PA CONSULTING'S ASSESSMENT OF NATIONAL GRID'S NATURAL GAS LONG-TERM CAPACITY SECOND SUPPLEMENTAL REPORT

September 10, 2021

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1 Executive Summary

PA Consulting ("PA") conducted an independent assessment of The Brooklyn Union Gas Company's d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation's d/b/a National Grid ("KEDLI," and collectively with KEDNY, the "Company" or "National Grid") Natural Gas Long-Term Capacity Second Supplemental Report for Brooklyn, Queens, Staten Island and Long Island (the "Report"). This review, conducted for the New York State Department of Public Service (the "Department"), focused on the solutions and contingencies proposed by National Grid to address the anticipated growth in Design Day[1] demand. The solutions, collectively referred to as the Distributed Infrastructure Solution (the "DIS") are a mix of infrastructure projects and new energy efficiency and demand side management measures.

PA's review of the DIS started with an assessment of the Design Day demand forecast. The Design Day forecast is critical since it is the basis for the gap between the forecast and the existing supply and demand side resources that drives the need for the solutions outlined in the DIS. The evaluation of the range of feasible solutions considered the technical feasibility, system reliability (ability to maintain gas flow on the peak day), economics, implementation issues, and legislated policies. The development of a preferred solution to meet the near-term projected peak-day demand gap is complex as a result of uncertainties, matters that are beyond National Grid's control, and evolving policy. As an overall assessment and given the uncertainties, PA has concluded the solutions proposed in the DIS are reasonable at this juncture but are not without risk.[2] This report summarizes the basis for our findings and provides additional details on our assessment as well as important caveats.

National Grid's assessment of its existing supply and Design Day demand forecast are summarized in Figure 1-1. Figure 1-1 shows that National Grid is anticipating a 9 MDth/day gap in the winter of 2022/23 which grows thereafter absent a combination of incremental supply and demand side measures to close the gap. PA focused on evaluating the gap and potential solutions over the next five heating seasons. While closing the gap over the longer term is also critical and it is appropriate to develop a long-term plan, the key issues we focused on are:

- Is the identified gap over the next five years a reasonable estimate?
- What demand side measures has National Grid identified to fill the gap and is it likely that those measures alone can fill the gap?
- What supply side measures has National Grid identified to fill the gap, are those measures necessary, and what are the implications of not proceeding with those measures?
- What are the risks associated with not implementing the DIS as proposed by National Grid and what are the implications with respect to the need to implement curtailments or a moratorium on new connections?

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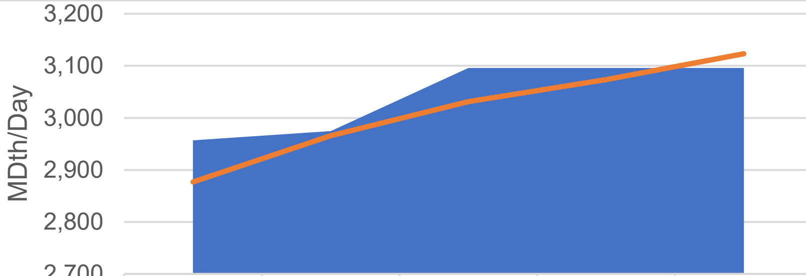
[1] According to National Grid's Second Supplemental Report, the Design Day is defined as the coldest winter day actually experienced in the downstate service territories, characterized by an average daily temperature of 0° Fahrenheit in Central Park (which is equivalent to 65 Heating Degree Days).

[2] Assessment of the reasonableness of the DIS plan is not intended to be dispositive regarding a determination of need for any Long-Term Capital Capacity Project as outlined in the Joint Proposal approved on August 12, 2021 in Case Nos. 19-G-0309 and 19-G-0310.

Figure 1-1: Design Day Forecasts



	2021/22	2022/23	2023/24	2024/25	2025/26
Total Supply	2,957	2,975	3,096	3,096	3,096
Design Day Demand	2,877	2,966	3,031	3,074	3,123

1.1 Design Day Demand Forecast

PA reviewed two major components of the Design Day load forecast: wind-adjusted Design Day demand conditions and the sales forecast that is translated into the Design Day demand. National Grid commissioned a study by Marquette Energy Analytics which determined that National Grid's Design Day standard is consistent with a one-in-33-year event accounting for wind and temperature[3]. PA's conclusion is that the study presents a reasonable Design Day demand planning criterion. With regard to the load forecast developed by National Grid we note that it is a point forecast rather than a range that had been used in National Grid's Natural Gas Long-Term Capacity Supplemental Report published on May 8, 2020.

PA understands that National Grid develops load forecasts reflecting a range of scenarios and that the forecast presented in the Report reflects a "middle of the road" outlook. However, the Report presents the DIS as a set of solutions in the context of a single demand scenario. Single point forecasts represent an exact prediction of what the future Design Day load will be. This may provide a sense of false precision since it ignores uncertainty and unpredictability due to a host of factors that can potentially influence the outcome. Instead, a range forecast leaves some margin of error and provides a range of plausible estimates and therefore various strategies to meet that demand. There is inevitable uncertainty in any forecast driven by a combination of economic growth and changing use patterns. In PA's review of the forecast, we developed alternative sales scenarios using high-level adjustments. In comparison to PA's scenario, the primary observation of our analysis is that National Grid's load forecast may ultimately be on the high side but it is within reason.[4]

1.2 Demand Side Measures to Fill the Gap

Based upon New York State's environmental goals the ideal solution would be to fill the gap with a combination of energy efficiency and demand side management measures and also have that be the lowest cost solution based upon the existing cost effectiveness tests. However, based upon PA's assessment of National Grid's analysis, our conclusion is that cost-effectively relying on demand side measures alone is unlikely to be sufficient to fill the gap identified over the next five years. Given the current status of National Grid's efforts to date, our assessment is that many of the proposed incremental demand side options ("Incremental"), defined as measures in addition to the demand side management ("DSM") measures

[3] Marquette's analysis assumes a 0-degree Fahrenheit day with a 12 MPH wind speed, the average wind speed on the 1% of historical coldest days from daily Central Park weather data going back to 1950. A 3 degree Fahrenheit day with 16 MPH wind is equivalent to a 0 degree Fahrenheit day with 12 MPH winds.

[4] The Design Day load forecast presented in the Report is based on econometric forecasts of key gas-usage elements using macroeconomic drivers from Moody's Analytics and is characterized as having a 50-50 chance of being higher or lower. National Grid also develops forecasts using alternative economic scenarios provided by Moody's Analytics. As a point of reference, PA's scenarios fall within the range of alternative forecasts developed by National Grid.

reflected in National Grid's Adjusted Baseline ("Baseline")[5] load forecast are in the early stage of testing. As a result, both customer uptake and the savings per participating customer are unproven. Since participation in the programs is voluntary, it is unclear whether customers will enroll at a rapid enough pace to avoid the need for near-term infrastructure enhancements even if budgets were expanded.

1.3 Infrastructure Measures to Fill the Gap

PA's evaluation of the major DIS infrastructure projects currently being proposed concluded that significant risk exists to the timely implementation of both the Iroquois ExC project and the Greenpoint Vaporizers 13 & 14. Further delays in the permitting and implementation of these infrastructure projects exposes National Grid to significant curtailment and moratorium risk within the next five years. The contingency infrastructure projects identified by National Grid remain conceptual and – even assuming ideal permitting and construction timelines – will likely not be in place in sufficient time to cover a Design Day supply/demand gap should any of the major DIS infrastructure projects fail to materialize.

1.4 Risks of a Moratorium on New Connections

National Grid's planning criteria is focused on providing safe, reliable, and cost-effective service to all existing and prospective customers requesting natural gas service. Consequentially, a moratorium on new hookups is not a strategy evaluated by National Grid. Rather, it is a potential outcome if the strategies in the DIS are not successfully implemented. PA's assessment has identified multiple uncertainties related to the design day demand forecast, the efficacy and uptake of the demand side measures, and risks associated with implementing the proposed infrastructure enhancements. In order to minimize the likelihood of a moratorium it is important to pursue both the proposed infrastructure enhancements and demand side measures. However, it is also a policy decision to determine what level of moratorium risk may be acceptable.

In summary, there is real supply risk, and therefore a risk that a supply/demand gap continues to exist, because the only plans National Grid has in place to offset supply risk are (a) demand side management programs that are not fully developed and cannot be expected to fill the gap by such time(s) as would be needed and (b) contingency projects that, even if determined to be feasible and they obtain the necessary approvals, are several years away from implementation – placing even more burden on DSM.

While National Grid's DIS is not unreasonable, it faces significant execution challenges. PA observes that had National Grid presented the range of forecasts that it had developed, as opposed to a single point estimate, it would have afforded its stakeholders alternative perspectives on both the timing and magnitude of need for the DIS components. Regardless of the design day forecast used, given the risks associated with the supply side solutions, it is imperative that the Incremental DSM programs reach scale and maturity as quickly as possible.

[5] Defined in the Report as the baseline demand forecast adjusted for energy efficiency, demand response, and heat electrification. For the purposes of this report, references to "Baseline DSM" reflect the DSM savings which are incorporated in the Adjusted Demand Forecast.

2 Introduction

The purpose of this report is to provide PA's findings following an independent review of National Grid's Natural Gas Long-Term Capacity Second Supplemental Report. This review, conducted for the Department, focused on evaluation of National Grid's load forecast and the mix of supply and demand options that National Grid identified to safely and reliably meet the long-term demand. National Grid has developed a plan, referred to as the DIS that recommends a mix of infrastructure investments and expansions in its energy efficiency and demand side management programs.

2.1 Scope of Work / Engagement and Timing

PA was tasked with the assessment of the content and conclusions contained in the Report. PA was specifically focused on the following workstreams:

- The reasonableness of the Companies' updated gas demand and supply forecasts, including the Companies' consideration of the potential impacts of climate policies on long-term gas demand;
- The status of the distributed infrastructure projects and non-infrastructure solutions;
- The Companies' presentation of additional options for addressing demand in the near/medium term under different scenarios, including the Companies' conclusions on the viability and risks of potential options; and
- Any other issues identified.

Since being engaged in July 2021, PA has observed public meetings hosted by the Department and by National Grid and reviewed feedback from customers and stakeholders related to the Report. PA's effort began in earnest in mid-July with a goal of completing delivery of this Report by September 10, 2021.

3 Key Issues and Observations

The following review and observations are based upon the Report, responses from National Grid to nearly 100 data requests, and over 20 interviews with various National Grid personnel and third-party consultants. Based upon this review, PA has concluded – subject to multiple caveats and concerns – that National Grid's outlook is reasonable. PA observed substantial areas of risk and uncertainty associated with each component of the supply / demand balance which may impact National Grid's ability to meet near term demand. This level of uncertainty coupled with limited capability to mitigate risk causes PA to question whether the DIS could be reprioritized, and whether National Grid could accelerate certain programs to minimize the potential impact associated with contingency supply options which entail long lead times, novel approaches, and their own substantial risk of approval and implementation. In summary, National Grid's DIS (including the proposed infrastructure projects) is a reasonable approach at this point in time given uncertainty regarding load growth and the efficacy of the DSM programs, assuming that avoiding moratorium risk is of critical importance to regulators and other stakeholders.

