LNG Facility – Low Demand Scenario



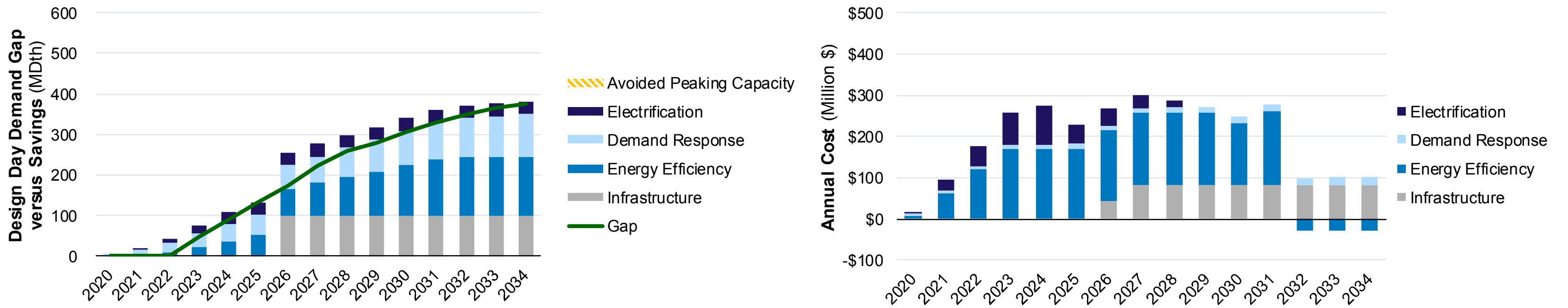


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

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.

LNG Barges (2026/27)

Figure A9: LNG Barges – High Demand Scenario



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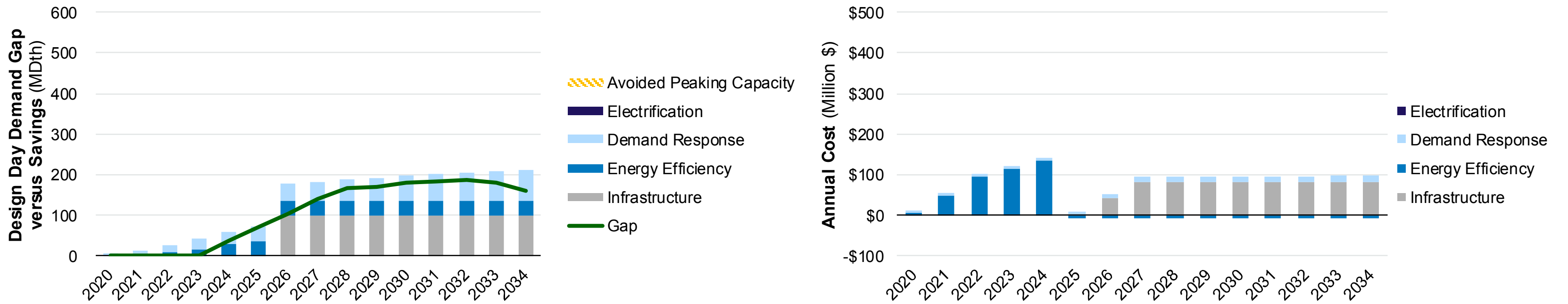
Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

Figure A10: LNG Barges – Low Demand Scenario



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Clove Lakes Transmission Loop Project (2026/27)

Figure A11: Clove Lakes Transmission Loop Project – High Demand Scenario

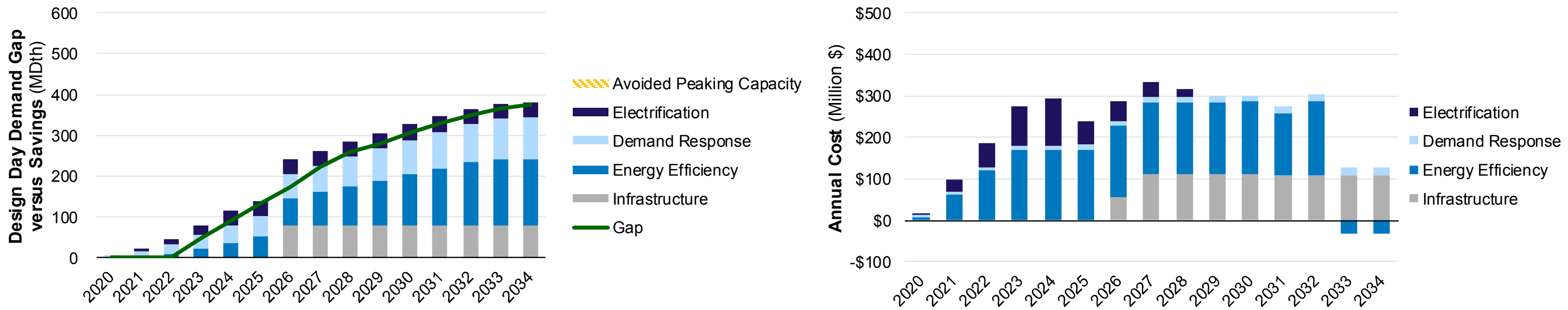

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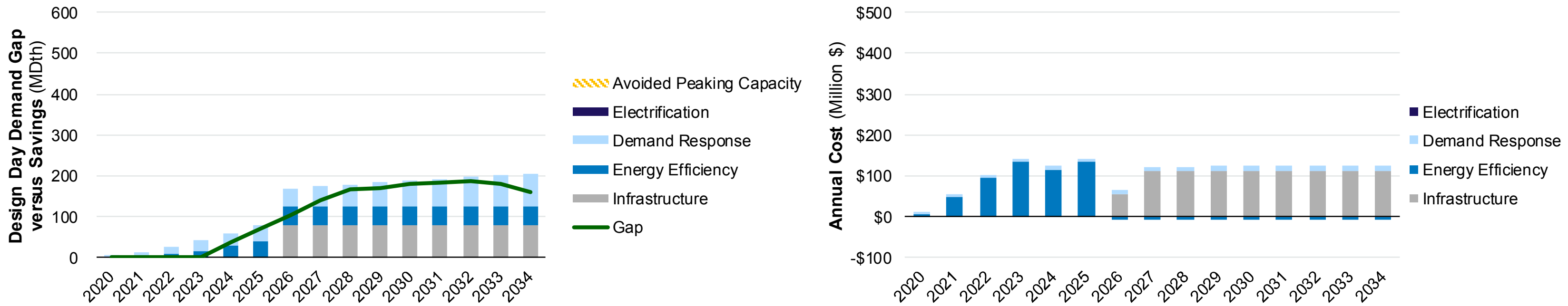
Figure A12: Clove Lakes Transmission Loop Project – Low Demand Scenario



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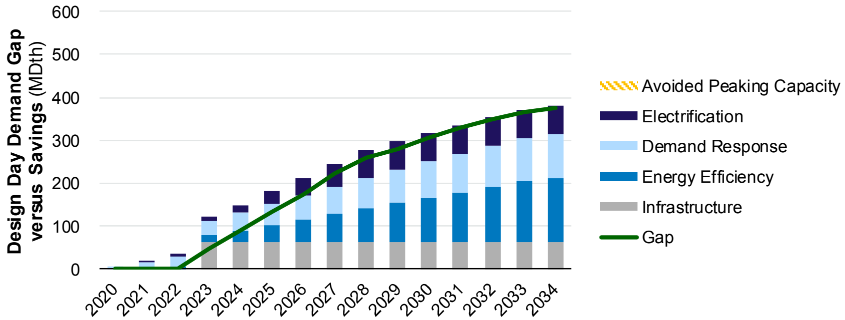
Iroquois Enhancement by Compression (ExC) (2023/24)

