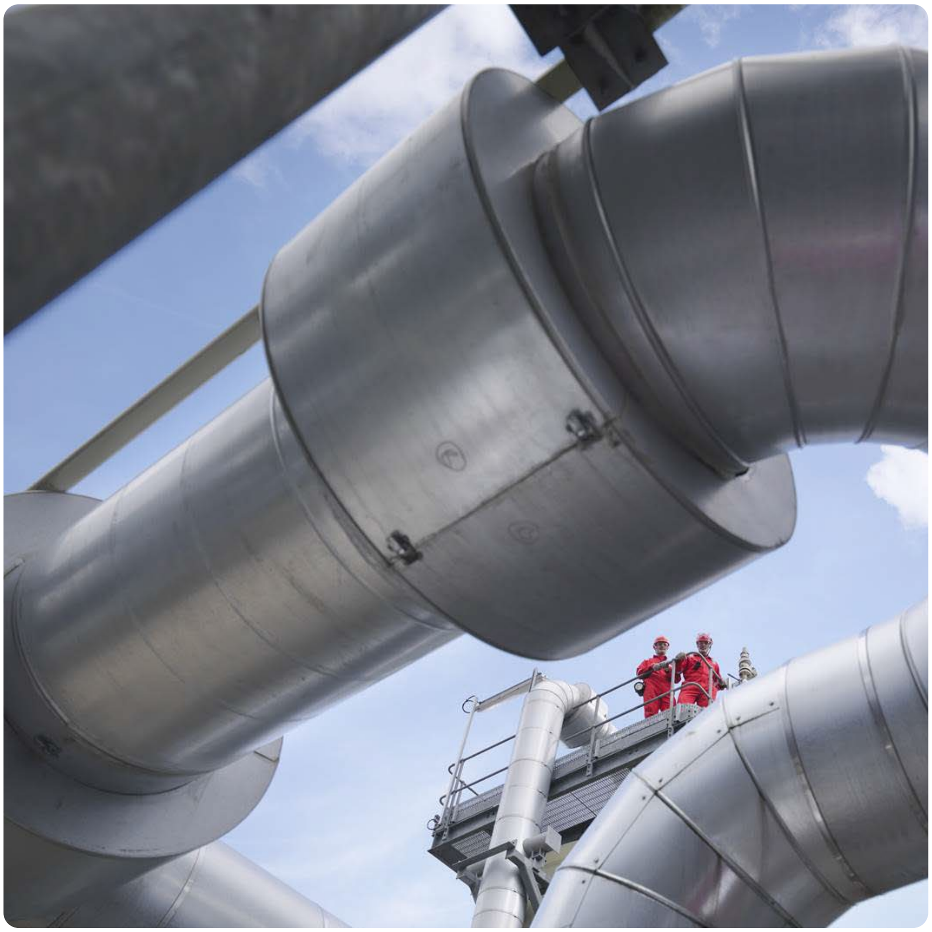

Final Report – NY Long Term Gas Planning

Prepared for NYDPS

December 11, 2023

Bringing Ingenuity to Life

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Version: FINAL

Figures

Tables

Glossary

AMA - Asset management agreement
AGREE - Alliance for a Green Economy
BCA - Benefit-Cost Analysis
C&I - Commercial & Industrial
CAC - Climate Action Council
ccASHP - cold climate air source heat pump
CHP - Clean Heat Program
CLCPA - Climate Leadership and Community Protection Act
CNG - Compressed Natural Gas
Commission - New York State Public Service Commission
ConEd - Consolidated Edison Company of New York, Inc
CPA - Consumer Power Advocates
DOB - Department of Buildings
DPS - New York State Department of Public Service
DR - Demand response
DSM - Demand side management
EDF - Environmental Defense Fund
EE - Energy efficiency
EJ - Earth Justice
ExC - Enhancement by Compression
FLT Plan - Final Gas Long-Term Plan
GHG - Greenhouse gas
GIRRP - Gas Infrastructure Reduction or Replacement Program
GNYHA - Greater New York Hospital Association
GSHP - Ground source heat pump
ILT - Initial Gas Long-Term Plan
Initial Report - PA's report filed on July 14, 2023
Iroquois - Iroquois Gas Transmission System
Joint Supply Portfolio - supply portfolio that allows combined use of ConEd and ORU supply contracts
LCF - Low-carbon fuel
LMI - Low-moderate income
LNG - Liquified natural gas
LPP - Leak-prone Pipe
LR - Load Relief
LT Plan - Long-Term Plan
MAOP - Maximum allowable operating pressure
MR - Main Replacement
MRP - Main Replacement Program
MVP - Mountain Valley Pipeline
NE:NY - New Efficiency New York
NPA - Non-Pipe Alternative
NPV - Net Present Value
NRDC - Natural Resources Defense Council
NYC - New York City
NYCI - New York Cap and Invest
NYCP - New Yorkers for Clean Power
NYECC - New York Energy Consumers Council
NYFS - New York Facilities System
NYS - New York State
NYSERDA - New York State Energy Research & Development
Order - Gas Planning Order
ORU - Orange & Rockland Utilities
OTG - Oil-to-gas
PA - PA Consulting Group, Inc.
PHMSA - Pipeline and Hazardous Materials Safety Administration
Planning Proceeding - Gas Planning Proceeding Gas Number 20-G-0131
Reverse AMA - Reverse Asset Management Agreement
RLT - Revised Gas Long-Term Plan
RNG - Renewable natural gas
ROFR - Right of First Refusal
Sales - Volumetric Gas
SC - Sierra Club
SC1 - Single-family Residential
SC2 - Commercial & Industrial
SC3 - Multi-family Residential
SLR - Service Line Replacement
SNG - Synthetic natural gas
TETCO - Texas Eastern Pipeline
TGP - Tennessee Gas Pipeline
the Companies - ConEd and ORU, collectively
the Department - New York State Department of Public Service
the Order - Gas System Planning Process
Transco - Transcontinental Gas Pipeline
TV - Temperature variable
UIU - Utility Intervention Unit
UoP - Units of Production
UPC - Usage Per Customer
VRF - Variable refrigerant flow

1 Executive Summary

The New York State Public Service Commission ("Commission") in its Gas Planning Proceeding Case 20-G-0131 ("Planning Proceeding") intends to ensure that the State, customers, Stakeholders, and other interested parties have the opportunity to understand and engage in the future of New York's Natural Gas Infrastructure. The Commission issued an order Adopting Gas System Planning Process ("The Planning Proceeding Order") on May 12, 2022, requiring gas utilities to submit comprehensive long-term plans, which comply with the requirements of the Climate Leadership and Community Protection Act ("CLCPA"), over the course of three years. On May 31, 2023, the Consolidated Edison Company of New York, Inc. ("ConEd") and Orange & Rockland Utilities, Inc. ("ORU") (collectively, the "Companies") filed their Initial Gas Long-Term Plan ("ILT Plan"). PA Consulting Group, Inc. ("PA") was retained to conduct an assessment of the Companies' long-term plan ("LT Plan") developed for the New York State Department of Public Service (the "Department") pursuant to requirements of the Commission in its Planning Proceeding. On July 14, 2023, PA filed an Initial Report ("Initial Report") summarizing our initial approach, observations, and recommendations. On September 22, 2023, the Companies filed their Revised Gas Long-Term Plan ("RLT Plan"). On October 16, 2023, PA filed a second report ("Preliminary Report") building upon our Initial Report's observations. Within this Preliminary Report, PA revised recommendations to reaffirm or clarify prior recommendations, removed prior recommendations addressed by the Companies within the RLT Plan and included additional recommendations. In this report, ("Final Report"), PA builds upon the Preliminary Report and includes additional observations focused on PA's final analyses, conversations with the Companies and Stakeholders, assessment of filed Comments and review of the Companies Final Gas Long-Term Plan ("FLT Plan"), filed on November 29, 2023. In this Final Report, PA updates some of its recommendations to reflect the FLT Plan.

PA believes successful, cost-effective, and equitable achievement of the State's ambitious climate goals requires a comprehensive assessment of the intersection of natural gas market supply and demand, technical analysis - including safety and operational risks -, economic and environmental analyses, and changing behaviors. PA also recognizes this process requires a delicate balance of statutory requirements ensuring delivery of gas services in a safe, reliable, and affordable manner.

Within the Initial Report, PA found that while the ILT Plan describes the "what" for each decarbonization pathway, it painted only a very high-level picture of "how" those outcomes will be achieved. In other words, the Companies outlined several pathways, but stopped short of defining and planning for substantial paradigm shifts PA understands the Commission and other Stakeholders anticipate.

In the Preliminary Report, PA described our assessment of the Companies' RLT Plan and focused on the trade-offs among ensuring safe, reliable, and adequate service, while reducing greenhouse gas emissions, natural gas demand, and thoughtfully shrinking supply and capacity assets, while also minimizing the potential for stranded assets and maintaining affordable rates. PA reaffirmed several prior recommendations and identified additional recommendations and opportunities for improvement.

In this Final Report, we build upon our Preliminary report to provide comprehensive discussion of the entire long-term planning process and our final recommendations for improving the Companies' FLT Plan.

1.1 Key Topics and Observations

Our assessment recognizes the importance of balancing many topics:

- First and foremost, ensuring that appropriate investments in the gas system are made to maintain safe, reliable, and adequate service to customers who continue to rely on gas to meet their energy needs.
- Customer behaviors have an impact on the pace of electrification. Methods to acquire further insight on the Companies' customer willingness to switch are needed.
- The Companies and Stakeholders agree that the gas system footprint needs to shrink significantly by mid-Century. It is important, then, to identify and, minimize those investments that are likely to become underutilized or stranded as the distribution system shrinks and results in markedly higher rates and bills for customers who are either unable to leave the gas system, choose not to leave the gas system, or are among the last to do so.

- Given the long lives of gas infrastructure assets and the capital-intensive nature of these investments, it is important to proactively and strategically plan for such significant energy transition decades in advance. The Commission recognizes this and has properly requested the Companies and Stakeholders to do through the Planning Proceeding Order.
- The need to implement successful energy efficiency and demand reduction programs that result in reduced annual consumption and peak demand for natural gas to achieve State and local greenhouse gas emissions targets.
- Strategically reducing the need for both supply and distribution assets over time as gas demand shrinks, further reducing costs for all customers.

Achieving desired outcomes for all Stakeholders – including the Companies, customers, and the communities in which they live, the State of New York and New York City – requires all parties to acknowledge a number of key considerations, including:

- Implementing any decarbonization pathway will take time and requires cooperative efforts of customers and their representatives, the Companies, and State and local legislators and regulators.
- The realities of customer needs, gas system needs, and regulatory requirements (including maintaining system safety, reliability, and affordable rates) in the short or intermediate term cannot be set aside even if they appear to be at odds with longer term objectives.
- Significant value is realized through planning for a "coordinated decarbonization" across New York to ensure safe, reliable, and affordable provision of energy services to customers. In contrast, an unplanned and uncoordinated decarbonization approach can result in stranded assets, suboptimal reliability of the gas and electric system and possibly lead to high gas and electric bills that are unaffordable to portions of the population, including disadvantaged communities.
- Identifying "no regrets" actions to be taken under any given pathway, coupled with ranges of potential outcomes, can offset the impact of many uncertainties as key assumptions including technology, policy, and customer preferences change over time.

Companies have addressed some of the recommendations made by PA and Stakeholders (e.g., including a BCA analysis of the pathways in their final plan) throughout this process. However, PA finds the Companies have yet to adequately address several recommendations made by PA and Stakeholders and instances in which the Companies are not meeting the Commission's Planning Proceeding Order. The following section outlines our recommendations intended to improve the Companies FLT Plan and, in some cases, meet the requirements of the Planning Proceeding Order.

1.2 Recommendations

In this section we summarize our Final Recommendations that are designed to improve the Companies FLT Plan and, in some cases, meet the requirements of the Planning Proceeding Order. We have not included here any of our prior recommendations that the Companies have addressed within the RLT or FLT Plans. Given the Companies' FLT Plan was filed prior to this Final Report, we recommend the Commission require that the Companies modify the FLT Plan accordingly.

Supply

- Provide more robust discussion on the flexibility limitations unique to each component of the Companies' supply portfolio – detailing specifically what limitations the Companies expect to see in adding additional flexibility to, or altering the terms of, firm pipeline transport and storage contracts, Reverse Asset Management Agreements (AMAs), or Delivered Services contracts.
  - The Companies provided additional discussion of flexibility limitations but did not provide an in-depth discussion of the unique flexibility limitations of each component of supply.
  - To the extent feasible, provide a more granular description of how capacity in the Joint Supply Portfolio (JSP) is allocated between the Companies based on their individual design-day requirements.
- As part of the framework for de-contracting, build upon the framework for capacity release as demand diminishes. Include in this framework a criterion for evaluating which pipeline capacity contracts are no

longer needed. Include a discussion of the types of counterparties (in- or out-of-state) that capacity can be released to.

- Improve NPA program design, implementation, and cost analysis:
  - Proactively communicate, educate, and recruit customers to adopt NPA program measures at scales needed to meaningfully shrink the gas system footprint.
  - Further leverage regional surveys and engagements with community groups to gauge customer interest and participation in supporting adoption of electric appliances and NPA solutions.
  - Continuously refine offerings and program scope regularly as customer adoption preferences evolve.
  - Maintain line-of-sight of the electric grid impacts of electrification (i.e., current and future grid concerns – real or perceived), while considering trade-offs of near-term gas system investments as compared to future electric system spend. To the extent already underway, discuss how the Companies are doing this within the FLT Plan.
  - Leverage other Stakeholders' reputation and tools to improve recruiting process, including community groups and local elected officials.
- Provide detailed assumptions and expectations for NPA programs going forward. Include, at least for each NPA expected to be completed in 2024, details such as (and as applicable) the number and type(s) of customers participating in the NPA, associated design day and annual demand reduction, avoided replacement investments resulting from the NPA, avoided pipe replacement miles and/or service lines, system reinforcement investments that can be delayed (and perhaps avoided), and other applicable information demonstrating the benefit of the NPA.[1]
- Provide a more comprehensive "No Infrastructure" option. PA understands the Companies' definition of the "no infrastructure" solution; however, PA observes proper planning would necessitate the Companies provide more specificity regarding alternatives to limit infrastructure investment to inform the Commission and Stakeholders. A "no infrastructure option" does not mean the Companies are prevented from making certain investments supportive of safe, reliable, and adequate services, including those driven by State and Federal Requirements and the obligation to serve. However, a more specific "no infrastructure" option would provide a lower end boundary on the level of total infrastructure investment with NPAs.[2]
- Consider including improvements to the NPA program design and deployment with the goal of scaling up NPA programs and to eliminate barriers to adoption. Ensure NPA program design structures minimize barriers to adoption, for example directing payments to Contractors, to avoid large capital outlays from customers. Stakeholders expressed concerns on this issue as a major barrier for adoption of NPA solutions, especially among the LMI customers. It is reasonable to expect that many customers would choose not to participate in the NPA programs if they are required to make material upfront out of pocket payments to the Contractors and wait for the payment to be processed and reimbursed by Companies.

Demand

- Frame a detailed/disaggregated perspective on both the customer counts and annual use-per customer ("UPC") across the different customer segments - Single-family Residential (SC1), C&I (SC2) and Multi-family Residential (SC3) - to conduct an appropriate assessment of load structure, given the distinct dynamics of each segment.
- Incorporate the economics of gas versus electric appliances. The current modeling efforts do not account for the evolving competition between the economics of gas appliances and electric appliances (e.g., gas furnace and heat pump) over the next decades. This dynamic view is potentially a very important dynamic feedback loop, as it could impact the total volumes of gas delivered to customers and thus the gas rates. Upon reduction in gas volumes, with all else equal, gas rates will increase over time and alternative electric solutions will be more cost competitive over time. PA expects significant value in providing historical adoption rates of various technologies (e.g., heat pumps) and supplementing the projections with an

[1] In ConEd and ORU Reply Comments, the Companies agree to provide any available NPA updates going forward and in future GSLTP cycles. See Section 3.3 for additional discussion on the Companies' comments.

[2] In ConEd and ORU Reply Comments, the Companies indicate the Deep Pathway fulfils this requirement. See Section 3.3 for additional discussion on the Companies' comments.

analysis that accounts for such dynamics. Given the importance of this subject, we encourage the Stakeholders to review and discuss the assumptions made in the analysis that was recently shared by the Companies.

- Specify the impact on EE and DSM programs on the annual usage per customer ("UPC"). Both Companies have multiple EE and DSM programs that have been helping customers save money while supporting the reliability of the gas and electric systems for decades. At least in some segments of the customer-base, the cumulative momentum of these initiatives along with the organic efficiency gains (attributable to behavioral factors, improved technology, Codes and Standards etc.) would be expected to be manifest in the trends of annual UPC.[3]
- Consider the impact of Electric Operations DSM measures on the customer behaviors and resulting electrification, energy efficiency, and other DSM program adoption assumptions.
- Consider a restructured approach to DR offerings, including but not limited to refined trigger temperatures, pro-active communication of the environmental and economic value of such programs (beyond the response incentives offered) to encourage customer adoption and consider regulatory changes such that company shareholders are incentivized to fund such measures over substantially more expensive delivered services and/or future capital investments.
- Provide more information such as annual participation rates and savings by program (NE:NY, Organic, etc.) and Pathway.[4]
- Consider the notion of adjusting the TV approach in the future provided analysis projects adequate headroom between observed and weather-adjusted Peak Load. Since the cost of reserving and contracting Delivered Services and peaking CNG resources can be multiples of the baseload gas the Companies acquire, even a small decline in forecasted Peak can provide relief to bill-payers – especially in the lower-income brackets.

Economic

- Clearly communicate the direct and inherent assumptions used in the Companies' modeling process. This approach would allow Stakeholders to compare these assumptions against their view on technology, policy, customer preference, etc. and be able to participate in the long-term planning process more proactively.
- Clarify the inherent tradeoff between emissions reduction, affordability, and strategies to mitigate affordability impact, while reducing GHG emissions. The Reference pathway would offer the least year-over-year increase in total customer gas bills; however, it does not offer a robust and dependable path to decarbonization and meeting CLCPA's targets. Although the Deep Electrification pathway meets the emissions reduction and CLCPA's emissions target, it is projected to have the most severe negative impact on affordability.
- Conduct an optimization process to identify and develop a long-term plan Pathway with the highest emissions reduction potential and lowest impact on affordability while maintaining system reliability and safety. From our understanding, it is unclear and unlikely the Companies have conducted such optimizations to identify a Pathway with highest societal value and least potential risk overtime. In addition, the Companies should conduct a sensitivity analysis to demonstrate the modeling robustness and share a view on the most sensitive assumptions and variables with the Stakeholders and the Commission to assess the prudence of these assumptions.
- Provide calculated bill impacts for each service classification that account for changes to the average volumes of gas consumed by each customer class over time. Although the Companies indicate in their FLT Plan that gas usage will become more efficient over time, they use a constant value for assumed gas consumption between 2023 and 2050 in each customer class, which is not an accurate assumption. To make the bill impact analysis more robust, Companies should use projected average gas volumes for

[3] In ConEd and ORU Reply Comments, the indicate this is an area of enhancement for future long-range volume forecasts. See Section 3.3 for additional discussion on the Companies' comments. PA further discusses this topic in Section 5.5.

[4] In ConEd and ORU Reply Comments, the Companies agree to provide this in the FLT Plan however, PA observes this was not completed. See Section 3.3 for additional discussion on the Companies' comments. PA further discusses this topic in Section 5.5.

each customer class and forecasted reductions in gas volumes for a representative customer in each class, rather than using a constant value.

- Identify ways to further manage bill impacts and affordability challenges. The Companies' bill impact analysis is relatively high and could pose affordability challenges for ratepayers, especially for lower-income customers who do not qualify for billing assistance programs. Under the Reference Case scenario, a "SC-1 Residential/Religious Firm Sales Service" customer's total bill is forecasted to experience an average increase of 5.4% per year (excluding inflationary price increases). Under the Hybrid and Deep Electrification scenarios, the average year-over-year total bill increases are projected to be 7.4% and 25.1% (excluding inflationary price increases). These forecasted rate increases are much higher than actual historical total gas bill increases over the past 5 years and are deemed "unacceptable" by Stakeholders.
- Redouble efforts to identify, early on, investments (especially pipe replacement investments) that could be potentially avoided by deploying NPA and electrification solutions. Given the likelihood that lead times to implement non-pipeline solutions will be several years, focus in earnest on those investments that are beyond the three-to-five-year horizon. This is the key to maintaining affordability while reducing emissions by keeping costs in a reasonable range. If the Companies and Stakeholders fail to identify investments that could be avoided in a timely manner, the Companies will have no option other than continuing to deploy capital to replace these pipes or continue to incur repair costs, while operating riskier assets, to maintain reliability and meet safety standards. These investments may likely be stranded or not fully utilized by mid-Century; however, they must be paid for by either fewer customers remaining on the gas system or backed by government interventions – both of which present challenges. Instead, it would be preferable to identify meaningful opportunities to avoid deploying those investments in the first place.
- Specify how the FLT Plan intends to benefit disadvantaged communities. The FLT Plan does not provide insight or sufficient details on how the plan ensures at least 35% of benefits are directed to disadvantaged communities, as required by the Order. Instead, the plan explained that the Companies will continue working on this topic and will provide further details in the next round of their report. Inclusion of the results of this analysis in the final version of the report will improve the plan.
- Increase planning coordination between the gas, steam, and electric systems. Although there is no direct language in the Planning Proceeding Order requiring utilities to conduct coordinated long-term planning for the gas, steam, and electric systems, PA recommends some coordination to ensure that safety, reliability, resiliency, and affordability objectives are properly considered as part of the long-term planning process.

Environmental

- Identify the pathway that is preferred to guide the Companies' actual investment plans. The Companies present Hybrid and Deep Electrification pathways as two potential pathways to meet CLCPA goals but do not identify a preferred plan. PA appreciates the challenges of a single point forecast when many variables are at play and finds a discussion on the range of possibilities is reasonable and useful. However, it is unclear which pathway is going to inform Companies' long-term planning and investment decision that need to be made in the near-term since there are clear tradeoffs between each pathway and it is inefficient and impossible to pursue all 3 pathways at the same time. In their RLT Plan, Companies "determined that many of the required actions are common to both the Hybrid and Deep Electrification Pathways, particularly prior to 2030". While that outcome may be the case to some extent, successful deployment of NPA and electrification solutions requires significant lead time, and the Companies would need to redirect some of the capital that is earmarked for pipe replacement toward electrification efforts and thus it is hard to imagine that Companies can successfully pursue both pathways and both strategies at the same time. Such process could lead to suboptimal allocation of capital to each strategy and inefficient utilization of scarce resources.
- Confirm the true cost estimates, emission reductions related to LCFs and whether advancement of LCFs will provide sufficient supply as per expectations; evaluate potential solutions for H2 leakage; weigh possible alternatives for LCFs. Given the importance of this subject, PA encourage the Stakeholders to review and discuss the assumptions made in the analysis that was recently shared by the Companies in the FLT Plan.

- Develop and share with Stakeholders a robust definition of hard to electrify customers and check that definition on a regular basis as developments in technology may change these assumptions. For example, the Companies have communicated that they are assuming dense high-rise buildings as hard to electrify given the space requirements and disruptions to day-to-day activities of residents for electrification. If new electric appliances are developed that could retrofit existing buildings, with minimal disruptions to day-to-day activities, the Companies may need to revisit this definition and account for the possibility of electrifying these buildings.
- Develop a list and geographical distribution of hard to electrify customers, coordinate with NYC Department of Buildings, and ensure Companies and Stakeholders have a long-term geographical view on where these hard to electrify buildings are located. This would be essential in developing a long-term view of which pipes are critical in supplying fuel to these buildings. This would help Stakeholders and regulators better understand which regions or neighborhoods are forecasted to remain on gas network and which regions/neighborhoods are forecasted to be potentially electrified.
- If and when possible, allow customers who may be interested in maintaining dual fuel options (e.g., maintain gas appliances)Given the rise in electric power grid reliability and resiliency concerns this can help customers get more comfortable with electrifying some of their use cases. We understand that in some cases customers are <u>required</u> to remove their gas appliances (e.g., distribution replacement NPA program) and in some cases customers are allowed to keep their gas appliances (e.g., load relief NPA). Dual fuel options help customers get more comfortable with the decision to electrify some use cases by providing a back-up option during extreme weather conditions and when power outages may take place. If customers are on sections of the gas network that are earmarked to remain on gas network they may be interested in retaining some of their gas appliances (e.g., gas furnace or gas stove) for days that the electric grid may be under stress or for cases of resiliency and reliability. We understand such an approach may to a minor extent negate the benefits of electrification, but in the long-term it will make customers more comfortable and provide resiliency value for extreme weather conditions.
- Update the analysis comparing the economics of different technologies used for space and water heating in various customers segments in New York. In the ILTP and RLTP Companies were relying on an economics comparison of various space heating technologies such as gas boilers, air-source heat pumps, etc. that was developed and filed in 2017.[5] Given the importance of this subject, PA encouraged Companies to update this assessment for the FLTP and Companies followed this recommendation. PA would encourage Stakeholders to review and further discuss the assumptions made in the FLTP to further improve this assessment and create alignment among Companies and Stakeholders' views on this crucial assessment.

Other

- During our review of the Companies' various long-term plans, PA was made aware that a lag exists between the time that construction projects are completed and the time those projects are reflected in the Companies' mapping systems. While this delay may lead to a reporting mismatch as described in Section 4.4.2, it could also raise a potential employee and public safety concern. PA recommends that the Companies ensure that the Commission and appropriate DPS Staff are aware of the procedures and systems in place that provide emergency response and other field personnel with accurate information about the gas system components they should expect to encounter in performing their work.

[5] Source: Page 10, Case 16-G-0061 - ConEd Gas Peak Demand Reduction Collaborative Report, filled on December 22, 2017.

2 Introduction

New York State has established several of the most progressive and ambitious decarbonization mandates in the United States, through a combination of both legislative and regulatory reforms which will impact the evolution of natural gas supply, planning, infrastructure, and operations. Relevant to the New York City Region, the City of New York has passed its own laws – most notably the Climate Mobilization Act which includes Local Law 97 calling for significant decarbonization of the built environment and Local Law 154 which aims to significantly limit fossil fuel service connections in new or renovated buildings in New York City. Other actions in New York City, including Executive Order 52, could pose challenges for aligning near-term investment in the natural gas system to provide safe, reliable, and adequate service with long-term decarbonization goals.[6] Although some of these actions are specific to New York City, these initiatives could have direct and profound impacts on the investment in and evolution of natural gas infrastructure and supply requirements across the State.

PA was retained to conduct an independent assessment of the Companies' LT Plan. This review is being conducted for the Department pursuant to requirements of the Commission in its Planning Proceeding Order. The Planning Proceeding order specified the assessment encompass specific criteria related to long-term gas plans, including but not limited to:

- Test the assumptions and check calculations and analyses used by the Companies.
- Evaluate the economic and environmental tradeoffs associated with different pathways.
- Assess a reasonable number of scenarios representing hydraulic models of the Companies' distribution systems.
- Participate in Stakeholder meetings and make requests of the Companies and Stakeholders.
- Suggest other solutions.

The long-term planning process design encourages Stakeholders to review the Companies' long-term plan filings, issue data requests, review data request responses, and suggest modifications. This approach also facilitates a process in which the Companies reflect Stakeholder comments and suggestions within the RLT and FLT Plans. PA has independently assessed the Companies' long-term plan filing process to determine if the Companies' FLT Plan complies with the goals of the Planning Proceeding Order. This Final Report summarizes our findings and observations pertaining to the FLT Plan and outlines suggested improvements for the Companies FLT Plan and, in some cases, meet the requirements of the Planning Proceeding Order.

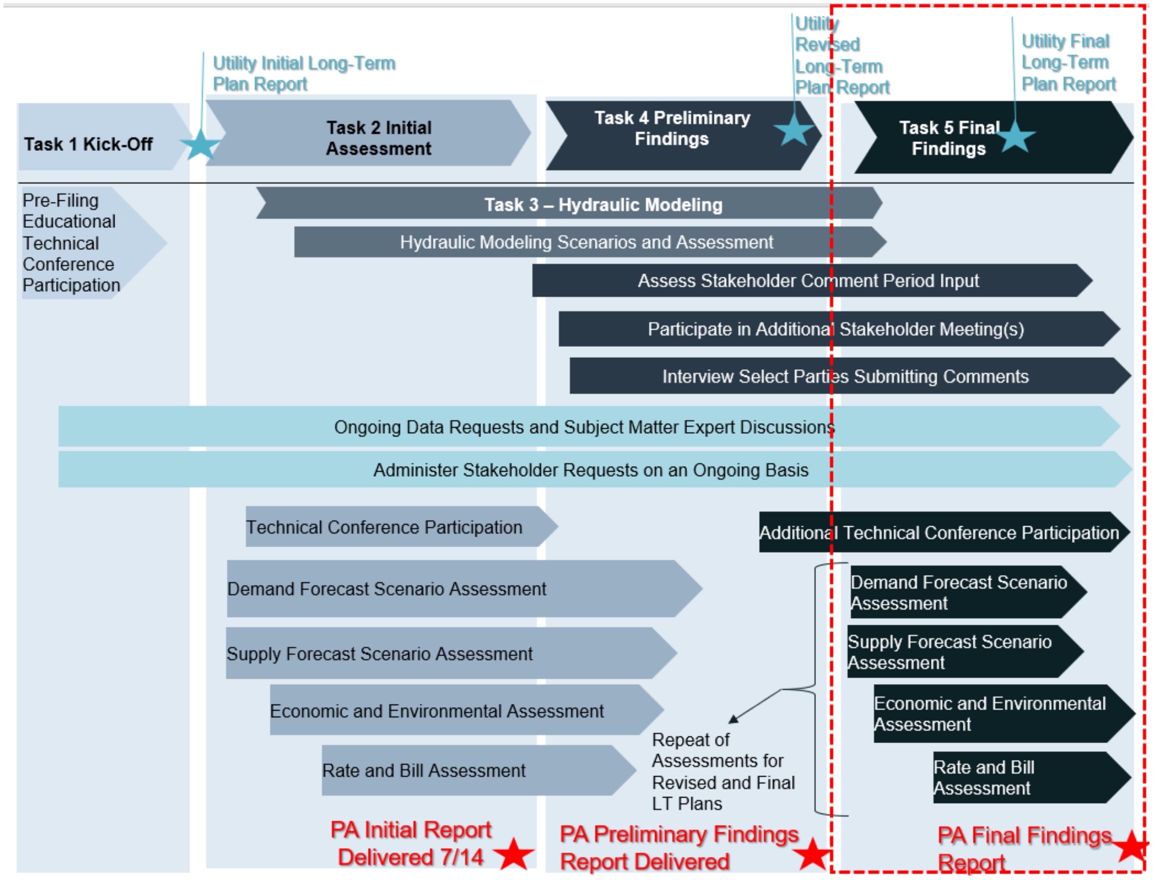
2.1 Scope of Work

PA's review of the ILT Plan, RLT Plan and FLT Plan was conducted over approximately nine months. During this time frame, PA submitted, and the Companies provided responses to, over 180 data requests, held several virtual meetings with various subject matter experts from the Companies and attended several virtual pre-filing and post filing technical conference presentations. The Companies' personnel have provided significant amounts of requested data, made their experts available for meetings, and have cooperated with PA. Additionally, PA has held several virtual meetings and two in-person meetings with the Companies' subject matter experts and DPS Staff on August 7th, August 8th.

Further, PA has reviewed all comments filed to date by Stakeholders and the Companies. As noted above, several technical conferences were held leading up to the development of the Preliminary Report, as well as this Final Report, and are summarized within Section 3 and discussed in greater detail throughout this Report. Figure 1 below illustrates the scope of work completed.

[6] Refer to Appendix A for more information on recent New York State and City policies.

Figure 1: PA Scope of Work Schedule



We have organized our Final Report to address key issues and observations reflecting our comprehensive view of Stakeholder Initial Comments, Companies' Reply Comments, and the Companies' FLT Plan. Our Final Report covers the following key topics:

- Stakeholder Engagement
- Supply Assessment
- Demand Assessment
- Economic Assessment
- Environmental Assessment

In the following section, we summarize the three pathways presented by the Companies and our observations on how the pathways evolved into the FLT Plan.

2.2 Companies' Pathways

The Companies present the following three decarbonization pathways within the FLT Plan, guided by the following primary assumptions:

1. **Reference Pathway** reflects current legal and policy framework, to a degree, and does not achieve state or city net zero GHG goals.
2. **Hybrid Pathway** refines the Reference pathway to incorporate both clean electricity and low-carbon gas fuels to meet State economy-wide GHG goals.
3. **Deep Electrification Pathway** reflects the assumptions of the Climate Action Council ("CAC")/ New York State Energy Research & Development ("NYSERDA") integration analysis and meets the State's economy wide greenhouse gas emissions goals. Includes assumption that the obligation to serve is removed in 2030, reflects shift from NPAs to legislated/ordered electrification.

The Companies filed their RLT Plan on September 22, 2023, and on November 29, 2023, the Companies filed their FLT Plan. The RLT and FLT Plans include revised assumptions, some of which are reflective of recommendations from PA and Stakeholders, as well as changes to the key projected outcomes of each of the three Pathways. Table 1: Companies' Key Projected Outcomes compares the key outcomes of the Companies plans for each Pathway.