Support for the reasonableness of National Grid's plan can be summarized across each main component of the forecast:

- The load forecast appears high for certain customer segments but is reasonable compared with alternative scenarios. Since National Grid operates with zero supply contingency relative to Design Day conditions, given the inherent uncertainty in forecasts, assuming a higher load is understandable and appropriately conservative.

- The infrastructure supply options continue to be delayed and face a real risk of outright cancellation. Planning for these resources does presumably entail some opportunity cost, however doing so does not inhibit National Grid's ability to comply with anticipated future climate related laws and environmental goals. PA has not seen evidence that the contingency resources identified in the Report can reasonably be relied upon. PA would also expect that National Grid could conduct "real option" analysis of the current infrastructure options to determine when resources and strategies should be refocused on alternative program components.

- Many of the DSM programs are largely in the early stage of testing and customer uptake is unproven as well as the realized reductions in peak day demand. As such there is little to substantiate that DSM, in the near term, can serve as a backstop if any of the DIS infrastructure solutions do not come to fruition. PA understands that National Grid is multiple years away from validating program feasibility and savings estimates. Further, such programs are heavily dependent upon customer adoption and it is unclear whether National Grid's customers will enroll at a rapid enough pace to de-risk the near-term infrastructure enhancements. While PA is concerned about whether these programs can be relied upon to meet peak demand, more time, peer utility benchmarking data, third party studies, and bottom-up analysis would be required to appropriately validate such expectations. PA expects that these programs will be proven to hold substantial potential and that the targeted savings represent a modest number of customers, however it is the engagement and subsequent ramp up of these programs in the next few years which is the critical unknown.

While National Grid's DIS is not unreasonable, it faces significant execution challenges. PA observes that timing expectations on supply resources and a single point estimate of load deserve reconsideration and that the Incremental DSM programs and contingency supply options need fulsome development. Key issues related to the DIS that PA focused on and associated observations follow.

3.1 Key Issues:

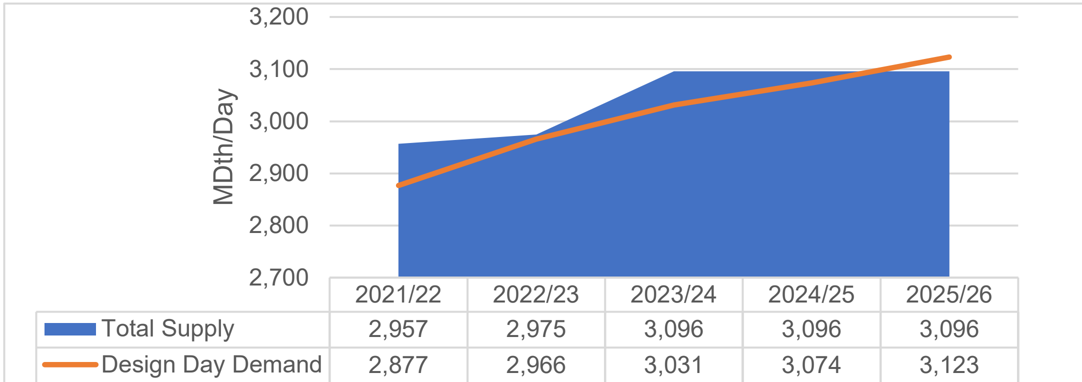
- **Supply Resource Sequencing vs. Load Growth:** As part of the above-mentioned optimization process, National Grid has stated that the DIS represents the least cost reliable resource portfolio. This strategy is based on a future which is reliant upon a combination of new gas delivery infrastructure and gas demand reduction. Irrespective of the cost and potential for stranded long-life assets under a net zero regulatory environment[6], National Grid's DIS relies on a combination of infrastructure and demand side management at its core. While the physical asset infrastructure has known capacity, it is by no means guaranteed to be implemented, and in fact carries substantial project development risk and potentially some operational risk. Perhaps the most substantial risk however is the indirect impact that an "infrastructure heavy" approach may have upon National Grid's near-term strategy. From PA's perspective, National Grid's approach to developing the DIS was to continue to pursue near term potentially viable infrastructure for additional supply and DSM programs to fill any shortfall caused by inability to execute the infrastructure plan. In the near term and based upon the programs identified by National Grid, it appears unlikely that Incremental DSM can be relied upon to displace or defer investment in the DIS supply projects, assuming the infrastructure can be completed ahead of when it is needed to meet the load forecast. Still, given the risks associated with developing new infrastructure, parallel planning efforts that include DSM provide the best opportunity to ensure customer demand can be reliably served. As illustrated below, when the additional CNG capacity (the "fifth CNG facility"), Iroquois Enhancement Compression project ("ExC"), the Greenpoint 13 & 14 vaporizers (the "Greenpoint Vaporizers") are completed on schedule, supply meets demand in 2024/25. At the other end of the spectrum when the major infrastructure projects (ExC and Greenpoint Vaporizers) are cancelled, supply may be sufficient to meet demand in 2022/23[7], but not thereafter. In order to achieve a similar supply/demand balance without ExC and the Greenpoint Vaporizers, Incremental DSM would need to reach nearly twice the level of currently planned (or assumed in National Grid's Adjusted Baseline demand forecast) DSM included in the DIS as shown in the third chart in Table 3-1 below. Note that in the charts below, the Design Day demand reflects National Grid's adjusted demand forecast, which does not include in the Incremental DSM components of the DIS (for the purpose of highlighting the magnitude and timing of the Incremental DSM necessary).

[6] Net Zero is illustrative here as it may represent a variety of different definitions. It is anticipated that National Grid will be required to contribute to the goals underlying the Climate Leadership and Community Protection Act.

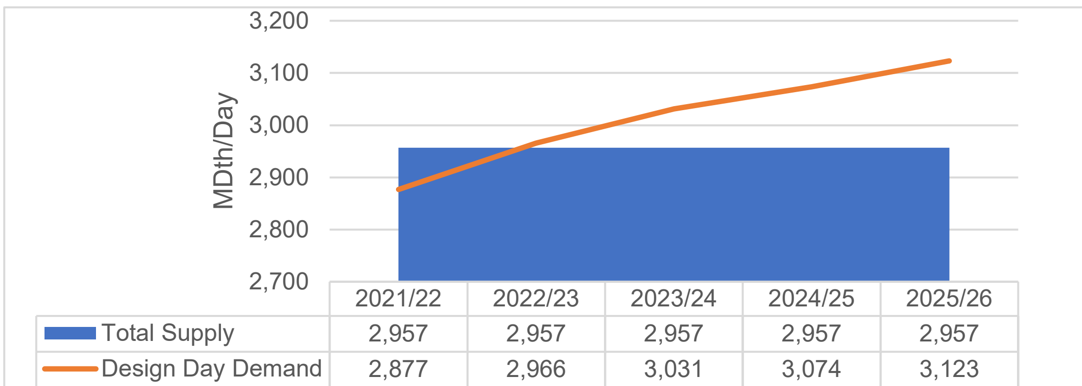
[7] Note: PA understands that National Grid believes it can manage a supply gap of up to 10 MDth/day. PA believes it is reasonable to assume a gap of that size would be manageable; the 2022/23 gap in this scenario is ~9 MDth/day, or approximately 0.3% of the Adjusted Baseline Demand Forecast. Otherwise, additional supply assets would be required to address that gap. PA notes that the fifth CNG facility fills the gap if it is in service by 2022/23.

Table 3-1: 5-Year Outlook of Supply & Demand Under Various Scenarios[8]

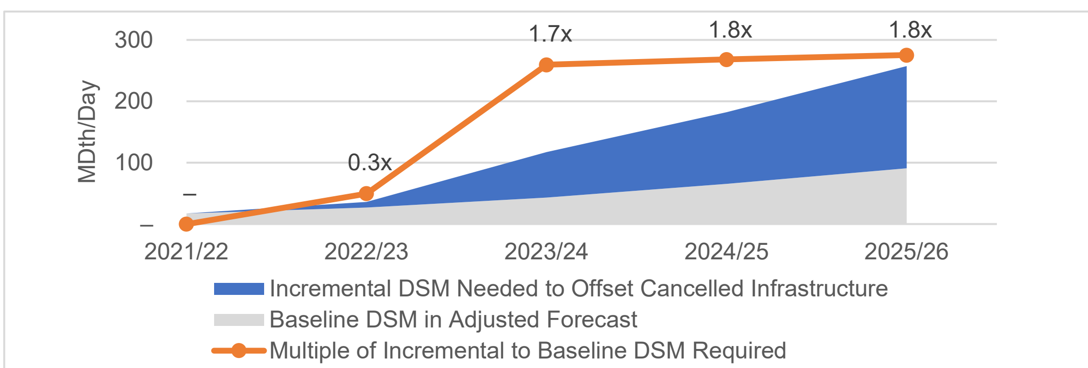
Supply / Demand with DIS Infrastructure[9]



Supply / Demand without DIS Infrastructure



Comparison of Baseline and Incremental DSM to Offset Supply Gap



1. **Supply Risks are Real:** National Grid has identified three primary near-term infrastructure investments as necessary under the DIS. All in, the likelihood that the three infrastructure investments are not operational without further delay or termination appears high. Under a scenario where only ExC is approved (the fifth CNG facility and the Greenpoint Vaporizers are cancelled), the

[8] Source: National Grid's forecast model provided to PA, filename: *Set - 1 DNY_TechnicalAnalysis_2021-06-30.*

[9] Assumes the earliest feasible in-service dates of 2022/23 for the fifth CNG facility and 2023/24 for both the Greenpoint Vaporizers and ExC.

ExC project on its own does not prevent a supply/demand gap. Further, this project is subject to highly uncertain federal approval. While the Greenpoint Vaporizers project is sufficient on its own to meet Grid's projected capacity needs in 2023/24, thereafter a demand gap persists in the absence of other supply. Finally, the additional CNG capacity is not a given; even if the fifth facility is permitted and constructed, there remain supply and transportation risks to any CNG facility's ability to provide Design Day supply. The contingency projects identified by National Grid in its Report are conceptual, are faced with long term and high-risk development timelines, and their successful implementation is anything but guaranteed. Finally, National Grid has ~250MDth/d of firm pipeline capacity whose contracts are set to expire, without a right of first refusal, in 2023 – not to mention the inherent risk of the availability of peaking supplies discussed below.