Figure A13: Iroquois Enhancement by Compression (ExC) – High Demand Scenario



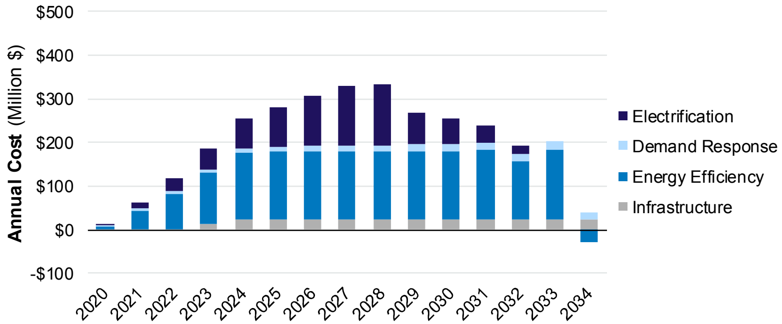


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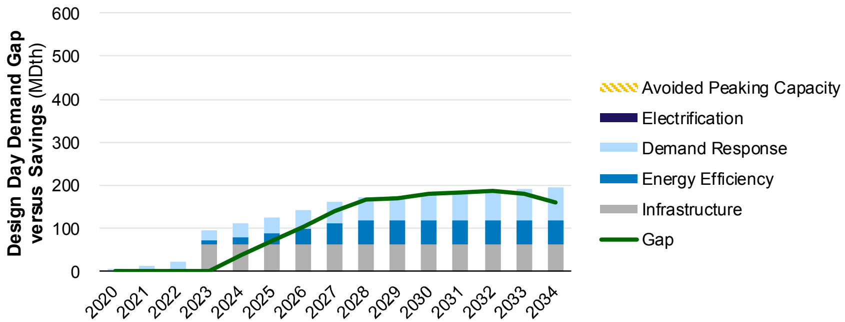
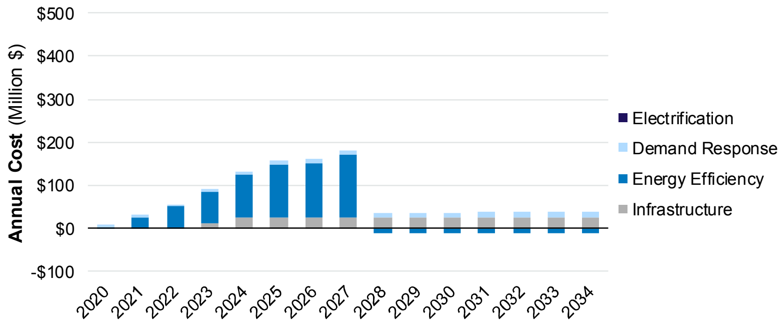
Figure A14: Iroquois Enhancement by Compression (ExC) – Low Demand Scenario





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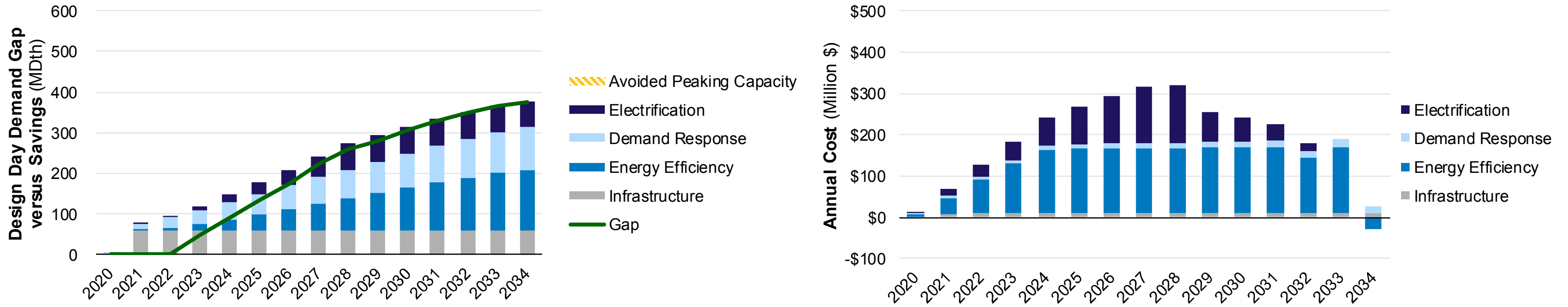
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

LNG Vaporization (2021/22)

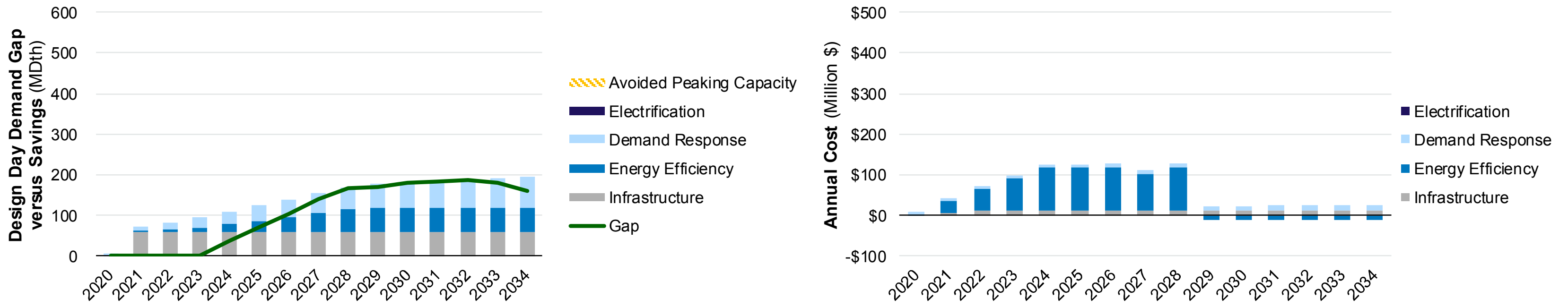
Figure A15: LNG Vaporization – High Demand Scenario



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 costs 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, if applicable. Demand side resource costs include program administration and incentive costs, net of commodity savings. Low gap is described in Section 5.