Table 1: Companies' Key Projected Outcomes

	Reference	Hybrid	Deep Electrification
FLT Plan			
2043 Gas Volume, % reduction from 2023	171 TBTU, 21% reduction	125 TBTU, 42% reduction	39 TBTU, 82% reduction
Gas Sector Emissions Reductions from 2023 (scopes 1 and 3)	23%	62%	87%
Gas Supply Mix (2043)	5% CNG	36% RNG, 6% clean hydrogen, 58% CNG	21% RNG, 79% CNG
Electric Peak, % increase from 2023 to 2042	ConEd: 34% ORU: 42%	ConEd: 13%-32% ORU: 29% - 67%	ConEd: 49%-91% ORU: 45% - 93%
RLT Plan			
2043 Gas Volume, % reduction from 2023	171 TBTU, 23% reduction	125 TBTU, 43% reduction	39 TBTU, 82% reduction
Gas Sector Emissions Reductions from 2023 (scopes 1 and 3)	25%	62%	87%
Gas Supply Mix (2043)	5% CNG	36% RNG, 6% clean hydrogen, 58% CNG	21% RNG, 79% CNG
Electric Peak, % increase from 2023 to 2042	ConEd: 30% ORU: 13%	ConEd: 15%-34% ORU: 31% - 70%	ConEd: 51%-92% ORU: 45% - 93%
ILT Plan			
Gas Volume, % reduction	173 TBTU, 18% reduction	129 TBTU, 39% reduction	49 TBTU, 76% reduction
Gas Sector Emissions Reductions from 2022 (scopes 1 and 3)	25%	62%	87%
Gas Supply Mix (2042)	5% CNG	37% RNG, 6% clean hydrogen, 57% CNG	13% RNG, 87% CNG

Electric Peak, % increase from 2022	ConEd: 32% ORU: 38%	ConEd: 25%-40% ORU: 20% - 45%	ConEd: 70%-105% ORU: 35% - 70%

The FLT Plan included modifications to the Companies' representative gas service costs for Deep Electrification in 2043 as well as Reference and Hybrid Pathway costs in 2050. PA notes that these costs provided by the Companies represent revenue requirement divided by total average volumes per customer (consolidated for ConEd and ORU across all service classes) and therefore are directional in nature, rather than representative of average customer bill impacts. PA discusses this, as well as the Companies' plans to provide more granular bill impacts, later in this Report. See Table 2 for the representative service costs provided in the FLT Plan.

Table 2: Companies' Representative Service Costs: FLT Plan[7]

ConEd		
Scenario	**Rate Impact (2023-2043)**	**Rate Impact (2023-2050)**
SC-1 Residential/Religious Firm Sales Service		
Reference	5.4%	4.3%
Hybrid	7.4%	6.7%
Deep Electrification	25.1%	37.5%
SC-2 Rate I General Firm Sales Service		
Reference	4.2%	3.6%
Hybrid	7.5%	9.1%
Deep Electrification	17.5%	58.8%
SC-2 Rate II General Firm Sales Service		
Reference	4.4%	3.8%
Hybrid	7.6%	8.8%
Deep Electrification	19.1%	64.4%
SC-3 Residential/Religious Heating		
Reference	4.7%	4.0%
Hybrid	7.3%	8.1%
Deep Electrification	18.5%	61.7%
O&R		
SC-1 Residential and Space Heating		
Reference	3.2%	3.5%
Hybrid	8.8%	14.9%
Deep Electrification	5.5%	14.9%
SC-2 General Service (small)		

[7] Source: Figure 32 of the FLT Plan.

Reference	2.8%	3.1%
Hybrid	5.4%	8.6%
Deep Electrification	11.7%	56.9%
SC-2 General Service (large)		
Reference	2.9%	3.3%
Hybrid	5.7%	9.2%
Deep Electrification	12.7%	62.3%

Over the long-term, the Companies demand forecasts diverge as the following key policy assumptions take effect. See Figure 2 from the Companies FLT Plan, summarizing the key assumptions driving demand, economic, and environmental forecast outcomes by Pathway.

Figure 2 Companies Key Policy Assumptions[8]

Reference
- Existing law and policy
- Continuation of existing investment in energy efficiency, electrification
- Preservation of current polices with respect to new gas service

Hybrid
- Elimination of 100' Rule, obligation to provide natural gas service
- Incremental (i.e., to Reference Pathway) energy efficiency program investments
- Reduction in system footprint
- Diversification of fuel resources (i.e., LCFs)
- Electrification programs

Deep Electrification
- Elimination of 100' Rule, obligation to provide natural gas service
- Incremental (i.e., to Hybrid Pathway) energy efficiency program investments
- Significant reduction in gas system footprint
- Nearly eliminates emissions from buildings
- No exceptions to legislation mandating electrification

The Companies present Hybrid and Deep Electrification pathways as two potential pathways to meet CLCPA goals but do not identify a preferred plan. PA appreciates the challenges of a single point forecast when many variables are at play and finds a discussion on the range of possibilities is reasonable and useful. However, PA acknowledges the expectation that the Companies identify a preferred plan within this proceeding. Some Stakeholders have expressed concern that important decisions such as resource allocations require near-term decisions and, absent a preferred plan, resource allocations may not be efficient, presenting apprehensions of stranded asset risk. Therefore, PA submitted Data Request DPS12-183, based on PA's recommendations and Stakeholder recommendations, which asked:

> "Please identify and provide the preferred portfolio of investments, summaries of the cost and bill impacts and emission impacts from these preferred options, as described within the Gas Planning Order. Include supporting components and analyses further identified by Stakeholders, as outlined in DPS12 -183 Attachment A."

DPS12-183 Attachment A, presented within the table below, reflects unaddressed PA and Stakeholder recommendations PA found to be critical in determining a preferred plan.

[8] Source: Figure 73 of the FLT Plan.

Table 3: Preferred Plan Key Components

#	Preferred Pathway including the following key components:	Supported by the following analyses:
1	Optimized assessment of highest emissions reduction potential and lowest impact on affordability, while maintaining system reliability and safety. This emissions reductions estimate shall reflect CLCPA GHG accounting results and meet CLCPA emission reduction goals.	Climate Act-compliant greenhouse gas accounting and the supporting assumptions.
2	Estimate electric rate base costs and approximate a combined gas and electric bill impact at the representative customer level, preferably the service class level.	Absent a separate independent analysis, electric rate base costs should be sourced from ConEd's January 2022 Integrated Long Range Plan – projections of incremental budget needed to meet the CLCPA EE & Electrification goals through 2030.
3	Assessment of anticipated increases to energy assistance funding needs, as well as major risks and uncertainties related to conforming to NYC's 6% energy burden threshold.	Analysis shall highlight the impact on lower-income and Disadvantaged Community customers.
4	Estimate of the impact of New York Cap and Invest (NYCI) costs on gas demand.	Use and provide DEC's Value of Carbon Guidelines for reasonable NYCI cost estimates.
5	Robust discussion on the feasibility and risks of achievement of this plan. This shall include discussions on the necessary changes to existing State and/or Federal legislation, regulations and/or policies (e.g., 100-ft rule, obligation to serve).	N/A
6	Regarding planned replacement of transmission pipeline segments relative to PHMSA's MAOP reconfirmation requirements, include an outline of necessary legislation and/or policy changes and how these translate into capital spend assumptions. Describe the following: -Explain transparently how ConEd determined that replacement of existing transmission pipelines was the best path to compliance and explain why each of the other five potential compliance methods were rejected -Communicate the degree to which the pipeline segments subject to MAOP Reconfirmation would have to be derated to achieve compliance; in other words, what would be the required MAOP of each segment, after derating the segment, which would satisfy the PHMSA's requirements. -Discuss the feasibility of achieving design day demand reductions that correspond to the potential reduced capacity of the system in the context of (1) the Company's overall strategies for reducing demand and (2) the PHMSA compliance deadlines for reconfirming the MAOP of the applicable pipeline segments.	Identify if applicable, whether verifiable, traceable, and complete records supporting a lower (than currently stated) MAOP exist for each applicable pipeline segment. Present (to the extent feasible), similar to the manner in which Table 10 of PA's Preliminary Report presents reductions in capacity, how derating the pipeline segments to the required MAOP levels would impact the hydraulic capability of ConEd's pipeline delivery system and the NYFS, and how those derates would impact deliveries to the National Grid system. Provide supporting design day reduction feasibility analysis in the context of (1) the Company's overall strategies for reducing demand, and (2) the PHMSA compliance deadlines for reconfirming the MAOP of the applicable pipeline segments.
7	Estimate of optimized supply, demand, and NPA solutions with the goal of estimating a lower-end boundary on the level of total traditional infrastructure investment, using NPAs. Within the optimized demand forecast, include a granular analysis on annual adoption of decarbonization solutions in terms of annual customer count, adoption rates by solution, UPC, etc. Consider the impact of Electric Operations DSM measures on the customer behaviors and resulting electrification, energy efficiency and other DSM program adoption assumptions. Describe how these programs could be leveraged or upscaled, along with the level of funding (gas and electric), and company and stakeholder engagement efforts needed over the next decade to meet these decarbonization targets.	Provide disaggregated perspective on both the customer counts and annual UPC across the different customer segments – SC1, SC2, and SC3. Present assumptions for customer fuel switching at the customer class level and appliance level, since not all appliances fail at the same time. Summarize estimated share of (1) heating systems that must be adopted to heat pumps and (2) buildings that must receive building shell retrofits to achieve this plan. Assess annual participation rates and savings by EE (NE:NY, Organic, etc.), Demand Response, and Interruptible Rate offerings.
8	Estimates of optimized NPA solutions should include details of each NPA expected. Such details include the number and type(s) of customers participating in the NPA, associated design day and annual demand reduction, avoided capital investments resulting from the NPA, avoided pipe replacement miles and/or service lines, and other applicable information demonstrating the benefit of the NPA. Supporting discussion on expected NPA delivery methods and barriers. Include a plan of partnership with Stakeholders, including NYC and its agencies, to efficiently identify electrification and other NPAs within priority areas. Plans on ways to fund electrification of these buildings to comply with state and local laws.	Include supporting participation design day and capital investment data. Specify the methods of outreach to convince users to electrify and target offerings to oil to gas conversions. This should include advertising the availability of federal incentives for electrification and weatherization (through the Inflation Reduction Act) and program designs to avoid customer financial burdens such as up-front payments (especially for LMI customers)
9	Robust discussion on hard to decarbonize customers, justification for difficulty in decarbonization, geographic concentration of customers, and detailed decarbonization plans for these customers if use of LCF is anticipated. Provide specifics on what type of LCF, the source of the fuels and their mix. Present the respective cost estimates, emission reductions related to LCFs and whether advancement of LCFs will provide sufficient supply.	Describe assumptions for oil to gas conversions, including options to persuade customers to electrify. Describe how existing hard to decarbonize customers are addressed. Include supporting assumptions on type, source, supply amount, mix, cost, emission reduction amount (by component) of LCF.

10	Robust discussion on optimization, flexibility, and limitations of certain components of the Companies' supply portfolio – detailing specifically what limitations the Companies expect to see in adding additional flexibility to, or altering the terms of, firm pipeline transport and storage contracts, reverse AMAs, or Delivered Services contracts. Describe the plan related to lifting the Southern Westchester County moratorium.	Granular description of how capacity in the Joint Portfolio is allocated between the Companies based on their individual design-day requirements. Specify and provide analysis of how the costs and risks of relying on Delivered Services compare to the costs and risks of other potential options (firm pipeline capacity, CNG, NPAs, etc.) for bridging the supply-demand gap. Define timing expectations on beginning the process of lifting the moratorium.
11	Robust discussion on anticipated disadvantaged community impacts and how the Companies plan to ensure that disadvantaged communities receive at least 35% of the benefits of energy efficiency, clean heat, and other NPA investments.	To the extent possible, identify the magnitude of NPA and other decarbonization solution capital investments within disadvantaged communities.
12	BCA and net present value calculations in a format similar to Project BCA Summary tables presented within the Companies' Area Load Relief NPA Project BCA findings. Assess and identify uncertainties which would benefit from future sensitivity and scenario analyses.	Spreadsheet of resulting BCA analysis calculations. Identify areas of consistency from the Companies' BCA Handbooks and Avoided Cost of Gas Working Group "best practices" (where applicable).

However, the Companies did not provide the preferred portfolio as requested. Instead, the Companies have not elected to select a plan or populated the template. Below is the Companies' response to this data request:

> "The Companies have not selected a single, preferred pathway because we strongly believe it is premature to do so at this time. We need to continue planning and preparing for a range of possible outcomes in order to meet our obligations to provide safe and reliable service. This decision is further supported by the BCA ratios, requested by stakeholders, to be included in our final plan. Initial analysis results (final analysis to be included in Final GSLTP) show a range of ratios for each pathway, which overlap with one another, demonstrating quantitatively, that it is unclear how the future will unfold. The Companies fully support the clean energy transition and CLCPA goals, which are part of our Clean Energy Commitment. However, the future trajectory of important factors, such as legislation/regulation, technology, and customer behavior, are not entirely within our control. Significant changes in all three of these areas are required to drive high levels of electrification, achieve a reasonable balance between affordability and emissions reductions, and realize the development of low carbon fuels. All of which are required for the Companies to pursue either the Hybrid or Deep Electrification Pathways. As discussed in our September Reply Comments, the Reference Pathway represents the current trajectory, factoring in all existing and planned demand reduction programs, as well as the current regulatory and legislative environment. The Reference Pathway will continue to inform our short-term rate case funding requests. The Companies believe that as New York State makes more progress in implementing the clean energy transition, the Reference case will converge with the Hybrid and Deep Electrification Pathways over time. This expected change in the Reference case is not a new trend, as the Companies' peak demand forecasts have changed dramatically in recent years, driven by both policy changes and the programs we've implemented to reduce demand. In fact, the peak demand forecast developed by the Companies in 2015 anticipated a 25% growth in peak demand for the 20-year forecast beginning with winter 2015/2016 compared with our current Reference Case which projects a 13% reduction in peak demand over the next 20 years. The Companies will continue to refine the Reference case annually to reflect new customer adoption rates, new policies, and new technologies."

PA appreciates that the Companies expect to follow the Reference pathway in the near-term however, it is unclear which pathway is going to inform the Companies' long-term planning and investment decisions which are required in the near-term or the longer term. For instance, the Reference pathway does not meet CLCPA requirements unless policy, regulatory, technological and customer preference changes happen. In addition, clear tradeoffs exist between each pathway, and it is inefficient and impracticable to pursue all pathways identified to date at the same time.

2.3 Key Final Long Term Plan Revisions

PA observes the FLT Plan includes several revisions, based on feedback and recommendations from Stakeholders and PA. We highlight the key revisions within the following section and within the following Supply, Demand, Economic and Environmental Impact Assessment sections of this Report. The FLT Plan includes:

1. Updated information on Tennessee 300 East Project and the Westchester Moratorium
2. Additional discussion on work done to date relative to Disadvantaged Communities
3. Discussion that reaffirms the Companies' decision not to select a Preferred Pathway
4. Additional affordability data on bill impacts by service class, BCA Ratios, "share of wallet", comparative customer electric and gas economics and supporting discussions
5. Additional discussion on PHMSA MAOP reconfirmation methods
6. Additional discussion on Supply Planning, such as flexibility limitations, the role of AMAs and potential capacity release and customer rate impact of Delivered Services
7. The Companies' list of supply contracts and rankings by city-gate for de-contracting considerations.

BCA Ratios

As requested by PA and Stakeholders, the FLT Plan includes pathway-level BCAs sensitivities, as shown in Table 4. PA understands the Companies used an approach consistent with the Planning Proceeding Order and the Commission's BCA Framework Order.[9] This approach reflects sensitivities around assumptions the Companies consider to be undetermined and sensitive in nature such as customer economics, depreciation, and electric peak. PA completed a cursory review, due to time limitations, and our observations are summarized below.

Table 4: BCA Ratio Results Summary[10]

NPV ($B, 2024-2043)	Reference		Hybrid		Deep Electrification	
	ConEd	ORU	ConEd	ORU	ConEd	ORU
Benefits (Low-High)	$14-$14	$2-$2	$23-$23	$3-$4	$33-$39	$5-$5
Costs (Low-High)	$55-$28	$3-$2	$77-$42	$9-$6	$142-$87	$12-$8
Net Benefit (Low-High)	$(41)-$(15)	$(2)-$(0.2)	$(54)-$(19)	$(5)-$(2)	$(109)-$(48)	$(7)-$(2)
BCA Score (Low-High)	0.25-0.48	0.47-0.91	0.30-0.54	0.40-0.68	0.23-0.45	0.39-0.68
CEI Total BCA Score (Low-High)	0.26-0.51		0.31-0.56		0.25-0.47	

PA finds the BCAs provide a useful, directional comparison of the Pathways. We applaud the Companies for including this information within the FLT Plan. Initially, we observe BCAs for each Pathway are rather similar and below 1.0, which is not surprising given benefit estimates do not include non-quantifiable assumptions. As modeled, the majority of benefits are the result of avoided fuel costs and avoided emissions, while costs accrue from incremental electric and implementation costs. PA understands the Pathway BCAs include the

[9] Case 14-M-0101, Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework.

[10] Source: Figure 33 Companies FLT Plan.

following quantified benefits and costs and includes the Companies' description of assumptions within Appendix C of this report.

Benefits:

- Customer benefits associated with avoiding the following: space heating, water heating, cooking/drying, energy efficiency, industrial costs, and paying CEI incentives;
- Customer benefits associated with avoiding the following: CEI electric T&D, CEI gas T&D, incentive program implementation, Non-CEI gas T&D and CEI steam;
- Customer benefits associated with avoiding the supply of electric, gas, steam and other fuels; and
- Customer benefits associated with avoided emissions.

Costs:

- Incremental customer costs for: space heating, hybrid heating, water heating, cooking/drying, energy efficiency, industrial costs, and CEI incentives.
- Incremental utility costs including, incremental CEI electric T&D, incremental CEA gas T&D, incremental incentive program implementation, incremental non-CEI gas T&D and incremental CEA steam.
- Incremental supply costs including, electric, gas, steam, gasoline, and other fuels.
- 3% cost of carbon, consistent with the NYS DEC BCA framework

The Companies indicate improved BCA ratios could be achieved through increased cost of carbon and inclusion of non-quantifiable benefits such as health, air quality, job creation, etc. From a high-level, PA agrees with this assertion. Additionally, we find a further review of the cost and benefit assumptions warranted to develop a well-informed understanding of the BCAs for each Pathway.

Wallet-Share

In our Initial Report, PA recommended the Companies develop a high-level view on the impact of building electrification to enable the development of a total energy "Share of Wallet" analysis which considers the scope and magnitude of investments needed to be deployed to the gas and electric networks to meet the State's decarbonization goals. In response, the Companies' FLT Plan did contain a brief discussion that presented conclusions from a bill-impact assessment that focused exclusively on the gas sector. Based on the 6% standard set by New York City as the total energy (gas plus electric) affordability threshold - and assuming equal shares of the two bills - the FLT Plan developed a wallet-share analysis of the impact of projected gas-bill changes. Consistent with PA's assessment, the FLT Plan reports that natural gas is projected to become increasingly unaffordable: While currently just the first 3 quintiles of the income distribution have gas costs exceeding the 3% threshold, by 2043 the first 4 quintiles will see their gas bills exceed the threshold under the Hybrid and Deep Electrification scenarios. By 2050, all 5 quintiles, i.e., the entire earning population, is affected under both scenarios. Although this assessment omits electricity bills, it nonetheless reinforces the prediction that, ceteris paribus, bill payers are likely to experience growing hardship.

3 Stakeholder Engagement

The Planning Proceeding Order anticipates gas utilities engage in a process that is understandable to Stakeholders and enables meaningful Stakeholder participation. PA understands our role is not only to evaluate the plans but also to assess and facilitate a robust Stakeholder engagement process. Active Stakeholders engaging in this proceeding are identified below:

- New York Energy Consumer Council ("NYECC")
- Earth Justice and Sierra Club ("EJ/SC") and Strategen Consulting
- Environmental Defense Fund ("EDF")

- City of New York
- Utility Intervention Unit ("UIU")
- NYSERDA
- Natural Resources Defense Council ("NRDC")
- Alliance for a Green Economy – New York ("AGREE")
- New Yorkers for Clean Power ("NYCP")
- Consumer Power Advocates ("CPA")
- Greater New York Hospitals Association ("GNYHA")

In addition, several individual customers submitted comments or provided comments during technical sessions. PA thoroughly reviewed all Stakeholder comments and summarizes the main points below. PA also requested and/or attended several technical conferences to facilitate discussions among Stakeholders and the Companies on topics that were common across Stakeholder comments.

3.1 Summary of Initial and Revised Stakeholder Comments

On August 21, 2023, several Stakeholders filed Initial Comments on the Companies' ILT Plan. Within PA's Preliminary report, we summarized and discussed these comments, along with our initial observations. On October 25, 2023, Stakeholders filed additional comments on PA's Preliminary Report and the Companies' RLT Plan. In this section of the report, Stakeholders' latest comments are summarized at a high-level and discussed within the respective Supply, Demand, Economic and Environmental assessment sections of this report. In these sections of the report PA outlines our observations, analyses, and recommendations in each of these areas, including how Stakeholder Comments have been considered in our analysis.

Stakeholder comments on the ILT Plan included NYSERDA, EJ/SC, Strategen Consulting[11], NRDC, the City of New York, and UIU. Many of the Stakeholder comments focused on similar themes as summarized in Table 5: Summary of Stakeholder Revised Comment Topics. The most common themes included comments on capital spending, non-pipe alternatives, and bill impacts. All the above-mentioned Stakeholders (except for UIU) emphasized the need for the Companies to minimize capital spending and investments to serve new customers. These same Stakeholders commented that the Companies should prioritize NPAs over pipe replacement programs. Most of the Stakeholders recommended more analysis of bill impacts, specifically those related to each pathway. Sierra Club/Earth Justice stated, "The Companies acknowledge that as more customers electrify and transition off the gas system, costs for the remaining gas customers will rapidly increase, yet neither pathway explains how they intend to manage those costs."[12] Another public commenter, Mr. Leonard, filed comments focusing generally on public safety issues. Although PA acknowledges his comments, they do not appear to be germane to the long-term gas planning process.

Stakeholders filing comments on the RLT Plan include NYSERDA, CPA, EJ/SC, AGREE, UIU, NYCP, the City of New York, NRDC, and three public commenters (GNYHA and Mr. Schumann). These Stakeholders continued to focus on similar themes as outlined in Table 5. The most common themes included comments on preferred pathway and bill impacts. Most Stakeholders suggest the Companies should select the Deep Decarbonization Pathway as the preferred plan and provide additional information allowing for effective comparison of all three pathways. All the above-mentioned Stakeholders expressed concern that the Companies have not adequately considered bill impacts and customer affordability issues. Many stakeholders suggested the Companies perform additional analyses on these topics and place additional emphasis on the need to minimize capital spending and prioritize NPAs. NYCP submitted comments and an accompanying data request for two bill impact analyses using a hybrid depreciation methodology which would begin to phase in Units of Production (UoP) depreciation in 2025. In 2025 (Year 1), the rate base would be divided into two components in a 10:90 ratio. The first component, to be depreciated using UoP, would consist of the most recently added 10% of the rate base. Straight-line (SL) depreciation would be applied to the remaining 90% of rate base. In Year 2, the division would be in a 20:80 ratio, where the most recently added 20% of rate base uses UoP. Thereafter, the percentage of assets depreciated using UoP would be increased by 10% annually,

[11] Strategen' s review was prepared for Earthjustice and Sierra Club.
[12] Source: Sierra Club and Earth Justice comments.

resulting in 100% UoP-based depreciation starting in 2034 (year 10). The Companies responded to NYCP's data request on November 30, 2023.

Table 5: Summary of Stakeholder Revised Comment Topics

Stakeholder	Preferred Pathway	Bill Impacts	Capital Spending	Non-Pipe Alternatives	Low Carbon Fuels	Disadvantaged Communities	Other
New York State Energy Research and Development Authority	X	X					X
Consumer Power Advocates		X					X
Earth Justice and Sierra Club	X	X	X	X	X	X	X
AGREE	X		X	X	X	X	
Utility Intervention Unit							X
New Yorkers for Clean Power	X	X			X		X
City of New York	X	X	X	X			X
Natural Resources Defense Council	X	X	X	X	X	X	X
Public Comments[13]	X	X		X	X	X	X

Stakeholder comments in the "Other" category include:

- The Companies should not adopt the Hybrid pathway (SC/EJ and Strategen).
- Affordability should be at the forefront of the plan (City of New York).
- BCA should be included to improve transparency (UIU).
- GHG emissions impacts of oil and steam should be included, along with additional clarity on assumptions (NRDC).

In Section 3.3, PA summarizes the Companies' filed comments on Stakeholder recommendations. PA considers Stakeholder and Companies' comments within the following Supply, Demand, Economic, and Environmental Impact Assessment sections of this Report.

3.2 Technical Conferences

As discussed in our Initial Report and Preliminary Report, PA participated in and summarized the topics discussed at the Pre-Filing technical conference on April 26th, as well as a June 21st technical conference to discuss the ILT Plan filed on May 31st. Subsequent technical conferences held in July, August, September, and October 2023 are summarized in Table 6 and discussed in detail throughout this Report.

[13] Greater New York Hospital Association and Jeff Schumann.

Table 6: Technical Conferences

Technical Conference Date	Technical Session Topic(s)	Summary
July 19, 2023	Updated Peak Forecasts PA's Initial Report	• Companies presented the results of the latest Peak Day Forecasts • PA discussed key themes of its Initial Report
August 10, 2023	Rate Plan	• Companies presented key components of the recently approved ConEd Rate Plan
September 12, 2023	Stakeholder Comments Capital Investments & NPAs	• Stakeholders individually discussed the key points of their filed comments • PA facilitated discussions on lifecycle timing for NPAs and risks related to reducing the level of LPP, Transmission PHMSA Compliance and other capital investments
September 14, 2023	Rate Impacts and Affordability	• PA facilitated discussions on acceptable rate increases • Substantial Stakeholder discussions on historical and projected rates drove the need to hold an additional session in September
September 27, 2023	Rate Impacts and Affordability (continued)	• Continuation of PA's facilitated discussion on rate increases • Continuation of rate increase and capital investment decision discussions amongst Stakeholders, PA, the Companies, and Staff
October 3, 2023	Companies' RLT Plan	• Companies presented the key changes of their recently filed RLT Plan • Stakeholders asked questions to verify their understanding
October 4, 2023	Emissions Accounting	• Companies presented the emissions accounting approach used within the RLT Plan
October 18, 2023	Disadvantaged Communities and Hydraulic Modeling	• Companies presented progress mapping Disadvantaged Communities within the service territory and plans to integrate gas infrastructure assets • The Companies discussed Hydraulic Models representing pressure reduction scenarios to meet MAOP Reconfirmation requirements and the resulting impacts for National Grid gas distribution service • Several Stakeholders asked the Companies questions to verify their understanding of the Hydraulic Modeling Scenario result and Disadvantaged Communities plans
October 19, 2023	Companies' RLT Plan – Hybrid and Deep Electrification Pathway Assumptions	• The Companies presented a more granular discussion on the Hybrid and Deep Pathways - the companies described and addressed Stakeholder questions on the assumptions and dependencies of aspects of each Pathway
November 30, 2023	Tennessee East 300 / Moratorium Update	• The Companies provided an update on the status of the Tennessee East 300 project and the related lifting of the Westchester Moratorium on December 1, 2023

3.3 Companies' Reply Comments

The Companies filed Initial Reply Comments on September 5th covering recommendations made by both PA in our Initial Report and Stakeholders, as described in our Preliminary Report. On November 21st, the Companies filed reply comments in response to issues raised in the PA Preliminary Report and in the various Stakeholder Comments.[14] The Companies structured revised reply comments within the following three categories:

1. Agreement, including supplemental explanation/data the Companies plan to provide in subsequent versions of its Gas System Long Term Plan ("GSLTP");
2. Recommendations that require additional explanation;
3. Recommendations that the Companies do not plan to accept.

Within this section of the report, PA summarizes the Companies' comments relative to PA's Revised Report and Stakeholder recommendations. As noted above, the Companies' revised reply comment responses are structured across three categories and are summarized below. Responses to PA's recommendations are identified in bold and non-bolded items represent recommendations made by Stakeholders.

1. Agreement:
    a. **Robust Definition of Hard to Electrify Customers**
    b. **Detailed Assumptions, Expectations, Design and Implementation of NPA programs**
    c. **Discussion on Flexibility Limitations of Certain Components of the Supply Portfolio**
    d. **Role of Reverse AMA and Potential Capacity Release**
    e. **Discussion on the Rate Impact of Delivered Services**
    f. **Build upon the Framework for De-Contracting of Pipeline Capacity**
    g. **Cost Evaluation: Bill Impacts**
    h. **Benefit Cost Analysis**
    i. **Energy Efficiency and Demand Response**
    j. **MAOP Reconfirmation Clarification and Pipe Replacement**
2. Additional Explanation:
    a. **Rate Pressure from Continued Pursuit of the Mains Replacement Program**
    b. **Comparative Customer Economics**
    c. **Temperature Variable, Design Day**
    d. **Retaining a Dual-Fuel Option**
    e. **Demand-Side Management**
    f. **Disadvantaged Communities**
    g. Cap and Invest
    h. Con Edison Should Establish a New "Clean Heat" Electrification Program
    i. **Electric System Investments**
    j. Provide Economy Wide Emissions
    k. **Provide a "No Infrastructure" Scenario**
    l. Hybrid and Associated Certified Gas and LCF Assumptions
3. Disagreement:

[14] Source: Companies Reply Comments. November 21, 2023.

a. Stakeholder Engagement
b. Mains Replacement
c. Reduction of Infrastructure Investment, Leak-Prone Pipe Replacement Program
d. Omission of Oil-to-Gas Conversions
e. **Detailed Plans for System Shrinking**
f. **Demand Response Reconfiguration**
g. **Selecting Preferred Pathway**
h. **"No infrastructure" scenario**

Next, PA considered the Companies' revised reply comments on several the topics listed above. As previously discussed, PA and several Stakeholders have continued to emphasize the importance of costs and affordability of the Companies Pathways, bill impact, infrastructure costs and overall affordability recommendations. PA notes the following points made by the Companies on these topics:

- Reaffirm their commitment through "active participation in the Energy Affordability Policy Proceeding, a statewide proceeding examining ways to enhance the structure of the Energy Affordability Program to provide greater relief to a larger set of customers. The Companies will seek to continue using the Energy Affordability Policy Proceeding as a framework to provide greater assistance to the customers that most need it."[14]
- Preparing a bill impact analysis and a "share of wallet" quantification of the effect the three principal pathways could have on customers. The Companies are also preparing a BCA for each of the pathways.
- Reiterated their focused efforts to identify investments with sufficient lead times such that the successful deployment of infrastructure, like NPAs, electrification, etc. shall eliminate the need for traditional infrastructure and, where possible, provide detailed information on NPA plans within the RLT Plan. Going forward, they will conduct detailed distribution level analyses to enhance NPA targeting capabilities and will provide additional details once offerings mature to the point enrollments can begin and in future long-term plan cycle updates.
- Agree with the City of New York that a new "Clean Heat" Electrification program could be effective. The Companies suggest conditions such as rules with predefined timelines, no exemptions, and penalties for non-compliance (similar to those put in place to aid the transition from oil to gas) are needed for this new program to be successful.
- Provided discussions on MAOP reconfirmation requirements, how derating the pipeline segments to the required MAOP levels would impact Con Edison's delivery system and the New York Facilities System, and the feasibility of achieving design day demand reductions that would allow derating of the system.

PA and Stakeholders have continued to recommend improvements to the level of transparency and data included within the Companies' RLT Plan. In revised reply comments, the Companies:

- Agree to provide detailed information on each of the proposed pathways, such as annual participation rates and savings by program (e.g., NE:NY) and pathway would be useful and shall incorporate it in the FLT Plan.
- State Hybrid and Deep Electrification Pathways already incorporate assumptions pertaining to customer migration that results from rate impacts, as was recommended by NRDC.
- Conclude the Reference Pathway modeling outputs will not change even with the updated comparative economics of gas appliances for space heating and shall provide electric system economic competitiveness cross-over point estimates in the FLT Plan.
- Expect to enhance future long-range volume forecasts with specifically estimated impacts of EE and DSM (gas and electric) programs on annual UPC, customer behaviors and resulting electrification, energy efficiency and other DSM program adoption assumptions. However, PA notes no changes to the FLT Plan.
- Describe efforts to advance work that benefits Disadvantaged Communities.
- Note they will update the emissions factor for RNG in future long-term plans as necessary as additional guidance and more granular emissions factors become available.

However, PA finds disagreements on a few recommendations, many of which remain unaddressed at this time. The Companies:

- Believe the current “hard-to-electrify” definition is appropriate for this stage of planning.
- Disagree with PA’s recommendation to adjust the TV approach in future forecasting exercises, assuming analysis projects adequate headroom between observed and weather-adjusted Peak Load.
- Consider dual-fuel option implications as plans for the shrinking of the gas network become more defined.
- Disagree there are sufficient details on New York Cap and Invest (“NYCI”) impacts on gas deliveries to include in planning efforts, as suggested by NYCP.
- Find that some level of cross-commodity planning may be appropriate, further guidance on the scope of such efforts would be helpful to ensure manageable process to discuss improvements needed in the electric T&D system, the feasibility of building new transmission, the actual investment needed, and the time required to complete necessary expansion or upgrades.
- Disagree economy-wide emission impacts of each Pathway, as requested by NYSERDA, are outside the focus of this Planning Proceeding.
- Believe the Deep Electrification Pathway fulfils the requirement of a “no Infrastructure” scenario, as recommended by PA.
- Find certified gas and LCF assumptions within the Hybrid Pathway largely relate to issues that are currently unknown. The Companies assert this is why certified gas and LCFs should continue to be considered until it is certain they should not be.
- Believe they have demonstrated a willingness to engage with Stakeholders. They cite the large number of data requests, participation in ten technical conferences and the consideration of PA and Stakeholder recommendations, many of which are reflected within the Companies’ FLT Plan.
- Cite several instances of statutory/regulatory obligations preventing a number of recommendations made by Stakeholders. For example, the obligation to provide customers with safe and reliable natural gas service requires main replacement and LPP programs. The Companies clarify they are not permitted legally to turn customers away, therefore the SC/EJ recommendation to omit oil-to-gas conversion are merely forecasting exercises for planning.
- Find how, where, and when the distribution systems may become smaller is subject to considerable uncertainty due to factors largely outside of the Companies’ direct control.
- Disagree with PA’s recommendation that restructuring their approach to Demand Response programs would provide useful insights and conclude gas DR is not a viable option for load relief at this time.

In addition, the Companies have not selected a single, preferred pathway because they strongly believe it is premature to do so at this time.

The following sections summarize the Companies’ filed comments.

PA next assessed the extent to which the Companies’ addressed PA’s Preliminary Recommendations in the FLT Plan. If a recommendation was addressed in the FLT Plan, it is still listed and is marked as addressed. Table 7 through Table 9 below summarize this assessment.