2. **DSM Programs have Uncertain Adoption and Savings Potential:** To date**,** components of the energy efficiency and demand response programs in the DIS are still in the development stage and / or not scaled up. National Grid's energy efficiency efforts have proven successful to date in achieving the state's New Efficiency: New York ("NE:NY") goals. And further efficiency savings are likely to be more resilient during severe cold weather conditions than demand response. While National Grid is continuing to evaluate how to increase energy efficiency and weatherization, there is meaningful uncertainty that adoption rates and the respective savings are able to meet targets. Outside of policy and other forces, the level of adoptions and continued participation required to meet near-term scale of proposed program savings is uncertain. Firm residential demand response and electrification efforts are early in deployment with limited Downstate New York specific data to de-risk the outlook. It is clear that DSM is a critical component of meeting demand; however, these programs appear to be at least one to two years from being mature enough to reduce the uncertainty of the targeted savings. The uncertainty of these Incremental DSM programs is reflected in the system-wide gas planning models developed between National Grid and Consolidated Edison Company of New York, Inc. ("Con Edison"). These models assume that no Incremental DSM measures will have been implemented by any given winter season; such a conservative approach is reasonable. That said, gas demand response in the US is relatively nascent compared to electric demand response. Electrification of heating equipment will require National Grid to establish clear strategies and plans in coordination with the regional electric utilities – coordination which is in progress but requires more time to mature. The current maturity level of National Grid's demand side programs suggests that incremental infrastructure will be necessary – at least in the near term and under National Grids' baseline demand forecast – to avoid a moratorium risk. In the longer term, a material shortfall in demand savings could place substantial stress on the rest of the system and implies that even more infrastructure support could be necessary.

3. **Load Growth as a Range:** The Report provides a single point estimate of load. While the forecast is characterized as the Adjusted Baseline, it is more than 1% higher in all years than National Grid's "high" estimate from the Long-Term Capacity Report published in May 2020[10]. Evaluating alternative load scenarios and the resources needed to deliver safe, reliable, low-cost supply would provide for the capacity to quantify trade-offs and risks. PA found that in certain segments of customer usage National Grid's forecast is materially higher than historical trends would indicate and that the overall load forecast is highly sensitive to small changes in assumptions about average customer usage. If future usage per customer for certain segments is more in line with historic trends, the resulting load is reduced so as to provide timing flexibility of the supply options while also de-stressing the allowable margin of error for DSM driven demand reduction without triggering moratorium.

[10] See Figure 2-2 of National Grid's Second Supplemental Report, Page 11.

4. **Climate Goals and the DIS:** PA's review did not evaluate whether the contemplated infrastructure investments are either consistent or inconsistent with New York's Climate Leadership and Community Protection Act ("CLCPA"). Abandoning efforts to complete new infrastructure would require that the DSM programs are rapidly accelerated, and that the traditional regulatory metrics used to determine whether certain costs are prudent for recovery would need to be reworked. In addition, customers would need to accept higher rates as the trade-off for increased DSM. Further, policymakers and customers would need to accept the risk of emergency curtailments which can have significant health and safety consequences, in the event that the Incremental DSM programs are unable to deliver the necessary peak demand reduction. Both paths (the DIS plan and a "DSM only" plan outlined above) hold meaningful risks. As discussed in Item 2 above, National Grid is in the early stages of ramping up the DSM programs. It is reasonable to expect that customers would respond to greater incentives to participate accelerating DSM programs. The challenge is determining to what extent larger incentives will increase participation, how those costs will be recovered and the willingness to accept the additional curtailment risk compared to pursuing the strategy put forward in the DIS.

5. **Near Term Moratorium Risk:** Given the above, under National Grid's current load forecast, the risk of a moratorium in the near term (the next 3-5 years) appears to be high based upon the following summary observations:

   - Timely permitting of the Greenpoint Vaporizers and ExC projects are generally out of National Grid's control and have already faced regulatory and other opposition
   - The fifth CNG facility, even if the facility is permitted, is not without supply delivery risk in peak demand conditions. While supply delivery risk would typically be synonymous with curtailment risk, it may be appropriate to consider such potential supply disruptions in the context of moratorium risk as well.
   - The contingency infrastructure projects are long lead-time solutions that remain conceptual at this time and are high risk, given the level of public opposition to other capital projects proposed by National Grid in recent years and the many associated permitting challenges that would be expected. Moreover, while perhaps technically feasible,[11] PA is not aware of the use of Liquified Natural Gas ("LNG") Barges as a source of peaking capacity at any natural gas utility in the United States. A Micro-LNG facility would also have to overcome challenges to trucking LNG supply through the City of New York.
   - Two of the three components (electrification and demand response) of National Grid's DSM strategy are in early development with high uncertainty of adoption and rate of growth.

If load growth does in fact fall in line closer to historical trends, the potential supply/demand gap narrows and provides for a lessening of both schedule and execution risk in the DIS plan. However, PA recognizes that relying on a lower load scenario to offset supply side challenges is a high-risk strategy. Quantifying moratorium risk in the near term should be considered vis-a-vis the timing of when National Grid develops its DSM relative to demand growth patterns.

3.2 Thematic Observations for National Grid Customers

- **Reliability vs. Cost:** National Grid's gas supply resources are planned and designed to be sufficient under a roughly "one-in-thirty-three year" peak winter event. Meeting this threshold

[11] PA did not assess the technical feasibility of any contingency project.

requires substantial investment in both system resiliency to avoid unplanned service disruptions as well as sufficient capacity to meet peak demand in very cold conditions. Planning for what is anticipated to be an uncommon event creates a natural tension between cost and reliability – optimizing for a balance between these two goals ultimately boils down to what level of reliability is reasonable to expect and how much ratepayers can reasonably be expected to pay for that reliability. Furthermore, an extreme event that results in turning off gas supply has the potential to create a serious public safety situation in instances of severe cold. Asking whether such reliability and safety margins are worth the cost is a reasonable question – making the optimization equation much more difficult to solve. This is perhaps the most important theme when considering whether certain projects are necessary and whether the load forecast reflects reasonable assumptions.

- **Safety vs. Cost:** The nature of natural gas and gas supply networks are such that restoration of service following an outage requires a methodical process that, in many cases, is much slower than what customers may be accustomed to for electricity service. Given that gas is predominantly used for heating and cooking, the ramifications of a prolonged outage on human health and safety can be substantially more dangerous than an equivalent electric outage. Determining the margin of safety that is acceptable is on one hand a matter of engineering and operational risk management, but on the other hand represents a difficult-to-quantify social cost. In the event of an emergency situation, curtailing large commercial customers may be done safely, however avoiding curtailment is an altogether better scenario than depending on curtailment to meet customer demand. At the point of curtailment, the margin of safety is too thin and the potential societal cost too high.

As long as residents of National Grid's KEDLI and KEDNY territories continue to use natural gas for heating, the traditional priorities of reliability and least cost create potential conflict with the broader societal and political goals of decarbonization. Meanwhile, the risk of a second moratorium or emergency curtailment action appears to be considerable at least for the next couple of years as DSM strategies mature, supply infrastructure options become clearer, the implications of environmental mandates are defined, and consumer preferences evolve.

4 Overview of National Grid's Load Forecast

The Report stated that the long-term load forecast reflects a slowing customer growth rate (declining from a 2008-2020 average of 0.6% to 0.4% average over the forecast period) and a declining usage per customer ("UPC") (declining from a 2008-2020 average of 1.8% to 0.8% average over the forecast period). However, due to the anticipated rebound in economic activity post-pandemic, the Design Day load is anticipated to increase by 3.0% in 2021/22 and 2022/23 and the overall adjusted load forecast is 1.3% higher than the forecast in National Grid's previous High Demand Scenario.

PA has four primary observations related to the 2021 load forecast used in the Report:

- National Grid presented its analysis and discussions pertaining to the DIS with reference to a single point estimate of load as opposed to a range of potential scenarios. While potentially simpler to reconcile the build-up to total demand, it also restricts the benefit of conducting sensitivity analysis when considering resource and demand reduction options. Further, PA observes that a single point estimate tends to indicate a false sense of precision and it may be more useful to assess whether there are margins on the positive and/or negative sides of the forecast which needs to be considered.
- While National Grid's overall forecasted load growth represents a decline against historical averages, it is important to evaluate not just the simple historical average, but the trend over time. A situation in which a demand-supply gap emerges one year later than anticipated may have material impact on moratorium risk, a load forecast based on the historical trends of key drivers provides an alternative view of likely outcomes.
- National Grid's load forecasting methodology involves analysis of the core components of demand – customer count and annual usage per customer – by customer segment for both service territories. An assessment of this approach highlights how elastic the load forecast is to changes in each variable. For example, moderate adjustments to Commercial and/or Multi-family customers' UPC rate in KEDNY and KEDLI has a material impact on the total load forecast. PA observes that in Section 4 of the Report, National Grid provides analysis of customer counts and UPC by customer segment, but not by region. A disaggregated analysis of UPCs suggested significant differences between historical trends and National Grid's outlook as presented in the Report.

Based upon our review, PA conducted further analysis of the projections.

4.1 Approach

PA's Load Forecast analysis began by developing projections[12] based on historical trends of Customers and UPCs for the three key customer segments – residential heat ("RH"), commercial ("COM") and multifamily ("MF") – across both KEDNY and KEDLI with the objective of comparing to National Grid's econometric forecast of the same variables in the Report.

- A comparison of PA's analysis of historical trends and National Grid's Baseline forecasts revealed that there were no significant differences as far as the customer counts were concerned across all segments.
- With respect to UPCs, PA's analysis of the trend for the RH segment in KEDNY indicated levels modestly lower than National Grid's Baseline forecast while the corresponding trend in KEDLI had a trajectory with values slightly higher than National Grid's forecast during the latter part of the

[12] The best fit specification was used based on a comparison of linear, logarithmic, and polynomial trends.

planning horizon. For both territories combined, this suggests a trend for RH UPC that is generally in line with the Baseline forecast.

- PA's analysis of the trends based on historical data for COM and MF UPCs in both service territories exhibited trajectories noticeably different from National Grid's respective Baseline forecasts. Therefore, PA's trend-based analysis rests on these two customer segments.

Based upon these observations, PA developed two alternative load forecasts: an extension of historical trends (the "Trend" forecast) and an average of National Grid's Adjusted Baseline and PA's Trend (the "Sensitivity" forecast).

4.2 Review of Design Day Conditions

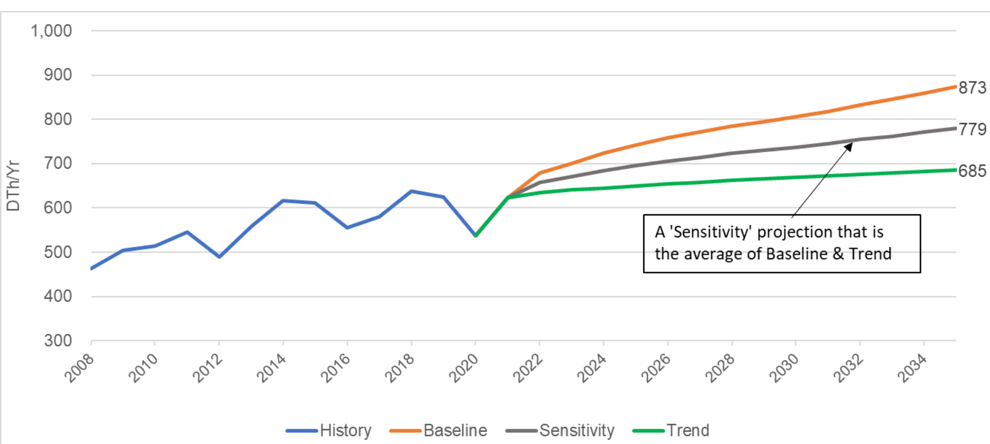
PA evaluated Marquette Energy Analytics' report on National Grid's Design Day conditions against common methods of quantifying and evaluating degree days. This report ultimately concluded that the design day parameters, which assumed an average daily temperature of 0-degrees Fahrenheit and a windspeed of 12 MPH, constituted a 1-in-33 year event, which was not an atypical time frame for a Design Day event when evaluated against other utilities. Upon review of the Marquette Report, PA found that the inclusion of wind speed likely results in a more sophisticated look at the factors that impact heating and that there were no obvious omissions or oversights inherent in the evaluation of the design day parameters.