Figure A16: LNG Vaporization – Low Demand Scenario



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

Figure A17: Iroquois ExC plus LNG Barges – High Demand Scenario

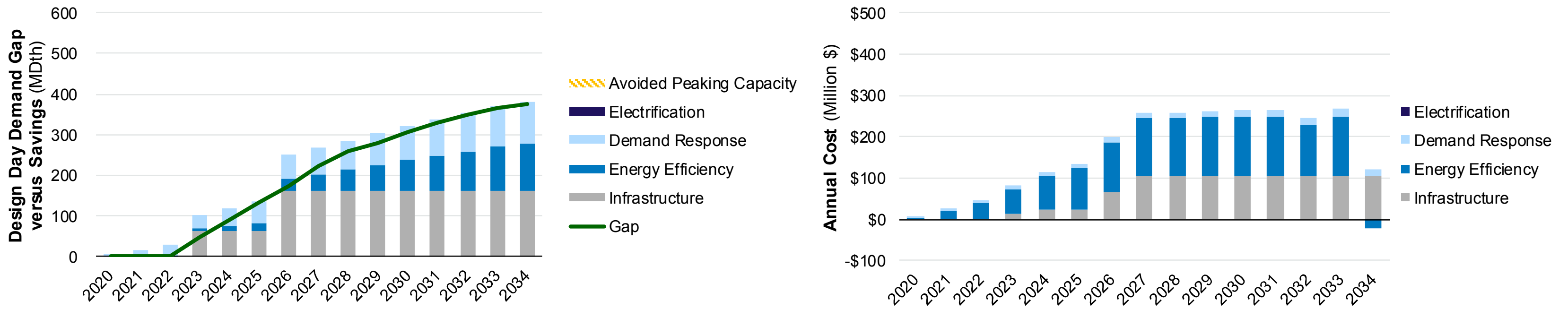

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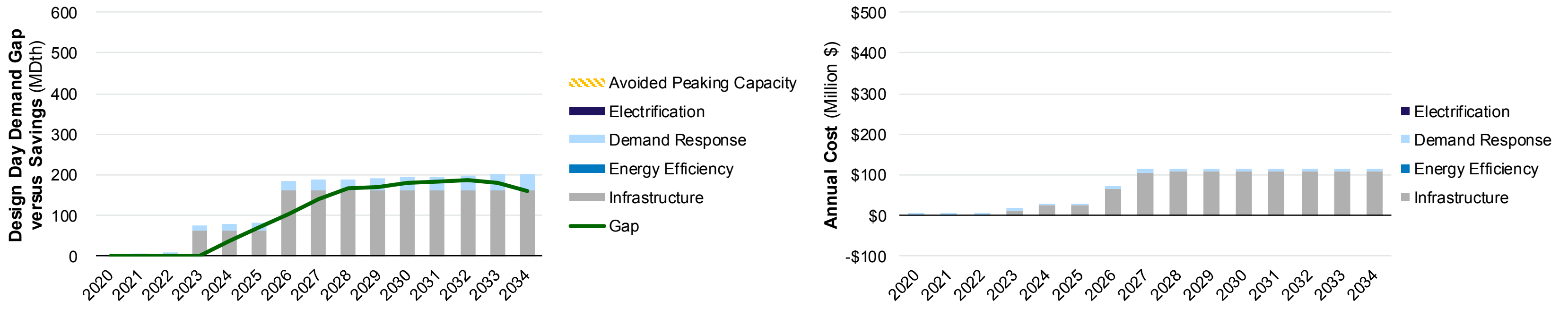
Figure A18: Iroquois ExC plus LNG Barges – Low Demand Scenario



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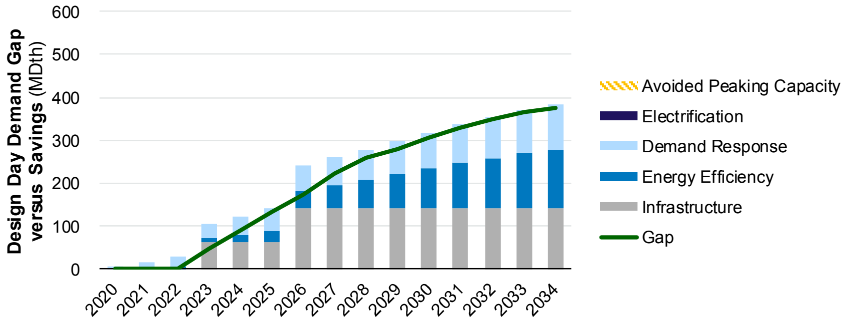
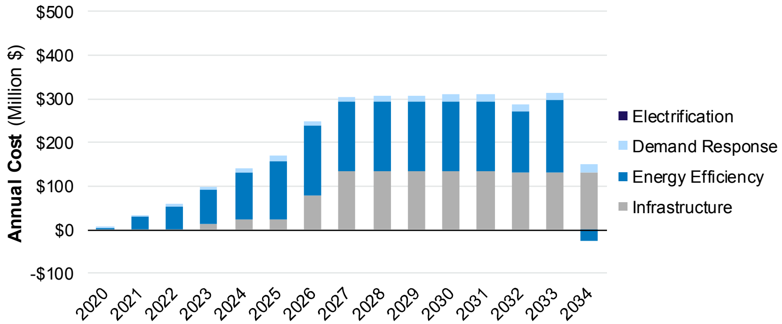
Iroquois ExC (2023/24) plus Clove Lakes Transmission Loop (2026/27)

Figure A19: Iroquois ExC plus Clove Lakes Transmission Loop – High Demand Scenario

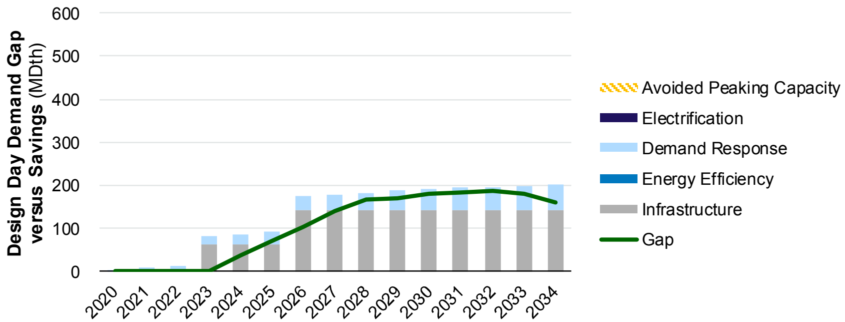


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

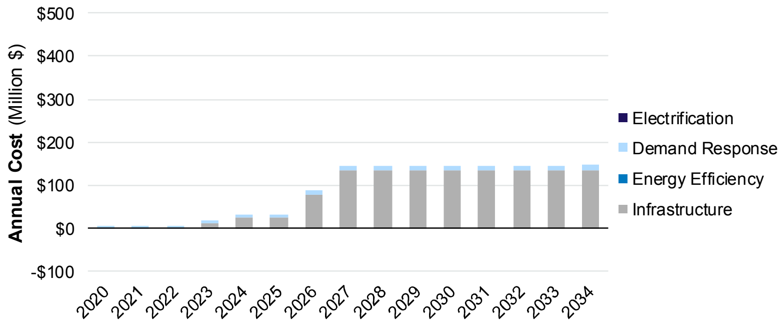


Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

Figure A20: Iroquois ExC plus Clove Lakes Transmission Loop – Low Demand Scenario



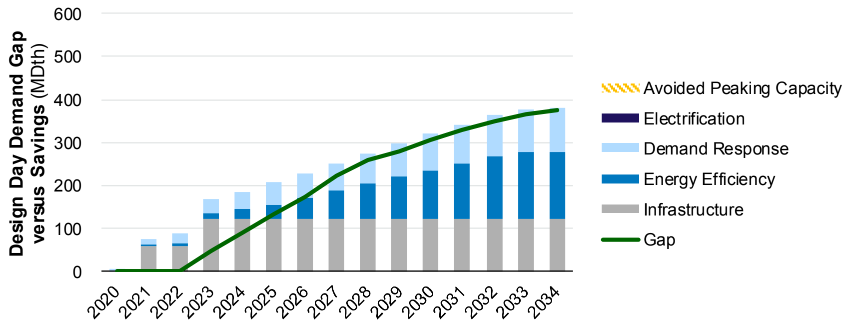
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



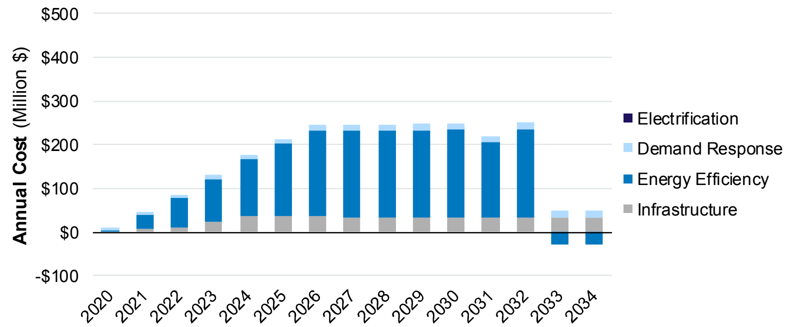
Notes: Annual costsw ith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