Table 7: Comments on Supply Recommendations

PA Recommendation	Addressed / Planning to Address	Additional Information / Not Addressed
To the extent feasible, provide a more granular description of how capacity in the Joint Portfolio is allocated between the Companies based on their individual design-day requirements.		✓
Provide additional details on steps to be taken as capacity contracts expire and design day demand declines over time, with an emphasis on flexibility that may be achievable in any renewed contracts.		✓
Provide the Companies’ perspective on how pipeline capacity availability and pricing may evolve over time as demand across all sectors declines.		✓

Quantify, for each year in the forecast period, the volume of Delivered Services that may be required under all scenarios under which either or both of TGP East 300 and ExC are not in service.	✓	
Provide a more detailed explanation of the meaning of “Reverse AMAs”, how those volumes are expected to be renewed, and how Reverse AMAs are considered in the context of capacity portfolio flexibility.	✓	
Restate and elaborate on the Companies’ perspective on Delivered Services risk.	✓	
Confirm that TGP East 300 is required only to alleviate Delivered Services risk, rather than to satisfy growing design day demand.	✓	
Provide more clarity on the relationship between new supply assets such as TGP East 300 and the timing related to lifting the Westchester moratorium.	✓	
Explain the extent to which ExC would alleviate any moratorium risk.	✓[15]	
Provide clarity with respect to Con Edison’s planned replacement of transmission pipeline segments to comply with PHMSA’s MAOP reconfirmation requirements.	✓	
Provide examples for both the ConEd and ORU service territories of how specific NPAs may displace the need to replace or reinforce the distribution system.	✓	
A more robust discussion on the costs relative to each pathway including, but not limited to BCA analyses, would further strengthen the LT Plan.	✓	
Build upon the framework for de-contracting of pipeline capacity and comment on how the availability and price of Delivered Services may evolve as demand for gas (including in the power generation sector) declines.		✓
More discussion on programs such as electrification/NPAs of new (and existing) customers and how strategic “shrinking” of the distribution system footprint could unfold and result in collaborative opportunities with Stakeholders moving forward.		✓
Improve NPA program design, implementation, and cost analysis.		
Provide a more comprehensive “No Infrastructure” option. Proper planning would necessitate the Companies provide more specificity regarding alternatives to limit infrastructure investment to inform the Commission and Stakeholders. A more specific “no infrastructure” option would provide a lower end boundary on the level of total infrastructure investment using NPAs.		✓
Provide detailed assumptions and expectations for NPA programs going forward.		✓

Table 8: Comments on Demand Recommendations

PA Recommendation	Addressed / Planning to Address	Additional Information / Not Addressed
Inclusion of more detailed steps along the decarbonization pathways, and include specific thoughts, expectations, or requirements for how to incentivize customers to become partners in the decarbonization process, commentary on existing incentives and how they may need to scale or evolve to achieve desired policy expectations, etc.	✓	✓
The Companies have developed a high-level top-down forecast that is helpful in depicting the potential emissions trajectory, supply and demand projections, and impact on rates under various potential futures. PA envisions significant value in supplementing this top-down forecast with bottom-up analyses and forecasts that could help Stakeholders understand and test validity of various assumptions used in this forecast, and potentially to adjust those assumptions if/when needed with minimal efforts throughout this process.		✓
Incorporate the economics of gas versus electric appliances. The current modeling efforts do not account for the evolving competition between the economics of gas and electric appliances (e.g., gas furnace and heat pump) over the next decades. This dynamic view is potentially a very important dynamic feedback loop, as it could impact the total volumes of gas delivered to customers and thus the gas rates. Upon reduction in gas volumes, all else equal, gas rates will increase over time and alternative electric solutions will		✓

15 It is important to note that the 2023 Reference pathway demand curve incorporates demand growth from lifting the Westchester moratorium, which PA understands will be lifted on December 1, 2023

be more cost competitive over time. PA expects significant value in providing historical adoption rate of various technologies (e.g., heat pumps) and supplementing the projections with an analysis that accounts for such dynamics. Companies have indicated they are working on providing an updated view on the economic comparison of gas and electric technologies. We encourage the Companies include this analysis in the FLT Plan.		
The current modeling does not account for partial electrification, i.e., customers either use gas for all appliances or, alternatively, electrify completely. Although this is a simplifying assumption, it may not be reasonable in practice as customers typically face a decision to replace their appliances at the end of the life of each appliance and upon their failure. Since not all appliances fail at the same time, customers will likely make a switch in different timeframes, thus not all appliances will be replaced all at once. The LT Plan could be improved by assessing customer fuel switching at the customer class and appliance level.		✓
The Companies have multiple EE and DSM programs that have been helping customers save money while helping the reliability of the gas and electric systems for decades. PA encourages the Companies to provide more information such as annual participation rates and savings by program (NE:NY, Organic, etc.) and pathway, of various DSM and EE programs and how these programs could be leveraged or upscaled to support these Decarbonization pathways and the level of funding and efforts needed over the next decade to meet these decarbonization targets.	✓	✓
The Companies are relying on a simplifying assumption to derive the gas volumes from forecasted gas peak demand using a fixed annual peak to volume ratio. While such an approach may have been prudent in the past, this approach will likely not be accurate as partial or full electrification unfolds in New York changing the peak to volume ratio over time. The LT Plan could be improved if the Companies further enhance their forecasting methodology to address this approach.		✓
Consider a restructured approach to DR offerings, including but not limited to refined trigger temperatures, pro-active communication of the environmental and economic value of such programs (beyond the response incentives offered) to encourage customer adoption and consider regulatory changes such that company shareholders are incentivized to fund for such measures over substantially more expensive delivered services and/or future capital investments.		✓
Consider the impact of Electric Operations DSM measures on the customer behaviors and resulting electrification, energy efficiency, and other DSM program adoption assumptions.		✓
Consider the notion of adjusting the TV approach in the future provided analysis projects adequate headroom between observed and weather-adjusted Peak Load. Since the cost of reserving and contracting Delivered Services and peaking CNG resources can be multiples of the baseload gas the Companies acquire, even a small decline in forecasted Peak can provide relief to bill-payers – especially in the lower-income brackets.		✓

Table 9: Comments on Economic and Environmental Recommendations

PA Recommendation	Addressed / Planning to Address	Additional Information / Not Addressed
The Companies should provide calculated bill impacts for each service classification, or at the least, the SC1, SC2, SC3 classes, and use projected volumes for each customer class rather than using a constant value for the volume of gas delivered to a representative customer.	✓	
The current modeling efforts do not account for the evolving competition between economics of gas and electric appliances (e.g., gas furnaces and heat pumps), which is a potentially very important dynamic feedback loop for how such dynamic could impact the total volumes delivered to customers and thus the bill impact analysis. PA believes significant value exists from supplementing the projections with an analysis that accounts for such dynamics.		✓
Significant value would be expected by conducting an energy share of wallet analysis to understand the bill impact of each scenario on customers' affordability.	✓	

PA understands that ConEd will file an annual Disadvantaged Communities Report including more data regarding investments, engagement, and workforce development efforts in disadvantaged communities and observes inclusion of this, as well as additional information such as footage of leak prone pipe, leak repairs, and associated avoided emissions in that report and the LT Plan, would strengthen the plan.	✓
Conduct an optimization process to identify and develop a long-term plan Pathway with the highest emissions reduction potential and lowest impact on affordability while maintaining system reliability and safety. From our understanding, it is unclear and unlikely the Companies have conducted such optimizations to identify a Pathway with highest societal value and least potential risk overtime. In addition, Companies should conduct a sensitivity analysis to demonstrate the modeling robustness and share a view on the most sensitive assumptions and variables with the Stakeholders and the Commission to assess the prudence of these assumptions.	✓
Identify ways to further manage bill impacts and affordability challenges. The Companies' bill impact analysis is relatively high-level and could pose affordability challenges for ratepayers, especially for lower-income customers, who do not qualify for billing assistance programs	✓
Increase planning coordination between the gas, steam, and electric systems. While there is no direct language in the Planning Proceeding Order requiring utilities to conduct coordinated long-term planning for the gas, steam, and electric systems, PA recommends some coordination to ensure that safety, reliability, resiliency, and affordability objectives are properly considered as part of the long-term planning process.	✓
Identify the pathway that is preferred to guide the Companies' actual investment plans.	✓

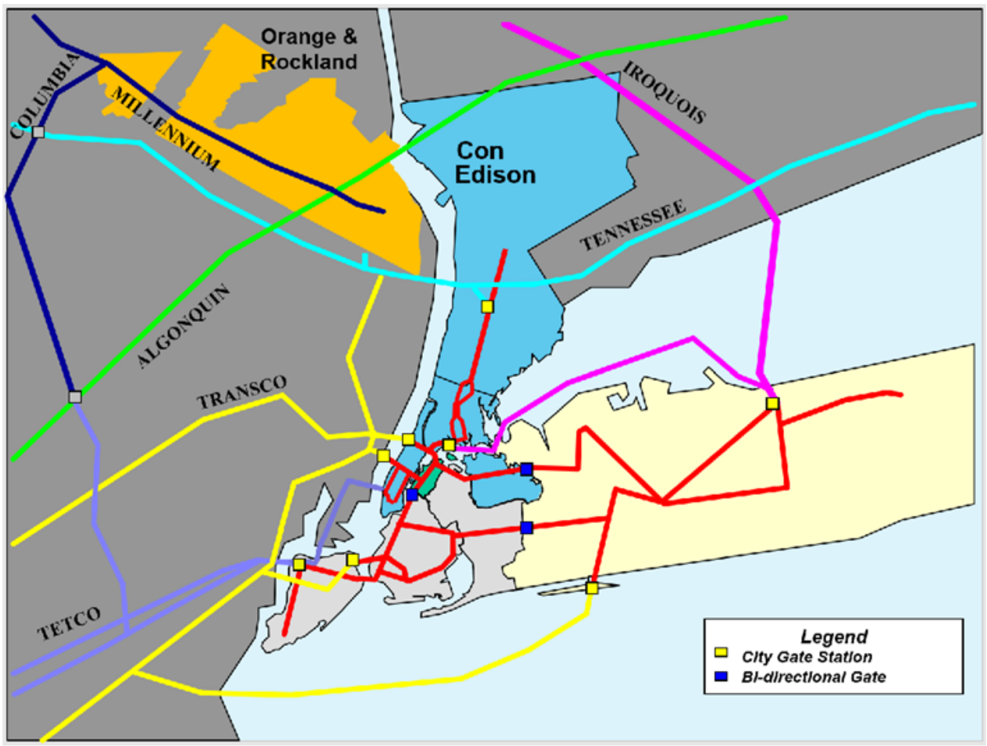
PA further considers the Stakeholder and Companies Reply comments within the following Assessment sections of this Report.

4 Supply Assessment

The Companies' distribution systems are connected to multiple interstate pipelines, including the Algonquin Gas Transmission Pipeline ("Algonquin") and via pipeline network known as the New York Facilities System ("NYFS"), which is operated jointly by ConEd and National Grid, Transcontinental Gas Pipeline ("Transco"), Texas Eastern Transmission Company ("TETCO"), Tennessee Gas Pipeline ("TGP") and Iroquois Gas Transmission System ("Iroquois"). PA recognizes the ORU system is served through a series of interconnections on the Millennium pipeline and that the JSP, consisting of 76 individual pipeline and storage contracts, supports the two separate and distinct ConEd and ORU distribution systems.

Figure 3 below, from the Companies FLT Plan, illustrates the interstate pipeline interconnections to the ORU and ConEd pipeline systems, including the NYFS.

Figure 3: ConEd and ORU Pipeline Facilities System Map[16]



ConEd has one on-system LNG facility at Astoria and one on-system trucked CNG facility in Westchester County to provide additional supply reliability. Additionally, the Companies are in various stages of contracting for incremental pipeline capacity through the TGP East 300 project, the ExC upgrade of the Iroquois pipeline, and the Mountain Valley Pipeline ("MVP").

TGP East 300 is designed to provide 115 MDth/day of firm capacity to the ConEd system. The project is made up of three separate components:

- An upgrade to an existing compressor station (referred to as Compressor Station 321 or CS 321) in Susquehanna County, Pennsylvania;
- An upgrade to an existing compressor station (referred to as Compressor Station 325 or CS 325) in Sussex County, New Jersey and;
- A new electric-driven compressor (referred to as Compressor Station 327 or CS 327) in the Township of West Milford in Passaic County, New Jersey.

[16] Source: Figure 13 of the FLT Plan.

Figure 4 below provides a map depicting the location of the three compressor sites which make up the TGP East 300 project.

Figure 4: TGP East 300 Compressor Stations[17]

At the time of our Initial Report, the TGP East 300 project was expected to be fully in service by November 1, 2023. It is PA's understanding that a portion of the full capacity of TGP East 300 was placed in service on November 1, 2023, and that the full 115 MDth/day of new capacity was in service as of November 16, 2023.

In our Preliminary Report, PA noted that, in 2021, the New Jersey Department of Environmental Protection issued a Highlands Applicability Determination ("HAD") to TGP which exempted construction of a new compressor station in the Highlands Preservation Area from a requirement to obtain a Highlands Preservation Area Approval for certain work activities. In an August 31, 2023 order, the Superior Court of New Jersey (Appellate Division) vacated the HAD issued to TGP and remanded the matter to the New Jersey Department of Environmental Protection ("NJDEP") to consider, among other things, whether TGP's proposed compressor station can qualify as a "routine upgrade" to its pipeline system.[13] It is PA's understanding that the basis of the appeal was whether the compressor could be constructed, rather than operated. PA is not aware that the NJDEP has taken further action. Now that the facility is in service, PA is uncertain whether the outcome of the appeal will have any bearing on continued use of the new TGP 300 East capacity.

The Iroquois expansion by compression ("ExC") project is designed to provide an incremental 62.5 MDth/day of firm capacity to the Companies. It will also provide 62.5 MDth/day of additional capacity to National Grid. PA's understanding is that Iroquois ExC is expected to be in service by November 1, 2025. However, at the time of this report, the project has not yet received required air permits from the New York and Connecticut state environmental agencies. PA will continue to evaluate the supply stack both with and without Iroquois ExC.

PA has undertaken its review of several supply and supply-related aspects of the ConEd and ORU systems, based on information presented in the FLT Plan and responses from the Companies to a number of related discovery requests. It is important that the Commission continue to follow developments related to the Iroquois ExC project and related uncertainties given the role that project is expected to play in ensuring reliable supply to meet customer demand. Our observations, based on available information at the time of this report, are summarized within the sub-sections below. We first highlight components of the supply stack and then discuss

[17] Map details from TGP East 300 Project website.

hydraulic models of the systems and the implications of certain supply assets on those models. We conclude with comments on supply-related aspects of the capital forecast and a discussion of NPAs.

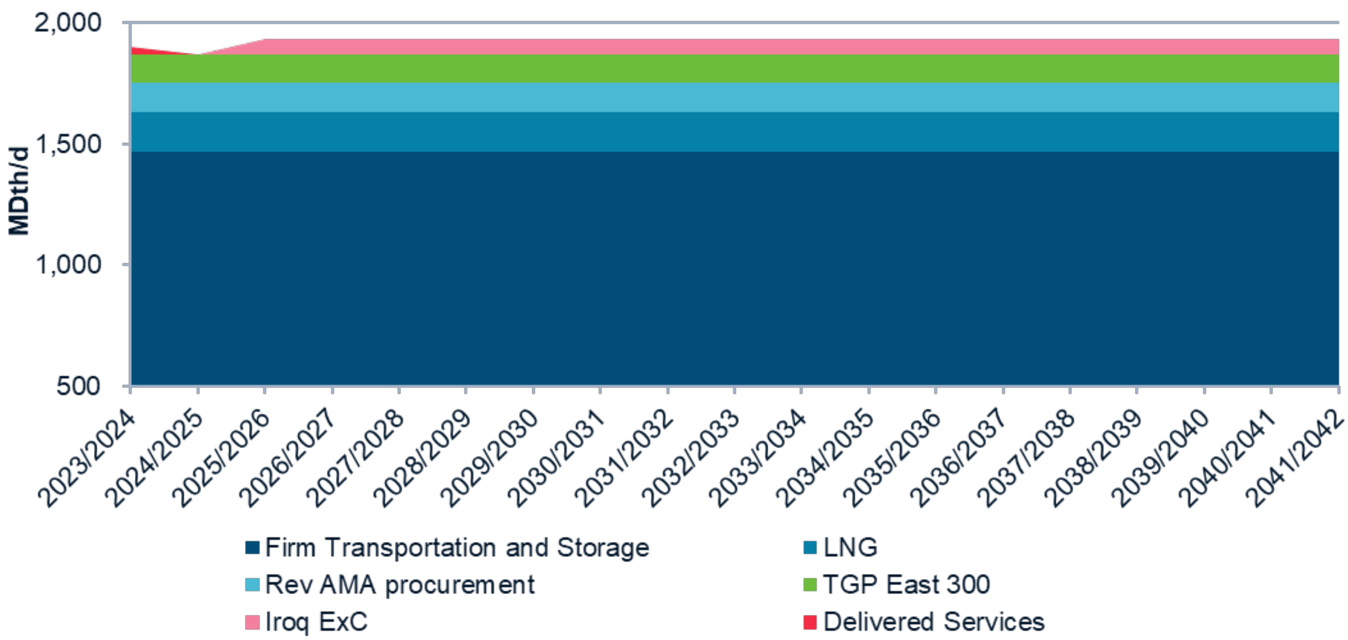
4.1 Supply Stack[18]

4.1.1 Long-term Contracts Assessment

The JSP supports customer demand and operations of two separate and distinct distribution systems. From an upstream perspective, the Companies manage a single portfolio of contracts operated and paid for by ConEd and ORU, with costs recovered from the Companies' ratepayers. However, operationally the distribution systems are not connected. Some interstate pipelines (e.g., TGP) cross both service territories and have city gate interconnections in each footprint. The Companies dictate which distribution system receives supply from its portfolio of contracts and have the flexibility to direct natural gas supply to either ConEd or ORU when a supplier's pipeline interconnects to both utility systems.

The FLT Plan includes a supply stack that reasonably breaks down the components of the portfolio. The Companies have acknowledged a need to provide a more granular description of the supply portfolio breakdown based on each Company's design day needs. Figure 5 provides the combined supply portfolio for the Companies.

Figure 5: ConEd and ORU Supply Portfolio[19] [20]

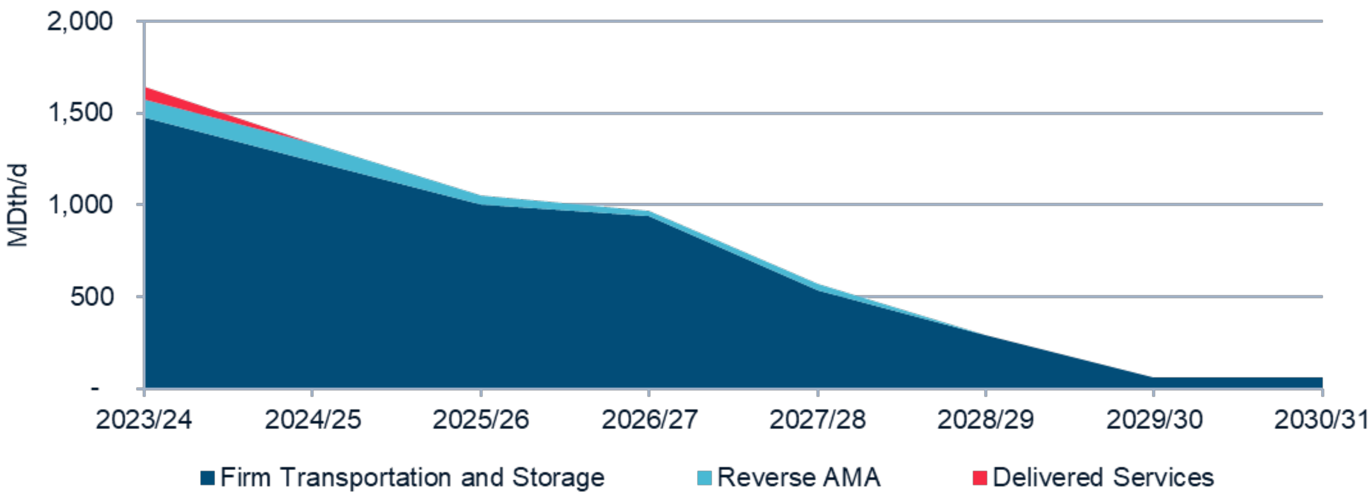


The supply stack presented by the Companies in Figure 5 assumes that Firm Transportation and Storage[21] volumes and Reverse AMA volumes are renewed throughout the 20-year forecast period reflected.[22] The

[18] The terms "Supply Stack" and "Supply Portfolio" may be used interchangeably.
[19] Incorporates data from the Companies response to DPS_9_173_Att. 2.xlsx and does not incorporate Delivered Services acquired for 2023-24 Winter Preparedness.
[20] The capacity associated with TGP East 300 is a component of the Firm Transportation and Storage category but is retained in this graphic to illustrate the volumetric impact on the supply portfolio.
[21] Firm Transportation contracts are those that obligate a pipeline to transport natural gas to the Companies when requested. Firm Transportation with Storage contracts are those that offer the same obligation for the pipeline to deliver natural gas to the Companies when requested, but also allow the Companies to access and utilize natural gas storage facilities. Storage contracts grant the ability to access and utilize storage, that in some cases are firm—meaning the pipeline must deliver those volumes – or interruptible – meaning the pipeline company can curtail the volume of natural gas delivered if the available capacity is used by higher priority firm customers.
[22] The Utilities have presented a 20-year forecast in the FLT Plan, which is consistent with expected planning parameters.

contracted components of the supply stack have expiration dates ranging from immediately after winter 2023-24 to after winter 2033-34. By winter 2026-27, when the Companies' projection of design day demand is expected to peak, 590 MDth/d of capacity flowing to city gates will have been subject to renewal. See Figure 6. The Companies have confirmed most of their contracts either have a right of first refusal ("ROFR") or are covered under a pipeline tariff blanket ROFR provisions. They have also confirmed that they have added renewal terms to all their Reverse AMA volumes. The volume of expiring contracts over the next several years is significant, and the Companies have acknowledged that they will address and provide more details related to restructuring existing contracts to maximize portfolio flexibility as design day demand peaks and as the Companies seek to eliminate potentially unnecessary contracted volumes in the future.

Figure 6: Volume of Contracts by Season of Expiration[23]



In the discussion of gas supply strategy, the Companies have noted they intend to extend or renew pipeline capacity contracts over the next 1-5 years and have the flexibility to make other decisions regarding the contracted portfolio in the 5-20-year timespan. In their responses, the Companies indicated that, when a firm contract is set to expire, pipeline operators are becoming less willing to accept negotiations for shorter renewal periods and that other flexibility characteristics tend to be unavailable due to the tight nature of the firm capacity market in the Northeast. Similarly, pipeline operators and storage companies are unlikely to be willing to decrease contract volumes – such reductions would put pipeline company revenues at risk. It would be valuable for the Companies to discuss flexibility limitations associated with long-term contracted capacity in the plan so that Stakeholders can better understand which components of the supply stack are best suited for evaluation from a flexibility standpoint.

The Companies may have the ability to generate savings for customers by releasing firm pipeline capacity to third parties when they determine the excess capacity is not required to serve design day demand. In this way, the Companies could generate some additional revenue and deliver those savings back to customers or use them to offset the risk and cost of stranded assets. As an enhancement to the plan, it would be valuable for the Companies to discuss their ability to release pipeline capacity and how any revenue from such releases could be used to alleviate costs to customers. It may also be valuable for the Companies to indicate which regions, pipelines, or contracts would be the best contenders for capacity release based on where demand is stagnant or eroding. The Companies should comment on the types of counterparties that they could release capacity to, including potential counterparties out-of-State.

In its discussion of the approach to pipeline renewals and renegotiations in the plan, it would also be valuable for the Companies to add information about how they believe general pipeline contract availability and flexibility might be impacted by evolving trends in natural gas consumption, including the implications of electrification. For example, it would be valuable to know if the Companies expect more flexible natural gas contracts to be available as demand for natural gas as a power generation fuel subsides across the region. This type of discussion can remain high level and need not be an in-depth analysis of the supply and demand landscape in the Northeast.

[23] This graphic does not include the firm capacity represented by TGP East 300.

4.1.2 Delivered Services

Delivered Services are natural gas volumes purchased from third parties that hold the rights to the underlying contracted capacity. The joint supply stack currently includes Delivered Services that, based on the Companies' statements in the RLT Plan, can be eliminated by 2029-30 in the Reference pathway, assuming certain upstream projects on which they have committed to capacity are completed and placed in service. The Companies have further indicated that Delivered Services hold risk in three primary categories.[24]

- **Ability to re-contract:** the counterparties that own Delivered Services capacity are not obligated to give the Companies an option to renew delivered service volumes once contracts expire.
- **Availability:** with increasingly constrained pipeline capacity in the northeast, the market of available Delivered Services is difficult to verify and may fluctuate; the parties holding the underlying capacity are free to sell it to a different party outside of the Companies' service territories.
- **Price volatility:** instead of purchasing natural gas in production regions where prices are low and relatively insulated from volatility, natural gas is purchased at citygates within or near to the New York area where prices tend to be volatile.

ConEd / ORU have indicated that, for the reasons discussed above, the Companies will prioritize de-contracting Delivered Services when expected peak day demand decreases sufficiently to eliminate unnecessary components of the supply portfolio.

The Companies currently have 33 MDth/day of Delivered Services contracted for winter 2023-24[25] and 3 MDth/day contracted for winter 2024-25 season; beyond that time, no Delivered Services volumes have been contracted. The Companies have indicated that they will use the contracted as well as incremental Delivered Services to bridge the gap between the existing supply and peak demand under differing scenarios[26].

The Companies provided a discussion and quantification of the volume of Delivered Services that may need to be acquired for scenarios wherein the ExC project is not successful[27]. As part of this discussion, the Companies should indicate how confident they are about their ability to contract for incremental Delivered Services – ideally offering ranges of volumes they believe could be contracted. Because the Companies have expressed a desire to reduce the volume of Delivered Services in their supply stack, it may be valuable to extend this analysis to the potential bill impacts of simultaneously removing Delivered Services from the supply stack and the impacts of using NPAs to shrink the system that was previously reliant on Delivered Services. Natural gas commodity and demand costs make up a significant portion of a customer's bill – between approximately 34-40%[28] for an average customer in 2022. Delivered Services also tend to be among the most expensive components of the natural gas supply. From winter 2020-21 to winter 2022-23, weighted average daily demand rates for Delivered Services have varied between approximately $2/Dth and $4/Dth. Some daily demand rates were priced in excess of $10/Dth for capacity. For context, reservation rates for the pipelines that serve this region vary between approximately $0.12/Dth/day and $0.60/Dth/day. It is important to note that, when annualized, pipeline contracts are more expensive - in part because Delivered Services reservations only occur for a few months during the year. Daily demand rates for short-term services, however, are (and are expected to be) more expensive. The higher rates associated with short term service contracts make it incredibly important that the Companies communicate the potential customers' savings associated with reducing the volume of contracted Delivered Services – be it through incremental capacity provided by new upstream sources like TGP East 300 or ExC, or through NPAs which have the potential added benefit of reducing the operating and capital expenses associated with maintaining infrastructure. It is important to note that Delivered Services are expensive both from a capacity standpoint and from a commodity standpoint. Delivered Services tend to be called upon during periods of peak demand when natural gas is scarce and expensive.

[24] Delivered Services risks discussed here were explained in ConEd's 2019 Rate Case Proceeding, Direct Testimony of Con Edison Gas Infrastructure, Operations and Supply Panel, pages. 151-153.
[25] This amount does not include any incremental peaking services acquired for 2023-24 as part of the Winter Preparedness filing.
[26] Source: Figure 28 of the FLT Plan and the Companies' response to DPS 9-173.
[27] This discussion also included a consideration of TGP East 300, but now that the project is in service, this component of the discussion is no longer relevant.
[28] Source: Response to DPS 7-153, calculated by taking the fraction of average commodity and demand costs over the average total bill.

The Companies' reliance on Delivered Services is highly sensitive to the available supply options. To illustrate how drastically the Companies' Delivered Services needs may vary, PA evaluated the volume of Delivered Services the Companies may require for the next several years under several firm supply scenarios. It is important to note that the below graphics do not account for any volume of Delivered Services that have been procured as part of the Companies' 2023-24 Winter Preparedness filing and that the demand curves represent the Companies' 2023 Reference pathway demand as is provided in DPS 9-173[29]. It is also important to note that the 2023 Reference pathway demand curve incorporates demand growth from lifting the Westchester moratorium, which PA understands will be lifted on December 1, 2023,[30] even though the Companies have noted in the response to DPS 4-121 that the incremental design day demand resulting from lifting the moratorium is relatively small when compared against the total design day demand – ranging between 2-6 MDth/d. PA evaluated the volume of Delivered Services that may be required to satisfy the 2023 Reference Pathway demand under the following scenarios:

- TGP East 300 and Iroquois ExC are successfully placed in service as scheduled in 2023-24 and 2025-26, respectively;
- Only TGP East 300 is successfully placed in service.

PA evaluated scenarios under which (a) neither TGP East 300 or Iroquois ExC are successfully placed in service, and (b) only Iroquois ExC is in service. With TGP East 300 now being in service, those scenarios have been excluded from the discussion below.

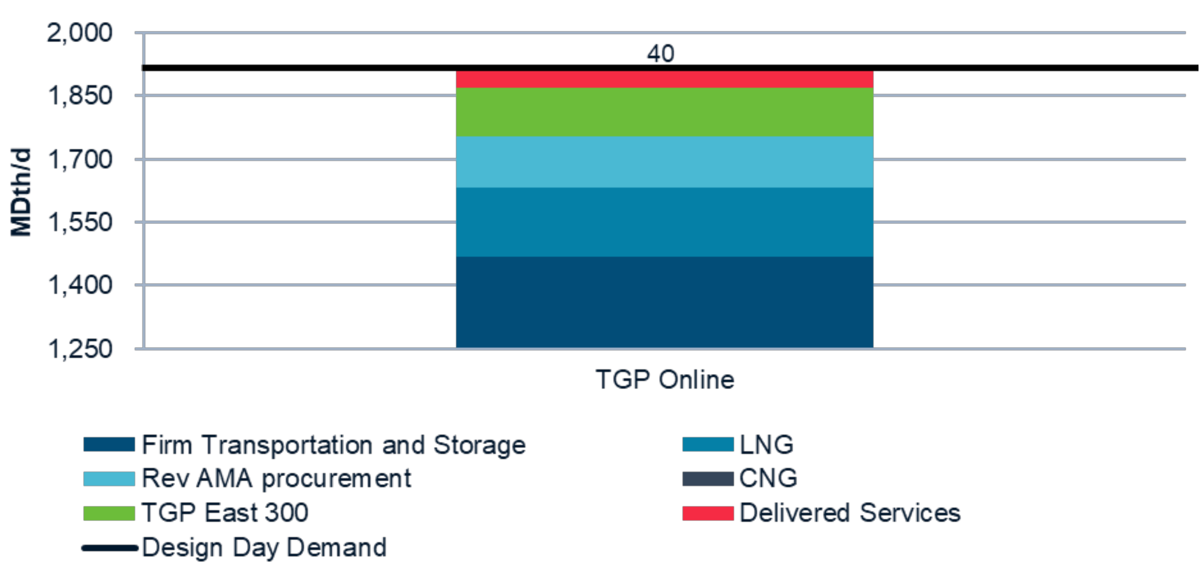
Eliminating Delivered Services is an important first step towards reducing the need for natural gas supply and the associated costs and emissions.

Winter 2023-24

In winter 2023-24, the Companies may need to procure approximately 40 MDth/d of Delivered Services as shown in Figure 7. It is key to note that even though TGP East 300 was fully in service as November 16, 2023, a need for Delivered Services to bridge the gap between supply and demand remains.

Because no portion of the TGP East 300 capacity was in-service until November 1 the Companies reasonably acquired Delivered Services that would have offset a portion of that required capacity. It is PA's understanding the Companies will have the ability to release any unneeded capacity associated with the TGP East 300 project to counterparties in the region, and revenues from the release of that capacity would be provided as credits to customers to offset the resulting duplicative costs.

Figure 7: 2023-24 Reference Pathway Supply Stack and Delivered Services

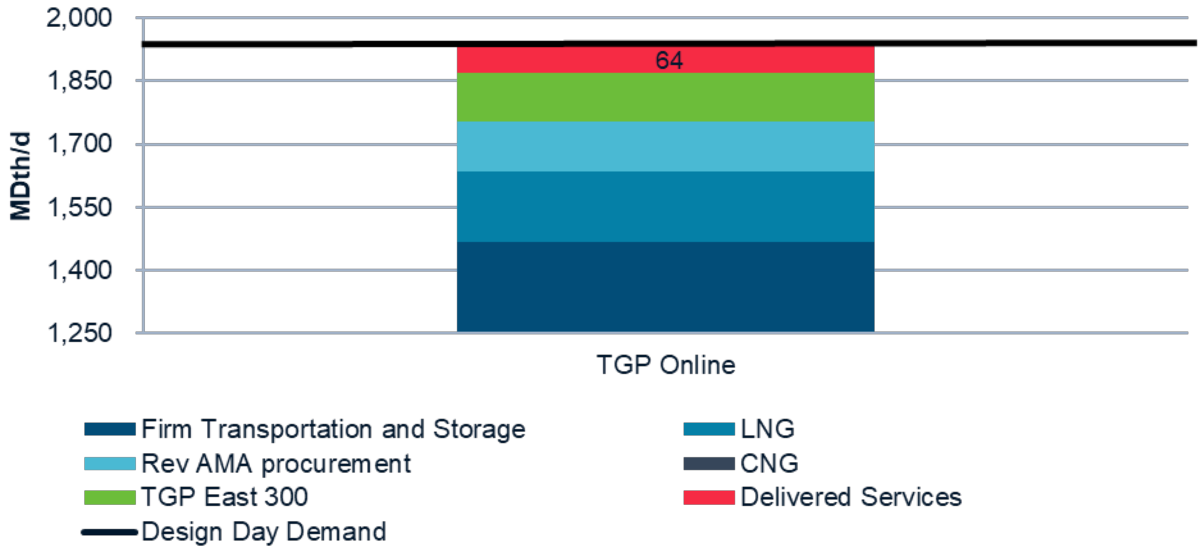


[29] This demand curve does not include any adjustment to the design day demand as discussed later in this report – though any downward adjustments to demand that are discussed later in this report will result in a demand curve that is more easily satisfied by the supply stack as presented in each scenario.
[30] Source: ConEdison. Notice Ending Temporary Gas Service Moratorium. November 17, 2023.

Winter 2024-25

In Winter 2024-25, the Companies' Reference pathway design day demand increases slightly. In this winter season, the quantity of Delivered Services is expected to be approximately 64 MDth/d, as seen in Figure 8.