4.3 Load Forecast Sensitivities

Recognizing that PA's analysis of COM and MF UPC historical trends deviate substantially from National Grid's Baseline forecasts, PA devised a "Sensitivity" projection which is the average of National Grid's Adjusted Baseline and the Trend in order to serve as a point of reference for sensitivity analysis. In conducting this sensitivity analysis, PA was made aware of the fact that National Grid routinely develops a range of econometric forecasts reflecting various economic scenarios. While these scenarios range both higher and lower than PA's sensitivity analysis, National Grid's Report is based upon a baseline scenario which is what PA focused its review upon.

Figure 4-1 below is an example of how PA's alternative projection were developed. Based on the historical data (shown in the blue curve) for KEDNY and KEDLI Commercial UPC over the 2008-21 period, the non-linear fitted Trend forecast (the green curve) appears considerably below National Grid's Baseline econometric forecast.[13]

Figure 4-1: DSNY Commercial Usage Per Customer Forecast Sensitivity

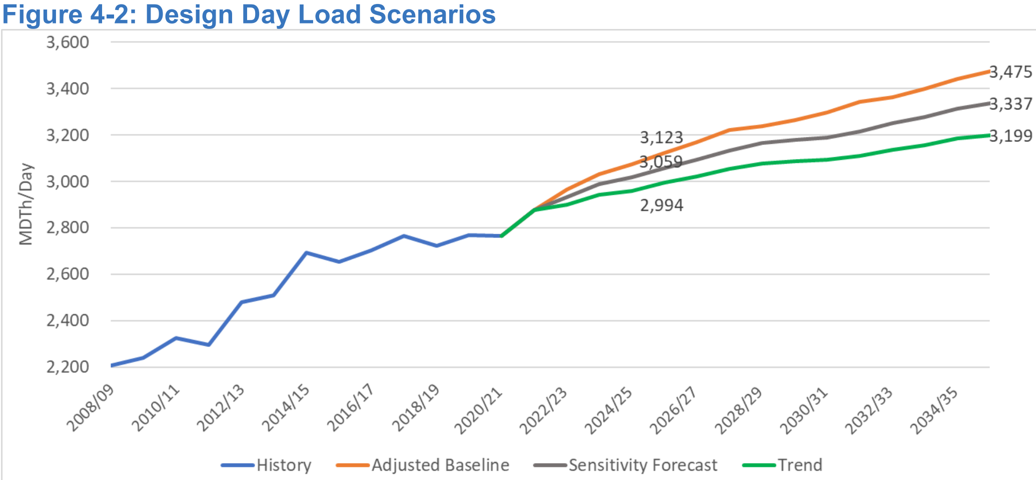


[13] Note: PA modified the Trend forecast such that the first year of the projection is identical to National Grid's Baseline forecast.

The resulting range of Design Day Usage forecasts allows for a scenario analysis reflecting alternative UPC trajectories with the underlying notion that gas-load forecasts are sensitive to relatively minor changes in assumptions regarding customer use patterns.

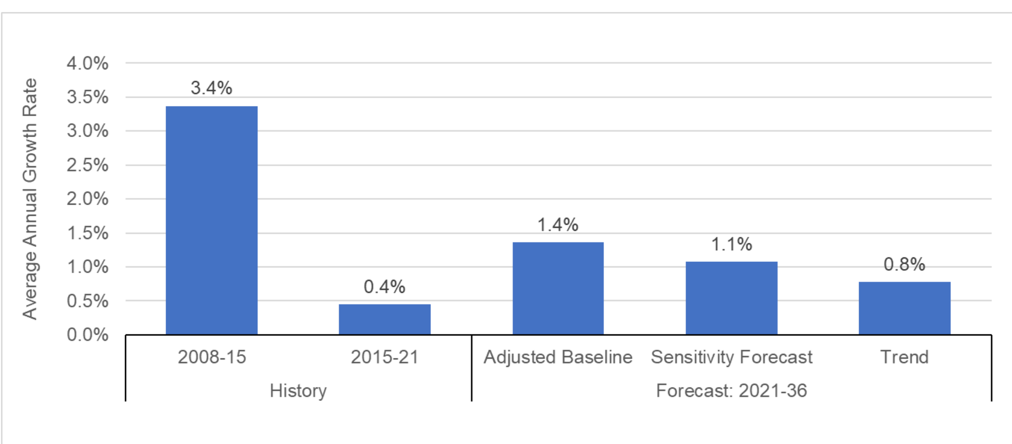
Figure 4-2 below compares National Grid's Adjusted Baseline with the two alternative load forecasts developed by PA. As mentioned above, the factor differentiating the alternative trajectories from the Baseline is the use of Sensitivity and Trend values of the COM and MF UPCs. Acknowledging that varying weather conditions explain the observed volatility, it is evident from historical data that even excluding the 2020/21 year due to Covid-related disruptions, there was a noticeable slowdown in load growth post-2015 – largely due to declining growth in UPC for the non-residential segments. The Sensitivity load forecast reflects non-residential UPC values approximately 10% below the forecasted levels of the Adjusted Baseline by 2035/36.

Figure 4-2: Design Day Load Scenarios



To illustrate the historical trend over time vs. the outlook, Figure 4-3 highlights the post-2015 drop in the annual growth rates in comparison to the implied growth rates in the Baseline and PA's scenario forecasts.[14] PA observes that given the continuing decline in gas load growth, the Sensitivity scenario (and even the Trend scenario) are reasonable alternatives reflecting modest adjustments to the non-residential UPCs. For comparison purposes in this report, PA's Sensitivity case is used as an alternative to National Grid's Adjusted Baseline forecast.

Figure 4-3: Design Day Load Average Growth Benchmarking



[14] National Grid developed alternative analyses of Design Day demand that project both lower and higher growth trajectories. PA's Sensitivity scenario is within the band of the National Grid Scenarios.

5 Supply Overview

Through the course of PA's review of National Grid's Report, PA evaluated National Grid's existing and projected supply stacks, the options available to National Grid in the DIS, and the Contingency projects that have been identified as potential alternatives to the DIS should one or more DIS components be delayed or denied.

5.1 Approach

The purpose of PA's supply analysis was to evaluate whether National Grid's outlook of proposed options as detailed in the Report is reasonable to meet the needs of its customers on a Design Day, and to identify aspects of the outlook which PA believes are at risk of not being approved or completed in a timely manner.

As stated in Section 2.8 of National Grid's Report:

> *In the near term, the distributed infrastructure components of the distributed infrastructure solution are the biggest components of the solution and are critically important to meeting gas demand over these next few winters as incremental DSM programs ramp up…such that no additional infrastructure projects beyond the LNG vaporization project and ExC project would be needed.*

PA has focused its supply side assessment on the benefits and risks associated with the Greenpoint Vaporizers and ExC, as well as National Grid's expectations of increasing CNG peaking capacity. Additionally, PA evaluated over 50 different hydraulic models of the New York Facilities System[15] simulating gas flows and system operating conditions and reflecting different combinations of supply assets in service under peak ("Design Hour[16]") conditions, as forecast for Winters 2021/22 through 2025/26.[17] Finally, PA assessed the infrastructure projects National Grid has identified as potential contingency alternatives to the Greenpoint Vaporizers and ExC. Beyond risks to the notable infrastructure projects, PA also evaluated contracting risk inherent in existing and prospective components of the supply stack.

5.2 Observations

PA developed the following observations about National Grid's Downstate New York supply resources and its ability to meet forecasted Design Day demand:

- **Firm pipeline capacity**: National Grid maintains several contracts which provide long-term, firm pipeline capacity with Transco, Tennessee Gas Pipeline ("TGP"), Iroquois Gas Transmission ("Iroquois"), and Texas Eastern Transmission ("TETCO"). It is safe to assume that the majority of this firm gas supply will be available throughout the forecast period considered in the Report, as National Grid retains a Right of First Refusal ("ROFR") for renewal upon expiration of the related contracts. Any risk to gas supply flowing under these contracts would be limited to unplanned disruptions or outages on the pipelines. National Grid's supply stack does however include some firm capacity for which it does not have a ROFR. These contracts are discussed below in more detail.

- **Short term peaking (and associated risks):** National Grid contracts for a portion of its natural gas capacity for only the winter months in anticipation of peak demand. Some of this capacity,

[15] The New York Facilities System is a network of natural gas transmission mains. See Appendix A for further detail.

[16] The peak hourly demand on a Design Day.

[17] National Grid has communicated to PA that if a certain modeling configuration fails to meet the forecasted Design Hour demand while maintaining minimum operating conditions National Grid has confirmed are required to provide reliable service, those modeling results are not provided. That being the case, PA cannot ascertain the degree to which any such models fail.

referred to as short-term peaking capacity, has been contracted for several years into the future. There is, and will be going forward, continuing risk that this type of capacity may not be available to National Grid, as other parties also have access to this same capacity and the amount that may be available can vary year to year.

- **Compressed natural gas ("CNG") facilities:** National Grid currently has in service four CNG facilities to support Design Day demand. Two sites on Long Island have been identified as viable candidates for a fifth facility, and both are under development in parallel.[18] National Grid's supply stack assumes the fifth facility is in service by winter 2022/23, however permitting risk still exists.
  - When a Design Day is forecast, significant coordination is required to transport fully-loaded CNG trailers to the facilities for injection during the morning peak hours, and then refill and redeliver the supply in time for the supply to be available during the evening peak hours. Future contracting risk may evolve as the market for available CNG is itself limited and as more natural gas utilities compete for CNG supplies.

- **Existing LNG:** Two LNG facilities – Greenpoint and Holtsville – are used to provide natural gas to the system during periods of peak usage, up to and including a Design Day demand. Greenpoint is the facility at which National Grid is proposing to build Vaporizers 13/14 as part of the Distributed Infrastructure Solution. These two facilities are critical components of the supply stack on a Design Day, currently providing more than 13% of National Grid's design day capacity. Proactive maintenance of these facilities will continue to be critically important in order to ensure National Grid has the available capacity to meet Design Day demands.[19]

- **Existing Renewable Natural Gas ("RNG")[20]:** Beginning in 2022, National Grid will source RNG from the Newtown Creek wastewater facility. RNG is natural gas that is sourced from the natural breakdown of organic material. The Newtown Creek facility converts decaying organic material found in wastewater into a natural gas product that can be used in National Grid's gas distribution system. With respect to Design Day demand on the system, the capacity which can be attributed to the Newtown Creek facility is very small (0.03% of total design day capacity).

Other observations regarding long-term planning:

- The hydraulic models of the New York Facilities System provided to PA by National Grid reflect forecasted design hour demand exclusive of Incremental demand side measures that are included as part of the DIS. To the extent those measures successfully reduce demand over time, the system operating conditions observed in the modeling results would be expected to improve; PA cannot quantify those improvements.