Iroquois ExC (2023/24) plus LNG Vaporization (2021/22)

Figure A21: Iroquois ExC plus LNG Vaporization – High Demand Scenario

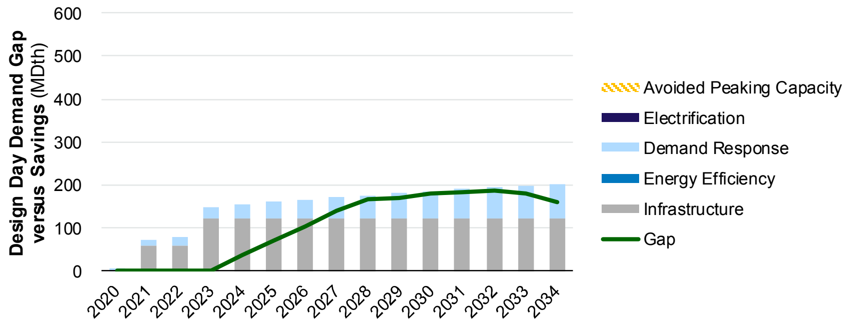


Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted high gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.

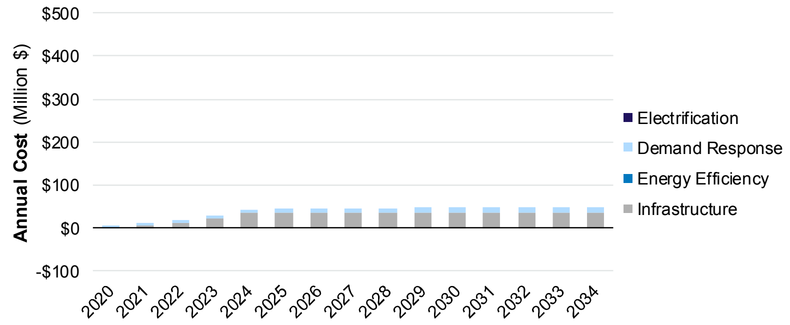


Notes: Annual costswith no discount rate applied. Infrastructure costs include fixed and commodity costs, net of commodity savings from avoided CNG trucking and short term contracted peaking supplies, if applicable. Demand side resource costs include program administration and incentive costs, net of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

Figure A22: Iroquois ExC plus LNG Vaporization – Low Demand Scenario



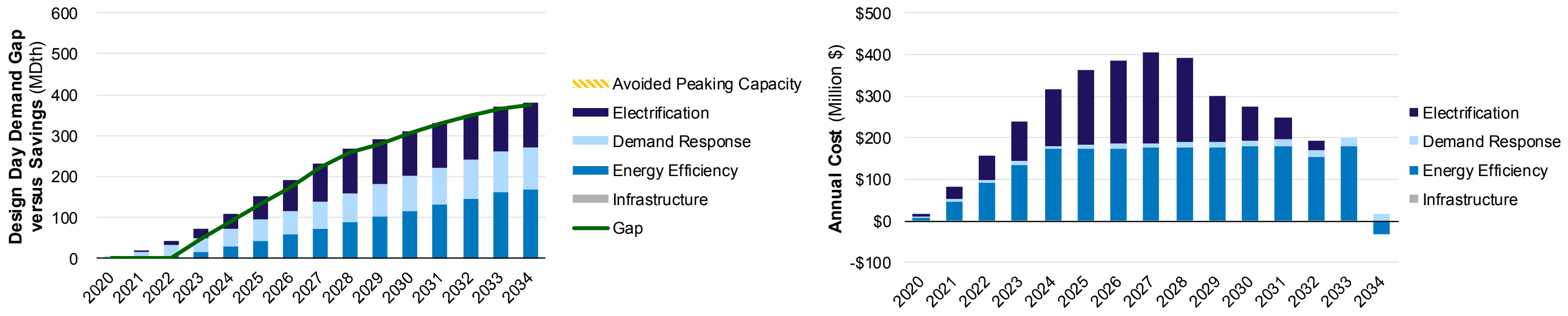
Notes: Forecasted design day savings attributable to incremental supply-side and demand-side resources, compared to the forecasted low gap, as described in Section 5. Avoidedpeaking capacity refers to avoided CNG trucking and short term contracted peaking supply.



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.

No Infrastructure

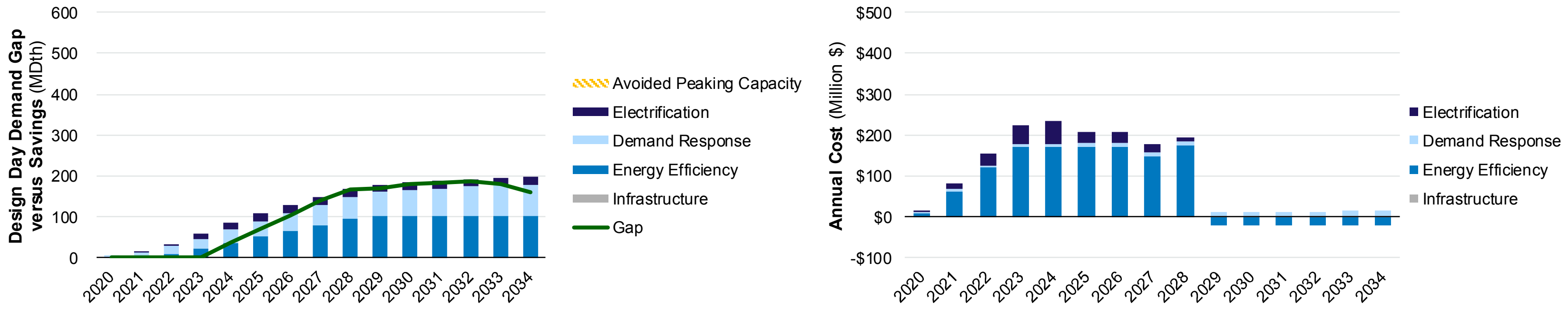
Figure A23: No Infrastructure – High Demand Scenario



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 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 A24: 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 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.

Appendix B – Updates to Technical Appendix

Supplemental to the Long-Term Natural Gas Capacity Report, National Grid released a Technical Appendix which provided additional context for some of the key numbers discussed in the report. This appendix provides updates to this information that occurred to derive the numbers in this supplemental report.

No Infrastructure Options

Several non-infrastructure-based (demand-side) options were considered that could address the capacity constraint in downstate New York in conjunction with or in lieu of various infrastructure options. These are energy efficiency, electrification, and demand response. The key assumptions regarding these options are presented below and represent the maximum size of each program. The actual program length and level of adoption required to address the gap between supply and demand for each solution in both the low and high gap scenarios is lower than the levels stated here.

Incremental Energy Efficiency Assumptions

With the increased levels of energy efficiency budgeted within NENY already being accounted for in the demand forecasts, it was assumed that incremental energy efficiency beyond the usual set of EE measures would be required to help close the demand gap without infrastructure. It was assumed that intensive weatherization, including a suite of measures like air sealing and insulation, would act as the primary incremental energy efficiency in a non-pipe solution because it's highly coincident with the design day and not part of National Grid's current programs. The assumptions behind this weatherization program are discussed below.