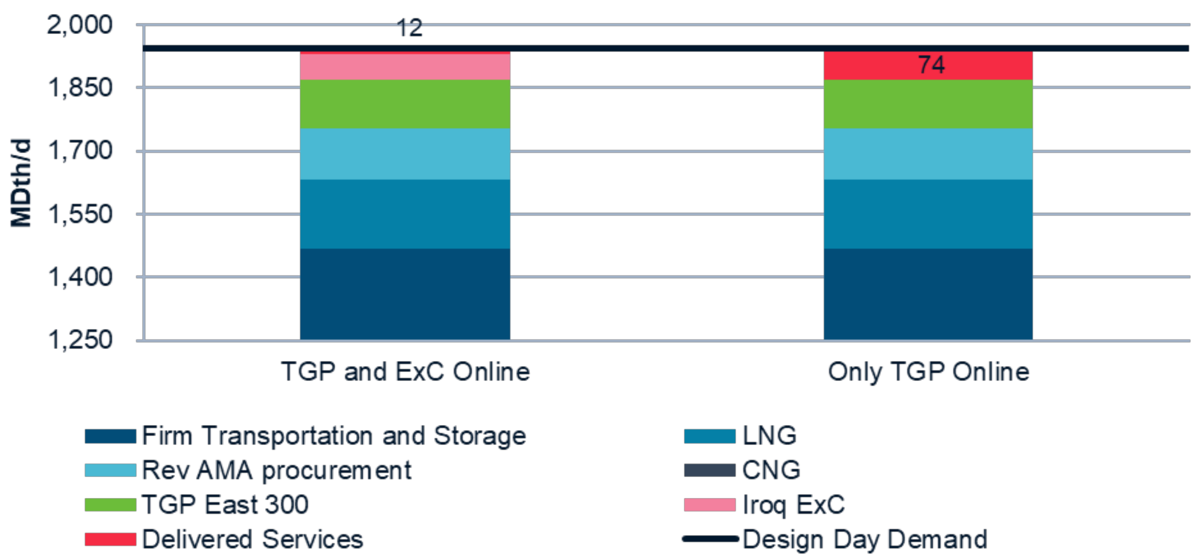
Figure 8: 2024-25 Reference Pathway Supply Stack and Delivered Services



Winter 2025-26

It is PA's understanding that, if remaining regulatory approvals are received, the Iroquois ExC project could enter service for the Winter 2025-26. If Iroquois ExC successfully enters service alongside TGP East 300, most of the Delivered Services necessary to meet design day demand under the Reference pathway are eliminated, leaving only approximately 12 MDth/d. If ExC does not enter service, the volume of Delivered Services necessary grows to 74 MDth/d. These potential scenarios are shown in Figure 9.

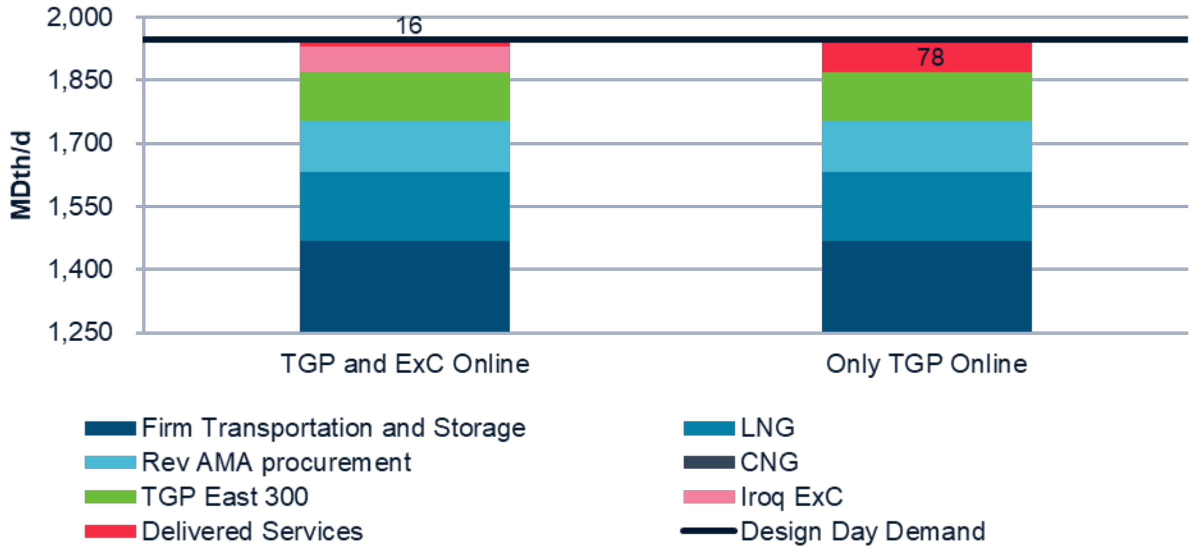
Figure 9: 2025-26 Reference Pathway Supply Stack and Delivered Services



Winter 2026-27

The scenarios in 2026-27 are very similar to the previous year with the only change being a slightly higher design day demand under the Reference pathway. Under the Reference pathway, demand peaks in 2026-27 and reaches an inflection point thereafter, decreasing in all subsequent years. Delivered Services volumes are expected to vary between 16 MDth/d in the "TGP and ExC Online" scenario and 78 MDth/d in the "TGP Only" scenario as shown in Figure 10.

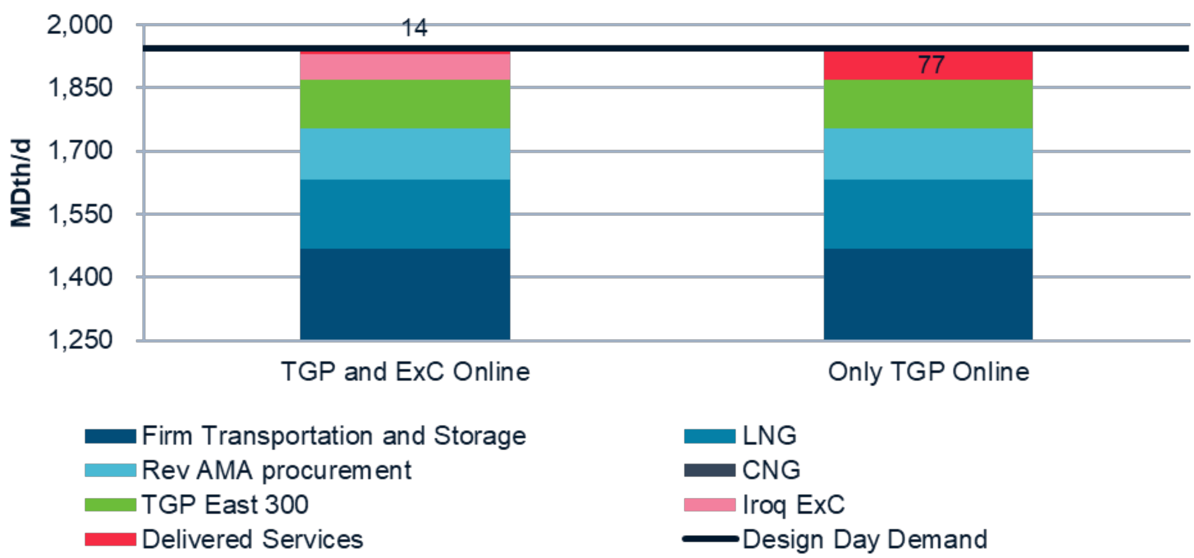
Figure 10: 2026-27 Reference Pathway Supply Stack and Delivered Services



Winter 2027-28 and Beyond

Winter 2027-28 represents the first year in which the Reference pathway forecast design day demand begins to trend downward after reaching a peak in the previous winter season. In this year, the volume of Delivered Services the Companies may need to acquire begins to trend down, varying between 14 MDth/d in the "TGP and ExC Online" case and 77 MDth/d in the "Only TGP Online" case as shown in Figure 11.

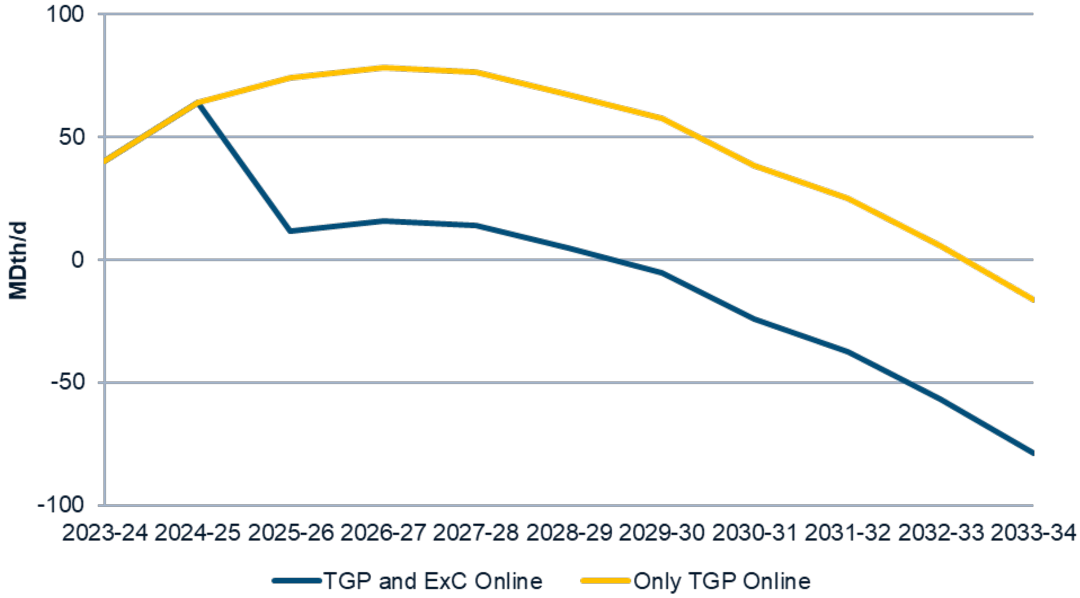
Figure 11: 2027-28 Reference Pathway Supply Stack and Delivered Services



After 2027-28, Reference pathway design day demand begins to trend downward such that, under the "TGP and ExC Online" scenario, no incremental Delivered Services are necessary starting in Winter 2029-30.

Figure 12 below shows the volume of necessary Delivered Services under the 2023 Reference Case demand. The "Only TGP Online" scenario does not see the need for Delivered Services to diminish until 2033-34.

Figure 12: Delivered Services Necessary Under Different Supply Scenarios



It is important to note that this analysis is based on the Companies' design day demand forecast. As discussed in Section 5, opportunities may exist for the Commission to investigate alternative approaches to developing design day forecasts across the entire natural gas LDC sector in New York. In some cases, alternative approaches might allow the Companies to reduce their use of Delivered Services more quickly. Regardless, reducing the use of Delivered Services is typically a good way to reduce emissions in a more cost-effective manner for customers.

4.1.3 Asset Management Agreements

Asset management agreements ("AMAs") are agreements in which a third party (an "asset manager") manages another party's gas supply and delivery arrangements. In delivery AMAs, a large purchaser of natural gas will allow another party to manage its gas supply and delivery arrangements but will require that the asset manager deliver gas to the purchaser when called upon to do so. The asset manager can then sell or release any remaining capacity that is not called upon by the purchaser to other parties. The asset manager is incentivized to allocate efficiently excess pipeline capacity because it shares revenue from such sales with the purchaser.

In supply AMAs, a producer of natural gas will allow an asset manager to use its pipeline capacity purchase then re-sell the producer's gas and will also share in the revenue in this arrangement.

In the FLT Plan, the Companies provided more detail about what they define as "Reverse" AMAs and indicated that the Companies had previously utilized AMAs to optimize their supply portfolio. In the FLT, the Companies discussed how AMAs can be utilized going forward to release capacity to other parties to generate revenue for customers. The Companies also provided historical data on revenue generated from AMAs that was returned to customers. It would be helpful for the Companies to expand on this discussion by describing, if possible, which contracts they can consider for AMAs or capacity releases, what kinds of counterparties they can release capacity to (both in- and out-of-state), and which regions in their territories they expect to experience decreases in demand that would allow them to consider utilizing AMAs.

4.1.4 Companies' De-Contracting / Re-Contracting Approach

As design day demand begins to decrease, in an effort to reduce the volume of contracts that are no longer needed, the Companies have created a methodology for considering how to de-contract capacity that is no longer required. The Companies prioritize reducing Delivered Services first, followed by the least flexible pipeline contracts. The methodology considers the following:

- Hydraulic models for various regions to identify where supply needs are subsiding, filtering the pipelines that can be considered for de-contracting;
- Which pipelines have capacities that either fit the necessary supply reductions or have flexible volumes;
- Flexibility characteristics in the pipeline contracts including access to storage facilities; and
- The cost of the contracts, and other characteristics including expiration dates and notice requirements.

These considerations outline a reasonable approach to prioritizing which contracts are eliminated as peak demand drops. This process helps the utilities revert to a least-cost flexible portfolio of supply that should responsibly minimize the rate impact of potentially expensive natural gas contracts. As discussed in Section 4.1.2, Delivered Services are a risky and often expensive source of supply, and this source of supply should be considered a priority for reduction. PA has analyzed the risk of Delivered Services in the past and understands the risks of Delivered Services include the potential that supply is not available when called upon, as well as the higher costs associated with this source of supply.

In the FLT Plan, the Companies indicated they have begun the process of ranking contracts that can be targeted for elimination as design day demand decreases and have included a ranking of the contracts considered for de-contracting.

4.1.5 ConEd LNG and CNG

Design day supply from ConEd's Astoria LNG facility is reflected in the ConEd portion of the Companies' supply stack[31] throughout the 20-year period shown. PA understands the hourly capacity of the LNG facility is 10 MDth, with a capacity of 8.3 MDth per hour (166 MDth per day) included in the design day supply stack.

The supply stack currently includes 25 MDth of CNG supply on a design day. As PA understands it, the CNG facility will be retired prior to mid-November 2024 since TGP East 300 is now in service and the Westchester County moratorium will be lifted December 1, 2023. PA finds it reasonable that the LNG facility remain in the Companies' supply stack going forward. This on-system supply asset provides important system stability and serves as an important design day resource.

4.2 Hydraulic Modeling

PA reviewed several hydraulic modeling scenarios of the ConEd and ORU systems. PA's comments with respect to the adequacy of each of the Companies' distribution systems (including the NYFS) to reliably deliver gas to customers on a design day assume that to the extent emergent needs require replacement of any pipeline delivery assets, those assets would be replaced.

PA has evaluated several hydraulic models of the New York Facilities System (NYFS)[32] as provided by ConEd.[33] The following summarizes the minimum gas supply and delivery infrastructure required to reliably serve ConEd's forecast of design day demand going forward (assuming the Companies have contracted for the required supply in each scenario) as reflected in those models. The models, and PA's conclusions below, are based on the Companies' forecasts of design day demand over time.

- **Winter 2023-24:** Forecasted design day demand can be served with existing infrastructure.
- **Winter 2024-25:** Forecasted design day demand can be served with existing infrastructure plus certain distribution system upgrades on the National Grid system. The Companies were able to communicate to PA that each of those upgrades is expected to be in service in 2024.
- **Winter 2025-26:** Forecasted design day demand can be served with existing infrastructure plus the same distribution system upgrades on the National Grid system as discussed above for Winter 2024-25.

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[31] Source: Figure 28 of the FLT Plan. As a practical matter, the LNG facility can serve only ConEd customers.
[32] As indicated in the Companies' FLT Plan, the NYFS is a regional network of pipelines jointly operated (and owned) by ConEd, National Grid Metro and National Grid Long Island. The NYFS is serviced by four interstate gas pipelines – Transco, TETCO, TGP and Iroquois. NYFS member utilities may receive gas from all four pipelines and transfer supplies among the utilities.
[33] Modeling scenarios were available and provided in response to DPS 1-3 for each future winter season through winter 2027-28. It is not unreasonable that additional models beyond that season have not yet been developed.

- **Winter 2026-27:** Forecasted design day demand can be served with existing infrastructure plus the same distribution system upgrades on the National Grid system as discussed above for Winter 2024-25.[34]
- **Winter 2027-28:** To serve forecasted design day demand in this winter season, the models indicate that in addition to existing infrastructure and the National Grid distribution system upgrades expected to be in service in 2024, either TGP East 300 or ExC must be in service.[35] PA notes that ConEd's design day forecast for 2027-28 is slightly lower than its forecast for 2026-27. That being the case, it is PA's conclusion that the requirement that either TGP East 300 or ExC be in service is driven by continuing demand growth on the National Grid system, which influences the overall capacity requirement for the NYFS.[36]

Notably, now that TGP East 300 has been placed in service, a portion of demand in New York City ("NYC") can be served by gas flowing to the south from Westchester County (rather than flowing to Westchester County from NYC). Further, additional capacity will then be available to National Grid via a transfer point on the NYFS. The result is improved reliability for both ConEd and National Grid customers in NYC with TGP East 300 in service.

PA has reviewed various hydraulic models of the ORU distribution system that were provided by the Companies. It appears that the ORU system is capable of reliably serving its forecasted design day demand through winter 2026-27. Importantly, since ORU's forecast of design day demand is declining year over year; the existing physical system should therefore be capable of meeting customers' design day requirements throughout the 20-year forecast period.

Based on PA's understanding of the Companies' design day demand beyond 2027, it appears that no additional supply assets (such as additional capacity on upstream pipelines, additional transmission lines on either the Con Ed or ORU system, on-system peaking assets) will be required thereafter to meet that demand, with TGP East 300 now in service and assuming ExC proceeds as planned by the Companies.[37] Notably, our review is focused on ConEd and ORU. PA has not conducted a recent assessment of whether additional NYFS assets would be required to reliably serve National Grid's design day demand.

4.3 Supply Assets and Implications

4.3.1 Iroquois ExC

As discussed previously, the ExC project would provide 62.5 MDth of design day capacity to the Companies.[38] PA expects that the Companies would be able to reduce reliance on Delivered Services or other supply assets once ExC is completed; the Companies confirmed that expectation. From a reliability and cost standpoint, the Iroquois ExC project appears to be a better alternative than Delivered Services.

4.3.2 LNG

The Astoria facility began operation in 1973 and has now provided LNG peaking capacity for ConEd customers for 50 years. Facilities, such as these, are often designed with the expectation of providing reliable service for 25-30 years. Prudent maintenance and repair practices can certainly extend the lives of these assets, as is evident at many LNG peak shaving facilities, including the Astoria facility. Nonetheless, mechanical equipment does wear out, technology matures, and the forces of nature take their toll over time.

[34] A fifth CNG facility on the National Grid system is required during this winter season; it is PA's understanding that the facility will be in service by Winter 2023-24. Without the fifth CNG facility, the NYFS model provided to PA does not produce acceptable design day results in Winter 2026-27 unless at least TGP East 300 or ExC is in service. Now that TGP East 300 is in service, it is reasonable to assume that design day demand on the NYFS can be served without support from the fifth CNG facility.

[35] The models further indicate that with only TGP East 300 (but not ExC) in service, the fifth CNG facility on the National Grid system is required to serve forecasted demand on a design day.

[36] PA was provided additional models in response to DPS 13-184. Upon review of those models, our conclusions noted here for each winter season are confirmed.

[37] PA's comments here are related only to supply assets; we opine on distribution system investments to ensure safety and reliability elsewhere in this report.

[38] ExC will also provide 62.5 MDth of design day capacity to National Grid.

Consequently, continued investment in replacement or upgrades of an LNG facility are necessary to ensure its continued reliable operation.

PA is aware of several planned capital investments at the Astoria LNG facility in the near term; these are discussed in Section 5.4.3 below. The Astoria facility provides approximately 8.7% (166 MDth/day) of design day capacity for the ConEd and ORU systems – an important contribution to the total supply stack. Notably, the facility can serve as an important resource even when demand does not reach design-day levels. For example, LNG supply was called upon on December 24, 2022, driven by extremely cold weather conditions that resulted in producers having difficulty delivering gas to the interstate pipelines as planned – and subsequent loss of pressure on those pipelines. Use of LNG as a supply resource for these types of events is consistent with industry practices. Alongside the events of Christmas Eve 2022, the possibility of design day conditions in any winter and planned or unplanned interstate pipeline system maintenance events clearly support retention of an on-system resource such as the Astoria LNG facility for as long as ConEd is serving gas customers.

4.4 Capital Investment Considerations Related to Supply

The ILT, RLT and FLT Plans discuss the Companies' CapEx forecasts under each of the three pathways – Reference, Hybrid, and Deep Electrification. Stakeholders have offered several comments related to those forecasts. Those areas of the CapEx forecast most closely related to supply are discussed below, with investments under the Reference pathway being the primary focus.

4.4.1 Transmission Pipeline Replacements

Compliance-related transmission investments on the ConEd system are specifically called out in the FLT Plan. ORU's capital forecast does not appear to include the need for this type of investment. A review of transmission system information reported to the Pipeline and Hazardous Materials Safety Administration ("PHMSA") and provided to PA indicates that ORU operates only approximately 1.2 miles of transmission main.

ConEd's capital forecast for each of the three pathways includes replacement of portions of its transmission system through 2035 to comply with Federal regulations.[39] These investments make up nearly 11% of the overall capital spending forecast in ConEd's Reference pathway.[40] PHMSA issued a final rule in October 2019 that requires operators of transmission lines to reconfirm the maximum allowable operating pressure ("MAOP") of certain of those pipelines in their systems. In the absence of traceable, verifiable, and complete records[41] supporting the MAOP, compliance can be achieved by several means, including re-testing the pipeline, reducing the MAOP of the pipeline, or replacing pipeline segments for which the applicable records are not available. PHMSA established an interim program milestone requiring that at least 50% of an operator's pipelines requiring reconfirmation be completed by July 3, 2028, with 100% completion required by July 2, 2035.

The transmission pipelines in the ConEd system are designed and operated to ensure that required gas volumes are delivered to the various distribution regulator stations throughout the service territory. Minimum design pressures at regulator stations and other points, or nodes, on the distribution system are established to ensure that design day demand can be reliably served throughout the system.

Stakeholders filed numerous comments on this issue.[42] Sierra Club and Earth Justice indicated that "the Companies should immediately...comply with PHMSA MAOP Reconfirmation regulations through pipeline derating[43] and targeted pipe retirement."[44] Strategen commented that "Con Edison should seek to avoid spending hundreds of millions on transmission projects by focusing on reconfirmation through lower-cost options in the short term (such as pipeline derating), while examining options for the retirement of segments

[39] Source: Page 84 of the RLT Plan.

[40] Source: Response to DPS 9-172. The 11% of the Reference Pathway capital forecast noted here is related to the forecast presented in the FLT Plan.

[41] 49 CFR Part 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines. (July 1, 2020)

[42] Stakeholder comments on the ILT Plan were filed in Case 23-G-0147 on August 21, 2023.

[43] Derating a pipeline segment involves restating the maximum pressure at which the segment may operate.

[44] Sierra Club and Earth Justice comments at page 15.

that are scheduled to be reconfirmed in the next decade."[45] This topic was among those discussed during a technical conference with Stakeholders on September 12, 2023. During that discussion, ConEd explained why derating portions of its transmission system was not feasible.

When considering whether it is possible to operate any pipeline segment at lower pressures, the capacity requirements of that segment must be considered. In the simplest of examples, reducing the pressure at the inlet to any pipeline segment, while requiring a minimum design pressure (the minimum pressure required to reliably serve downstream demand on a design day) at the outlet of that segment results in a corresponding loss of pipeline capacity. Table 10 below illustrates the impact of reducing the upstream pressure on a generic 24-inch, 5-mile pipeline segment on the volume of gas that segment can deliver.

Table 10: Illustrative Impacts of Lower Operating Pressures on Pipeline Capacity

Pipe Size (inches)	Segment Length (miles)	Inlet Pressure (psig)	Minimum Outlet Pressure (psig)	Capacity (Mcf/hour)	Loss of Capacity (%)
24	5	325	150	23,499	N/A
24	5	275	150	18,849	20%
24	5	225	150	13,773	41%
24	5	200	150	10,892	54%

While Table 10: Illustrative Impacts of Lower Operating Pressures on Pipeline Capacityis not intended to mimic the ConEd/NYFS transmission system, it does illustrate the magnitude of design day demand reductions that might be required in order to operate these pipelines at lower pressures. Importantly, PA would expect that similar demand reductions on the National Grid system might also be required. Additionally, ConEd presented a high-level analysis of its transmission system during an October 18, 2023 technical conference, in which Stakeholders participated. ConEd demonstrated, via hydraulic modeling results, how the transmission system would perform under design day conditions for winter 2023-24 if the MAOPs on the transmission system were reduced to the levels that can be supported with current records. The analysis showed that actual pressures on several segments of the system would fall below minimum levels required to reliably deliver gas to customers further downstream on its distribution systems. ConEd further explained that there are two different pressure systems within its transmission system, and that if those systems were derated to the MAOPs supported by current records, the design day demand served from the higher-MAOP system would have to be reduced by 40% to provide reliable service. Even more significant, the design day demand on the lower-MAOP system would have to be reduced by 55%.[46] These results are not inconsistent with those illustrated in Table 10: Illustrative Impacts of Lower Operating Pressures on Pipeline Capacity. Finally, ConEd explained that the hydrostatic testing PHMSA compliance alternative is not feasible given the number of power generation peaking facilities that rely on natural gas during the summer months; the pipelines cannot be taken out of service to perform hydrostatic testing without impacting the reliability of the electric grid.

PA concludes that it is infeasible to derate the pipeline segments that are subject to MAOP reconfirmation. Most of these segments are part of the NYFS, which makes up the very backbone of the pipeline system upon which ConEd and National Grid-NYC customers rely. In general, there is an inherent risk of failure associated with re-testing these types of pipelines – particularly in metropolitan areas – which often have been in service for decades (even in circumstances where taking those pipelines out of service for re-testing might be feasible).[47] PA is aware the replacement path is not uncommon as operators across the United States address this specific compliance issue.

[45] Source: Page 21 of the Strategen comments.
[46] PA notes that according to Appendix B, page B-2 of the FLT Plan, even under the Deep Electrification pathway design day demand on the Con Ed system is not forecast to approach a 40% reduction until after 2034, and a 55% reduction until three years later.
[47] According to an annual report filed with PHMSA in early 2023, nearly 90% of ConEd's transmission pipelines were installed prior to 1960.

Additionally, at least one of these segments delivers gas from the Astoria LNG facility to the ConEd distribution system, which further contributes to a conclusion that derating and retirement are not feasible. Moreover, when comparing the planning horizon that is required to undertake these projects to PHMSA's interim and final completion deadlines, it is incumbent on ConEd to promptly complete the required work.

Strategen accurately indicated in its comments that there are six possible methods for achieving compliance with PHMSA's MAOP Reconfirmation requirements. ConEd included in its FLT Plan an explanation of why it determined that replacement of existing transmission pipeline segments was the best path to compliance and why each of the other five methods was rejected. ConEd further explained the level of design day demand reductions that would be required to derate the applicable segments.

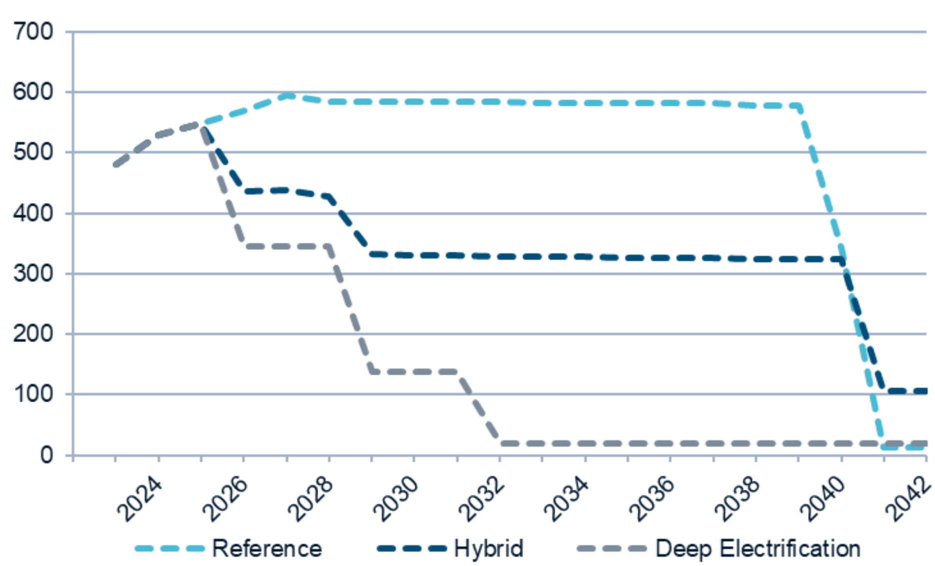
4.4.2 Leak Prone Pipe (Distribution)

LDCs throughout the United States have been prioritizing replacement of legacy mains and service lines, commonly referred to as Leak-Prone Pipe, for many years. Replacement of leak prone distribution pipe in both the ConEd and ORU service territories makes up a significant portion of the capital forecast in each of the pathways presented in the FLT Plan. A summary of those forecasts is shown in Table 11. Annual Capital Spending for LPP Programs in each of the pathways is shown in Figure 13 and Figure 14 for Con Ed, and ORU, respectively.

Table 11: Capital Spending LPP Programs vs. Total (2023-2042) [48]

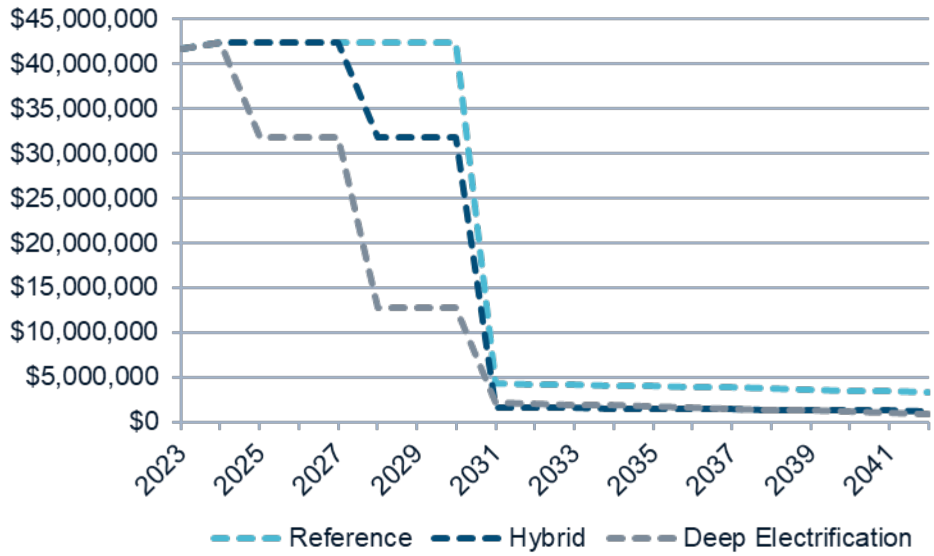
Company	Pathway	LPP ($ million)	% of Total
Con Ed	Reference	10,072	55%
	Hybrid	6,250	45%
	Deep Electrification	3,217	36%
ORU	Reference	384	52%
	Hybrid	323	49%
	Deep Electrification	236	58%

Figure 13: Con Ed LPP Replacement CapEx Forecasts[49]



[48] Source: Response to DPS 14-185. The percentages and amounts in Table 11are based on the FLT Plan.
[49] *Ibid.*

Figure 14: ORU LPP Replacement CapEx Forecasts[50]



LPP capital spending as reflected in

Figure 13 for ConEd includes the Gas Infrastructure Reduction or Replacement Program ("GIRRP") and service line replacements (the majority of which are replacement of LPP). Likewise, LPP capital spending reflected in Figure 14 for ORU includes main and associated service line replacements. Note that LPP capital spending under the Reference and Hybrid pathways for ORU is identical through 2030 and is substantially the same thereafter.

Types of pipes that are considered "leak prone" may reasonably vary between operators of natural gas distribution systems based on their own risk profile with their Distribution Integrity Management Program (DIMP) Plans. For ConEd, LPP includes all unprotected steel, cast iron and wrought iron mains that are 12-inches in diameter and smaller, and all unprotected steel service lines.[51] ORU includes bare steel and Aldyl A (early vintages of plastic) mains and service lines.[52] The Companies have communicated to PA the LPP inventories in their respective distribution systems as of December 31, 2022, as shown in Table 12 and Table 13 for ConEd and ORU, respectively.

Table 12: ConEd Leak Prone Pipe in Service as of December 31, 2022[53]

	Miles of Main	Number of Service Lines
Unprotected Steel	701.6	46,284
Cast Iron	660.2	0
Wrought Iron	44.6	0
Total	**1,406.4**	**46,284**

[50] *Ibid.*
[51] Source: Response to DPS 4-95.
[52] Source: Response to DPS 1-11.
[53] Source: Response to DPS 1-10. As discussed in this Section, ConEd and ORU define" LPP" differently.

Table 13: ORU Leak Prone Pipe in Service as of December 31, 2022[54]

	Miles of Main	Number of Service Lines
Bare Steel	90	1,625
Aldyl-A Plastic	74	8,961
Total	**164**	**10,586**

As indicated in the FLT Plan, Con Ed plans to remove from service all LPP mains and service lines by approximately 2040 in the Reference pathway.[55] ORU plans to remove from service all LPP mains and service lines by the end of 2030.[56]

ORU cites its experience with rock impingement resulting in cracking of Aldyl-A pipe as its reasoning for including that material in its LPP inventory. ConEd has not identified similar risks but replaced approximately 4 miles of Aldyl-A main during the period 2016-22.[57] As of December 31, 2022, Con Ed had approximately 26 miles of Aldyl-A main and 63 Aldyl-A service lines in its distribution system.[58]

Consensus among Stakeholders in comments filed on August 21, 2023 is that the Companies should minimize investments in LPP replacements. Recommended alternatives include repair of the most consequential leaks, more active leak detection activity, and methane capture. Strategen cited a Washington, DC based study that found one-time repair costs of the largest leaks in the study to be between 1% and 10% of the cost of replacement.[59] While the relationship of the costs and benefits of repairing versus replacing LPP infrastructure will vary based on a number of factors (e.g., the circumstances and scope of each segment of LPP main, the proximity of the gas main to other underground infrastructure, whether the main is beneath concrete or asphalt), a benefit of replacement which cannot be quantified is the avoided costs of additional leak repairs for as long as the gas system needs to remain in service. Another consideration is the reduced risk of potentially significant leaks that may result in an incident which places life and property at risk. Those circumstances also carry costs which are difficult to quantify. While it may be appropriate to compare the annual cost of leak repairs on LPP to the cost of a replacement program, PA believes other factors and costs should be considered by the Companies, the Commission, and all Stakeholders. These factors include:

- Costs associated with shutting down, repairing, then relighting disrupted customers;
- Cost to companies as well as to the public (inconvenience) of reactive repair work versus planned replacement work;
- Risk of incident to life and property – minimized with replacement;
- Consider actual repair costs in the context of avoided repair costs as LPP is (and has been) replaced over time; and
- The older the LPP infrastructure becomes, the potential that leak rates may accelerate.