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[18] Only one of the two sites (Hicksville or Farmingdale) would proceed to construction. National Grid has assumed in its supply forecast that Farmingdale (which would have twice the capacity of Hicksville) is the ultimate location.

[19] PA notes the agreement in National Grid's recently completed rate cases for National Grid to conduct further studies for the upgrade of its Greenpoint and Holtsville facilities, with particular focus on LNG storage tanks and related systems. With the tanks having been in service for approximately 50 years, developing a plan that allows them to be inspected and modernized is not only appropriate, but necessary. It is possible that the tanks and related facilities will perform as expected until such time as they can be evaluated, however it is reasonable to assume that a risk of failure increases each year that goes by without this work being completed. The loss of a single tank, if that were to occur, may or may not render the entire facility out of service for a winter season but at the very least would adversely impact the available Design Day capacity.

[20] The use of the term "RNG" is used for convenience and is not intended to imply consideration of the environmental attributes or benefits of such gas.

- Based on PA's review of supply and demand forecasts as well as models of Design Hour gas flows on the distribution system provided by National Grid, National Grid is, or would be, positioned to serve Design Day demand in the coming winter seasons with the following supply assets[21]:
  - Only 3 of the 4 CNG facilities currently in service may be needed at the Design Hour for the winter of 2021/22, assuming existing infrastructure and supply assets.
  - All four existing CNG facilities are required for the winter of 2022/23 with existing infrastructure, assuming adequate supply assets have been procured.
- For winter 2023/24, in addition to the existing infrastructure and supply assets, EITHER the Greenpoint Vaporizers OR a fifth CNG facility must be in service. Given the continuing uncertainty around approval of the vaporizers, National Grid must pursue the fifth CNG site in earnest – or face a risk of a moratorium on new service connections.
- For winter 2024/25, in addition to the existing infrastructure and supply assets, the fifth CNG facility and EITHER the Greenpoint Vaporizers OR ExC must be in service. If both Greenpoint AND ExC are in service, Design Day demand can be reliably served with only four CNG facilities operating.[22]
- For winter 2025/26, all infrastructure included in the DIS – the Greenpoint Vaporizers, ExC, the fifth CNG facility – must be in service in order to serve Design Day demand.

Table 5-1 summarizes the minimum infrastructure that must be in service for the coming winter seasons, based on the series of hydraulic models of the New York Facilities System provided by National Grid and reviewed by PA.

Table 5-1: Minimum Infrastructure Required to Serve Design Day Demand[23]

Winter Season	Existing Infrastructure	CNG 5	Vaporizers 13 & 14	ExC
2021/22	✓			
2022/23	✓*			
2023/24	✓	✓		
	✓		✓	
2024/25	✓	✓	✓	
	✓[24]	✓[24]		✓[24]
	✓		✓	✓
2025/26	✓	✓	✓	✓

*As noted previously, adequate supply must be procured. Where there is more than one "minimum" infrastructure option that satisfies Design Hour criteria, each option is included.

[21] Upon review of the provisions of the New York Facilities Agreement (see Appendix A) and based on information included in the gas flow models, it appears that certain Design Hour gas flows from Con Edison to National Grid may exceed the maximum flows established in that Agreement. Additional investigation would be required to confirm, and models would have to be revised and re-evaluated (as applicable) to ensure PA's observations regarding the capabilities of the physical system would be unchanged. A given system configuration may well be viable overall even where certain hourly flows exceed limits established in the Agreement, however doing so may give rise to operational risks and concerns that are not apparent in the models.

[22] In the event that the two DIS facilities that are in service are the fifth CNG facility and ExC, then the TGP expansion to provide additional capacity to Con Edison must also be in service to maintain reliable pipeline system pressures on a design day in winter 2024/25. The TGP expansion is currently pending before FERC.

[23] Source: Hydraulic modeling results provided by National Grid to PA.

[24] In this scenario, the TGP expansion for Con Edison must also be in service.

DIS Infrastructure Timing

Given the risk of permitting delays on completing any of the DIS infrastructure projects, PA attempted to ascertain how the timing of project approvals is expected to impact completion dates. Recognizing the potential for seasonal construction limitations, PA asked National Grid to identify permitting deadlines associated with being able to complete the projects prior to particular winter seasons. Table 5-2 summarizes those deadlines and confirms that, despite delays to date, time remains for the projects to be permitted and completed prior to when they are expected to be required on a Design Day.

Table 5-2: Permitting Deadlines Associated with Winter Season Availability

	In-Service by Winter	Permit Deadline
Greenpoint Vaporizers	2022/23	10/1/2021[25]
	2023/24	9/1/2022
	2024/25	9/1/2023
ExC	2022/23	n/a
	2023/24	Q1 2022[26]
	2024/25	Q1 2023
	2025/26	Q1 2024
Fifth CNG Facility	2022/23	9/30/2022[27]

Observations Regarding Contingency Projects

Few details surrounding the contingency projects identified in the Report were provided to PA. National Grid considers these projects "conceptual" at the time of our review. Based on PA's review of the projected timelines to implement any of the contingency solutions, as well as the lack of any detailed planning and engineering conducted to date, it appears reasonable to assume that the earliest any of these projects could be placed in service would be just prior to winter 2026/27 – and even later if the projects are met with permitting challenges and other public opposition similar to the level National Grid has experienced with other infrastructure projects (e.g., the Greenpoint Vaporizers and MRI). Delayed completion of contingency projects places even more burden on demand side initiatives which, as acknowledged by National Grid, are an ambitious ramp-up of current programs even at the level included in the DIS. The contingency projects have not been developed in parallel with the DIS infrastructure projects. To date, National Grid has instead taken the approach to delay commencement of any detailed planning until more is known about the permitting outcomes of the DIS projects. The absence of any substantive planning for any of the contingency projects at this point in time exacerbates the risk that a Design Day supply/demand gap would occur in the event of a failure of one or more major DIS project.

5.3 Supply Risk Assessment:

PA has identified contracting risks that could materially impact the availability of natural gas capacity within the next several years. This risk is present in several components of the supply stack:

[25] National Grid highlighted in its Third Supplemental Report filed on August 25, 2021 that it had agreed to New York State DEC's request to extend the final permit decision to November 4, 2021; that being the case, an in-service date of winter 2022/23 is unlikely.
[26] National Grid highlighted in its Third Supplemental Report filed on August 25, 2021 FERC's announcement that it will prepare a supplemental Environmental Impact Statement ("EIS") for the project; the EIS must be completed by December 2, 2021. This likely translates to a FERC decision on the project no sooner than Q1 2022. As noted elsewhere in this report, state level permits are also required. This anticipated timing likely places an in-service date of winter 2023/24 at risk.
[27] PA infers from National Grid's response that approvals beyond September 30, 2021 would push the availability of the fifth CNG facility to winter 2023/24.

- **Existing Long-term Firm Transportation Contracts:** While the majority of National Grid's firm gas contracts have a contractual Right of First Refusal ("ROFR"), 346 MDth/d of this contracted capacity is currently contracted at discounted or negotiated rates and lacks a ROFR. Of this volume, three contracts representing 246 MDth/d expire in 2023. National Grid has indicated its intent to extend these agreements beyond their current expiration dates provided the load forecast continues to justify their need as part of the capacity portfolio.
  - National Grid's supply stack assumptions reflected in the Report do include this capacity through winter 2035/36. This may imply the absence of risk in that capacity being available throughout the forecast period. In the absence of a ROFR, that is not necessarily the case. At the very least, it is possible that National Gridmay be unable to extend these contracts at the rates it is currently paying and may have to pay substantially higher rates.
- **Operational Risk and Contingency:** Some degree of risk exists in the normal operation of pipeline infrastructure. Should a compressor or other piece of infrastructure fall offline during a design day event, potentially significant volumes of long-term firm contracted supply may not materialize. In a scenario where supply only narrowly outpaces design day demand, the implications of such unplanned downtime become magnified.
- **Short Term Peaking Capacity:** National Grid has identified approximately 58 MDth/d of short-term peaking capacity currently in the supply stack that is expected to be available for contracting indefinitely, but for which no ROFR exists. As National Gridstated in the Report, their ability to re-contract for these volumes is not guaranteed.
- **Cogeneration Peaking Capacity:** Of National Grid's existing 65 MDth/d of cogeneration natural gas peaking capacity, a contract representing approximately 25 MDth/d of that capacity is up for renewal in 2022, with another approximately 10 MDth/d up for renewal in 2025. In both cases, there is no guarantee that there will be an extension of the existing contracts.
- **CNG Compression Capacity:** As it pursues the development of a fifth CNG site to supplement its Design Day capacity, National Grid has noted that the available market for CNG supply is becoming more constrained as increasing numbers of natural gas utilities are seeking to incorporate CNG supply into their own portfolios. These constraints, in tandem with National Grid's process for contracting for CNG supplies on a year-to-year basis, places security of that supply at some risk each year.

5.4 Infrastructure Assessment

PA evaluated each of the potential incremental infrastructure projects included as part of the DIS on the basis of each project's ability to offset the supply/demand gap at particular points in time.

- PA considered the likelihood and associated timing of project approval, including the risks of permitting delays and/or denial and the related impact on National Grid's ability to reliably serve Design Day demand.
- PA did not consider the relative costs of the projects, inasmuch as the projects fall into one of two categories: either they are positioned to be in service within the next three years and are not presented as alternatives to one another (Greenpoint Vaporizers, ExC and the fifth CNG site), or they are conceptual alternatives to the projects included in the first category and are not expected to be available until winter 2025/26 at the earliest given that no detailed planning has begun.
- Additionally, PA did not validate the technical capabilities of the projects beyond assessing gas flow models that demonstrated the level of supply provided; rather, PA assumed that the projects (if constructed) would provide the level of Design Day capacity identified by National Grid.

The risks associated with securing the necessary approvals for the Greenpoint Vaporizers require that National Grid pursue completion of a fifth CNG facility in earnest. While National Grid has demonstrated its ability to design and deliver these types of projects, PA anticipates that National Grid may face permitting and/or community relations challenges in successfully completing another facility. As noted above, it is imperative that the fifth CNG facility be available by winter 2023/24 in the event the vaporizers are either denied, or further delayed.

Beyond permitting risk, projects such as the Greenpoint Vaporizers also carry a level of execution risk. National Grid has indicated a construction timeline of approximately one year to complete the project once it receives all required approvals. While PA cannot cite specific risks that can be attributed to National Grid, it remains possible that with projects of such size and scale, delays due to equipment and material availability, skilled labor availability, and even inclement construction weather can all impact the construction timeline.

ExC also faces permitting risks; chief among them is securing approval from FERC. Having announced in late May that it will prepare a full Environmental Impact Statement ("EIS") for the project, FERC's procedural schedule calls for the final EIS to be issued on November 12, 2021, with a final decision to be rendered on or before February 9, 2022. Permits are also required at the state level in New York and Connecticut, and those agencies are expected to act only after FERC issues its decision to approve the project. While PA is not aware of any concrete evidence that there is a risk of timely execution of the project (if approved), it is likely that Iroquois will only make certain commitments related to material, equipment, and construction labor after the project is fully approved. Collectively, these approval risks could impact the date by which the project can be placed in-service.