Program Length and Customer Adoption

It was assumed that after a fifteen-year program, weatherization would reach roughly 33% of customers. The number of eligible customers is based on National Grid data and includes single family, multifamily, and commercial customers, including income qualified customers. The fastest assumed ramp-up sees roughly 10,000 installations in 2021, 20,000 in 2022, and 30,000 every year after. This penetration compares to 32,000 weatherization and air sealing projects completed in Massachusetts combined in 2015 and 2016.[36] Currently there are limited weatherization contractors in downstate New York. Achieving 30,000 installations in 2023 will require just over 1,000 full time employees assuming a similar rate of FTEs per weatherization project seen in Rhode Island in 2018.[37] This will require close coordination with NYSERDA and other stakeholders in downstate New York.

Savings

A half-year convention was assumed for the first-year impact of weatherization (i.e., savings are discounted by half for first year installs, as we assume that they will occur evenly throughout the course of the year and thus, on average, be in place for six months in the first year in which they are installed). With an assumed measure life of 15 years, after the install year each installation

[36] "Home Energy Services Impact Evaluation, August 2018," Navigant Consulting, accessed at http://ma-eeac.org/wordpress/wp-content/uploads/RES34_HES-Impact-Evaluation-Report-with-ES_FINAL_29AUG2018.pdf

[37] Rhode Island 2018 Energy Efficiency Year-End Report dated May 15, 2019, available at: http://www.ripuc.ri.gov/eventsactions/docket/4755-NGrid-Year-End%20Report%202018%20(5-15-19).pdf

contributes savings to all of the following years in the analysis. The weatherization program was assumed to have the following savings per customer:

- 200 therms per year for residential heating customers (~15% of annual load)
- 1,200 therms per year for commercial customers (~20% of annual load)
- 4,200 therms per year for KEDNY multifamily customers and 6,000 therms per year for KEDLI multifamily customers (~20% of annual load).

The amount of savings in these estimates are comparable with savings estimates from algorithms for weatherization and air sealing published in the New York Technical Reference manual (TRM).

These annual savings are converted to design day savings using a design day factor of 1.3%. This is based on the ratio of heating degree days on the design day versus the total throughout the year, as energy consumption for space heating (and therefore savings from weatherization) correlate highly with heating degree days. In addition, these retail savings are converted to wholesale savings values using a factor of 102%, which is slightly higher than the service territories' LAUF to match the factors used in the demand forecasts.

Costs

Incentive rates for weatherization were assumed as follows:

- $15/therm for residential heating customers
- $12/therm for commercial customers
- $10/therm for multifamily customers

These costs are based on the cost per first-year savings for the established and successful weatherization programs in Massachusetts in 2017-2019 which provide a model for the magnitude of savings we are targeting in New York. These incentives average to around 75% of the total cost of the weatherization measures. Customers would be responsible for paying for the balance of project costs.

These costs were assumed to increase 2% annually. In addition to these incentives, program and administrative costs were assumed to be 15% of the incentive costs, which were assumed to be incurred one year earlier than the corresponding incentives were provided. The magnitude of the program and administrative costs are in line with other weatherization programs in New England.

Benefits

The avoided gas commodity costs and avoided greenhouse gas emissions are monetized as benefits of a weatherization program. For avoided gas commodity costs, the cumulative annual gas savings associated with weatherization through 2034/35 are monetized at $2.50/therm. For avoided GHG, the cumulative annual gas savings through 2034/35 were assumed to save pipeline gas that emits roughly 117 lbs CO_2/Dth, 2.2 x 10^{-4} lbs. N_2O/Dth, and 0.7 lbs. CH_4/Dth[38]. These emissions values were then monetized according to the EPA's latest social cost of pollutants under a 3% discount.

[38] https://www.eia.gov/environment/emissions/co2_vol_mass.php, https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf, http://theconversation.com/the-us-natural-gas-industry-is-leaking-way-more-methane-than-previously-thought-heres-why-that-matters-98918

Summary

The key assumptions defining the savings and costs associated with an incremental energy efficiency program are shown in Table B1 below.

Table B1: Summary of Incremental Energy Efficiency Assumptions

Parameter	Assumption	Source
15-Year Weatherization Program Penetration	33%	Benchmark with MA and RI weatherization programs
Annual Savings per Res Weatherization	200 th	TRM estimates and percent savings on space heating usage
Annual Savings per COM Weatherization	1,200 th	TRM estimates and percent savings on space heating usage
Annual Savings per KEDNY MF Weatherization	4,200 th	TRM estimates and percent savings on space heating usage
Annual Savings per KEDLI MF Weatherization	6,000 th	TRM estimates and percent savings on space heating usage
Design Day Factor	1.3%	Average of Res DDF and ratio of design day HDD to annual HDD
Retail to Wholesale Factor	2%	Based on stated LAUF and effective losses from demand
Incentive Rate for Res Weatherization	$15/th	Benchmark with MA and RI weatherization programs
Incentive Rate for COM Weatherization	$12/th	Benchmark with MA and RI weatherization programs
Incentive Rate for MF Weatherization	$10/th	Benchmark with MA and RI weatherization programs
Administrative Cost Adder	15%	Assumption based on program experience

Incremental Electrification Assumptions

Though incentivizing electrification is not normally within the purview of a gas utility, it is assumed to be necessary here to help address the demand gap in downstate New York as energy efficiency and demand response reach their limits of achievability. While some amount of electrification is assumed within the demand forecast, it is assumed that National Grid would need to provide a separate incentive to drive enough customers to adopt electric heating. This can also facilitate adoption of cold-climate heat pumps which will have a higher impact the design day.

Our assessment is that the increased electric usage in the winter resulting from the level of electrification discussed below would not cause the winter electric peak demand to exceed the current summer electric peak demand. However, further consideration is warranted for how the electric grid would be impacted.

The assumptions surrounding this program are discussed below.

Adoption

An electrification program was assumed to be offered to residential natural gas customers in both KEDNY and KEDLI. Of this population, it was assumed that roughly 5% of customers would consider replacing their heating equipment per year as their existing equipment neared the end of its useful life. Of this 5% of customers, the percentage that are assumed to install an electric heat pump rather than the typical natural gas heating equipment increases from 2% in 2021 up to 23% in 2026. This ramp up is driven by increasing customer awareness for heat pumps and is capped by the assumed customer acceptance of a 5-year payback period. This payback period is assumed to be targeted by the incentive program, discussed in the costs section below. In the end this led to roughly 13,000 electrifications per year around 2026 (after the ramp up).

Residential customers had two assumed paths for electrification:

1. Customers with a ducted furnace and central AC (~20% of residential customers in DNY) could switch to an air-source heat pump.
2. Customers with a boiler and room AC or PTAC (~80% of residential customers in DNY) could switch to a ductless mini split heat pump.

The heat pumps were assumed to be cold climate in order to have the full impact on the design day. The heat pump technology assumptions are shown in Table B2 below.

Table B2: Summary Electrification Technology and Cost Assumptions

Technology	Efficiency	Capacity (Tons)	Full Installed Cost	Incremental Installed Cost	Annual Gas + Electric Bill Savings (KEDNY/KEDLI)
ASHP	16 SEER/11.8 EER/10 HSPF	5	$19,500	$10,200	-$660 / -$255
Minisplit	16 SEER/12 EER/10 HSPF	5	$17,370	$11,000	-$950 / -$480

Savings

Of the current natural gas customers converting to electric heating, 50% were assumed to keep 10% of their pre-electrification design day consumption. This remaining consumption was assumed to be from non-heating end uses like cooking that may not be electrified along with the heating. Note that the assumed pre-electrification design day consumption that's being saved is the average post- weatherization, which implicitly assumes that choosing to participate in weatherization and choosing to electrify are independent.