When considering the pace and scope of replacement of LPP in the current environment in New York State, there are at least three competing priorities:

- Continued safe, reliable, and adequate service;
- The State's overarching policy to systematically eliminate LPP; and
- Minimization of capital investments and potential stranded costs.

Of these items, safety and reliability are of the utmost importance. In PA's view, decisions about whether to repair or replace LPP impacts all three of these criteria. Consider the following analysis which is summarized

[54] Source: Response to DPS 1-11. As discussed in this Section, ORU and ConEd define" LPP" differently.
[55] Source: Page 57 of the RLT Plan.
[56] Source: Response to DPS 1-13 and RLT Plan, at page 72.
[57] Source: Response to DPS 1-12.
[58] Source: Responses to DPS 1-12 and DPS 4-93.
[59] Source: Page 18 of Strategen comments. PA's review of the study report cited by Strategen confirms that the author's conclusion is based on the cost to repair the two largest leaks in the 2021 study.

in Table 14 below, ConEd repaired an average of over 10,000 leaks per year during the five-year period 2018-2022 – of which more than 6,500 may have been associated with LPP.[60] During those same five years, ConEd retired 22% of LPP mains that were in service as of January 1, 2018. It is safe to assume that additional leak repairs would have been required had LPP mains not been replaced in those five years. To illustrate the potential magnitude of incremental leak repairs that may have been necessary, consider that at the end of 2017 ConEd had 1,814 miles of LPP mains in service: 913 miles of unprotected steel and 901 miles of cast iron. Given the average number of leaks eliminated between 2018 and 2022 was 4.14 per mile of LPP, had ConEd been only repairing LPP leaks (rather than replacing LPP), the number of leaks repaired in 2022 could well have been 30% greater than the number actually repaired (in addition to the incremental repairs that would have been completed in 2018-2021).[61] PA observed from ConEd's annual distribution reports to PHMSA that a very small number of unrepaired leaks are carried forward from one calendar year to the next[62], thus it is a safe assumption that all of the incremental leaks identified in this illustration would have been repaired. In addition to the incremental leak repair costs that would have been incurred, ConEd's system would have had (at the end of 2022) over 400 more miles of LPP main in service as well as the attendant risks of having those mains in service.

Table 14: Illustrative Leak Repair Analysis – ConEd Distribution System[63]

	2017	2018	2019	2020	2021	2022	Average
Total Leak Repairs		12,351	10,557	8,936	9,854	8,622	10,072
Implied LPP Repairs (65%)		8,028	6,862	5,808	6,405	5,630	6,547
Miles of LPP Main at 12/31	1,814	1,743	1,678	1,573	1,486	1,406	
% 2017 Mains Retired 2018-22	(1,814 minus 1,406) divided by 1,814						22%
Miles retired 2018-22	(1,814 minus 1,406)						408
LPP Repairs per Mile LPP Main		4.61	4.09	3.69	4.31	4.00	4.14
Incremental Repairs in 2022	(408 times 4.14)						1,689
Percent Increase in 2022 Repairs	(1,689 divided by 5,630)						30%

PA performed the same analysis for the ORU distribution system. Based on annual reports filed with PHMSA, ORU repaired an average of 540 leaks per year during the five-year period 2018-2022 – of which approximately 184 may have been associated with LPP.[64] During those same five years, ORU retired an estimated 38% of LPP mains that were in service as of January 1, 2018. It is safe to assume that additional leak repairs would have been required had LPP mains not been replaced in those five years. To illustrate the potential magnitude of incremental leak repairs that may have been necessary, consider that at the end of

[60] ConEd stated, during technical conference with Stakeholders on September 12, 2023, that 65% of its leak repairs are associated with LPP.

[61] The number of incremental repairs illustrated here is subject to variability based on weather (among other factors). For example, the colder the winter season, the more likely it is that a greater number of cast iron leaks will materialize.

[62] The average number of unrepaired leaks on the ConEd system that were carried into the subsequent calendar year, as reported to PHMSA for 2018-2022, was slightly less than 8.

[63] The leak repair and LPP mains mileage data in Table 14 is sourced primarily from annual distribution system reports to PHMSA responses to DPS 10-178 and DPS 10-179 (2017 mileage was estimated based on average miles of LPP. ConEd supplemented that data with more precise LPP mains mileages, as those are not transparent in the PHMSA reports given ConEd's definition of LPP. Nonetheless, PA is able to confirm that the supplemental data provided is reasonable.

[64] In the response to DPS 10-178, the Companies indicated that 34% of leak repairs in 2022 were related to LPP.

2017 ORU had an estimated 264 miles of LPP mains in service. Given the average number of leaks eliminated between 2018 and 2022 was 0.9 per mile of LPP, and if ORU had been only repairing LPP leaks (rather than replacing LPP), the number of leaks repaired in 2022 could well have been 53% greater than the number actually repaired (in addition to the incremental repairs that would have been completed in 2018-2021).[65] PA observed from ORU's annual distribution reports to PHMSA that a very small number of unrepaired leaks are carried forward from one calendar year to the next[66], thus it is a safe assumption that all of the incremental leaks identified in this illustration would have been repaired. In addition to the incremental leak repair costs that would have been incurred, ORU's system would have had (at the end of 2022) approximately 100 more miles of LPP main in service and the attendant risks of having those mains in service. Table 15 below summarizes the analysis.[67]

Table 15: Illustrative Leak Repair Analysis – ORU Distribution System[68]

	2017	2018	2019	2020	2021	2022	Average
Total Leak Repairs		638	558	482	518	504	540
Implied LPP Repairs (34%)		217	190	164	176	171	184
Miles of LPP Main at 12/31	264	244	220.6	208.1	186.9	164.3	
% 2017 Mains Retired 2018-22	(264 minus 164) divided by 264						38%
Miles retired 2018-22	(264 minus 164)						100
LPP Repairs per Mile LPP Main		0.89	0.86	0.76	0.94	1.04	0.90
Incremental Repairs in 2022	(100 times 0.53)						90
Percent Increase in 2022 Repairs	(53 divided by 122)						53%

The preceding analysis is not intended to be precise, but rather directional. For example, it assumes that no LPP mains would have been replaced in the preceding five years – hardly a reality under any set of assumptions or criteria. It also does not differentiate whether the repairs were on LPP mains or LPP services; rather, it is based on the average annual repairs per mile of LPP main. The analysis attempts to quantify only incremental leak repairs; additional leaks on the gas distribution system also translate to increased safety risks as well as the potential that more segments of the system may need to be shut down for repairs, resulting in significant costs (and inconvenience) associated with safely restoring service to customers. Additional leaks also translate to additional emissions. Finally, and importantly, our analysis is not intended to imply that the cost of the illustrative incremental leak repairs would have exceeded the cost of replacement. As stated previously, there are more factors to consider than a simple comparison of the cost to repair leaks and the cost to replace infrastructure.

[65] The number of incremental repairs illustrated here is subject to variability based on weather (among other factors). For example, the colder the winter season, the more likely it is that a greater number of cast iron leaks will materialize.
[66] The average number of unrepaired leaks on the ORU system that were carried into the subsequent calendar year, as reported to PHMSA for 2018-2022, was less than 1. Zero known leaks were carried forward at the end of 2020, 2021 and 2022.
[67] The Companies provided leak repair data for ORU in response to DPS 7-157. The repair data differs from that reported to PHMSA. PA did not explore these differences given the analysis is illustrative. The same analysis, when using the repair data in DPS 7-157, results in a 47% increase in leak repairs in 2022. This difference has no bearing on the miles of LPP main removed from service.
[68] Source: Annual gas distribution reports to PHMSA and responses to DPS 10-178 and DPS 10-179. (2017 mileage was estimated based on average miles of LPP main replaced 2019-2022 and the response to DPS 1-11).

PA does not disagree that more active leak detection activities (such as those recommended by Stakeholders) as well as the use of Advanced Leak Detection technology (as required in the recent gas rate plan for Con Edison and discussed in the Companies' FLT Plan) can promote a safer system but notes that all parties must understand that such activities would (or will) also be expected to increase the number of leaks identified as well as corresponding repair costs.

PA does not disagree that considerations that may avoid the risk of overinvesting in what may be a shrinking system are appropriate. However, the Companies, the Commission, and all Stakeholders must also consider the safety and reliability implications of placing too much focus on repair (as opposed to replacement) of LPP mains and service lines which would allow LPP to remain in the system longer than current replacement programs and timelines contemplate.[69] As discussed later in this report, PA supports identification of opportunities such as non-pipeline alternatives that would allow LPP replacement costs to be avoided where possible.[70] Stakeholder recommendations stop short of a strategy to "only repair" LPP; PA agrees that risks are associated with drawing such lines in the sand given the importance of maintaining safe, reliable service. Moreover, PA is not aware of any correlation between the likelihood that a given NPA may succeed at some time in the future such that replacement of LPP can be avoided, and the condition of the LPP assets in that given area that is considered an NPA candidate.

PA observed an inconsistency in the data sourced from ConEd's annual distribution reports to PHMSA (and presented in Table 14) and the Companies' response to DPS 1-10. Specifically, for ConEd, the calculated miles of LPP main removed from service annually from 2018-2022 presented in Table 14 is not consistent with the annual miles of LPP main replaced as reflected in DPS 1-10. Table 16 below summarizes the data.

Table 16: Con Ed Distribution System – Miles of LPP Removed from Service

Year	Miles of LPP Main Removed From Service per Annual PHMSA Reports and ConEd (as shown in Table 14	Miles of LPP Main Replaced per DPS 1-10	Implied Miles Removed but Not Replaced
2018	71	92	-21
2019	65	97	-32
2020	105	67	38
2021	87	106	-19
2022	80	101	-21

When evaluating miles of main replaced and miles of main removed from service, the total miles removed must be equal to or greater than the total miles replaced (since the miles replaced were also removed from service). It follows then that the change in the miles of LPP mains in service from one year to the next should be the sum of LPP mains replaced and LPP mains removed from service but not replaced. Or, said differently, the miles of main removed from service but not replaced are calculated as "total miles removed from service" minus "total miles replaced". As shown in Table 16, in 2020, 38 (105 minus 67) miles of LPP mains were removed from service but not replaced. However, in each of the other four years, the implied miles of LPP mains removed from service are less than the miles replaced. Moreover, the negative calculated values for

[69] The Commission's Order in Case 15-G-151, at page 6, indicates that New York gas LDCs, at that time, were replacing about 400 miles of LPP each year, resulting in a range of replacement timelines between 11 and 45 years. The Commission stated that its goal" will be to reduce the statewide average replacement timeline to 20 years..."
[70] It is PA's understanding that there are approximately 3 miles of LPP main associated with the 65 NPAs that had been identified at that time. Additionally, the response to DPS 4-99 indicates that the Reference Pathway capital forecast for ConEd assumes that approximately 11.5 miles of LPP would be retired but not replaced as a result of NPA implementation.

those years suggest that ConEd either identified additional LPP mains in those years (resulting in a larger inventory at the end of the year than at the end of the previous year) or – albeit illogical -- may have added LPP mains to its system in those years. Certainly, PA is not suggesting that the latter is the case.

PA asked ConEd to reconcile and explain these apparent inconsistencies. ConEd explained that the data provided in DPS 1-10 and the data reflected in Table 16 are sourced from two separate reporting systems. ConEd further explained that the mileage provided in DPS 1-10 utilizes data from its Work Management System, which captures all leak prone pipe replacement work completed during a given time frame, regardless of mapping status. On the other hand, the mileage reflected in Table 15 represents the difference in LPP mains mileage between PHMSA Annual Reports for Gas Distribution and is sourced from ConEd's mapping system. ConEd stated that the data reflected in Table 14 does not include adjustments for work that was completed but not yet mapped at the time the applicable PHMSA Annual Report was submitted, and that due to the time required to accurately map completed work, all LPP replacement work completed at a given time will not be reflected in a mapping system export.[71]

Based on the foregoing explanation, PA can conclude that the progress ConEd is making towards eliminating LPP mains from its distribution system, as reflected in its annual reports to PHMSA, is understated since there is a lag in mapping LPP replacement/retirement work that has been completed. Moreover, such a lag could call into question whether ConEd's emergency response and other operations personnel have access to as-built records that supersede the information contained in the mapping system. It is important that the appropriate labor resources are dispatched to perform both planned and unplanned work, and that the appropriate equipment and materials are available to those ConEd and/or contractor personnel. Although PA assumes that ConEd has appropriate procedures and systems in place, we recommend, in the interest of employee and public safety, that ConEd (as well as ORU) ensure that the Commission and appropriate DPS Staff are aware of those procedures and systems that provide field personnel with accurate information about the gas system components they should expect to encounter in performing their work.[72]

4.4.3 LNG Investments

The Companies' capital spending forecasts include ongoing investments at ConEd's Astoria LNG facility. As part of its review of the supply stack, PA evaluated both recent and planned investments associated with this peaking resource.

Although periodic reinvestment in pipeline facilities is to be expected, an LNG facility is more complex and requires more ongoing investment. The peak-shaving capacity of the facility and its importance to gas supply, especially during design day conditions, is integral to reliable supply of natural gas to ConEd's customers. The ongoing investments in the LNG facility are applicable to each of the Reference, Hybrid, and Deep Electrification pathways, as the LNG system is assumed to be in service throughout the time period addressed by the Long-Term Plan.

Based on information received from ConEd, LNG project investments completed in the past 5-7 years total nearly $32 million.[73] Among these projects were investments in fire detection and suppression (approximately $10.5 million) and vaporization equipment ($9.8 million). Currently, projects totaling approximately $30 million are in progress, and additional potential investments totaling approximately $97 million are being considered over the next 20 years.[74] Many of these projects, including those recently completed, involve replacement of equipment or systems that date to the original 1973 construction of the facility (e.g., replacement of vaporizers, compressors, liquefaction equipment, instrumentation systems, electrical systems, and fire protection systems). These projects are largely replacements of the existing systems; while performance upgrades associated with updating to modern equipment are to be expected, none of the investments result in incremental capacity. Our review of these projects found them to be reasonable investments that are required to maintain the function and reliability of the LNG facility.

[71] Response to DPS 10-181.

[72] PA evaluated whether the same records inconsistency exists at ORU. While annual PHMSA reports do not include details about specific types of plastic pipe, PA can confirm that the bare steel mains remaining in service at the end of the years 2018-2022 as reported to PHMSA match those provided in response to DPS 10-179.

[73] Source: Response to DPS 4-97.

[74] Source: Response to DPS 4-98.

4.5 NPAs

PA has undertaken a review of the NPA solutions that are both underway and anticipated within the RLT Plan, along with program documentation requested by PA and provided by the Companies. At a high-level:

- ConEd presently offers Load Relief ("LR") and Main Replacement ("MR") NPA offerings which have experienced limited success. Based upon learnings from these NPA offerings, ConEd is now developing Service Line Replacement ("SLR") NPA offerings. PA commends the Companies continue offering and learning from the Load Relief and Main Replacement NPA offerings to inform the development of the new SLR NPA.
- ORU has identified an initial set of potential NPA projects for evaluation and has begun the process of implementing NPA projects in the second half of 2023. However, offering NPAs at scale will be challenged by unique attributes of the service territory, as compared to ConEd.
- Many Stakeholders expressed strong opinions on and support of how the Companies can expand NPA offerings.

PA observes that the Companies believe more time is needed to successfully implement such offerings at scale, and that Stakeholders acknowledge identifying and ultimately implementing any NPA is a process that will take considerable time. PA emphasizes the consideration of Stakeholder feedback provided at the SLR Town Hall Presentation by the Companies including, but not limited to, suggestions for improved outreach, education, and project delivery.

4.5.1 Current Limitations

ConEd follows a process to assess the applicability and feasibility of LR[75] and MR[76] NPA solutions, as discussed in greater detail within PA's Initial Report. Based on Companies' responses to Data Requests and discussions with Companies' subject matter experts, PA has learned that NPA offerings to date have yielded limited positive results. PA understands that ConEd has now identified a number of potential NPAs and the initial 65 have resulted in few viable projects. Although the Companies acknowledge shifts in customer engagement strategies, PA observes that material improvements to the NPA feasibility assessment, customer engagement process, and scope of offerings are all necessary to scale the offerings to the magnitude needed to offset traditional capital investments. We further discuss these observations within this section.

In August, the Companies presented the latest potential NPA projects to DPS Staff. PA was in attendance and notes the following topics were discussed:

- Potential for NPA projects to advance with BCA ratios lower than 1;
- Obstacles to customer adoption include a lack of familiarity, questioning electric system reliability or lack of interest, despite the portfolio of offerings that include a set of brand new appliances (water heater, dryer, stove, heat pump) and electric panel upgrades installed at no cost to them; and
- Challenges in obtaining adoption from all customers on a main targeted for replacement. Main Replacement NPA projects will only go forward if every customer on that main agrees to electrify in the same time frame.

PA understands that ORU NPAs have also experienced limited traction. Beyond the limitations discussed above, certain attributes within the ORU service territory present unique challenges to offering NPAs at scale. For instance, according to ORU, the Kiryas Joel community in which there is a sizable amount of real estate development driving growing gas demand given strong preference for natural gas appliances and reluctance to switch to electric.

[75] ("Load Relief") offerings mitigate the need for traditional distribution system reinforcement projects associated with system load growth
[76] Main Replacement Program ("MRP") offerings incentivize customers in a defined area to convert all their current gas uses to electricity, thereby eliminating the need to replace the main if all customers agree to discontinue the use of gas

4.5.2 Stakeholder Comments

Stakeholders filed Initial and Reply Comments that uniformly support interest, further analysis, and discussion of NPAs. Stakeholder comments touched on several key NPA issues summarized below:

Service Line Replacement NPAs

On October 26th, the companies held a town hall meeting to present the new NPA offering for Service Line Replacements. PA participated in this session, along with several Stakeholders. The Companies provided an overview of ConEd's current NPA portfolio offerings (Area Load Relief, Electric Advantage/Main Replacement) and the new SLR program. The goal of the SLR program is to reduce the number of gas service line replacements and targets service lines installed before 1972. In addition to service from a pre-1972 service line, eligible customers must convert all existing gas end-uses to electric. To encourage this conversion, the Companies will offer incentives designed to cover 100% of project costs up to $20,000, with variation on customer and project type as presented within Figure 15 below.

Figure 15 Proposed NPA SLR Incentive by Customer Type[77]

Customer Segment	Incentive (Non-DAC)	DAC Add-On	Incentive Cap
Residential: Single-Family	Up to $10,000	Up to $5,000	$15,000
Residential: 2-4 Dwelling Units or Multi-Family (5+)	Up to $15,000	Up to $5,000	$20,000
Small & Medium Businesses	Up to $10,000	Up to $5,000	$15,000
Commercial & Industrial	Up to $10,000	-	$10,000

Although this NPA program is still in the initial design and market feedback phase, the Companies estimate an eligible population of approximately 40,000 buildings within the ConEd service territory. This program will next move into final design phase in early 2024 and is expected to launch Q3 2024. Given this timeline, the Companies described expected customer engagement and outreach approaches and elaborated on how the SLR program avoids individual service line replacements as compared to Electric Advantage/Main Replacement offering, which avoids main replacement and one or more service replacements. PA appreciates that this new SLR offering only requires the adoption of one customer as opposed to the other NPAs that require several customers to adopt at a given time. We find this approach to be a positive evolution in NPA offerings.

In this session, Department Staff, Stakeholders, and the Companies discussed many topics including but not limited to differences between the offerings, methods of customer outreach and engagement, incentives, NPA program funding and cost recovery. PA observes that the Companies intend to consider the comments in their final design of the new SLR or other NPA offerings. In particular, the Companies should ensure NPA program delivery structures minimize barriers to adoption, such as collecting up-front project costs to customers. PA commends the Companies continue offering learning from the Load Relief and Main Replacement NPA offerings to inform the development of the new SLR NPA. PA recommends that the Companies consider Stakeholder feedback provided at the SLR Town Hall Presentation such as suggestions for improved outreach, education, and project delivery.

Selection Criteria

Several Stakeholders recommend that the Companies focus more on NPAs instead of making further investments in the gas system, and current NPA offerings are limited by the selection criteria set-forth by the

[77] Source: ConEd Non-Pipe Alternatives Town Hall Gas Service Line Replacement Program. Slide 13. October 26, 2023.

Companies given the Companies have leeway in excluding potential offerings through criteria such as concerns for execution risk. PA agrees that improvements can be made to the selection process, that execution risk presents ambiguity, and further elaboration is needed on the use of execution risk in selecting NPAs. We received the following response to our data request DPS2-82:

> "There is not currently a precise definition for execution risk of an NPA portfolio. The Company expects to refine this process as it gains additional experience implementing NPAs. Execution risk for Area Load Relief NPA portfolios is evaluated by weighing the quantity, complexity, and diversity of the proposed demand side solutions against the population of eligible customers and the timeline of the system infrastructure needs. The Company informs this by assessing the implementation rates of existing system wide incentive programs for gas EE, Clean Heat and similar metrics from previous NWS projects. Execution risk for GIRRP NPAs (formerly MRP) consists of the risk of a customer backing out of a commitment to electrify all gas end uses after work has begun on other homes needed to avoid the main replacement. Additionally, the identification of an emergent safety issue requiring short term replacement of the gas main after commitments to the customers have been made or while electrification work is ongoing, but not yet completed, presents additional execution risk."[78]

PA believes improvements can be made to the selection process and proposes several recommendations in the NPA Recommendations section below.

Avoidance of Pipe Replacements

As discussed previously, Stakeholders filed several comments recommending that the level of replacement of LPP be reduced signficantly and that the Companies should instead focus on NPAs. The ConEd Reference pathway capital forecast contemplates only a minimal amount of avoided LPP replacement, while both the Hybrid and Deep Electrification forecasts reflect a greater level of LPP replacement avoidance over the next 20 years. Given the expectation that NPAs will take multiple years to develop, coupled with the requirement in the recent gas rate order that 240 miles of LPP main be removed from service during the current rate plan (2023-25), it is reasonable to expect Con Edison's LPP replacements will continue at that required pace for at least the term of the rate plan, if not beyond.[79]

The relatively slow pace of NPA development at ORU suggests that LPP replacements are likely to follow the current plan that all LPP be removed from service by 2030.[80] PA would not recommend that ORU relax its pace of LPP replacement in favor of more focus on NPAs at this time, even though its target program completion timeline is a few years shorter than the Commission's statewide goal as discussed in Section 4.4.2.

NPA Program Scale

PA observes the Companies believe that more time is needed to successfully implement such offerings at scale. At the September 12th technical conference, PA facilitated discussions on the time needed to scale NPA offerings. PA asked for input on what may be a reasonable amount of time for a given NPA to develop, and whether Stakeholders believe those timelines would vary based on the targeted purpose of the NPA. Stakeholders acknowledged that identifying and ultimately implementing any NPA is a process that will take considerable time. For example, NRDC agreed that given the early stage of the process NPAs require a fair amount of lead time before electrification to avoid replacement is viable. UIU noted that beaurocracy of review takes a lot of time and timelines will be different based on the cirsumstances. NYC supported comments made by NRDC and added that more transparency on where the system is best to pursue electrification is needed, given the responsibility cannot all fall on the company. NYC notes that planing for electrification does not happen over night and customer visibility into such plans is needed.

Gas Rate Plan

[78] Source: Response to DPS 2-82.

[79] As per Appendix 19 of the Joint Proposal approved in Case 22-G-0065, Con Edison's targeted miles of LPP main removed annually will remain at 80 beyond 2025, unless and until changed by the Commission.

[80] The Commission's Order in ORU's last rate case (Case 21-G-0073) established a target of 66 miles of leak-prone main be removed/replaced annually from 2022-2024, with a minimum annual removal/replacement target of 20 miles. Further, the 20 miles-per-year target remains in effect beyond 2024, unless and until changed by the Commission.

It is also important to note that within the recently approved Gas Rate Plan for ConEd, a general NPA framework was established and a session to review service replacement NPA development efforts is anticipated in 2023. Establishing this NPA framework should avoid delays in exploring opportunities which were pending resolution of this framework. For example, ConEd will now assess potential gas service line replacement NPA projects.

4.5.3 NPA Observations

As previously discussed, the Companies held a town hall meeting on October 26th to present the new SLR NPA offering. In this session, Department Staff, Stakeholders, and the Companies discussed the topic of NPA program funding and cost recovery. As a result, PA requested a meeting with the Companies SMEs to understand and compare the annual costs that customers would pay over-time under two scenarios:

1. A successful Gas Service Line Replacement NPA implementation costing $15,000 (which PA understands may be a representative cost of a single-family residential service line replacement NPA in a DAC). In this scenario, replacement of an LPP service line is avoided.
2. Replacement of a LPP service line where the capital investment to complete the replacement is $23,500 (based on Con Ed's average service line replacement cost provided in response to DPS 4-100). In this scenario, an NPA would have been deemed infeasible.

This meeting was held on Monday, November 27th. Based on the net present value of each investment, the SLR NPA is advantageous for customers from a financial perspective. In other words, the analysis illustrates that the costs customers will pay for an SLR NPA are less than those that would be paid for a service line replacement. PA understands that the NPA recovery vehicle is the existing Monthly Rate Adjustment (MRA)[81] cost recovery mechanism, and that all customers (regardless of class) pay the same volumetric MRA rate. Further, it is PA's understanding that all costs recovered via the MRA are allocated to the customer classes based on gas throughput volumes; this appears to be a different cost allocation methodology than would be in effect for more traditional service line replacements (for example, PA expects that the cost of replacing residential service lines would be allocated to and recovered from residential customers as part of a cost of service study presented in a rate case). However, given that all customers would benefit from (for example) lower emissions resulting from the future avoided use of natural gas resulting from implementation of an NPA, sharing NPA costs among all customer classes seems reasonable.

PA recognizes it will take time to scale-up NPA offerings. We understand successful NPA offerings necessitate certain customer behaviors, absent policies or regulations which force customer compliance. Therefore, we recommend continued efforts focused to improve customer education and program delivery methods. These efforts, among others, are needed to scale offerings over the long-term, such that the Companies can rely upon NPAs as a dependable method for reducing demand, emissions, and traditional capital investments.

PA observes NPA program design and implementation could be improved to accelerate progress. For example:

- Proactively communicate, educate, and recruit customers to adopt NPA program measures at scale needed to meaningfully shrink the gas system footprint.
- Leverage regional surveys and engagements with community groups to gauge customer interest and participation in supporting adoption of electric appliances and NPA solutions.
  - Use customer feedback to refine offerings and consider expansion of incentives to cover electricity costs.
  - Leveraging other Stakeholders reputation and tools to improve recruiting process.
- Refine offerings and program scope regularly as customer adoption preferences evolve.
- Maintain line-of-sight of the electric grid impacts of electrification (i.e., current and future grid concerns – real or perceived), while considering trade-off of near-term gas system investments as compared to future electric system spend.

81 A brief review of ConEd's Tariff demonstrates that the MRA is a multi-purpose mechanism that recovers (or refunds) a variety of types of costs.

- Ensure NPA program delivery structures minimize barriers to adoption (for example, directing payments to Contractors). It is reasonable to expect that many customers would choose not to participate if they are required to make material payments directly to Contractors, as is the case with the Companies' rebate offerings.

The Companies have agreed to share more NPA program details going forward, as the programs mature to the point that enrollments can begin. PA observes the provision of detailed assumptions and expectations for NPA programs going forward, within the FLT Plan would be valuable and appreciates the Companies have agreed to this. For example, such assumptions would include, at least for each NPA expected to be completed in 2024, details such as (and as applicable) the number and type(s) of customers participating in the NPA, associated design day and annual demand reduction, avoided capital investments resulting from the NPA, avoided pipe replacement miles and/or service lines, and other applicable information demonstrating the benefit of the NPA.

4.6 Recommendations

Recommendations for supply are summarized below.

- Provide more robust discussion on the flexibility limitations unique to each component of the Companies' supply portfolio – detailing specifically what limitations the Companies expect to see in adding additional flexibility to, or altering the terms of, firm pipeline transport and storage contracts, Reverse Asset Management Agreements (AMAs), or Delivered Services contracts.
  - The Companies provided additional discussion of flexibility limitations but did not provide an in-depth discussion of the unique flexibility limitations of each component of supply.
  - To the extent feasible, provide a more granular description of how capacity in the Joint Supply Portfolio (JSP) is allocated between the Companies based on their individual design-day requirements.
- As part of the framework for de-contracting, build upon the framework for capacity release as demand diminishes. Include in this framework criteria for evaluating which pipeline capacity contracts are no longer needed. Include a discussion of the types of counterparties (in- or out-of-state) that capacity can be released to.
- Improve NPA program design, implementation, and cost analysis:
  - Proactively communicate, educate, and recruit customers to adopt NPA program measures at scales needed to meaningfully shrink the gas system footprint.
  - Further leverage regional surveys and engagements with community groups to gauge customer interest and participation in supporting adoption of electric appliances and NPA solutions.
  - Continuously refine offerings and program scope regularly as customer adoption preferences evolve.
  - Maintain line-of-sight of the electric grid impacts of electrification (i.e., current and future grid concerns – real or perceived) while considering trade-offs of near-term gas system investments as compared to future electric system spend. To the extent already underway, discuss how the Companies are doing this within the FLT Plan.
  - Leverage other Stakeholders' reputation and tools to improve recruiting process, including community groups and local elected officials.
- Provide detailed assumptions and expectations for NPA programs going forward. Include, at least for each NPA expected to be completed in 2024, details such as (and as applicable) the number and type(s) of customers participating in the NPA, associated design day and annual demand reduction, avoided replacement investments resulting from the NPA, avoided pipe replacement miles and/or service lines, system reinforcement investments that can be delayed (and perhaps avoided), and other applicable information demonstrating the benefit of the NPA.[82]
- Provide a more comprehensive "No Infrastructure" option. PA understands the Companies' definition of the "no infrastructure" solution; however, PA observes proper planning would necessitate the Companies

[82] In ConEd and ORU Reply Comments, the Companies agree to provide any available NPA updates going forward and in future GSLTP cycles. See Section 3.3 for additional discussion on the Companies' comments.

provide more specificity regarding alternatives to limit infrastructure investment to inform the Commission and Stakeholders. A "no infrastructure option" does not mean the Companies are prevented from making certain investments supportive of safe, reliable, and adequate services, including those driven by State and Federal Requirements and the obligation to serve. However, a more specific "no infrastructure" option would provide a lower end boundary on the level of total infrastructure investment with NPAs.[83]

- Consider including improvements to the NPA program design and deployment with the goal of scaling up NPA programs and to eliminate barriers to adoption. Ensure NPA program design structures minimize barriers to adoption, for example directing payments to Contractors, to avoid large capital outlays from customers. Stakeholders expressed concerns on this issue as a major barrier for adoption of NPA solutions, especially among the LMI customers. It is reasonable to expect that many customers would choose not to participate in the NPA programs if they are required to make material upfront out of pocket payments to the Contractors and wait for the payment to be processed and reimbursed by Companies.

5 Demand Assessment

As described in the Companies' FLT Plan, ConEd provides gas service in Manhattan, the Bronx, portions of Queens and portions of Westchester County, representing approximately 1.1 million customer meters. This area also represents a relatively high concentration of disadvantaged communities, with approximately 45% of all census tracts determined as such.

As similarly discussed in the FLT Plan, ORU provides gas service through two separate gas distribution systems in Orange County and Rockland County, representing over 100,000 customer meters. ORU has a limited number of disadvantaged communities interspersed throughout the service areas.

This section of the report provides an assessment of the Companies demand forecast through an analysis of historical trends and macro-economic forecasts. Accurately determining the demand forecast, especially on a design day basis, is critical to ensuring safe, reliable, and adequate natural gas service is always available for all customers. Most important is that service continues uninterrupted on the coldest days of the winter.

Section 4.1 of this report provides an analysis of the Companies' supply stack. Alternatives for that supply stack are compared to the Companies' demand forecast. In this section we provide some considerations for reducing design day over time. Such reductions could ultimately reduce the need for Delivered Services and potentially other components of the supply portfolio in the future. However, given the complexities of the demand forecast, considerations for other gas LDCs in New York, and implications of setting the forecasting demand incorrectly, we do not recommend a modification to the Companies' demand forecast at this time. However, we provide guidance for further Commission investigation into matters related to the demand forecast process, among other recommendations.

5.1 Introduction

PA's assessment of the Companies Peak Load forecast for ConEd and ORU combined analytical insights from:

- Disaggregated historical billing data for the broad service classification segments in each territory. The ConEd territory is characterized by 4 major classifications: SC1 – Single Family Residential & Religious, SC2 – Commercial and Industrial, SC3 – Multi-family and one that aggregates the remaining narrowly-defined rate classes including SC13, SC14 and Special Contracts as 'Misc'. ORU has just the SC1 and SC2 categories;[84]
- Regional macroeconomic and demographic data obtained through Moody's Analytics; and
- Various datasets provided by the Companies in response to data-requests.