6 Demand Side Management

PA evaluated the reasonableness, uncertainties, and variables related to National Grid's portfolio of demand side management programs. The programs that PA focused on for the purpose of this review included energy efficiency ("EE"), demand response ("DR"), and electrification ("ELEC"). National Grid views measures as either existing programs included within the Adjusted Baseline demand forecast, Baseline, or envisioned savings required to meet a supply/demand gap, Incremental. As discussed in the Report, there are various permutations of each DSM program related to the KEDLI and KEDNY service territories, from Residential to Commercial and Industrial ("C&I") customers, as well as programs which are already deployed and programs which are in varying phases of development.

Whereas the infrastructure supply options have known operating and capacity parameters, the DSM programs are subject to a variety of technical, environmental, behavioral (e.g., customer participation and compliance), and economic drivers. Further, natural gas demand management programs are less common and have received less examination at scale across the US compared to the decades of experience and field validation of measures utilized in the power sector. As such, PA's approach to evaluating the reasonableness of the DSM outlook was to evaluate historic data available from National Grid's programs and compare such data to market potential studies and peer utility benchmarks. PA placed an emphasis on key variables and considered the operational and execution risks associated with each in context of moratorium risk.

6.1 DSM Program Considerations

As stated in Section 2.8 of the Report:

> *The Distributed Infrastructure Solution includes no expansions of gas supply capacity after 2024/2025[28] and relies on incremental DSM components to offset all projected Design Day gas demand growth after 2027/2028.*

National Grid is in early stages of ramping up DSM plans and has conducted this process in a manner typical of a regulated utility – developing a market study, designing and executing a pilot, studying the results, and scaling a program to more customers over time. This approach is defensible under the current environment where cost, reliability, and safety are the optimization parameters. Under a scenario where climate impact becomes at least as important as cost, reliability and safety, such a multi-year scaling approach could theoretically be accelerated, and greater demand savings pursued. However, this carries its own set of risks and increased costs. It also requires changes to the traditional view that expenditures must be cost effective under the current construct of the applicable cost / benefit test. It is similarly likely such a scenario requires considerations of new, and perhaps innovative, rate design. To illustrate a potential acceleration scenario, under PA's sensitivity load forecast and the DIS, energy efficiency may be accelerated to avoid a supply gap through 2025/26 but will require incentive levels that result in programs with a near zero benefit to cost ratio ("BCR").

National Grid's DSM programs, both those currently being executed and those facing multiple years of ramp up before maturity, will incur monetary and non-monetary costs. Absent regulatory directive and a clear social mandate, taking on the additional cost and risk associated with greater reliance on DSM without new infrastructure is unlikely a reasonable strategy to achieve low cost, reliable, and safe service. However, National Grid would be best served to evaluate how long is reasonable to wait on permitting decisions for

[28] PA's note: Except to the extent one or more contingency projects would be required in the absence of the Greenpoint Vaporizers, ExC, or the fifth CNG facility.

the Greenpoint Vaporizers and ExC before initiating DSM acceleration, else it risks both a lack of supply and a lack of time.

6.1.1 Energy Efficiency

Energy efficiency programs employ technologies and products aimed to help consumers use less energy, during peak and off-peak periods, while also reducing emissions. Natural gas energy efficiency programs typically encourage building envelope and insulation improvements, efficient equipment, and efficient appliances via financial incentives to engage participation. Savings are also obtained through marketing-driven efforts, also described as behavioral programs.

PA assessed the achievable energy efficiency savings, also defined as the reasonably achievable portion of technical or economic savings potential from a program and customer level perspective. In other words, total program and customer level savings anticipated to occur in response to proposed programs and incentives. PA evaluated information provided by National Grid, coupled with PA's knowledge of programs in other states and countries, third party studies, and other benchmarking findings of other US gas utilities.

KEDLI and KEDNY residential and multi-family customers provide the greatest potential for peak day savings, due to the number of residential customers and their heating usage, especially multi-family and low-income single-family buildings, according to the Downstate New York Gas Measure and Market Evaluation[29] prepared at the request of National Grid. Similar conclusions are made by another third-party study[30] completed for New York State Energy Research and Development Authority ("NYSERDA") including the following notable natural gas energy efficiency potential conclusions:

1. Due to low natural gas avoided costs, natural gas economic potential is observed at approximately 53% of technical potential.
2. Natural gas energy efficiency economic potential mainly arises within retrofit measures.
    - Key retrofit energy efficiency measures included energy management systems, air sealing, smart thermostatic radiator enclosures, and boiler stack economizers represent approximately 57% of the total economic natural gas efficiency potential, on a combined basis.
    - Notwithstanding the substantial technical potential of replacing multi-family natural gas forced-air furnaces and boilers with more efficient equipment, low natural gas costs render most space heating equipment replacements non-economic. Retrofits of inefficient natural gas boilers, furnaces, and water heaters represent 9% of the total 10-year economic potential.
    - Hot water improvements represent substantial cost-effective savings potential within multi-family buildings, representing approximately 17% of natural gas economic potential evaluated.
3. Building envelope (also referred to as building shell) improvements embody significant technical potential and account for approximately 26% of natural gas technical potential and 11% of the natural gas economic potential.

PA finds that despite substantial natural gas energy efficiency savings technical potential, low-cost natural gas reduces the economic potential. As a result, achievable energy efficiency savings potential is limited without the inclusion of social cost of carbon or other metrics to create additional financial incentives to induce participation. Behavioral savings are less likely to occur on a persistent basis and the differentiation

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[29] Source: National Grid. *Downstate New York Gas Measure and Market Evaluation 2019-2028*. Prepared by DNV-GL, December 2020.

[30] Source: NYSERDA. *Assessment of Energy Efficiency Potential in New York State Multifamily Buildings*. Prepared by CADMUS, June 2021.

of persistent vs. behavioral EE requires consideration, in terms of savings potential and cost effectiveness. PA also finds it is reasonable to assume that specific programs and incentives are needed to support continued and incremental energy efficiency savings within the KEDNY and KENDLI gas service territories. However, given the industry-wide immaturity of natural gas DSM, coupled with the EE program magnitude anticipated by National Grid, uncertainty of achievable savings remains a concern.

6.1.2 Demand Response

National Grid's DR programs aim to reduce peak demand during system emergencies, while also improving system reliability. In other words, DR programs serve as effective tools to alleviate gas pipeline capacity issues often occurring during peak hours/days. DR programs are typically classified as Firm or Non-Firm. Non-Firm entails incentives for customers with Non-Firm service, sometimes targeting customers to maintain dual-fuel equipment when peak load shedding is needed. Firm DR offerings incentivize peak hour/day savings across C&I, multifamily ("MF") and residential customers. Given the limited number of residential natural-gas end uses (space-heating, water-heating, cooking, and appliances) and the critical nature of space-heating, achievable residential gas demand response savings potential is limited.

Typically, DR programs are considered to fall within several forms: Direct Load Control ("DLC") of equipment (typically space heating/water heating for residential customers) via various tools such as DLC smart thermostats and appliance devices, price/incentive-based options including Non-Firm customer load shedding, and behavioral response. As a result, DR program savings are driven by several key variables:

- Customer enrolment,
- Peak hour savings by customer and number of hours per event,
- Reliability factor – capturing the impact of event participants and the extent of their savings, and
- Snapback factor – for some programs

National Grid offers and anticipates expansion of Firm Residential Bring Your Own Thermostat ("BYOT")[31], Firm Residential Behavioral[32], Commercial & Industrial and Multi-Family Firm Daily DR[33], and Peak Period DR programs, as well as Non-Firm/Temperature Controlled service. Firm measures advancing from pilot stage are still early in development, appearing approximately one to two years from the maturity needed to reduce savings uncertainties. Further hampering maturity, 2020/21 pilot results are overshadowed by limited sample sizes, coupled with mild weather test events. Despite the limitations, PA found 2020/21 test event net reductions in alignment with third party conservative DR and moderately cold scenario potential. Additionally, Daily DR (for C&I and MF customers) exceeded the 2020/21 savings enrolment goal, but the BYOT DR program (for residential customers) fell 11% short of the enrollment participant goal.

Unique to Demand Response is the essential measurement of load reductions/load shifting, often requiring customer meter and equipment (e.g. DLC devices, dual fuel equipment) upgrades. Devices such as smart thermostats are increasingly popular, driving potential customer adoption rates but also introduce privacy and security risks. While customers can take additional measures to address these concerns, some may avoid devices altogether. Further, National Grid identifies limitations in meter deployment impacting successful metering of enrolled participants. PA agrees with this assessment and finds customer population limitation uncertainties (e.g. limited service territories, BYOT device data collection and customer privacy restrictions or concerns) contribute to overall DR program uncertainty. PA finds BYOT and Daily Peak program one-time metering/deployment costs diminish one-year BCRs, as reflected within the 2020/21 pilot results. Given the measure deployment risks previously described, it is possible future deployment costs will

[31] Program utilizes Wi-Fi connected thermostats to remotely lower temperature set points and shift peak hour gas loads on event days.
[32] A non-incentivized program which uses e-mail messaging to notify customers of impending cold weather and suggests methods to lower gas consumption during peak hours.
[33] Program incentivizes firm service customers capable of reducing peak day gas loads over a 6 or 8-hour period on event days.

further impact program BCRs. However, hourly measurement/AMI technology enlists a multitude of benefits beyond DSM (allowing the customer to view and manage consumption) such as providing higher reliability and more accurate billing. PA finds winter season natural gas sector Demand Response programs, particularly residential, exist at levels where potential magnitude of savings is not well understood. Metering and measurement risks combined with the magnitude of KEDNY and KEDLI participation growth, at untested Design Day conditions contribute to the overall uncertainty around whether savings may fall short of targets.

6.1.3 Electrification

Electrification programs aim to address supply side constraints and decarbonization goals by encouraging customers to substitute electricity for natural gas for space and water heating and/or other appliances. Substitution can be done via retrofits, but it is typically more cost effective at the end of the equipment's useful life. Electrification of natural gas presents unique challenges, including equipment cost and low natural gas prices which create lower operating costs. Improvements in heat pump technology, with respect to performance in cold climates, increases the potential for electrification savings but, customer adoption barriers remain especially given customer perceptions and awareness. Successful programs provide customers with the education and financial incentives necessary to persuade participation. Peer benchmarking shows bundling of various DSM offerings (such as EE and ELEC) increases potential. While dual-fuel utilities, such as Con Edison, operate conversion programs, electrification programs beyond dual-fuel service territories are just beginning.