Costs

Achieving a 5-year payback period for electrification requires providing an upfront and ongoing incentive. An upfront incentive of 50% of the installed cost of the system was assumed, followed by an ongoing incentive of $1,500 to $2,000 per year (depending on the technology) that offsets the increase in customer bills. This increase in customer bills is due to the higher cost of electricity as compared to natural gas on a per-energy basis, even with the relatively high efficiency of heat pumps. Note that this assumes that there are no major changes to current residential electric and natural gas rates in downstate New York. Customers would receive these incentives for five years in order to achieve the payback, at which point the customer would no longer receive the ongoing incentive. In addition to these incentive costs, program and administrative costs were assumed to be 25% of the incentive costs, which were assumed to be incurred one year prior to the corresponding upfront incentives.

Benefits

The avoided greenhouse gas emissions are monetized as a benefit of an electrification program. For avoided GHG, the cumulative annual gas savings through 2034/35 were assumed to save pipeline gas that emits roughly 117 lbs. CO_2/Dth, 2.2 x 10^{-4} lbs. N_2O/Dth, and 0.7 lbs. CH_4/Dth. The added electric emissions from increased electric consumption during the heating season were then subtracted out from the savings. These net emissions savings were then monetized according to the EPA's latest social cost of pollutants under a 3% discount.

Summary

The key assumptions defining the savings and costs associated with an incremental electrification program are shown in Table B3 below.

Table B3: Summary of Incremental Electrification Assumptions

Parameter	Assumption	Source
HVAC Turnover	5%/yr.	Assumed 20-yr average life of HVAC consistent with demand forecasts
Payback Acceptance	23%	Residential payback acceptance curves
Percent Partial G2E	50%	Assumed half of customers would keep non-heating equipment during switch
Percent UPC Savings for Partial G2E	90%	Residential design day consumption by end use
Targeted Payback Period	5 Years	Targeted assumption
Upfront Incentive Percent	50%	Assumed value
Administrative Cost Adder	25%	Assumption

Incremental Demand Response Assumptions

While some amount of demand response is assumed within the demand forecast, additional demand response would be necessary to address the capacity constraint in downstate New York without infrastructure. Since the savings from these programs are so coincident with the design day by their nature, they are assumed to warrant increased focus. The key assumptions behind the incremental demand response are discussed below.

Adoption

The temperature-controlled (TC) program is assumed to keep 100% of current KEDNY customers for all supply scenarios except for NESE. Note that this accounts for the TC customers that are already assumed to stay on non-firm rates in the low demand scenario.

The thermostat direct load control (DLC) program participation was assumed to increase linearly over 4 years to reach 20% of residential heating customers by 2024 in the high gap scenario. However, this program was assumed to be unnecessary in each solution to address the design day need.

Savings

The TC customers are assumed to each save 50 Dth on the design day. This is based on historical event day savings from the TC program.

For customers participating in the thermostat DLC program, it was assumed that they would save 2% of their design day usage per customer. This is based on benchmarks with other direct load control programs in New England.

Costs

It is assumed that there are fixed program costs of $2 million per year for the residential thermostat program and $4 million per year for the TC program, based on historical program costs and costs for similar DLC programs. There are also assumed to be annual participation incentives of $50 per participating thermostat per year and $6,500 per participating TC customer per year. These are assumed based on other demand response programs and doubling the incentive that is currently offered for TC programs.

The avoided greenhouse gas emissions are monetized for the non-firm retention program, which count as a cost since customers are expected to switch from gas to higher emitting fuel oil during peak events. To calculate net GHG emissions, two design days' worth of pipeline gas consumption per year was assumed to be replaced with an equivalent amount of fuel oil on a per-BTU basis. Whereas pipeline gas was assumed to emit roughly 117 lbs. CO_2/Dth, 2.2×10^{-4} lbs. N_2O/Dth, and 0.7 lbs. CH_4/Dth, fuel oil was assumed to emit 175% as much CO_2, 600% as much N_2O, and 0% as much CH_4. The net emissions were then monetized according to the EPA's latest social cost of pollutants under a 3% discount.

Summary

The key assumptions defining the savings and costs associated with an incremental demand response program are shown in Table B4.

Table B4: Summary of Incremental Demand Response Program Assumptions

Parameter	Assumption	Source
TC Customers Kept on TC Rate	100%	Participation needed to meet capacity constraint
Design Day Savings per TC Customer	50 Dth	Based on historic event day savings
Percent Res Thermostat Participation	20%	Participation needed to meet capacity constraint
Percent UPC Savings	2%	Benchmark with NE DLC programs for design day
Fixed TC Program Costs	$4,000,000/yr.	Benchmark with gas demand response programs
Fixed Thermostat Program Costs	$2,000,000/yr.	Benchmark with gas demand response programs
TC Incremental Incentive per Cust	$6,500/yr.	Based on current effective participation incentives
Thermostat Incentive per Cust	$50/yr.	Assumed incentive for costs

Program Design Considerations

For each of the major program areas, there are several other program design elements that will need to be developed and vetted if these plans are adopted. These issues were not factored into the current analysis. These include:

- Creation of detailed weatherization programs and implementation plans by National Grid
- Regulatory considerations to enable program deployment
- Establishing cost effectiveness of those programs as designed
- Developing a structure for home energy audits
- Size of the contractor workforce and workforce development in coordination with NYSERDA efforts in this area, including advance notice of program development to the contractor workforce; providing incentives to contractors, product and installation standards; training; coordination with NYSERDA programs; financing mechanisms; and marketing and targeting to optimize savings and equity.
- Coordination with the joint utilities on electrification programs

Infrastructure Options Cost and Net Present Value (NPV)

Infrastructure Cost Inputs and Assumptions

As discussed in section 9.1 of the Long-Term Capacity Report, the cost of each infrastructure option was assessed on multiple aspects, including Project Cost, Annual Operating Cost, Commodity Cost, and Corresponding Savings. Details for each of these aspects can be found below.

Table B5 provides detail on the total project cost and associated annual cost to the Downstate NY customer base.

Table B5: Total Project and Annualized Cost

Option	Total Project Cost*	Annualized Cost	Annualized Project Cost Detail
Offshore LNG Port	$800M	$160M	Estimated to be 20% of the total project cost based on National Grid experience
LNG Import Terminal	$1.2B	$240M	Estimated to be 20% of the total project cost based on National Grid experience
Northeast Supply Enhancement (NESE) Project	$1B	$193M	Annual cost per negotiated agreement with Williams – roughly falls in line with the 20% estimate for other infrastructure options
Peak LNG Facility	$500M	$100M	Estimated to be 20% of the total project cost based on National Grid experience
LNG Barges (x2)	$410M	$82M	Estimated to be 20% of the total project cost based on National Grid experience
Clove Lakes Transmission Loop Project	$320M	$112M	Annual cost is made up of two charges: • $48M demand charge modelled on NESE cost structure • $64M annual cost estimated to be 20% of total project cost based on National Grid experience
Gas Compression on the Iroquois Gas Transmission System	$272M (NG portion $136M)	$24M	Annual recourse rate per the IGTS filing – which is $1.06/Dth/Day
LNG Vaporization	$59M	$12M	Estimated to be 20% of the total project cost based on National Grid experience

**Details / Sources of the Total Project Cost can be found in Section 10 of the Long-Term Capacity Report and Section 7 of the Supplemental Report*

Value of Commodity and GHG

To best account for commodity costs in the least complicated way, a set of simplifying assumptions were used. A baseline case was constructed in which excess demand is assumed to be met by pipeline gas. For any solution with an infrastructure component, some portion of this excess demand was assumed to be met by that infrastructure, capturing any net change in emissions rate for LNG-based solutions which were assumed to emit at 109% the rate of pipeline gas. As incremental energy efficiency is ramped up the decreased demand is assumed to remove commodity from the system, as compared to the baseline case. Our model accounts for this reduction in commodity at a rate of $2.50/Dth. Additionally, for the large infrastructure solutions, to the extent that CNG trucking and short-term contracted peaking supplies were assumed to be replaced to the extent that they could be. The net change in commodity costs and GHG for these options was then calculated, given assumed commodity costs of $8.75/Dth for short-term peaking supplies and $12.75/Dth for CNG trucking, and assumed relative emissions of 115% for CNG trucking.