5.2 Historical Trends

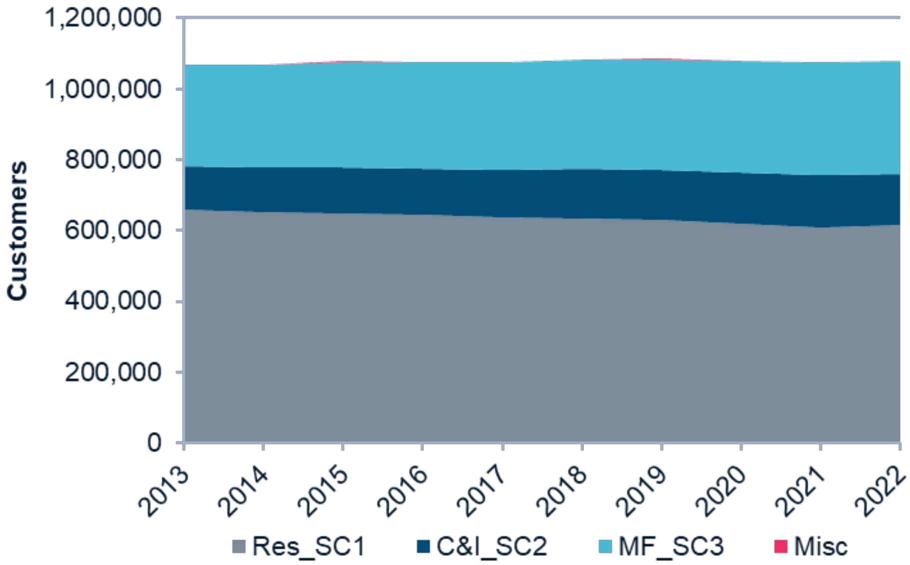
[83] In ConEd and ORU Reply Comments, the Companies indicate the Deep Pathway fulfils this requirement. See Section 3.3 for additional discussion on the Companies' comments.
[84] ConEd also offers services to transportation customers (e.g., SC-9 is a service classification that serves customers that procure the commodity either through the Company or on their own from third-party suppliers).

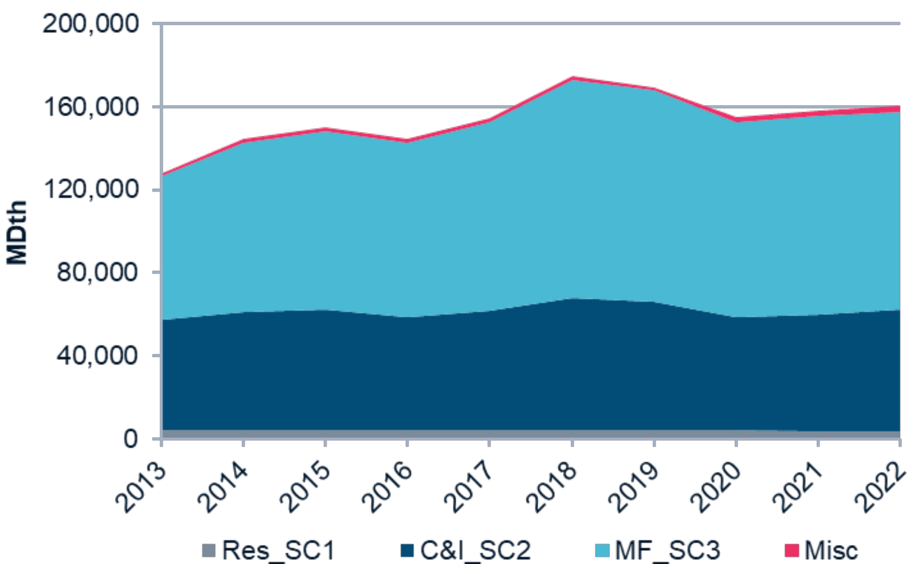
The assessment of the Companies' Peak Load forecast begins with a characterization of gas usage as revealed by the last decade of billing data.

ConEd

Figure 16 provides a disaggregated view of the ConEd billing activity – customers and sales over the 2013-22 period.

Figure 16: ConEd Customers & Sales, 2013-22





Service Classification 1 (SC1): This is defined as Residential and Religious Firm Service for purposes including auxiliary space heating. Territory-wide, this segment has experienced declining customers steadily over the past decade at an average annual rate of -0.8%, with all counties seeing sustained declines likely due to the electrification in single-family homes. Moreover, annual volumes have fallen at an even higher average annual rate of rate of -2.1% pointing to steadily declining average UPC. Given that activity constitutes just over 2.4% of overall ConEd sales, activity in this service classification has a minor impact on the overall business.

Service Classification 2 (SC2): This provision is the General Firm Sales service which covers non-residential customers. Despite the disruptive effects of the COVID-19 pandemic, the C&I customer-base has seen steady growth across ConEd at an average rate of 2.0% over the last decade – with the exception of Westchester County that is showing relative stagnation.[85] Sales to C&I customers also grew over the last decade (at an average rate of 1.1% per annum) but COVID-19-related factors resulted in a major setback due to shutdowns, business closures, and work-from-home. Although sales to Manhattan and Brooklyn customers have shown a healthy rebound post-COVID-19, evidence suggests a noticeable slowdown in growth across the territory during the last 5 years, with Westchester County's volumes exhibiting a decline – plausibly due to the impact of electrification. Accounting for over 36% of ConEd sales, any long-term change in this segment is potentially significant. The lower growth rate of sales relative to the number of customers implies declining UPC – that might reflect a combination of COVID-19-related shutdown of businesses and the substantial vacancy rate in commercial real estate, especially in Manhattan. In other words, the growth of meters does not translate into a comparable sales growth. While there are a growing number of vacant buildings that formerly housed commercial activity being converted for residential purposes, especially in lower Manhattan, there remains some uncertainty regarding the speed with which commercial sales will resume pre-COVID-19 levels. It is possible that partial electrification (due to fuel switching for selected end-uses) might be contributing to the declining UPC in this sector.

Service Classification 3 (SC3): This classification is the Residential and Religious – Heating – Firm Sales Service. Accounting for over 60% of ConEd gas sales, primarily the multi-family sector, especially in Manhattan, is subject to a plethora of influences and dynamics that present growing uncertainty as to both the customer count as well as future sales, and the system peak load. It is worth noting that this customer classification is likely characterized by customers not only with space-heating load but also, despite the considerable diversity in usage patterns across the residential and commercial segments, a potentially relatively low load factor in some cases. Although the latter suggests the potential opportunity for efficiency/conservation programs aimed at peak reduction, a lack of detailed peak-load data limited PA's ability to conduct analysis to substantiate this situation.

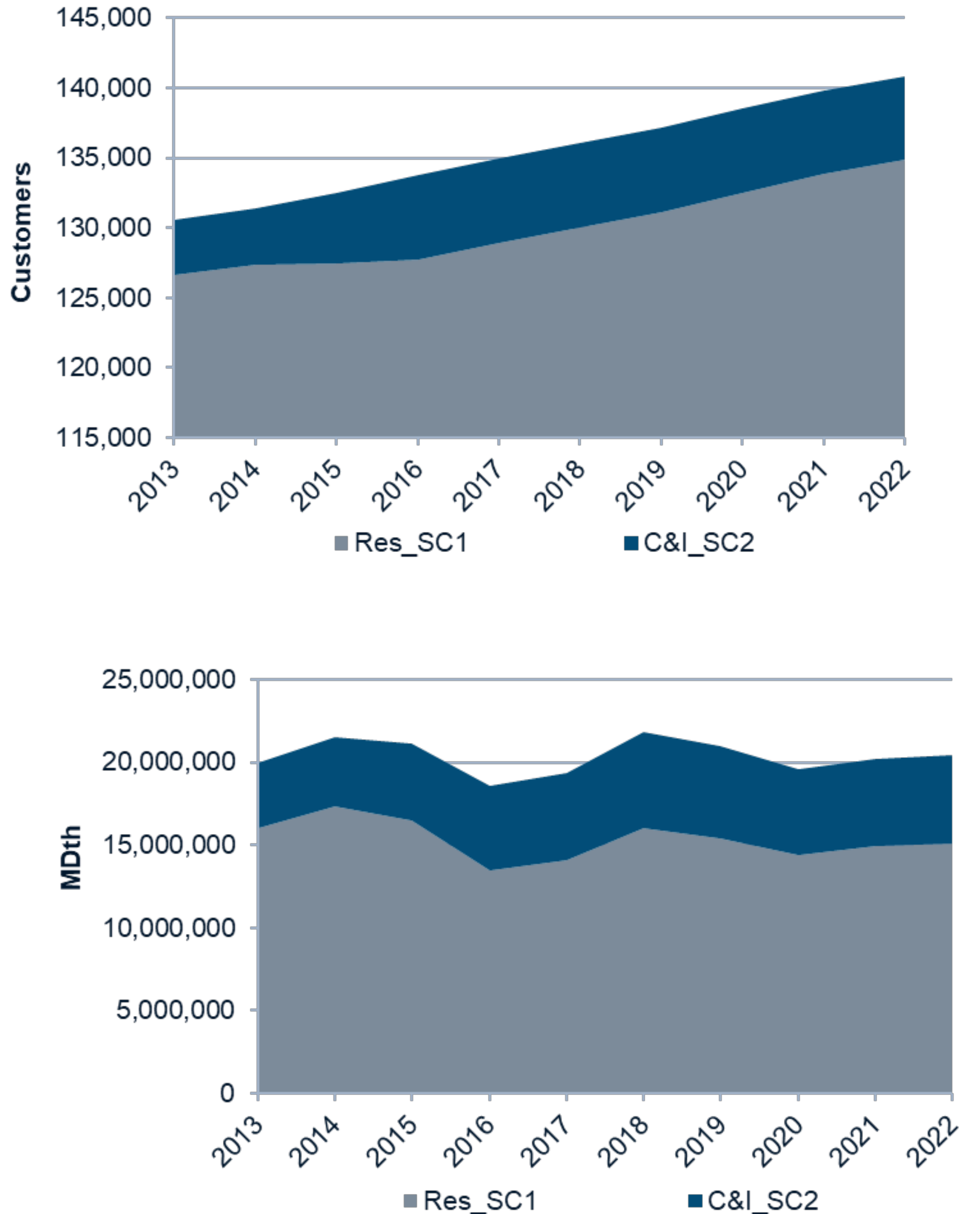
Customer counts in this segment have seen some growth over the past decade (approximately 1.2% annually) but across all counties there are signs of a slowdown – reflecting the region's demographic dynamics. Although, the customer-base in Manhattan was seriously impacted by COVID-19-related disruptions, evidence supports a rebound during the last year or so. However, in total, a noticeable slowdown in the overall customer growth is evident. Sales have grown at a modest rate – suggesting a stable UPC – with Westchester being the only area showing signs of a flattening and a possibly declining UPC path. Historically, over 75% of new units in large construction projects in New York City have been for residential space and that trend is likely to persist for a few more years – given the backlog due to COVID-19.

ORU

Figure 17 shows the historical data for customers and sales in the ORU territory for the 2013-22 period.

[85] The current moratorium may have had a small impact on growth in Southern Westchester County.

Figure 17: ORU Customers and Sales, 2013-22



SCI: A review of the customer-mix and gas-usage dynamics in the ORU territory reveals the dominance of the residential sector in the territory. With a 95% share of the customer-base and a 74% share of sales in 2022, the SC1 customer-base has seen minor but steady growth over the last 10 years at an average annual rate of 0.7%. (Some reclassifications of customers in 2015 that moved around 2,000 customers from SC1 to the SC2 category is seen.) The UPC has shown a rising trend over the last 6-7 years which might reflect new construction including larger homes, consistent with the area's population growth.

SC2: The customer-base in the C&I segment, however, has seen a slow decline since 2017. Coupled with a slight positive trend in the UPC, C&I sales have been ostensibly flat during the last 6 years – signaling a complete recovery after COVID-19.

Overall, the ORU market is trending toward an even greater residential orientation.

The absence of a tendency for the residential UPC to trend downward suggests that electrification has made little to no impact in the ORU territory in contrast with Westchester County. If this trend signals a lack of customer preference for partial or overall electrification, it might present a challenge for reducing the reliance on natural gas.

5.3 Customer Connection Forecasts

In assessing the Companies' design day forecasts, it is informative to gain perspective on the territories' macroeconomic and demographic landscapes to assess forecasted customer connections and resulting customer counts. According to the data obtained from Moody's Analytics[86], the salient features of the forecast for the ConEd territory are shown in Table 17.

Table 17: ConEd – Average Annual Growth Rates (2017-42)

	Employment		Population		Households	
	NYC	Westchester	NYC	Westchester	NYC	Westchester
2017-22	-0.9%	0.0%	-1.3%	0.2%	-1.5%	0.1%
2023-32	0.0%	0.5%	-0.1%	0.4%	0.0%	0.4%
2033-42	-0.3%	0.0%	-0.3%	0.0%	-0.2%	0.1%
2043-52	-0.4%	-0.1%	-0.5%	-0.2%	-0.4%	-0.1%

COVID-19-related factors clearly had a profound impact on the ConEd territory, leading to a loss of gas customers due to out-migration of residents and significant closure of businesses. Although a substantial portion of the departed population has returned – as evidenced by the partial bounce-back of residential customers and volumes – the forecast anticipates a continued decline in New York City's population, thereby implying a structural shift in ConEd's potential customer-base. In Westchester County, there is positive Population growth forecasted for the next decade followed by a flattening.

With respect to the residential sector– in particular, the multi-family segment – the stalled growth of population and households portends a future with relatively adverse conditions with respect to customer growth in New York City, with Moody's forecasting that the post-COVID-19 recovery is complete and that population and household levels are not going to return to pre-2020 levels. The picture for Westchester County is different, with the forecast showing complete recovery and ongoing growth over the next 15 years.

Although the Companies' forecast incorporates load increments attributable to post-COVID-19 recovery, Moody's data suggests that the recovery in NYC is complete and that the economy has settled into a new normal. Consistent with the Population and Household decline is the projected slowdown in the area's Employment – with long-term implications for the non-residential segment of the gas market. The post-COVID-19 work-from-home phenomenon, though partially reversed, has established itself as the new normal and has cemented a combination of small-business closures and an underutilization of commercial real estate exhibited by a historically high commercial vacancy rate. Moody's forecasts that while a post-COVID-19 recovery does show a return to pre-2020 Employment levels in the outer boroughs, Manhattan's workforce will likely never see pre-COVID-19 levels despite a partial rebound. The projections are for the post-2030 Employment trajectory to mirror the region's Population decline with the average annual growth rate dropping from 0.0% during the 2022-31 period to -0.3% during the 2032-2042 period.

Based on these forecasts, it is reasonable to expect a sustained long-term plateauing of the number of gas customers across all segments in New York City. It is to be noted that the recent Population decline in New York City was not matched by a reduction in meter counts in SC2 and SC3 segments – suggesting that service connections were preserved but, as evidenced by data for the SC2 segment noted above – closures and vacancies led to falling UPC.

In contrast, basic macroeconomic trends are relatively positive for Westchester County, as compared to New York City. As discussed above, even though Population and Households are forecasted to keep growing, the C&I sector is showing indications of plateauing and possibly decline. With aggregate gas usage in

[86] The data was acquired in June 2023.

Westchester County amounting to just over 20% of the ConEd load, the positive potential impact reflected by macroeconomic trends is more than offset by the predicted erosion of sales due to electrification. In fact, the Companies' 2022 Reference Case projected that Westchester County's contribution to the ConEd peak turned negative in 2031-32.

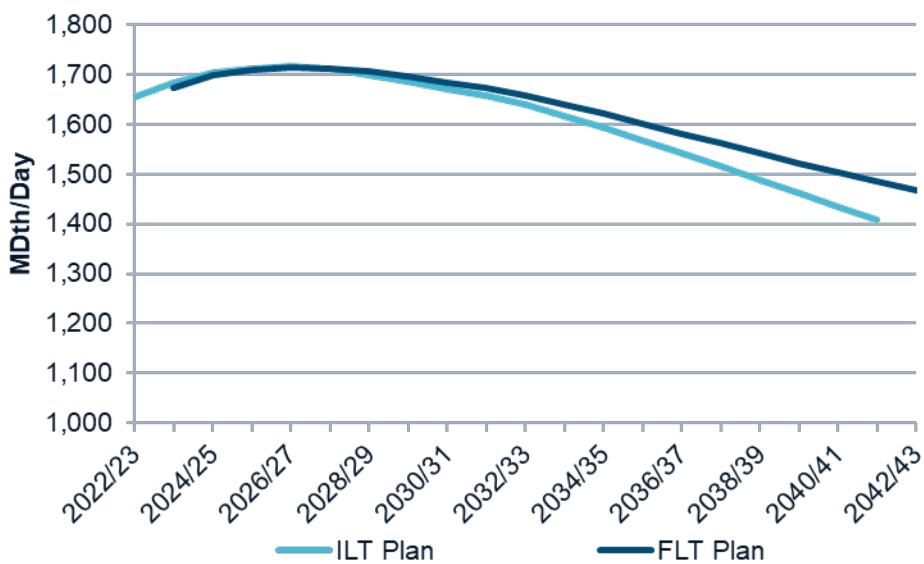
5.4 Load Forecast Observations

This section assesses the RLT Plan Peak Load forecasts for ConEd and ORU received by PA via DPS 5-126, focusing on analysis and critique of the main drivers of usage growth and providing an alternative perspective. We recognize that post-COVID structural changes to gas usage, ongoing macroeconomic dynamics, projected impact of local laws in New York City, etc., present considerable uncertainty as to how demand will evolve – especially beyond 2027/2028. However, based on discussions with the Companies' subject-matter experts and a distillation of Stakeholders' comments, we offer that reasonable arguments can be made for Peak-day demand being lower than levels presented in the FLT Plan. The case for an alternative view rests on (i) a firming of regional macroeconomic patterns leading to a new normal of lower customer growth – particularly in New York City, (ii) the curbing of new gas connections due to the implementation of local laws, and (iii) improving technology and economics of heat-pump technology.

5.4.1 ConEd Peak Forecast

Analysis of historical data and Peak forecasts reveals that annual volumes and Peak-day loads are highly correlated. With electrification-related impacts on gas-usage already manifest in a declining SC1 customer-base and projections of future shrinkage across all customer segments, it is natural to expect that declining volumes will be accompanied by a similar pattern in Peak demand. Figure 18 shows the ILT Plan Reference Case Peak Load forecast (from the Companies' Filing) and the RLT and FLT Plans.

Figure 18: ConEd Reference Case Peak Load Forecast

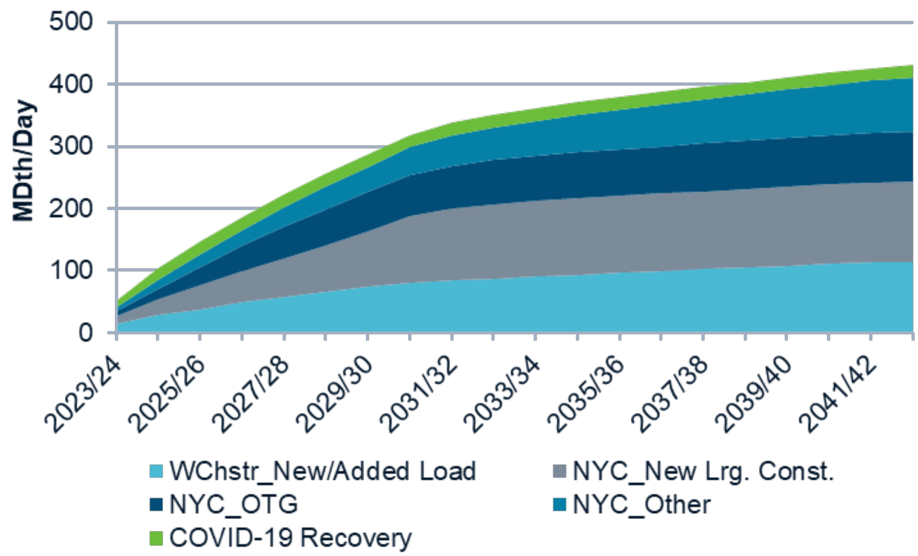


With the macroeconomic forecast pointing to a slowly accelerating negative growth in New York City's Households – the prime driver of the size of the customer base – it is reasonable to expect that prospects for continued new development, especially in the SC3 segment, are discouraging. Furthermore, the influence of the local laws and guidance under CLCPA imply a policy-induced hurdle in continued growth of the customer-base. Set to go into effect during the 2027-28 heating season, Local Law 97 places prohibition on new large construction projects from obtaining natural gas connections. Together with the expectations of improving technology and economics of heat-pump technology, a noticeable dampening of new SC3, and SC2 to a limited extent, customer additions after 2028 is likely. The local laws do grant exceptions to some classes of buildings which are projected to implement their fuel switching more gradually.

Considering these developments, PA analyzed the major elements contributing to load growth in the 2023 Update for ConEd to examine scenarios in which system gas usage might be lower than what is portrayed in the latest forecast. While we are cognizant of the fact that reliability is paramount, we also recognize that Peak Load forecasts establish standards for infrastructure planning and resource adequacy. Specifically, we allude to the procurement of expensive resources like peaking and/or baseload Delivered Services and CNG that sit at the top of the Companies' supply-stack and demand a considerable price premium as compared to pipeline gas. A lower Peak Load would alleviate the need to contract for relatively expensive gas to serve projected load and offer the potential of bill savings to customers. It is, therefore, informative to study key aspects of the forecast to identify areas that could lead the Peak to be less than forecast.

Figure 19 illustrates the incremental components that make up the cumulative impact on ConEd Peak Load. Three drivers of incremental Peak Load in the Companies' forecast are most important to this analysis – additional load due to large new construction, OTG conversions, and the COVID-19 recovery.

Figure 19: ConEd Incremental Peak Load Components – Cumulative (2023-42)

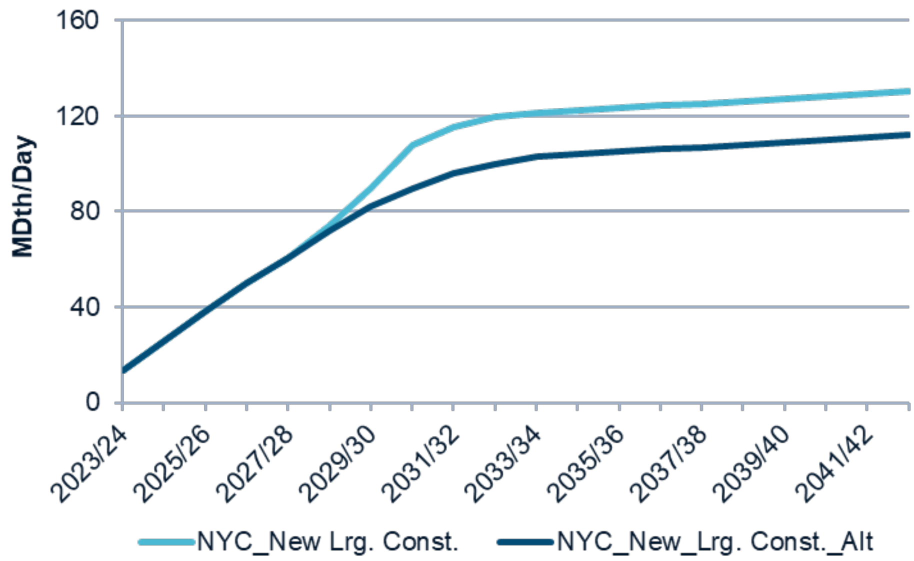


Large New Construction Projects – New York City

New large construction projects account for the largest increments in the ConEd peak forecast. As shown in Figure 19 above, large construction continues to add significant Peak Load through 2030-31 and contributes a total of 130 MDth/Day by 2042. PA considers this an aggressive assumption. The incremental load continues well beyond the date on which local laws are expected to impose prohibition on gas connections in most large buildings (i.e., 2027-28) and in fact, accelerates though 2030-32. Even acknowledging exemptions for certain kinds of projects, it is reasonable to expect that growth begins to taper off soon after the laws are enacted. In discussions with load-forecasting subject-matter experts from the Companies, PA was informed that the additions to load over the next 4-5 years reflect actual records of approved new construction projects and work-in-progress and that beyond 2027-28, the projected figures were the product of econometric models that were driven by macroeconomic variables.

While PA understands the uncertainty associated with the market's reaction to the various local laws coming into effect, it is our opinion that the latest load forecast reflects a rather aggressive build-up of new load beyond 2028. With the territory's Population already in decline and data from Moody's Analytics showing forecasts of persistently negative growth in both Population and Employment, it is reasonable to expect that these trends will get reflected in new development activity once the current pipeline of projects is exhausted. Therefore, a strong argument exists for a moderated alternative ('Alt') trajectory of this impact that exhibits a high point around 2027-28 – around the time the pipeline projects reach completion – and the cumulative new load begins to flatten as illustrated in Figure 20.

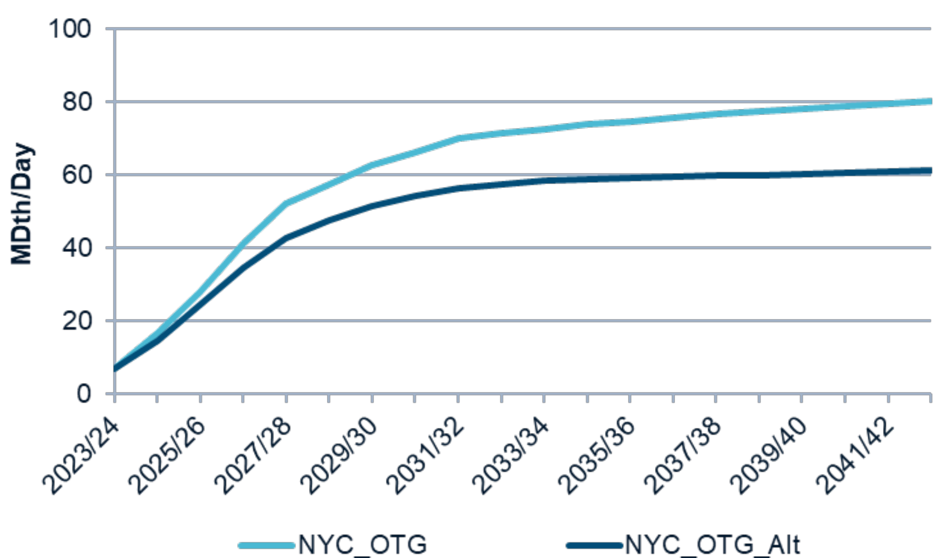
Figure 20: Additional ConEd Load due to Large New Construction – Cumulative (2023-42)



Oil to Gas Conversions – New York City

The next category of incremental load that may not fully materialize is the OTG conversions – especially in large new buildings in New York City. As shown in Figure 21 below, the additional load due to buildings switching from fuel oil to gas accelerates through 2027-28 and then assumes a moderating path that begins to flatten by 2031-32 – adding a cumulative 80 MDth/Day of demand by 2042. OTG conversions amount to a substantial increment to the system Peak in advance of the implementation date of the local laws. It is reasonable to expect that many large gas customers will hasten to convert their heating systems from fuel oil to gas in anticipation of the restrictions due to local laws. However, comments from some Stakeholders who raised the plausibility of some customers switching to electric heating instead have merit. Figure 21 presents an alternative trajectory of OTG impacts on the Peak Load that reflects incremental impacts that begin to moderate soon after the 2027/2028 and are exhausted by early 2030s. Understanding that the impact of the local laws is a phenomenon without precedent, we urge the Companies to provide a more detailed explanation behind their forecast, especially pertaining to OTG conversions.

Figure 21: Incremental ConEd Oil-to-Gas (OTG) Conversions Load – Cumulative (2023-42)



COVID-19 Recovery

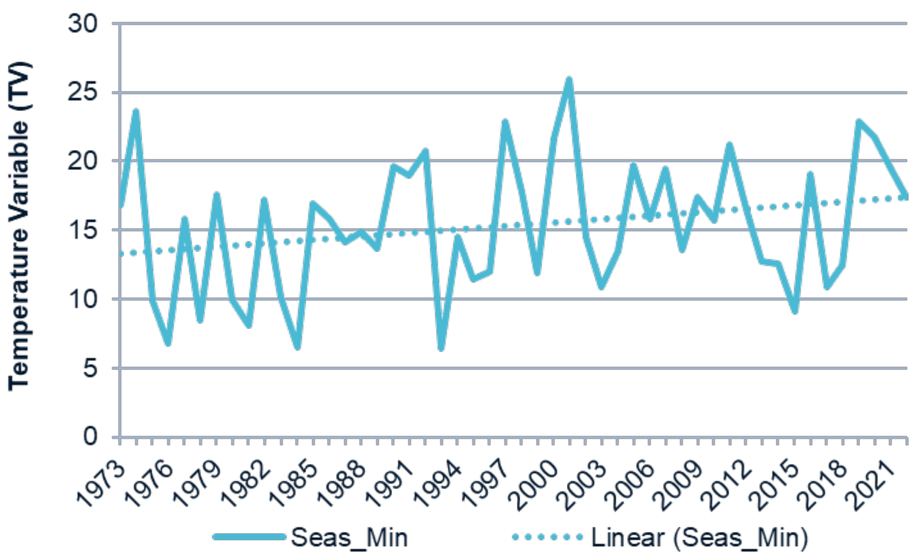
Lastly, while it does not constitute significant additional load, PA considers the Companies' projection of COVID-19-recovery (cumulatively 33 MDth/Day by 2024-25 and thereafter) to be on the high side. Based on Moody's forecasts, both Employment and Population have attained stable levels, signaling a near complete recovery in New York City and Westchester County.

5.4.2 ConEd Peak Forecast and Climate Change

As delineated by the Companies in their RLT Plan, the Peak Load forecast uses a reference of 0°F Temperature Variable ("TV") [87] for design day conditions (i.e., a circumstance in which the weighted average of the average temperature of two consecutive days equals 0°F). PA studied the data for the seasonal minimum temperatures over the 1900 – 2022 period and determined that the last time the ConEd service territory experienced such extreme conditions was in the 1933-34 heating season.

Analysis of the TV history reveals a rising trend that is accelerating as demonstrated by the linear trend fitted on the 123-year history for 1900-2022 which shows an annual rise of 0.03 degrees. The corresponding rates of increase for the 70-year (1953-2022), 50-year (1973-2022) and 20-year (1993-2022) spans were 0.067 degrees/year, 0.085 degrees/year and 0.097 degrees/year, respectively. The results of this analysis provide some evidence of ongoing climate change that suggests future peak-producing conditions will be a bit warmer than what is considered currently – if the factors leading to this phenomenon continue on their current trajectories. Figure 22 below shows the history of the seasonal minimum TV for the last 50 years and a linear fitted trend line.

Figure 22: ConEd Temperature Variable History – 1973 – 2022



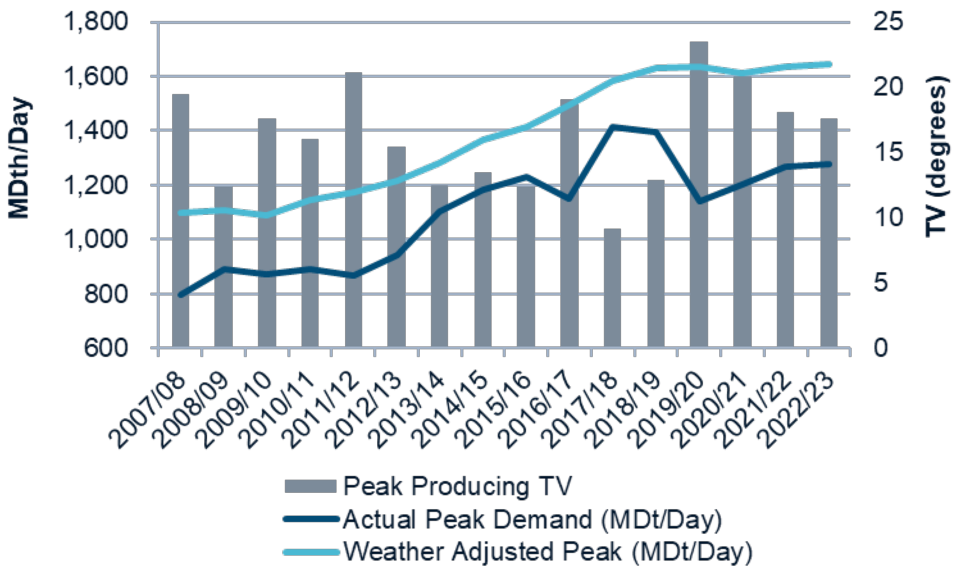
This analysis highlights the significance of the design day criteria for the long-term planning process. Although PA is not recommending a change to the existing methodology of selecting a design day TV, this discussion can be informative for Stakeholders as it provides a perspective on the implications of alternative design day conditions for the planning process and, more importantly, the effect it has on customer bills. Since the zero-degree circumstance in the current planning criteria is shaped by events that occurred just twice in the last 120 years and have not been seen in the last 90 years, the chances of this level of an event happening in the future are diminishing due to climate change. This trend suggests it may be appropriate to revisit the forecasting methodology. We appreciate that the gas market in New York faces a plethora of uncertainties

[87] ConEd uses a Temperature Variable (TV) to quantify weather conditions when analyzing and forecasting Peak Load. The formula for calculating the system TV on a daily basis incorporates two days' worth of daily average temperature. The current day's average temperature is weighted at 70% and the previous day's GDA at 30% The heating season for, say, 2023-24, is defined as the November 2023 – March 2024 period. These figures might differ from those calculated by ConEd since the Companies' definition of TV is based on a gas-day while PA's data reflects the calendar day.

with respect to future sales in the medium term, but have the opinion that considerations raised by this analysis might plausibly become valid and prudent over time.

Figure 23 below shows data for the last 16 years as provided by the Companies. On the left y-axis the chart shows the actual system peaks relative to the corresponding weather-adjusted level based on design conditions. The right y-axis shows the TV values for the respective peak-days. Based on this data, the average peak-producing TV over the last 16 years was 16.4 degrees. Extrapolating the trend from Figure 24 above, the typical peak-producing temperature by 2042 could be between 1.5 to 2.0 degrees higher. So, while peak gas usage is projected to continue growing for a few more years, this analysis suggests that when demand does begin to decline, capacity – upstream and/or on the Companies' system – might be released thereby implying shrinking needs for infrastructure investments and for realizing lower emissions. The salient observation is that long-term climate patterns coupled with demand erosion present plausible future opportunities for a path of declining capacity requirements and capital expenditures that can accelerate the diminishing role of natural gas.

Figure 23: ConEd Historical Peaks and TV Values



Several salient observations from the data in Figure 23 emerge.