PA assessed the reasonableness of the proposed program sizes by assuming an average appliance life of 20 years to approximate potential annual appliance electrification rates. National Grid assumes Baseline Electrification participants are largely driven by the impact of NE:NY heat pump programs, given service territory overlaps. Proposed assumptions reflect approximately 4% residential heating and multifamily appliances switch to electric while C&I switches at a higher rate of approximately 6% in mid 2020s, increasing to approximately 13% in mid 2030s. PA utilised the NYC Pathways Low Carbon Fuels scenario as a benchmark to determine whether National Grid's proposed Baseline Electrification rates are aligned with this scenario. PA also determined Incremental Heat Electrification and NPAs solutions reflect significantly higher customer adoptions of heat electrification than modelled in the NYC Pathways Low Carbon Fuels scenario. Substantial uncertainties influence the success of electrification such as organic and incentivized customer adoption rates, time required to scale program, cost-effectiveness of coordination with electric distribution companies ("EDCs"), and the economics of lower priced natural gas and finally unknown cost/benefit as marginal customers are enrolled. The success of Baseline and Incremental Electrification Programs will hinge on close coordination and aligned strategies between National Grid, EDCs, and regional power providers as well as substantial financial incentives.

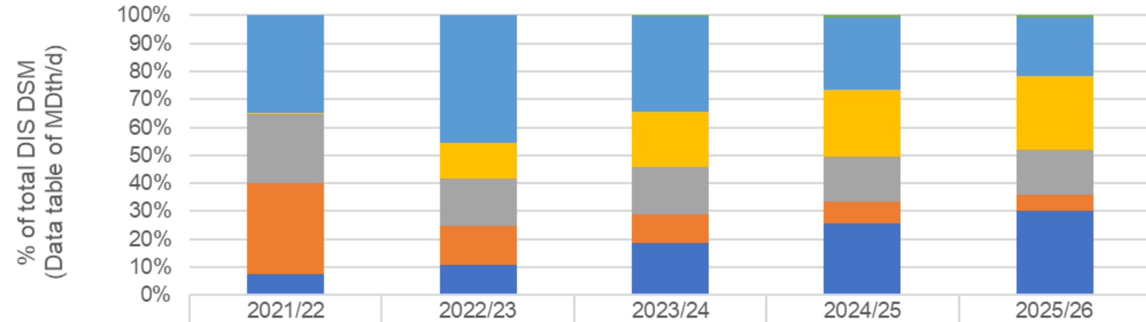
6.2 Approach and Observations

PA evaluated each component of the DSM outlook, with an emphasis on the key variables:

- Customer participation or enrolment rates
- Annual savings per customer

PA assessed information provided by National Grid, coupled with PA's knowledge of programs in other states and countries, third party studies, and benchmarking findings of other US gas utilities. To the extent possible PA evaluated granular variables for each program including but not limited to year-over-year participation and enrolment rates, appliance replacement rates, net savings potential including reliability, snapback, and event hours. Key historical and projected data was used to gauge proposed savings performance against known targets such as NE:NY goals, NY Heat Pump Adoption and stipulations included within the recently approved Joint Proposal.

Figure 6-1: Contribution of DSM Components

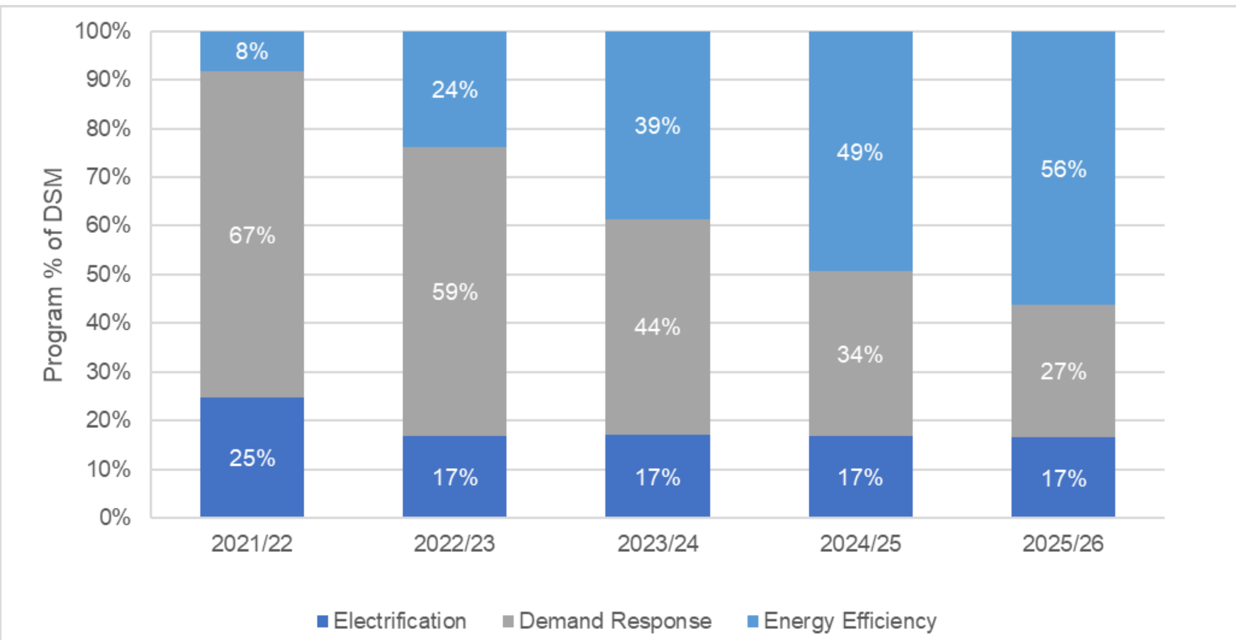


	2021/22	2022/23	2023/24	2024/25	2025/26
ELEC (Incremental)	–	–	0.1	0.6	1.4
DR (Incremental)	9.5	29.6	32.0	34.4	36.7
EE (Incremental)	0.1	8.4	18.8	31.3	46.1
ELEC (Baseline)	6.7	10.9	16.0	21.5	27.7
DR (Baseline)	8.7	9.2	9.6	10.1	10.6
EE (Baseline)	2.1	7.1	17.4	33.7	52.4

EE (Baseline) DR (Baseline) ELEC (Baseline) EE (Incremental) DR (Incremental) ELEC (Incremental)

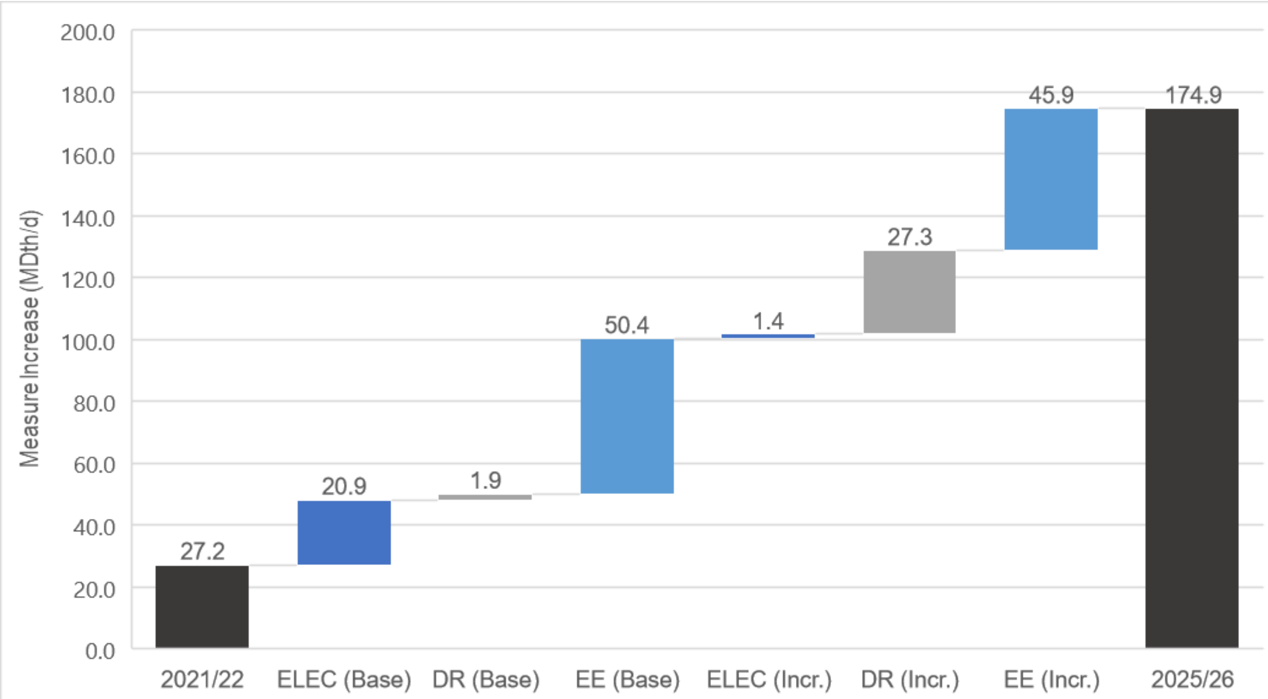
As presented above in Figure 6-1, 2021/22 season savings are primarily driven by Baseline measures (65%). However substantial Incremental DSM growth in subsequent years reduces Baseline measures share of total DSM by the 2025/26 season. This is primarily driven by substantial ramp-up of Incremental DR and EE measures. From a total program measure perspective, DR represents the material share of 2021/22 season savings. Substantial Incremental DSM growth, reduces the DR share of total DSM measures by 2025/26, as presented within Figure 6-2, summarizing combined DSM programs percent contributions below.

Figure 6-2: Percent Contribution of DSM Programs (Baseline and Incremental)



As discussed earlier, National Grid is in early stages of ramping up DSM and Figure 6-3 below presents increases within respective DSM components from the 2021/22 to 2025/26 season. To achieve 2025/26 DSM savings, substantial customer participation and savings increases within Energy Efficiency (both Baseline and Incremental), Incremental Demand Response and Baseline Electrification are required.

Figure 6-3: DSM Component Increases 2021/22 through 2025/26



The following tables provide a summary of PA's evaluation and observations related to each DSM component.