Annual Cost Schedules in High and Low Demand Scenarios

Tables B6 and B7 provide an annual breakdown of infrastructure, non-infrastructure, and avoided commodity cost (e.g., corresponding savings) for each supply alternative. The Net Present Values (NPV) from the Long-Term Capacity Report were calculated with these values utilizing a 6.3% discount rate.

Table B6: Annual Costs – High Demand Scenario

Annual Net Cost of Infrastructure in the High Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$74	$171	$171	$171	$171	$171	$171	$171	$171	$171	$171	$193	$193	$193
LNG Terminal (400 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$98	$218	$218	$218	$218	$218	$240	$240	$240
Offshore LNG (400 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$58	$138	$138	$138	$138	$138	$160	$160	$160
Peak LNG (100 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$50	$100	$100	$100	$100	$100	$100	$100	$100
LNG Barges (100 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$41	$82	$82	$82	$82	$82	$82	$82	$82
CL (80 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$56	$112	$112	$112	$112	$112	$112	$112	$112
IGC (62.5 MDth) in 2023/24	$0	$0	$0	$12	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
LNG Vaporization (60 MDth) in 2021/22	$0	$6	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	$0	$12	$24	$24	$65	$106	$106	$106	$106	$106	$106	$106	$106
IGC + CL (142.5 MDth) in 2023-27	$0	$0	$0	$12	$24	$24	$80	$136	$136	$136	$136	$136	$136	$136	$136
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	$6	$12	$24	$36	$36	$36	$36	$36	$36	$36	$36	$36	$36	$36
No Infrastructure	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Annual Cost of Incremental No-Infrastructure in the High Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG Terminal (400 MDth) in 2026/27	$16	$94	$179	$235	$291	$108	$49	$41	$29	$14	$0	$0	$0	$0	$0
Offshore LNG (400 MDth) in 2026/27	$16	$94	$179	$235	$291	$108	$49	$41	$29	$14	$0	$0	$0	$0	$0
Peak LNG (100 MDth) in 2026/27	$16	$93	$178	$261	$281	$239	$238	$232	$221	$210	$189	$220	$16	$17	$17
LNG Barges (100 MDth) in 2026/27	$16	$93	$178	$261	$281	$239	$238	$232	$221	$210	$189	$220	$16	$17	$17
CL (80 MDth) in 2026/27	$17	$98	$188	$277	$300	$248	$246	$238	$224	$210	$215	$193	$224	$17	$17
IGC (62.5 MDth) in 2023/24	$12	$62	$118	$176	$235	$263	$291	$317	$324	$261	$250	$237	$195	$206	$17
LNG Vaporization (60 MDth) in 2021/22	$12	$62	$118	$176	$235	$263	$291	$317	$324	$261	$250	$237	$195	$206	$17
IGC + LNG Barges (162.5 MDth) in 2023-27	$7	$27	$48	$69	$91	$114	$138	$159	$163	$167	$171	$175	$157	$182	$17
IGC + CL (142.5 MDth) in 2023-27	$8	$34	$61	$89	$118	$149	$177	$180	$184	$189	$193	$198	$177	$206	$17
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$9	$41	$75	$109	$145	$183	$218	$222	$227	$232	$238	$213	$247	$17	$17
No Infrastructure	$15	$82	$157	$240	$323	$370	$397	$417	$409	$319	$295	$272	$220	$229	$17

Annual Value of Avoided Commodity in the High Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	-$1	-$2	-$3	-$3	-$3	-$4	-$4	-$5	-$5	-$6	-$7	-$7	-$7	-$8
LNG Terminal (400 MDth) in 2026/27	$0	-$1	-$2	-$5	-$8	-$9	-$8	-$8	-$7	-$7	-$7	-$7	-$7	-$6	-$6
Offshore LNG (400 MDth) in 2026/27	$0	-$1	-$2	-$5	-$8	-$9	-$8	-$8	-$7	-$7	-$7	-$7	-$7	-$6	-$6
Peak LNG (100 MDth) in 2026/27	$0	$0	-$2	-$4	-$7	-$10	-$14	-$17	-$20	-$23	-$27	-$30	-$32	-$32	-$32
LNG Barges (100 MDth) in 2026/27	$0	$0	-$2	-$4	-$7	-$10	-$12	-$15	-$17	-$20	-$23	-$26	-$28	-$27	-$27
CL (80 MDth) in 2026/27	$0	$0	-$2	-$4	-$7	-$10	-$14	-$17	-$20	-$23	-$26	-$29	-$33	-$34	-$34
IGC (62.5 MDth) in 2023/24	$0	$0	-$1	-$3	-$5	-$8	-$10	-$13	-$16	-$19	-$21	-$24	-$27	-$29	-$30
LNG Vaporization (60 MDth) in 2021/22	$0	-$1	-$2	-$3	-$6	-$8	-$11	-$14	-$16	-$19	-$22	-$25	-$28	-$30	-$31
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	-$1	-$2	-$3	-$4	-$5	-$7	-$10	-$12	-$15	-$17	-$20	-$22	-$23
IGC + CL (142.5 MDth) in 2023-27	$0	$0	-$1	-$2	-$4	-$6	-$9	-$12	-$15	-$17	-$20	-$23	-$27	-$29	-$30
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	-$1	-$2	-$4	-$5	-$8	-$11	-$14	-$18	-$21	-$25	-$28	-$32	-$34	-$34
No Infrastructure	$0	$0	-$1	-$3	-$6	-$8	-$11	-$14	-$17	-$20	-$22	-$25	-$28	-$31	-$32

Annual Value of Avoided GHG Emissions in the High Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG Terminal (400 MDth) in 2026/27	$0	-$1	-$5	-$11	-$19	-$25	-$27	-$28	-$29	-$31	-$32	-$33	-$35	-$37	-$38
Offshore LNG (400 MDth) in 2026/27	$0	-$1	-$5	-$11	-$19	-$25	-$27	-$28	-$29	-$31	-$32	-$33	-$35	-$37	-$38
Peak LNG (100 MDth) in 2026/27	$0	-$1	-$5	-$11	-$19	-$26	-$32	-$40	-$48	-$56	-$65	-$75	-$82	-$85	-$89
LNG Barges (100 MDth) in 2026/27	$0	-$1	-$5	-$11	-$19	-$26	-$33	-$40	-$48	-$57	-$66	-$76	-$83	-$86	-$90
CL (80 MDth) in 2026/27	$0	-$1	-$5	-$12	-$20	-$27	-$34	-$41	-$50	-$58	-$68	-$78	-$88	-$96	-$100
IGC (62.5 MDth) in 2023/24	$0	-$1	-$3	-$7	-$13	-$20	-$29	-$38	-$49	-$57	-$66	-$75	-$85	-$95	-$103
LNG Vaporization (60 MDth) in 2021/22	$0	-$1	-$3	-$7	-$13	-$20	-$28	-$38	-$48	-$57	-$65	-$74	-$84	-$95	-$103
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	-$1	-$2	-$5	-$8	-$11	-$16	-$21	-$27	-$34	-$41	-$48	-$56	-$61
IGC + CL (142.5 MDth) in 2023-27	$0	$0	-$1	-$3	-$6	-$10	-$15	-$21	-$28	-$34	-$42	-$50	-$58	-$68	-$74
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	$0	-$2	-$4	-$8	-$13	-$19	-$26	-$34	-$43	-$52	-$62	-$73	-$80	-$83
No Infrastructure	$0	-$1	-$4	-$10	-$18	-$28	-$39	-$50	-$63	-$73	-$83	-$94	-$106	-$119	-$128