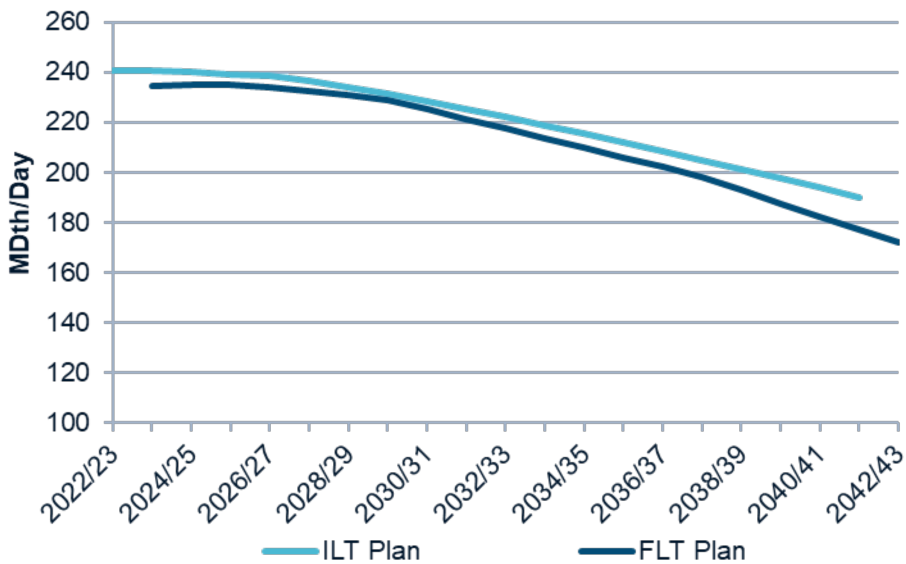
- A clear inverse relationship between the temperature (TV) and Peak Load – a lower TV engenders a higher peak-day load.
- The weather-adjusted (design) level has moved in tandem with the growing system peak. Unlike the electric system that ensures reliability with the assistance of a reserve margin, gas utilities adopt an extreme weather design day planning condition to determine the resources to be acquired. On very cold days that fall short of design day conditions, a slice of capacity exists that functions as a form of reserve margin for the gas system. On those same very cold days, if the gas utility does not use the capacity to serve its load, electric generators in the New York City metropolitan area can access that capacity for their needs; it does not go unused.
- A simple statistical analysis to examine the TV-sensitivity of the ConEd Peak Load suggests that based on a non-linear relationship, the implied Peak drops about 39 MDth/Day for an increase in TV from 0 degrees to 1 degree (with the corresponding change being around 38 MDth/day for a further 1 degree increase to 2 degrees).
- An examination of data for the last 16 years above shows that the system has managed to ensure ample 'headroom' of 'reserve' supplies – proxied by the gap between the weather-adjusted and the actual peak levels. Furthermore, there are indications that the 'reserve' gap might be increasing. For example, if the design criterion were to rise to 1 degree TV, the weather-adjusted peak would decrease by around 39 MDth – still affording ample resources to assure reliability.

- Given that the climate trends are pushing the typical seasonal minimum TV up, it is not unreasonable to imagine considering the notion of adjusting the TV approach in the future. Since the cost of reserving and contracting Delivered Services and peaking CNG resources can be multiples of the baseload gas the Companies' acquire, even a small decline in forecasted Peak can provide relief to bill-payers – especially in the lower-income brackets. However, as mentioned above, PA is cognizant of the need to ensure reliability, especially given the possibility of a multi-day cold-snap akin to the one experienced in Texas during Winter 2020-2021. Therefore, it is important to balance acquisition of adequate peak day resources with retaining reliability of the overall gas LDC system. However, the ability to maintain system reliability while also updating the design day criterion becomes more realistic as electrification increases resulting in further declines in peak gas load.

5.4.3 ORU Peak Forecast

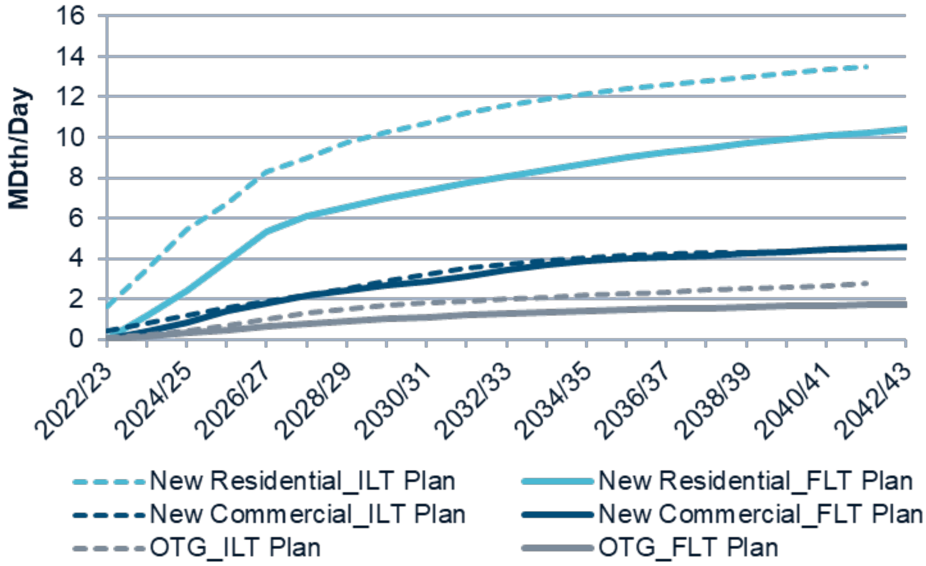
In the ORU territory, the annual volumes and Peak Load are highly correlated. Consistent with recent history, the dynamics shaping gas usage are such that the negative effects of electrification and declining Commercial customers is offset by growth in the Residential sector. The following discussion highlights some salient aspects of the FLT Plan.

Figure 24: ORU Reference Case Peak Load Forecast



The FLT Plan for the ORU territory assumes flat sales through 2027-28 with the peak forecast exhibiting an accelerating decline starting 2024-25, as shown in Figure 24 above. As discussed above, the dominance of gas usage by the residential sector in the ORU territory is growing, given the gradual shrinkage in the non-residential customer-base that began well before the COVID-19 disruption. Although PA is in broad agreement with the general trajectory of the forecast, there are some salient dynamics that merit discussion and consideration.

Figure 25: ORU Peak Load Increments (Cumulative)

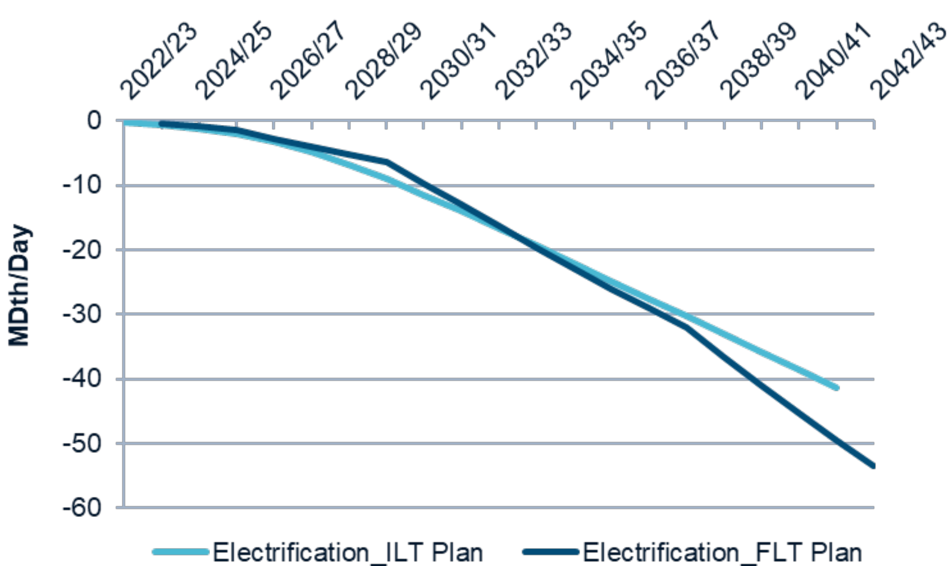


A review of the three incremental drivers of the Peak Load – Residential customer growth, Commercial customer growth and OTG conversions – reveals that new Residential load is the largest contributor with a cumulative contribution of over 10 MDth/day by 2042-43, as depicted in Figure 25.This trend is consistent with Moody's forecast of continuing but slowing Population growth in the region.

Although the Companies revised the projected incremental load due to new residential construction and OTG lower in the FLT Plan, it is not clear why the glidepath of additional Commercial load remained practically the same. The combination of an established declining trend in the Commercial customer base (presumably because of electrification) and a flat UPC[88] would suggest a resulting load forecast that is declining over time. Although the contribution of commercial usage towards Peak Load is comparatively low, we suggest the Companies reassess this matter.

Overall, the trend in ORU's Peak Load conforms to the established dynamics in the local market and is consistent with the macroeconomic and demographic forecast provided by Moody's Analytics.

Figure 26: ORU Electrification Impacts on Peak Load – Cumulative (2023-42)



[88] The relatively flat UPC suggests that commercial customers are electing to undertake electrification of all their end-uses and not just space-heating.

The FLT Plan's incremental impacts of electrification shows a progress glidepath that, as in the 2022 Reference Case, is a bit slower in the earlier years but then accelerates after the mid-2030s. The impact of electrification, decreasing Commercial customer-base, and volumes is readily inferred from recent history. However, anecdotal observations and Stakeholder discussions during technical conferences have alluded to customer resistance to electrification of residential end-uses in the territory's communities, especially in Orange County. This customer behavior presents challenges to the Companies' ability to advance CLCPA and decarbonization goals.

Overall, the trend in ORU's Peak Load conforms to the established dynamics in the local market and is consistent with the macroeconomic and demographic forecast provided by Moody's Analytics.

5.5 DSM Observations

ConEd and ORU offer several DSM programs and included varying degrees of impact within the three pathways. In our Initial Report, PA summarized our initial observations on Demand Response ("DR"), EE and Electrification. In the sections below we summarize our additional observations, with an emphasis on how DSM assumptions compare by pathway and initial Stakeholder comments.

PA finds the Companies incorporate similar assumptions among the Reference, Hybrid, and Deep Electrification pathways in the near term. As presented within Table 18, some assumptions align across all three or just one or two of the pathways. While some Reference and Hybrid Pathway assumptions align in the near-term, over the long-term, key assumptions under the Hybrid and Deep Electrification pathways diverge.[89]

Table 18: Overview of DSM Pathway Assumptions

<table>
<tr><th></th><th>Reference</th><th>Hybrid</th><th>Deep Electrification</th></tr>
<tr><td>Through 2030</td><td colspan="3">Reference, Hybrid and Deep Electrification
Soundview area load relief wraps up in 2024; No new area load relief projects prior to 2028.
One area load relief project in implementation at any given time, spending approximately $1M in gas EE work
Whole building electrification NPAs achieve $1.5M per year by 2026.
NPA Electrification work funded via electric rate base beginning in 2028 and building envelope upgrades funded via electric rate base beginning in 2024.
Growing percent of EE savings from building envelope upgrades over time drives reduction in overall gas EE (assuming recovered from electric rate base).
Impact of Demand Response offerings excluded from all scenarios.</td></tr>
<tr><td rowspan="2">Beyond 2030</td><td></td><td colspan="2">Hybrid and Deep Electrification
Legislative and policy changes are assumed to drive the adoption of electrification technologies in later years.
Abandonment of pipe is driven by utility incentive programs like NPAs or from compliance with legislative requirements (absent utility incentives) or a blend of both.
Utility incentives for electrification will be recovered from the electric utility's customers. As a result, the gas capital cost forecasts do not include the costs of electrification programs beyond when it is assumed that NPA incentives for electrification begin to be recovered as part of the electric rate base.</td></tr>
<tr><td colspan="2">Reference and Hybrid
50% of EE savings coming from building envelope upgrades by 2030.
Complete phase out of gas energy efficiency programs by 2035.</td><td>Deep Electrification
90% of savings coming from building envelope upgrades by 2030.
Assumes obligation to serve removed in 2030 and policy shifts away from NPA</td></tr>
</table>

[89] Source: Response to DPS 4-104.

		framework to legislated and ordered shift to electrification.
	Reference, Hybrid and Deep Electrification • Phase out of utility gas EE offerings by 2035 reflecting impact of future building codes and standards, with overall decline beginning in 2026. • Impact of Demand Response offerings excluded from all scenarios.	

Demand Response

As noted within the table above and discussed within our Initial Report, DR program savings are not anticipated in any of the pathways. However, the Planning Proceeding Order identified the need to explore methods of DR and emphasized the need for DR methods that do not rely on oil as offerings should avoid emissions and decrease the need for new infrastructure. Within this section, PA discusses the value of DR offerings and recommends the Companies consider refined DR offerings within future alternative scenarios.

Historically, customers on interruptible rates generally rely on alternative fuels, such as oil, when their gas service is interrupted. In the future, growing numbers of dual-fuel heating customers will have the capability to rely upon electricity as a heating alternative. DR and interruptible service offerings targeted at such customers not only reduce gas usage on very cold peak days, but also reduce GHG emissions.

As discussed within PA's Initial Report, ConEd operated a gas DR Pilot Program to test the feasibility of incentivizing customers to reduce net natural gas demand during the entirety of peak gas demand days (24-hour period from 10:00 am to 10:00 am the following day), on very cold winter days. However actual weather over the four-year pilot period did not trigger temperatures and the resulting responses. As a result, ConEd concluded the DR Pilot was not a viable option for load relief and therefore ended this pilot.

PA observes it is important that DR offerings are structured for success, otherwise such measures cannot be expected to provide peak reduction reliably. We note successful DR offerings need to provide sufficient incentives to encourage participant responses, at appropriate trigger temperatures. Although not entirely necessary, use of AMI metering also brings substantial value for both customers and companies through real-time monitoring of usage, verification of peak day savings and payment, as compared with more cumbersome processes employed with less advanced meters. PA observes that ConEd customers have AMI metering and are advantaged from this perspective, as compared to other gas utility customers.

PA recommends the Companies consider a restructured approach to re-launch DR and other Interruptible Service offerings, including but not limited to trigger temperatures (such as in alignment with temperatures triggering peaking asset services), partnerships with communities and neighborhoods such that customers understand the environmental, and economic value of such programs (beyond the response incentives offered). Further restructuring might entail program cost recovery and Shareholder incentives; however, such changes would require consideration and approval from the Commission and are outside of the Companies' control.

Electrification

The concept of electrification represents the fuel-switching that occurs when appliances or equipment that are typically fueled by natural gas or other fossil fuels are replaced by appliances that use electricity, for example heat pumps, electric stoves, electric water heaters, and electric dryers. Most policy initiatives incorporate electrification as a major decarbonization pathway to reach GHG emission targets. Often, decarbonization strategies focus on the decarbonization of the power sector as the primary backbone of decarbonization and then rely on that decarbonized electricity to displace fossil fuels consumed in a range of energy end uses such as transportation, buildings, and industrial applications. Although electrification of some fossil fuel demand is expected in nearly all decarbonization pathways, accelerated electrification of all sectors (e.g., transportation, building, industrial) needs careful, strategic, and proactive planning to ensure a smooth economy-wide transition meeting customer needs such as reliability, affordability, resiliency, safety, and overall societal benefits. Although clear evidence is emerging, that electrification is a key pillar in decarbonization efforts, an ongoing debate continues across the United States about the role of natural gas in our economywide decarbonization efforts, and this debate is far from being settled. The role of natural gas as an energy source to maintain affordable and reliable energy and the significant role that natural gas has in today's economy, at a minimum as a transition fuel, is undeniable.

Plenty of initiatives and programs exist in New York to support the electrification of the transportation and buildings sectors. NYS Clean Heat Program ("CHP") is a prime example of a public-private partnership supporting the deployment of low carbon solutions. PA understands that the NYS CHP, launched April 1, 2020, provides customers, contractors, and other heat pump solution providers with a consistent experience and business environment, and includes initiatives to advance the adoption of efficient electric heat pump systems for space and water heating applications throughout the State. Electric utilities provide incentives to encourage adoption of certain eligible heat pump technologies, including cold climate air source heat pump ("ccASHP") systems, ground source heat pump ("GSHP") systems, variable refrigerant flow ("VRF") systems, commercial and multifamily heat pump systems, and heat pump water heaters. NYS CHP is implemented in coordination with a portfolio of NYSERDA-led market development initiatives, which aim to build market capacity to deliver building electrification solutions.

The Companies have depicted the role of electrification under various pathways and levels of adoption in helping the Companies meet the State's decarbonization goals. Given the accelerated timeline and the wide scope of the Planning Proceeding Order spanning a wide range of topics (e.g., supply, demand, NPAs, etc.) the Companies have developed a high-level top-down approach to forecast the rate of electrification and as a result the potential GHG emissions implications. Under the Hybrid and Deep Electrification pathways, the Companies are projecting a respective 63% and 83% reduction in GHG emissions compared to 2023 baseline.

Although there are different ways to project how electrification could unfold in the building sector across various timelines and various regions, two primary pillars must be addressed to properly incorporate electrification and its impact on gas utilities - the time when a new building is built and conversions from gas to electric appliances. When a new building is built, it could be built with or without a gas hook-up depending on a variety of factors including residents' preference, home developers' familiarity with heat pump technology and their experience, local building codes, state and local policies, economics of each technology, proximity to existing natural gas main, cost, etc. The FLT Plan could benefit from further explanation on the assumed share of future new builds forecasted to be hooked up to the gas network, and the share that is assumed to be fully electric, especially considering the emerging local policies and limitations on new gas hook ups in New York.

The second path to account for electrification is conversion from gas to electric. Upon the failure of various appliances (gas furnace, boiler, water heater, stove, etc.), customers will face a decision to either replace the appliance with a similar technology (e.g., replace a gas furnace with another gas furnace) or switch the technology (e.g., from gas to electric or electric to gas). Since not all appliances fail at the same time, the switching decision for all appliances is typically not made in the same timeframe. PA noticed that in the interest of time and simplifying modeling efforts, the Companies are making a simplifying assumption that buildings will either use gas for all applications or will fully convert to electric. However, the projections could provide a more robust view if partial electrification of various appliances are accounted for in the FLT Plan.

Both Companies have specific programs and rebates to promote adoption of efficient electric appliances. The Companies could augment the FLT Plan to provide a brief overview of these programs, level of funding for each program, level of adoption by year, target customers, and the effectiveness of these programs to date, summary of lessons learned, and how these programs are projected to be leveraged in the future to support the pathways depicted in the report. The Inflation Reduction Act ("IRA") has specific provisions for adoption of more efficient appliances and electrification of various applications (e.g., heat pump, heat pump water heater, electric stoves, heat pump clothes dryer). The FLT Plan and the long-term load forecasting can significantly benefit from a discussion on how these rebates and incentives can improve the economics of various use cases and lead to higher adoption of electrified appliances.

The Companies have expressed some difficulty signing up meaningful number of customers to deploy electrification and NPA solutions. Issues ranging from lack of customer familiarity with various technologies (e.g., heat pump, induction stoves, heat pump water heaters), low interest in such technologies, speedy nature of replacing all these appliances, concern about power grid reliability and dependency of these technologies on the power grid, are among the primary concerns shared by residents to the Companies.

Evolving Competition Between Gas and Electric Appliances

The Initial Report included recommendations to help improve the long-term gas planning process, including consideration of the evolving competition between gas and electric appliances. PA believes the competition between the economics of gas and electric appliances is a very important dynamic feedback loop and if not accounted for, could result in misguided conclusions. The feedback loop intends to reveal how customers account for the economics of electric and gas appliances in purchasing decisions, such as purchasing a water heater. Although there are several other factors at play, this cost comparison is an important element of a customer's decision to choose between substitute goods, in this case gas and electric appliances, and should be accounted for in the long-term modeling process, especially if there are significant differences in annual operational cost of substitute goods.

In their Initial Reply Comments, the Companies disagreed with the proposed recommendation and indicated that this dynamic is not applicable to the Hybrid and Deep Electrification scenarios.

> "PA Consulting recommended that the evolving competition between the economics of gas appliances and electric appliances be included as part of the modeling. This is not applicable to the Hybrid and Deep Electrification modeling since those are top-down policy driven models." [90]

PA reiterates the importance of this assumption and encourages the Companies to account for this dynamic of evolving competition in future LT Plans. Although we understand that policy is assumed to be the primary driver of decarbonization in Hybrid and Deep Electrification scenarios, the economics of electric and gas appliances could play a significant role in informing customers' decision and adoption of electric appliances. As an example, under the Deep Electrification scenario, gas customer rates are forecasted to grow by 15.2% year over year on average. Under such a significant rate increase, economics of gas appliances will quickly fall out of favor in a few years compared to electric alternatives, leading to a significant shift away from gas appliances, much higher in scale and faster than what the Companies have modeled under the Deep Electrification scenario. As a result, if not properly accounted for, the risk of stranded assets and rate increases under the Deep Electrification scenario will be much higher than depicted in the ILT Plan and RLT Plan.

In their Reply Comments, Earth Justice/Sierra Club also agreed that the Companies should incorporate the assumptions regarding this dynamic of competition between gas and electric appliances. They mentioned that the Companies' assumptions of the economics of gas versus electric appliances are out of date, as they rely on assumptions developed in 2017.

Therefore, PA reaffirms the recommendation to the Companies to upgrade their modeling efforts to account for the dynamic competition between the economics of electric and gas appliances, and how gas and electric rates can influence the appliance adoption decision, thus having an impact on total delivered gas volumes and the long-term planning for gas in this preceding.

Targeted and Coordinated Deployment of NPA and Electrification Solutions

Customers in NY have been adopting energy efficient and electrified appliances and this trend is expected to continue and further accelerate over the next decades, especially driven by federal and state policies including the IRA incentives, efficiency standards and GHG emissions reduction targets. Although this is a strong start, there is a potential for cultivating further value from adoption of these efficient and electrified appliances. By developing a comprehensive and strategic view on potential decarbonization solutions, the Companies can send the signal to customers residing in certain geographies to further encourage adoption of these electrified solutions. These targeted and coordinated deployments of NPA solutions could be aggregated over time to identify pockets of the gas network that could be capped to avoid costly pipe replacement. An unplanned and uncoordinated decarbonization can result in deployment of capital in replacing pipes that are underutilized, since a good portion of customers in certain geographies have electrified or will electrify their appliances. Such a future is not ideal as it leads to overspending on capital, suboptimal reliability of the gas and electric system, and even leading to high gas and electric bills that are unaffordable by significant portions of the population across New York, including disadvantaged communities.

In addition, the Companies will need to ensure their long-term gas and electric planning efforts are in harmony to ensure there is sufficient capacity on the grid for electrification of homes and appliances, and to eliminate the concerns of grid reliability as discussed earlier.

Granular EE and DR Assumptions

[90] Source: ConEd and ORU Initial Reply Comments.

As noted within Section 3.3 the Companies indicate the effects of EE and DSM programs on annual UPC, customer behaviors, and resulting program adoption assumptions have been incorporated into the modeling, but the program specificity is not available. This is an area the Companies expect to enhance in future long-range volume forecasts. The Companies have also agreed that inclusion of more detailed EE and DR information, such as participation rates and savings by program, is useful to stakeholders. Within reply comments, the Companies noted plans to incorporate this within the FLT Plan. However, in PA's review of FLT Plan, this additional information was not found.

5.6 Recommendations

Recommendations for demand are summarized below.

- Frame a detailed/disaggregated perspective on both the customer counts and annual UPC across the different customer segments - Single-family Residential (SC1), C&I (SC2) and Multi-family Residential (SC3) - to conduct an appropriate assessment of load structure, given the distinct dynamics of each segment.
- Incorporate the economics of gas versus electric appliances. The current modeling efforts do not account for the evolving competition between the economics of gas and electric appliances (e.g., gas furnace and heat pump) over the next decades. This dynamic view is potentially a very important dynamic feedback loop, as it could impact the total volumes of gas delivered to customers and thus the gas rates. Upon reduction in gas volumes, with all else equal, gas rates will increase over time and alternative electric solutions will be more cost competitive over time. PA expects significant value in providing historical adoption rates of various technologies (e.g., heat pumps) and supplementing the projections with an analysis that accounts for such dynamics. Given the importance of this subject, we encourage the Stakeholders to review and discuss the assumptions made in the analysis that was recently shared by the Companies.
- Specify the impact on EE and DSM programs on the annual UPC. Both Companies have multiple EE and DSM programs that have been helping customers save money, while supporting the reliability of the gas and electric systems for decades. At least in some segments of the customer-base, the cumulative momentum of these initiatives, along with the organic efficiency gains (attributable to behavioral factors, improved technology, Codes and Standards etc.), would be expected to be manifest in the trends of annual UPC.[91]
- Consider the impact of Electric Operations DSM measures on the customer behaviors and resulting electrification, energy efficiency, and other DSM program adoption assumptions.
- Consider a restructured approach to DR offerings, including but not limited to refined trigger temperatures, pro-active communication of the environmental and economic value of such programs (beyond the response incentives offered) to encourage customer adoption and consider regulatory changes such that company shareholders are incentivized to fund for such measures over substantially more expensive delivered services and/or future capital investments.
- Provide more information such as annual participation rates and savings by program (NE:NY, Organic, etc.) and Pathway.[92]
- Consider the notion of adjusting the TV approach in the future provided analysis projects adequate headroom between observed and weather-adjusted Peak Load. Since the cost of reserving and contracting Delivered Services and peaking CNG resources can be multiples of the baseload gas the Companies acquire, even a small decline in forecasted Peak can provide relief to bill-payers – especially in the lower-income brackets.

[91] In ConEd and ORU Reply Comments, the indicate this is an area of enhancement for future long-range volume forecasts. See Section 3.3 for additional discussion on the Companies' comments.
[92] In ConEd and ORU Reply Comments, the Companies agree to provide this in the FLT Plan however, PA observes this was not completed. See Section 3.3 for additional discussion on the Companies' comments.

6 Economic Assessment

PA has completed a review of several economic issues, based on information presented in the ILT, RLT and FLT Plans, responses from the Companies to a number of related discovery requests, and Stakeholder's comments. Stakeholders have expressed significant interest and concerns about the sensitivity of the bill impact and affordability implications of the proposed long term gas planning.

6.1 Bill Impacts

The Planning Proceeding Order requires the Companies to provide clear quantitative and qualitative explanations for their proposed capital projects, an estimated bill impact, and a net present value of the estimated costs.

In their ILT Plan and RLT Plan, the Companies conducted a high-level bill impact analysis for a "Representative Gas Service Customer" depicting the bill impact on customers under the three pathways. There are two primary drivers for gas rates - fuel supply and delivery rates. The Companies forecasts account for both the evolving supply mix and the emerging changes in the delivery network. This analysis is beneficial in helping stakeholders understand the potential implications of the long-term investments needed under each Pathway, the impact on customer bills, and, potentially, affordability issues, especially for the disadvantaged community and LMI customers. In this high-level analysis, the Companies did not calculate the bill impact for each customer class, instead they divided the total revenue requirement by total number of customers remaining on the system in each Pathway to demonstrate a directional view on potential rate and affordability implications for each pathway.

In their FLT Plan the Companies provided a projected bill impact analysis for each customer class as depicted in Table 19 below. The bill impact analysis conducted for all pathways as depicted in the FLT Plan report[93], and presented within Table 19 is relatively high and could pose affordability challenges for ratepayers, especially for low-income customers. Under the Reference Case Pathway, a SC-1 customer's bill is forecasted to increase from $562 per year to $1,170 per year, a 108% increase over 20 years which translates to an average total bill increase of 5.4% per year (excluding inflationary price increases).

Table 19: Annual Average Rate[94] Impacts for ConEd and O&R Customer Classes and Pathway

ConEd		
Scenario	**Rate Impact (2023-2043)**	**Rate Impact (2023-2050)**
SC-1 Residential/Religious Firm Sales Service		
Reference	5.4%	4.3%
Hybrid	7.4%	6.7%
Deep Electrification	25.1%	37.5%
SC-2 Rate I General Firm Sales Service		
Reference	4.2%	3.6%
Hybrid	7.5%	9.1%
Deep Electrification	17.5%	58.8%
SC-2 Rate II General Firm Sales Service		

[93] Source: Figure 32 of the FLT Plan.

[94] There are different methods of demonstrating the rate impact of proposed decarbonization pathways. Table 19 demonstrates the average rate increase per year over the forecast period. PA has also conducted a Compound Annual Growth Rate (CAGR) analysis for year-over-year rate increases over the forecast period. See Appendix D for the CAGR analysis.

Reference	4.4%	3.8%
Hybrid	7.6%	8.8%
Deep Electrification	19.1%	64.4%
SC-3 Residential/Religious Heating		
Reference	4.7%	4.0%
Hybrid	7.3%	8.1%
Deep Electrification	18.5%	61.7%
O&R		
SC-1 Residential and Space Heating		
Reference	3.2%	3.5%
Hybrid	8.8%	14.9%
Deep Electrification	5.5%	14.9%
SC-2 General Service (small)		
Reference	2.8%	3.1%
Hybrid	5.4%	8.6%
Deep Electrification	11.7%	56.9%
SC-2 General Service (large)		
Reference	2.9%	3.3%
Hybrid	5.7%	9.2%
Deep Electrification	12.7%	62.3%

Table 20: Representative Residential Gas Costs (Revised Plan)

Pathway	2023	2043	Average Total Bill Year Over Year Increase
Reference	$1,700	$3,400	5.0%
Hybrid	$1,700	$4,300	7.6%
Deep Decarbonization	$1,700	$8,800	20.9%

For the ConEd service territory, our bill impact assessment has determined that the rate impact in the FLT Plan between 2023 and 2043 across all customer classes was generally lower than what was forecasted in the Revised plan. However, in the "SC-1 Residential/Religious Firm Sales Service" *Reference* and *Deep Electrification* Pathways, the rate impact between 2023-2043 were higher than average rate impact (5.4% vs 5% for *Reference* and 25.1% vs 20.9% for *Deep Electrification*), as projected in RLTP. From 2023-2050, rate impacts in the "SC-1 Residential/Religious Firm Sales Service" *Reference*, the "SC-2 Rate I General Firm Sales Service" *hybrid*, the "SC-2 Rate II General Firm Sales Service H*ybrid*, and the "SC-3

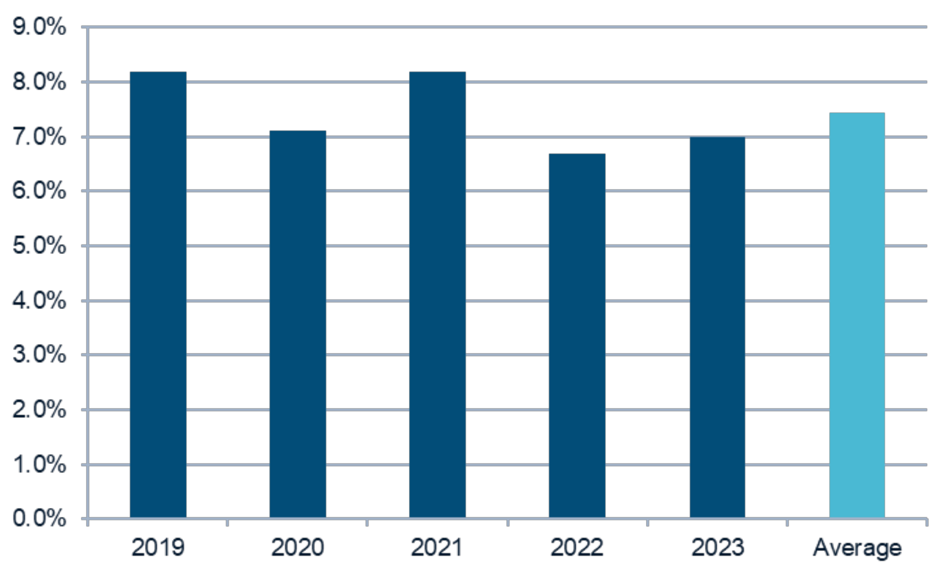
Residential/Religious Heating" *Reference Pathways* were higher than average rate impact, as projected in the RLTP.

Average annual rate impacts from both the *Reference* and the *Hybrid* Pathways range from 4%-8% in the 2023-2043 timeframe. The *Deep Electrification* Pathway is forecasted to experience the largest rate impact across all Pathways. The rate impact of *Deep Electrification* is projected to be int the 17%-26% range between 2023 and 2043 in three of the four customer classes, except for "SC-1 Residential/Religious Firm Sales Service". The "SC-1 Residential/Religious Firm Sales Service" customer class is projected to experience the smallest rate impact of *Deep Electrification* from 2023-2050, at 37.5%, with rate impacts above 55% for *Deep Electrification* in all other customer classes. Although the *Deep Electrification* Pathway experiences the highest bill impacts, as discussed in previous sections, this Pathway is the most effective in achieving state emission requirements set forward through the CLCPA.

For the O&R service territory, our bill impact assessment has determined that the rate impacts between 2023-2043 for nearly all customer classes are considerably lower than what was forecasted in the RLTP. There was one exception, in the "SC-1 Residential and Space Heating" *Hybrid* Pathway, where the rate impact was higher than average rate impacts, as projected in RLTP, by approximately 15%. From 2023-2050, rate impact was generally lower than forecasted in the RLTP, with the exception of "SC-1 Residential and Space Heating" *Hybrid* Pathway and "SC-2 General Service (large)" *Hybrid* pathway, where rate impacts were higher than average, as projected in the RLT Plan. From 2023-2043, average annual rate impacts are projected to remain between 2.8% and 12.7% across all Pathways. In the "SC-1 Residential and Space Heating" customer class, rate impacts for *Deep Electrification* are lower than rate impacts for *Hybrid* (5.5% vs. 8.8%).

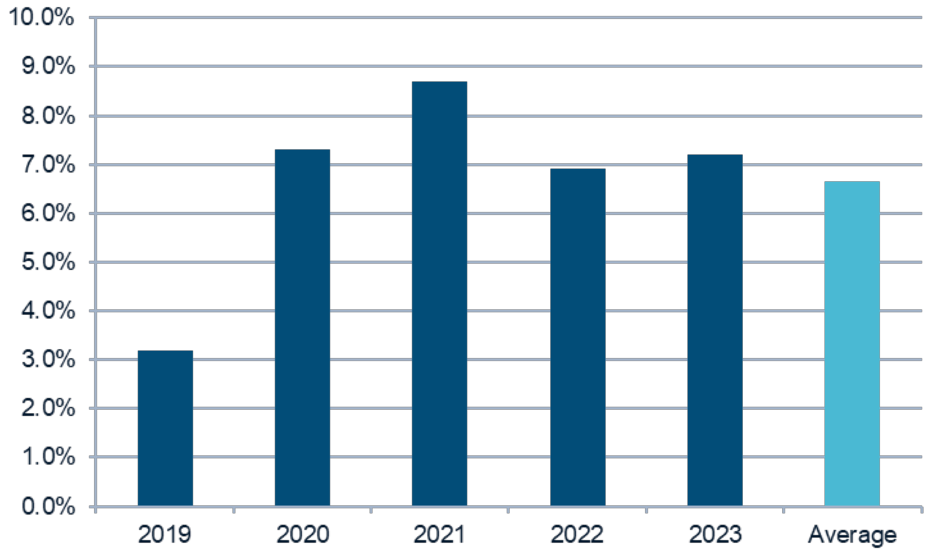
Historically, the average total bill increases for a representative gas customer in the SC1 class has been 7.4% on average between 2019 and 2023, and 6.7% for a representative customer in SC3 class. The total bill increases for an average ConEd residential gas service customer have been 7.3% in 2020, 8.7% in 2021, and 6.9% for 2022 for residential customers in SC3 class[95]. Note that unlike the values forecasted in the FLT Plan that excludes inflationary price increases, these historical rate increases include inflationary price increases. It should be noted that gas rates are typically set through a separate regulatory process and these rate forecasts by no means are intended to be indicative of how rates would be set over the forecast period. The most recent rates were established by the Commission when it approved a Joint Proposal that set gas rates through January 1, 2026.