Energy Efficiency	Baseline
2021/22 Goal	2.1 MDth / day
Evaluation	• To date, EE goals under NE:NY have been achieved • Compared to a third-party market potential study for EE in the DNY region, pro-rated 5-year outlook reflects the goal is achievable with "headroom" for further incentives to bolster adoption (subject to the considerations of cost/benefit and other tradeoffs referenced above) • Number of customers to be engaged in EE program represents less than 1% per annum (market saturation is not a risk)
Observations	• Determination and differentiation of persistent vs. behavioral EE needs to be evaluated, in terms of savings potential and cost effectiveness • Achievement of recently approved Joint Proposal NE:NY savings goal stipulation is likely • As a more mature National Grid DSM program, energy efficiency has reasonable, achievable potential to help mitigate Design Day gap
Assessment	• Potential headroom for further incentives to bolster adoption over the near-term. However, such increases are subject to determining how larger incentives will increase participation and how the costs will be recovered.[34]

[34] PA explored the potential for accelerated DSM to avoid near term infrastructure investment while also applying a cost effectiveness view via Total Resource Cost ("TRC") measure by completing a sensitivity on the most mature program, EE. PA utilized DNV GL Market Potential study, provided by National Grid, to assess potential for savings above and beyond proposed Baseline Non-Behavioral and DIS Weatherization EE programs. PA found there is potential from an unconstrained view (assume all customers are adopted, high incentives and TRC below 1 is acceptable). However, this sensitivity also highlights that accelerated

Energy Efficiency	Incremental
2021/22 Goal	0.1 MDth / day
Evaluation	• Incremental EE reflective of additional savings from weatherization and energy efficient connection programs • Use of aerial thermal imagery survey to identify “high value” customers and encourage participation • Compared to a third-party market potential study for EE in the DNY region, pro-rated 5-year outlook reflects “headroom” for further incentives to bolster adoption • Preliminary IDD filing presents reasonable 5-year program cost effectiveness at 2.0 BCR[35], further indicating “headroom” for growth
Observations & Concerns	• On a combined basis, EE aligns with best practices including partnering and bundling of EE offerings, direct install and collaboration with electric utilities • Achievement of substantial increases anticipated over the near-term appears challenging **Concerns:** Time required to scale program; Inability to track detailed savings (due to lack of hourly meters); Unknown cost/benefit as marginal customers are enrolled
Assessment	• While the Incremental EE plans are in early development the forecast appears in line with market potential • Given headroom and funding for weatherization to take place, additional participation should be considered beyond 2025

Demand Response	Baseline
2021/22 Goal	8.7 MDth / day
Evaluation	• Limited 2020/21 winter test event results due to mild winter • Reflective of achieving reduced peak demand at a pilot-levels, with moderate growth assumptions • Number of customers engaged in DR 2020/21 pilot program represents a small percent of customer base: less than 200 Daily DR participants and approximately 2,200 BYOT participants (10% short of BYOT target) • BYOT[Error! Bookmark not defined.] and Daily Peak programs meter deployment risk b eyond the upcoming winter season, coupled with general population limitation risks (e.g., materialization of planned expansion of limited service territories, BYOT devices and customer privacy restrictions or concerns)
Observations	• Daily DR program pilot successes include Design Day enrollment of 17,790 dth/d, or 6% above target; 90% prior season participation and test event

savings are subject to important questions such as how much larger incentives will increase participation, how those costs will be recovered, and the willingness to accept the additional curtailment risk.

[35] C&I average BCR of 2.6; Multifamily average BCR of 2.4; combined Residential combined average below 1.0.

	reliability performance of 83%; Test event net reductions align with third party reduction potential results under conservative DR and moderately cold scenario • 2020/21 BYOT DR program pilot successes include 99% prior season participation and test event reliability performance of 68%; However, pilot data is based on a very limited sample size completed under mild weather test event conditions • Limited historic data and high-level forecasting approach limit ability to assess program reasonableness[36] • 2021/22 achievement of C&I DR goals within recently approved Joint Proposal likely, however future years require Incremental DR savings to meet subsequent goals
Assessment	• The DR programs have not been subject to Design Day conditions nor have a meaningful number customers been signed up • PA anticipates that Design Day conditions are likely to cause a substantial drop in participation and reliability compared to pilot performance

Demand Response	Incremental
2021/22 Goal	9.5 MDth / day
Evaluation	• Reflects addition of Peak Period Demand Response program, increased Daily DR and BYOT • BYOT program assumptions consistent with third party benchmarking • Number of customers to be engaged in DR program represents between 1%-2% per annum (market saturation is not a risk) • Assessment of Firm DR customer class options limited by high-level program forecasting approach • National Grid redefined strategy excludes mitigation of historic Non-Firm rate switching resulting in elimination of potential peak day savings, in this version of DIS
Observations & Concerns	• Cost-effectiveness headwinds likely, higher incentives anticipated to further customer adoptions • Ranked second highest of Distributed Infrastructure Solution element by National Grid's customers • Achievement of C&I DR goals within recently approved Joint Proposal requires both Baseline and Incremental programs • Recent approval of Non-Firm rates increases likeliness of savings from mitigation of Non-Firm customer attrition; However, the magnitude is uncertain given customers must also consider back-up equipment costs and maintenance, decisions about fuel technology, fluctuations in back-up fuel price, and the potential environmental liabilities

[36] Forecast based on 2020/21 Winter Pilot data with "moderate CAGRs" representing historic achievements trend.

	Concerns: Lead time to develop and roll out program at scale; Customer adoption rates; Lack of cold weather data to assess reliability contraction under Design Day conditions; Unknown cost/benefit as marginal customers are enrolled
Assessment	• Downward adjustment to Firm Incremental DR forecast to account for latest Baseline forecast data provided by National Grid • PA recommends addition of Non-Firm savings to account for mitigation efforts anticipated to offset a portion of Non-Firm to firm rate switching, considering recently approved incentivized Non-Firm rate structure and previous inclusion within First Supplemental Report (noting that Non-Firm retention savings will be incorporated in future Adjusted Baseline demand forecast updates)

Electrification	Baseline
2021/22 Goal	6.7 MDth/d
Evaluation	• Number of customers to be engaged represents 0.2% total customers per annum, growing to 3% cumulative by 2035 • Year-over-year incremental customer participation increases anticipated at approximately 6% over the near-term • In addition to customer adoption, coordination with Con Edison and partnership with contractors and material suppliers will be fundamental to success
Observations & Concerns	• Assuming an average appliance life of 20 years, Baseline Electrification reflects approximately 4% residential heating and multifamily appliances switch to electric while C&I switches at a higher rate of approximately 6% in mid 2020s, increasing to approximately 13% in mid 2030s. Resulting total customer adoption rates aligned with NYC Pathways Low Carbon Fuels scenario • The program represents a small portion of overall customer base however, coordination with electric utilities, economics and customer perceptions of heat pumps coupled with overall willingness to embrace electrification present uncertainties and challenges **Concerns:** Customer adoption rates; Time required to scale program; Cost-effectiveness of coordination with electric distribution companies; Less favorable economics of low priced natural gas; Unknown cost/benefit as marginal customers are enrolled
Assessment	• PA expects that success of this program will hinge on close coordination and aligned strategies between National Grid, EDCs and regional power providers and substantial financial incentives. Referrals are unlikely to be sufficient.

Electrification	Incremental
2025/26 Goal	1.36 MDth/d
Evaluation	• Reflects significantly higher customer adoptions: residential heating, multifamily and C&I switching rates increase from 15% in 2026 to over 30% • Material savings assumed over mid to late 2020s driven by substantial year-over-year customer participation rates
Observations & Concerns	• Long-term plan assumes aggressive appliance switching rates with substantial increases anticipated beginning in 2027, exceeding the NYC Pathways scenarios • Significant barriers to electrification of heat include coordination with electric utilities, economics and customer perceptions of heat pumps and overall willingness to embrace electrification **Concerns:** Lead time required to scale program, coordination with electric distribution companies given substantial switching rates, Unknown cost/benefit as marginal customers are enrolled
Assessment	• Currently, there is limited information to determine the capacity of Incremental Electrification to help address a supply gap or whether it is a reasonable expectation. In short, until a business plan is developed corresponding with market data, PA does not feel this program savings should be depended upon.

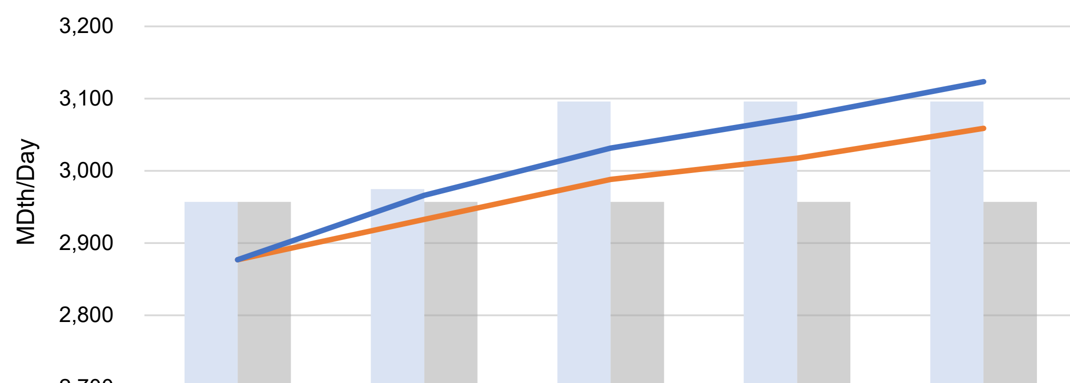
7 Assessing the Risk of a Supply Gap

As discussed throughout this report, there is real supply risk, and therefore a risk that a supply/demand gap emerges and persists. This is because the plans National Grid has in place to offset supply risk are (a) Incremental DSM that is at least one to two years away from achieving scale and (b) contingency infrastructure projects that, even if determined to be feasible and obtain the necessary approvals, are also several years away from implementation – placing even more burden on DSM.

The DSM programs in National Grid's DIS are presented as both the solution to fill the gap and as highly uncertain and unprecedented. As shown below, in a scenario where supply components of the DIS plan do not materialize, National Grid's adjusted demand forecast will soon outpace supply, presenting a moratorium risk as soon as 2022/23 in the absence of adequate incremental supply resources. Under a sensitivity scenario where MF and COM usage levels are more closely aligned with historical trends, National Grid would have roughly two years to develop, implement, and execute on the DSM components of the DIS plan (particularly since incremental supply resources are not forthcoming in the next two years). As stated previously, PA believes it is appropriately conservative to plan for relatively higher forecasts for reliability planning. Over the next two years National Grid should focus on acceleration of DSM execution before a present-day moratorium concern becomes a safety risk in the form of emergency curtailment to the extent load growth outpaces supply capability by the time a mortarium would actually take effect.

Under the most optimistic supply scenario (with DIS) as shown in Figure 7-1 below, full and timely implementation of all infrastructure supply resources similarly provides for two years for the DSM programs to be proven out and implemented to offset the supply gap. As such, perhaps the most critical observation is that National Grid in effect has roughly two years to achieve its goals of current DSM programs, execute on its plans for future programs, and quickly progress through development of feasibility analysis of alternative supply options.

Figure 7-1: Supply vs. Demand Sensitivities[37]



	2021/22	2022/23	2023/24	2024/25	2025/26
Available Supply (with DIS)	2,957	2,975	3,096	3,096	3,096
Available Supply (No DIS)	2,957	2,957	2,957	2,957	2,957
Sensitivity Load Forecast	2,877	2,933	2,988	3,017	3,059
Adjusted Baseline Demand	2,877	2,966	3,031	3,074	3,123

[37] Note: The Available Supply (with DIS) curve assumes the Greenpoint Vaporizers and ExC are in service by 2023/24 and the larger of two potential CNG facilities is in service by 2022/23. The Incremental DSM savings in the DIS are not represented.

APPENDIX A

National Grid and Con Edison jointly own and operate the New York Facilities System, an intra-city transmission pipeline system which is connected to and receives natural gas supply from multiple interstate pipelines.

The New York Facilities Agreement governs how the jointly owned pipeline system will operate and, among other things, specifies each utility's allocated share of interstate pipeline capacity entitlements at each city gate (e.g., each interconnection with an upstream transmission pipeline) as well as maximum hourly volumes of gas that are permitted to flow from one utility to the other. While gas flow is bidirectional at the pipeline interconnections known as Lake Success and Newtown Creek, on a Design Day gas flows from Con Edison to National Grid.

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