Table B7: Annual Costs – Low Demand Scenario

Annual Net Cost of Infrastructure in the Low Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$74	$171	$171	$171	$171	$171	$171	$171	$171	$171	$171	$171	$171	$171
LNG Terminal (400 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$98	$218	$218	$218	$218	$218	$218	$218	$218
Offshore LNG (400 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$58	$138	$138	$138	$138	$138	$138	$138	$138
Peak LNG (100 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$50	$100	$100	$100	$100	$100	$100	$100	$100
LNG Barges (100 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$41	$82	$82	$82	$82	$82	$82	$82	$82
CL (80 MDth) in 2026/27	$0	$0	$0	$0	$0	$0	$56	$112	$112	$112	$112	$112	$112	$112	$112
IGC (62.5 MDth) in 2023/24	$0	$0	$0	$12	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24	$24
LNG Vaporization (60 MDth) in 2021/22	$0	$6	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12	$12
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	$0	$12	$24	$24	$65	$106	$106	$106	$106	$106	$106	$106	$106
IGC + CL (142.5 MDth) in 2023-27	$0	$0	$0	$12	$24	$24	$80	$136	$136	$136	$136	$136	$136	$136	$136
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	$6	$12	$24	$36	$36	$36	$36	$36	$36	$36	$36	$36	$36	$36
No Infrastructure	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Annual Cost of Incremental No-Infrastructure in the Low Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG Terminal (400 MDth) in 2026/27	$11	$54	$101	$125	$146	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0
Offshore LNG (400 MDth) in 2026/27	$11	$54	$101	$125	$146	$9	$0	$0	$0	$0	$0	$0	$0	$0	$0
Peak LNG (100 MDth) in 2026/27	$11	$54	$101	$125	$146	$9	$10	$10	$11	$12	$12	$13	$13	$14	$14
LNG Barges (100 MDth) in 2026/27	$11	$54	$101	$125	$146	$9	$10	$10	$11	$12	$12	$13	$13	$14	$14
CL (80 MDth) in 2026/27	$11	$54	$101	$143	$128	$150	$10	$10	$11	$12	$12	$13	$13	$14	$14
IGC (62.5 MDth) in 2023/24	$8	$31	$57	$83	$110	$138	$144	$167	$11	$12	$12	$13	$13	$14	$14
LNG Vaporization (60 MDth) in 2021/22	$8	$34	$62	$90	$117	$120	$123	$110	$128	$12	$12	$13	$13	$14	$14
IGC + LNG Barges (162.5 MDth) in 2023-27	$4	$5	$5	$6	$6	$6	$7	$7	$7	$8	$8	$8	$9	$9	$9
IGC + CL (142.5 MDth) in 2023-27	$5	$5	$6	$6	$7	$8	$8	$9	$9	$10	$10	$11	$11	$11	$12
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$5	$5	$6	$7	$8	$9	$10	$10	$11	$12	$12	$13	$13	$14	$14
No Infrastructure	$14	$82	$157	$228	$242	$218	$220	$192	$212	$12	$12	$13	$13	$14	$14

Annual Value of Avoided Commodity in the Low Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	-$1	-$2	-$2	-$2	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$3	-$3
LNG Terminal (400 MDth) in 2026/27	$0	$0	-$1	-$3	-$5	-$7	-$6	-$5	-$5	-$5	-$5	-$5	-$5	-$5	-$5
Offshore LNG (400 MDth) in 2026/27	$0	$0	-$1	-$3	-$5	-$7	-$6	-$5	-$5	-$5	-$5	-$5	-$5	-$5	-$5
Peak LNG (100 MDth) in 2026/27	$0	$0	-$1	-$3	-$5	-$7	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8	-$8
LNG Barges (100 MDth) in 2026/27	$0	$0	-$1	-$3	-$5	-$7	-$6	-$6	-$6	-$6	-$6	-$6	-$6	-$6	-$6
CL (80 MDth) in 2026/27	$0	$0	-$1	-$3	-$5	-$8	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10	-$10
IGC (62.5 MDth) in 2023/24	$0	$0	-$1	-$3	-$4	-$5	-$7	-$10	-$11	-$11	-$11	-$11	-$11	-$11	-$11
LNG Vaporization (60 MDth) in 2021/22	$0	$0	-$1	-$3	-$4	-$6	-$8	-$10	-$11	-$12	-$12	-$12	-$12	-$12	-$12
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IGC + CL (142.5 MDth) in 2023-27	$0	$0	$0	-$1	$0	$0	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	$0	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1	-$1
No Infrastructure	$0	$0	-$2	-$4	-$7	-$10	-$13	-$15	-$18	-$20	-$20	-$20	-$20	-$20	-$20

Annual Value of Avoided GHG Emissions in the Low Demand Scenario ($M/Year)

Supply Solution	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
NESE (400 MDth) in 2021/22	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
LNG Terminal (400 MDth) in 2026/27	$0	-$1	-$3	-$6	-$10	-$13	-$14	-$14	-$15	-$15	-$16	-$16	-$17	-$18	-$19
Offshore LNG (400 MDth) in 2026/27	$0	-$1	-$3	-$6	-$10	-$13	-$14	-$14	-$15	-$15	-$16	-$16	-$17	-$18	-$19
Peak LNG (100 MDth) in 2026/27	$0	-$1	-$3	-$6	-$10	-$13	-$13	-$14	-$14	-$15	-$15	-$16	-$16	-$17	-$18
LNG Barges (100 MDth) in 2026/27	$0	-$1	-$3	-$6	-$10	-$13	-$13	-$14	-$14	-$15	-$15	-$16	-$17	-$17	-$18
CL (80 MDth) in 2026/27	$0	-$1	-$3	-$6	-$10	-$15	-$18	-$19	-$19	-$20	-$21	-$22	-$22	-$23	-$24
IGC (62.5 MDth) in 2023/24	$0	$0	-$1	-$3	-$6	-$10	-$14	-$20	-$23	-$24	-$25	-$26	-$27	-$28	-$29
LNG Vaporization (60 MDth) in 2021/22	$0	$0	-$1	-$3	-$6	-$10	-$14	-$18	-$23	-$25	-$26	-$27	-$29	-$30	-$31
IGC + LNG Barges (162.5 MDth) in 2023-27	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IGC + CL (142.5 MDth) in 2023-27	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IGC + LNG Vapor. (122.5 MDth) in 2021-23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	$1	$1	$1
No Infrastructure	$0	-$1	-$4	-$10	-$17	-$23	-$30	-$37	-$45	-$50	-$52	-$55	-$57	-$59	-$62