Figure 27: Historical Total Bill Impact YOY Increase- SC1



[95] Source: NY PSC Order on Cases 19-E-0065 and 19-G-0066, Issued on January 16, 2020.

Figure 28: Historical Total Bill Impact YOY Increase- SC3



Under the Hybrid and Deep Electrification Pathways, the average year over-year-total bill increases for ConEd are projected to be respectively in the 7-8% range and 17-25% (excluding inflationary price increases). The potential total bill impacts under these scenarios are significant from a customer affordability perspective as shown in Figure 32 of the FLT Plan.

The primary drivers of these significant total bill increases are: The significant reduction in total volumes of gas delivered in the bill impact calculation, and the investments in the gas network (i.e., rate base).

PA recommends the Companies prioritize various investments under each Pathway and identify potential investments that could be reduced or eliminated, with the goal of reducing the revenue requirement and ultimately the total bill impact on customers.

In the version of the bill impact calculation presented in the FLT Plan, the Companies used the average volume of gas consumed by a representative customer in each class constant over the forecast period. As demonstrated in the Companies' forecast, the volumes of gas consumed by customers will decline over time because of EE programs and electrification. If the reduced volumes of gas discussed in Section 5.4 are used in this analysis, the total bill increases will be higher than the values discussed in this report. PA recommends the Companies develop a more sophisticated view on the projected volumes of consumed gas to help develop a more accurate view on the bill impact over the forecast period. Furthermore, gas forecast trends should be tied specifically to investment requirements with the objective of minimizing new investments as demand is forecasted to reduce over time under each scenario.

As discussed in the electrification section of this report (Section 5.5), the Companies are not accounting for the dynamic feedback loop between gas and electric rates and the dynamic competitiveness of these technologies under various policy and technology developments. Under a rapid electrification future (potentially fueled by policy mandates, rebates, or technological advancement or customer preference) the average volumes of gas delivered to customers could decline much faster than projected in the report, creating even higher bill impacts and affordability challenges for customers remaining on the gas network. Thus, PA recommends the Companies incorporate a more dynamic view of the gas and electric rates into the FLT Plan to better reflect a scenario where an accelerated decarbonization pathway unfolds.

The Companies briefly discussed the impact of building electrification on the electric grid in terms of system peak demand and the size of electric load. The Planning Proceeding Order does not require the Companies to discuss the impact of building electrification on the electric grid. However, PA suggests the Companies consider developing at least a high-level point of view of the impact of each pathway on the electric grid and demonstrate electric grid readiness for supporting building electrification. Such analysis would be helpful to inform the potential pace at which buildings could electrify in various neighborhoods/regions across the service territory of the Companies.

Developing a high-level view on the impact of building electrification would also allow Companies and Stakeholders to develop a total energy “Share of Wallet” analysis which considers the scope and magnitude of investments needed to be deployed to both the gas and electric networks to meet the State’s decarbonization goals. PA observes that the Companies’ FLT Plan did contain a brief discussion that presented conclusions from a bill-impact assessment that focuses exclusively on the gas sector. This is further discussed in Section 6.2.

Impact of Decarbonization on Gas and Electric Rates

The energy industry is responsible for a significant share of GHG emissions in our economy. Therefore, all energy systems including electric, gas, steam, and other systems will need to undergo a significant transformation to reduce and ultimately eliminate GHG emissions from the entire lifecycle of all energy carriers. Such a substantial transformation will require significant investments to ensure a reduction in GHG emissions while maintaining reliability and safety for the operation of these systems. For example, in the natural gas industry, aging pipes that are beyond their useful life will likely need to be replaced or repaired and will require significant investments. At the same time, investments are needed to reduce emissions from natural gas production and distribution to produce and blend low emission fuels (e.g., RNG and hydrogen). All these investments will ultimately show up on customer bills and will need to be fully or partially paid by end use customers.

The electric system will also need to undergo a similar pattern of reducing GHG emissions by replacing aging infrastructure with renewable energy sources and investing in transmission and distribution networks to ensure safety and reliability of the grid.

Although both gas and electric systems follow a similar pattern, requiring significant investments over the next decades, the volume of gas and electric is expected to follow a different trajectory. The total volume of natural gas consumed is expected to significantly decline over time because of energy efficiency and building electrification, a trend that is already present and discussed in detail in the electrification section of this report. Although energy efficiency will put downward pressure on electricity demand, the total volume of electricity consumed is expected to significantly increase as a result of building and transportation electrification.

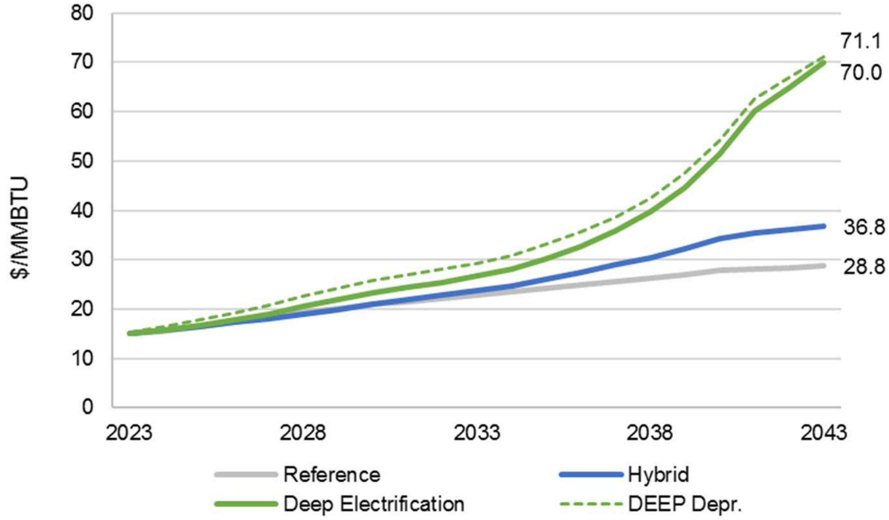
Gas and electric rates are typically calculated through sophisticated rate-setting formulas and procedures, beyond the scope of this document. However, in simple terms, rates are primarily determined by dividing the total size of utility’s rate base (which is directly influenced by new investments) divided by the total volume of gas or electricity that is consumed each year by each customer class. As described above, both gas and electric systems will require significant investments. Gas consumption is forecasted to decline, and electric consumption is forecasted to increase. Therefore, the upward pressure on gas rates is forecasted to be much higher than the pressure on electric rates and potentially the affordability pressure on gas customers is projected to be more intense. This affordability challenge will need significant attention from policy makers, regulators, and key stakeholders in New York to ensure the State takes a comprehensive view on affordability of energy carriers in New York.

Accelerated Depreciation

The Companies have discussed the potential for creation of stranded asset risk and/or affordability risks, meaning customers may not be able to afford significantly higher bills forecasted in the bill impact analysis. The Companies have proposed the following accelerated depreciation as a potential solution to address this issue in the long-term. However, it is important to note that this would also increase rates in the short-term.

Our assessment suggests that accelerated depreciation is not going to be effective in meaningfully reducing the risks discussed above. The Companies’ analysis suggests that accelerated depreciation will only reduce the gas system rates from $71.1 /MMBtu to $70.0 /MMBtu under Deep Electrification pathway, a negligible 1.7% reduction in rates, as shown in Figure 29 below.

Figure 29: Accelerated Depreciation Customer Rate Impact



Some valuable recommendations have been made by Stakeholders on potential changes to the depreciation schedule to minimize the negative bill impact on various customer segments including the LMI customers. The Consumer Power Advocates (CPA) expressed concerns about the potential negative rate impact that could be borne by hospitals and indirectly by patients.

New Yorkers for Clean Power (NYCP) referenced a depreciation study prepared for ConEd by Gannett Fleming using two different depreciation schedules, a Straight Line depreciation (SL) and depreciation apportioned uniformly among Units of Production (UoP). NYCP believes that the UoP depreciation is fairer and more stable than SL depreciation schedule over time. However, switching from the current depreciation practices[96] could have a significant adverse impact on rate payers in the short term. NYCP recommends a hybrid depreciation approach in a phased manner to retain the advantages of UoP depreciation method while protecting customers from rate shocks. The Companies responded to NYCP's data request on November 30, 2023.

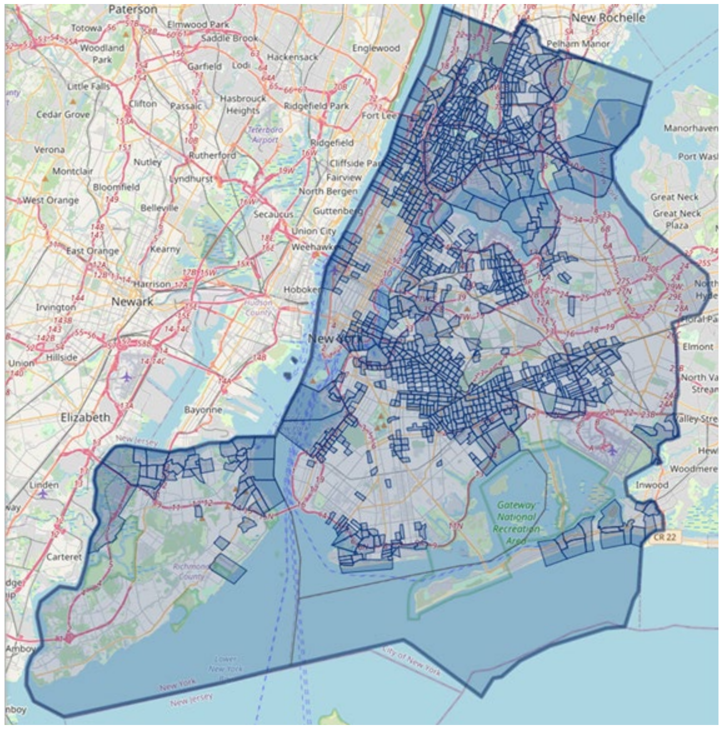
We acknowledge that making changes to the depreciation schedule is a tool in policymakers' toolbox that should be used if/when regulators deem suitable, but it may currently be premature to heavily rely on this last resort tool as it does not effectively alleviate the stranded asset and affordability risks. We acknowledge such a change is more suited for a generic proceeding, given the impact on all gas utilities in New York. Therefore, we encourage the Commission, the Companies, and Stakeholders to collaborate on ways to first and foremost identify and avoid unnecessary investments that will likely be stranded or underutilized to avoid the significant stranded asset risk depicted in the Companies' FLT Plan. The potential for alternative approaches to depreciation can then be considered in the next rate case.

6.2 Affordability

ConEd provides gas service in Westchester County, Manhattan, the Bronx, and portions of Queens which represent a relatively high concentration of disadvantaged communities, with approximately 45% of all census tracts determined as such and illustrated in Figure 30 below.

[96] New Yorkers for Clean Power acknowledges that SL is the standard practice in New York State currently and switching the deprecation schedule could have short term negative impacts.

Figure 30: New York City Disadvantaged Communities[97]



Information pertaining to disadvantaged communities in the FLT Plan was largely limited to the Energy Affordability Programs and mapping techniques that Companies are pursuing to identify and locate DACs in their territories. It is unclear how the Companies' FLT Plan will ensure that at least 35% of benefits will be assigned to disadvantaged communities. Given the importance of this topic, a technical conference was held on October 18th. At this Session, the Companies described the base mapping tool easily providing the Companies with the ability to identify customers within Disadvantaged Communities. This was developed in collaboration with NYSERDA and will be expanded to include asset and engineering data layers for increased visibility and near-term decision making and long-term planning. The Companies also described an internal Environmental Justice Working group tasked to evaluate all policies and procedures to ensure decision-making frameworks are developed and used to ensure benefits or burdens to Disadvantaged Communities are considered. Examples of areas where such decision-making frameworks would be applied are Program Design, Financial Incentives, Program Promotions, Engineering, Capital Planning and Strategic Corporate Philanthropic Giving. At this session, several Stakeholders asked questions to better understand the mapping tool and how quickly it will be scaled to ensure near-term investment decisions consider the impacts of Disadvantaged Communities.

PA understands ConEd will file an annual Disadvantaged Community Report including more data regarding investments, engagement, and workforce development efforts in disadvantaged communities. Inclusion of information, such as a forecast of both the mileage of LPP main replacement/retirement, as well as the number of LPP service line replacements/retirements, LPP mains mileage and number of service lines replaced, as well as retired but not replaced, the number and type of leaks repaired as well as those eliminated by replacement, and associated avoided emissions applicable to disadvantaged communities would strengthen the FLT Plan. Although actual results may vary, pro-active development of investment plans that address specific needs of disadvantaged communities and inclusion of this information in the FLT Plan would be consistent with the Commission's Order.

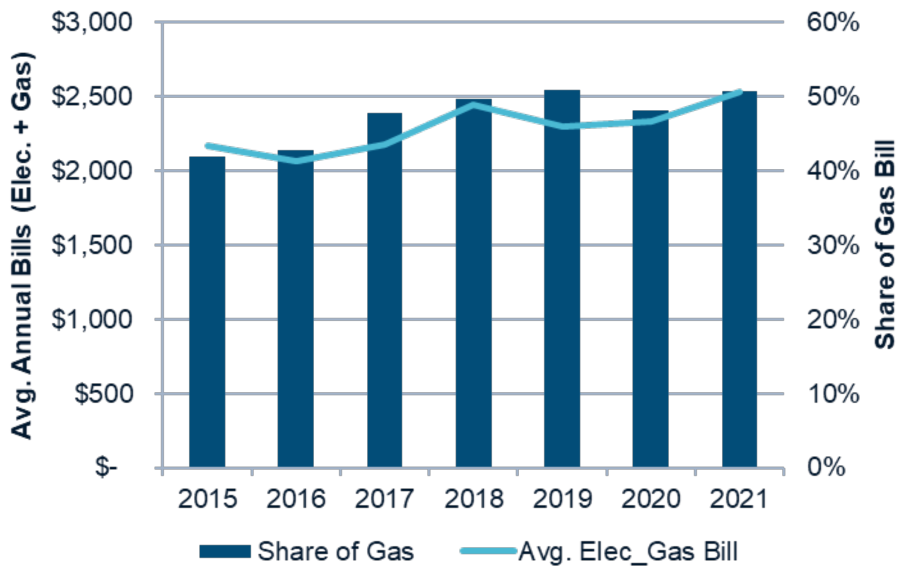
[97] Source: Figure 10 of the FLT Plan.

PA completed a cursory assessment of New York State energy burden, often referred to as the wallet-share. In 2016, New York City set a target that low-income New Yorkers[98] should pay no more than 6% of their income toward energy bills (covering electricity and natural gas and fuel oil). However, despite this policy goal, New York City's analysis[99] indicated that over 400,000 low-income families in New York City pay over 6% of their pre-tax income toward their energy bills. A similar "6 percent" policy was formally adopted by the Commission in 2016.[100]

With the effects of electrification projected to accelerate the steady decline in the residential natural gas customer-base and the Companies' Reference Case forecasting declining average usage, even without higher infrastructure spending, rising bills are projected to put a growing pressure on affordability for the LMI segment.

To frame this situation in a historical context, PA calculated typical annual total Residential gas and electric bills for the ConEd service territory.[101] As exhibited in Figure 31, the combined electric and gas utility bill has risen steadily over 2015-2021 period, with the annual gas portion constituting a rising fraction over the typical household utility charges. (Note: Energy affordability is generally defined with respect to the combined spending on electricity, natural gas, and fuel-oil. Lack of data on fuel-oil usage limited this analysis to just electricity and gas consumption. Additionally, the figures here are actual reported bill levels and do not reflect weather-adjusted usage)

Figure 31: Combined Annual Average Residential Gas and Electricity Bills



PA used American Community Survey data for county-level[102] median incomes and income distribution to develop a characterization of the wallet-share of average utility bills for the ConEd territory.[103] As shown in Figure 32, a residential combined gas and electricity bill for the ConEd territory has averaged approximately 3.30% wallet-share over the 2015-21 period with a declining trend. Although the wallet-share has remained well below the critical 6% level for ConEd customers as a whole, significant income disparities exist across the territory, highlighting concerns regarding energy affordability. The median income in the Bronx has

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[98] New York City Mayor's Office defines a low-income family earning less than 200% of the Federal Poverty Level, with thresholds based on family-size. E.g., a family with 4 persons had a threshold of $49,200/annum in 2019. See 'Understanding and Alleviating Energy Cost Burden in New York City', NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity, 2019, p. 3.

[99] ibid.

[100] See Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Adopting Low Income Program Modifications and Directing Utility Filings (issued and effective May 20, 2016)

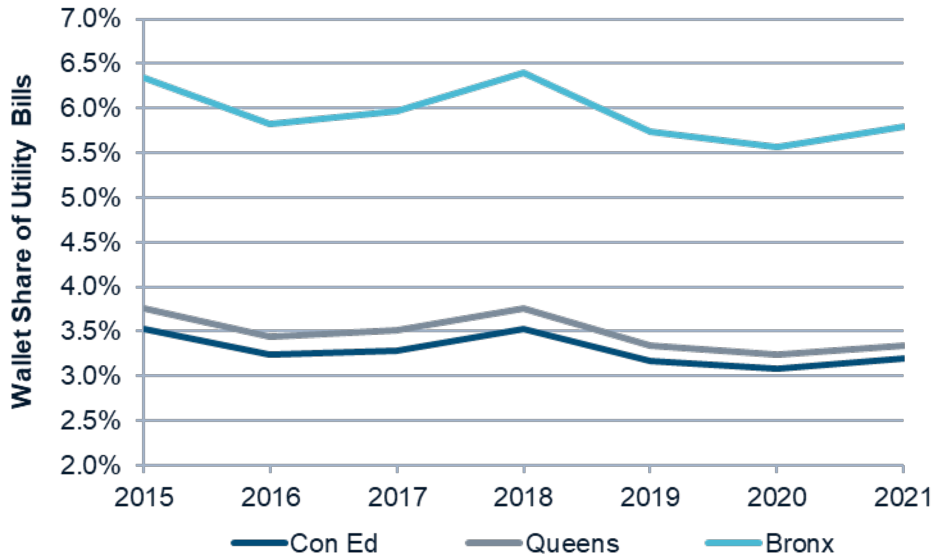
[101] Source: EIA 861 and EIA 176.

[102] Source: https://data.census.gov/table?q=DP03. The analysis covered Bronx, New York, Queens and Westchester counties.

[103] The Median Income for the ConEd territory was calculated as a weighted average of the county figures using shares of Residential customers as weights. Wallet-share is calculated as the ratio of the combined annual utility bills to the area's median income.

consistently been around 55% of the ConEd overall territory, resulting in a wallet-share of electric and gas utility bills being just below the 6% mark in recent years – implying that just under 50% of the households in the borough are deemed as being stressed with respect to energy affordability. Furthermore, substantial portions of households in the other three counties in the ConEd footprint earn below the respective median levels implying that several hundred thousand families could also be distressed with respect to utility bills.

Figure 32: ConEd-area Wallet Share of Residential Utility Bills



With the decline in residential natural gas customer-base forecasted to accelerate and the Companies' Reference Case projecting falling UPC, even in the absence of new infrastructure spending, energy affordability is projected to become an even more acute problem than it is currently. Bearing in mind that incomes at the lower end of the spectrum do not grow at rates akin to those at the higher end, the combination of the Companies' projection of a doubling of the typical gas bill by 2040, the LMI segment might experience a growing hardship.

As mentioned earlier, PA recommended the Companies develop a high-level view on the impact of building electrification to enable the development of a total energy "Share of Wallet" analysis, which considers the scope and magnitude of investments needed to be deployed to the gas and electric networks to meet the State's decarbonization goals. In response, the Companies' FLT Plan did contain a brief discussion that presented conclusions from a bill-impact assessment that focuses exclusively on the gas sector.

Based on the 6% standard set by New York City as the total energy (gas plus electric) affordability threshold - and assuming equal shares of the two bills - the FLT Plan developed a wallet-share analysis of the impact of projected gas-bill changes. Consistent with PA's assessment, the FLT Plan reports that natural gas is projected to become increasingly unaffordable. Currently just the first 3 quintiles of the income distribution have gas costs exceeding the 3% threshold but, by 2043, the first 4 quintiles will see their gas bills exceed the threshold under the Hybrid and Deep Electrification scenarios. By 2050, all 5 quintiles, i.e., the entire earning population, is affected under both scenarios. Although this assessment omits the electricity bills, it nonetheless reinforces the prediction that, ceteris paribus, bill payers are likely to experience growing hardship.

6.3 Observations

- Based on the 6% standard set by New York City as the total energy (gas plus electric) affordability threshold - and assuming equal shares of the two bills - the FLT Plan wallet-share analysis of the impact of projected gas-bill changes. While this omits the electricity bills, it nonetheless reinforces the prediction that, ceteris paribus, bill payers are likely to experience growing hardship.
- There is an inherent tradeoff between emissions reduction and affordability in the ILT, RLT and FLT Plans. The Reference pathway would offer the least year-over-year total gas bill increase however, it does not offer a robust, dependable, and predictable path to decarbonization and meeting CLCPA's requirements.

Although the Deep Electrification pathway meets the emissions reduction and CLCPA's emissions target, it will have a severe negative impact on affordability.

- Given the tradeoffs between the objectives of emissions reduction and affordability, there are an unlimited number of pathways that could be developed by changing various assumptions including policy drivers, technology trends, cost assumptions, etc. To develop the long-term plan with the highest emissions reduction potential and lowest impact on affordability, a multivariable optimization process should be conducted to identify the most optimal pathway. From our understanding, it is unclear and unlikely the Companies have conducted such an optimization process to identify the pathway with the highest societal value and least potential risk over time with sufficient sensitivity analyses to account for variables that can change beyond the modeling assumption inputs.

The pace of electrification and deployment of NPAs is very important. The window of opportunity for avoiding investments that may not be fully utilized (or stranded) is closing. Almost $10B of the investments is driven by reliability/main pipe replacement, thus, if NPAs do not scale quickly and a sufficient level of NPAs or electrification is not achieved in a timely manner, the Companies will have no option other than replacing the pipes to maintain system reliability.

6.4 Recommendations

Economic recommendations are summarized below.

- Clearly communicate the direct and inherent assumptions used in the Companies' modeling process. This approach would allow Stakeholders to compare these assumptions against their view on technology, policy, customer preference, etc. and be able to participate in the long-term planning process more proactively.
- Clarify the inherent tradeoff between emissions reduction, affordability, and strategies to mitigate affordability impact, while reducing GHG emissions. The Reference pathway would offer the least year-over-year increase in total customer gas bills; however, it does not offer a robust and dependable path to decarbonization and meeting CLCPA's targets. Although the Deep Electrification pathway meets the emissions reduction and CLCPA's emissions target, it is projected to have the most severe negative impact on affordability.
- Conduct an optimization process to identify and develop a long-term plan Pathway with the highest emissions reduction potential and lowest impact on affordability while maintaining system reliability and safety. From our understanding, it is unclear and unlikely the Companies have conducted such optimizations to identify a Pathway with highest societal value and least potential risk overtime. In addition, the Companies should conduct a sensitivity analysis to demonstrate the modeling robustness and share a view on the most sensitive assumptions and variables with the Stakeholders and the Commission to assess the prudence of these assumptions.
- Provide calculated bill impacts for each service classification that account for changes to the average volumes of gas consumed by each customer class over time. Although the Companies indicate in their FLT Plan that gas usage will become more efficient over time, they use a constant value for assumed gas consumption between 2023 and 2050 in each customer class, which is not an accurate assumption. To make the bill impact analysis more robust, Companies should use projected average gas volumes for each customer class and forecasted reductions in gas volumes for a representative customer in each class, rather than using a constant value.
- Identify ways to further manage bill impacts and affordability challenges. The Companies' bill impact analysis is relatively high and could pose affordability challenges for ratepayers, especially for lower-income customers who do not qualify for billing assistance programs. Under the Reference Case scenario, a "SC-1 Residential/Religious Firm Sales Service" customer's total bill is forecasted to experience an average increase of 5.4% per year (excluding inflationary price increases). Under the Hybrid and Deep Electrification scenarios, the average year-over-year total bill increases are projected to be 7.4% and 25.1% (excluding inflationary price increases). These forecasted rate increases are much higher than actual historical total gas bill increases over the past 5 years and are deemed "unacceptable" by Stakeholders.

- Redouble efforts to identify, early on, investments (especially pipe replacement investments) that could be potentially avoided by deploying NPA and electrification solutions. Given the likelihood that lead times to implement non-pipeline solutions will be several years, focus in earnest on those investments that are beyond the three-to-five-year horizon. This is the key to maintaining affordability while reducing emissions by keeping costs in a reasonable range. If the Companies and Stakeholders fail to identify investments that could be avoided in a timely manner, the Companies will have no option other than continuing to deploy capital to replace these pipes or continue to incur repair costs, while operating riskier assets, to maintain reliability and meet safety standards. These investments may likely be stranded or not fully utilized by mid-Century; however, they must be paid for by either fewer customers remaining on the gas system or backed by government interventions – both of which present challenges. Instead, it would be preferable to identify meaningful opportunities to avoid deploying those investments in the first place.
- Specify how the FLT Plan intends to benefit disadvantaged communities. The FLT Plan does not provide insight or sufficient details on how the plan ensures at least 35% of benefits are directed to disadvantaged communities, as required by the Order. Instead, the plan explained that the Companies will continue working on this topic and will provide further details in the next round of their report. Inclusion of the results of this analysis in the final version of the report will improve the plan.
- Increase planning coordination between the gas, steam, and electric systems. Although there is no direct language in the Planning Proceeding Order requiring utilities to conduct coordinated long-term planning for the gas, steam, and electric systems, PA recommends some coordination to ensure that safety, reliability, resiliency, and affordability objectives are properly considered as part of the long-term planning process.

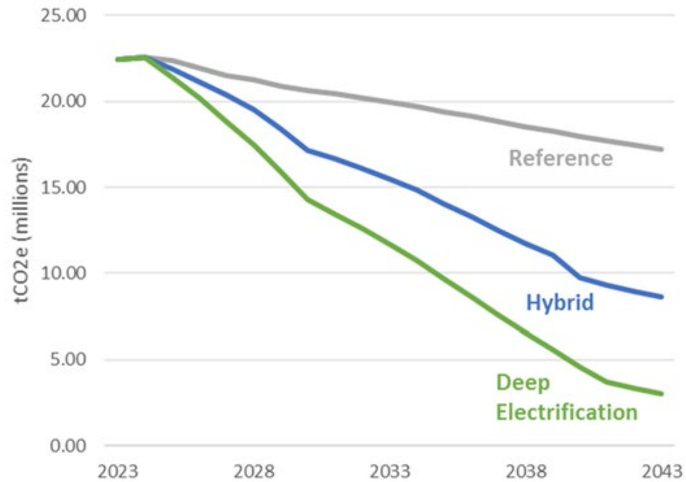
7 Environmental Assessment

PA conducted a review of several environmental items covered by the FLT Plan, based on information presented in the plans, responses from the Companies to a number of data requests, Stakeholder Comments, multiple Technical Session discussions, and the Companies' Reply Comments. The environmental assessment is an important consideration of the FLT Plan, as it essentially determines the extent to which the Companies will be able to reduce emissions and meet the environmental goals of the State and City of New York.

7.1 Emissions Reduction

Based on the FLT Plan, the Deep Electrification pathway is projected to meet the CLCPA GHG emission reductions targets. Although the Hybrid pathway reduces GHG emissions by 62% compared to 2023 baseline, the Deep Electrification pathway is forecasted to achieve 87% reduction in emissions, and the Reference pathway only offers a 23% reduction in emissions. These latter two pathways do not meet the CLCPA emission reductions target. This result is at least partially due to the Reference pathway's heavy reliance on conventional natural gas and only blending 5% certified natural gas into the pipelines. Figure 33 below illustrates the Companies forecasted emissions reductions under each pathway.

Figure 33: Companies' Forecasted GHG Emission Reductions by Pathway[104]



The Hybrid and Deep Electrification pathways represent two fundamentally different futures. The Deep Electrification pathway depicts a future where the majority of use cases for natural gas such as space heating, water heating, cooking, commercial and industrial processes use electricity instead of natural gas. As a result, the footprint of the gas network is significantly smaller and the total volumes of natural gas flowing through the pipes are almost 1/5 of the volumes in 2023 (82% reduction in gas volumes). The composition of gas and its life cycle GHG emissions that is projected to flow through the pipes is 79% certified gas and 21% RNG. The Hybrid pathway depicts a future that the flow of natural gas through the gas network is also smaller (42% reduction in gas volumes compared to 2023), however, gas continues to play a significant role in supporting the energy needs of customers in New York. To that end, most of the gas pipeline network will need to be replaced or repaired to ensure safety and reliability of the gas network in the decades to come. The composition of gas that is projected to flow through pipes is 36% RNG, 6% clean hydrogen, and 58% certified natural gas.

It is important to note that the recently approved Joint Proposal includes, among many other things, authorizations and requirements furthering the Companies' plans to implement a Certified Natural Gas Pilot, Interconnect Renewable Natural Gas and other decarbonization measures such as[105]:

- ConEd shall implement a Certified Natural Gas Pilot whereby the Company may procure certified gas during the rate period, limited to an annual cost above traditional supplies of $800,000 per year and recovered through the GCF.
- ConEd is required to: commit to purchase Certified Natural Gas from parties with specified certifications; conduct supplier surveys to gather information regarding supplier work practice standards, greenhouse gas emissions, and methane intensity; and file annual reports detailing progress of the program.
- ConEd may recover interconnection costs related to renewable natural gas supply through the MRA, up to a cap of $10 million over the term of the gas rate plan and would incorporate such costs into base rates in the next gas rate filing.
- ConEd is required to notify customers of alternative non-fossil options to natural gas service prior to issuing a service determination.
- Requires ConEd to consider electrification as an alternative to gas main replacement under certain circumstances and whether gas mains may be eliminated rather than replaced as part of the GIRR.
- Pursuant to the Gas Service Line Replacement Program, encourages ConEd to conduct outreach and education to customers regarding electrification where customers are slated to receive a gas service replacement, endeavor to develop NPA projects under the existing framework adopted in 19-G-0066, and engage with stakeholders to discuss progress.

[104] Source: Figure 73 of the FLT Plan and the Response to DPS 1-35.
[105] Source: Pages 94-95 of The Planning Proceeding Order.

Based on PA's analysis and comments provided by Stakeholders, the major concern with the Hybrid scenario is the reliance of this scenario on blending low-carbon fuels (e.g., RNG, SNG, H2) into the gas supply to decarbonize the GHG emissions from gas supply. Although we agree that all these low-carbon fuels have a role to play in decarbonization of the gas supply, according to energy industry best practices to date, we believe the role for these low carbon fuels is going to be much smaller than depicted in the FLT Plan. The Companies need to conduct further analysis to demonstrate the feasibility of blending these LCFs into the pipeline. These LCFs are significantly more expensive compared to the current supply of natural gas and could pose significant pressure on affordability. The projected bill impacts of blending such fuels is significant and it is unclear how the companies are planning to manage use of such fuels while also maintaining bill affordability.

The Companies indicated that the Hybrid and Deep Electrification pathways are top-down and therefore it is unclear what needs to happen for these projections to come true. In other words, while the Companies forecast significant adoption of electric appliances under the Deep Electrification pathway or significant blending of low-carbon fuels, there is no guarantee that costs will come down as projected in these scenarios and customers will embrace these technologies as forecasted in the FLT Plan.

Given its significant price premium and low round-trip efficiency in producing low carbon hydrogen from electricity, consensus is growing among energy industry experts that H2 is not an ideal fuel for end use applications that could instead be electrified, such as water heating and space heating, and feel this precious fuel should be reserved for hard to decarbonize applications only. There are significant concerns among Stakeholders that the Companies' projected cost declines for LCFs assumed in the FLT Plan may not materialize.

To that end, the Companies should develop and provide a robust view on these hard to electrify buildings and use cases across their service territory and make a case for use of these expensive fuels. Also, it is unclear how the cost of these expensive fuels will be recovered and if customers have an ability and willingness to pay for these premium products. We also encourage the Companies to understand and clearly communicate to Stakeholders what makes some of the buildings in their territory hard to electrify, the geographical distribution of these hard to electrify buildings, and usage profile to assess the feasibility and economics for a targeted local network to transport H2 to these buildings.

Additionally, there are significant technical challenges to safely blend H2 into natural gas pipelines, including pipe embrittlement, flame temperature, flame tipping, etc. that needs to be properly accounted for to safely blend, transport, and burn H2 in end-use applications.

Furthermore, due to high dependence on evolving low-carbon fuels, the pursuit of the Hybrid pathway, like the Reference pathway, does not provide optionality and flexibility to course correct if the economics of LCFs does not improve as projected in the FLT Plan, leaving the Companies with no viable options to pivot to a low-cost decarbonization pathway. Similarly, the Companies may face insufficient supply of LCFs if the LCF technologies do not evolve as projected in the FLT Plan.

Stakeholders have expressed valid concerns around the availability of RNG and projected price of RNG as forecasted by the Companies. According to the FLT Plan, even in an optimistic scenario, the Companies can only acquire sufficient volumes of RNG equaling 20% of the current volumes.

> "As a result, the estimated maximum amount of RNG that we will be able to source is 48 TBTU of RNG per year, representing approximately 20% of current annual volumetric usage"[106]

It is noteworthy that the market for RNG is projected to be very tight with many gas LDCs and other hard to electrify commercial and industrial customers hoping to access the limited supply of RNG.

NYSERDA has noted that the Companies' GHG accounting methodology should reflect economy-wide emissions expected, utilizing the State's GHG accounting Methodology developed by the Department of Environmental Conservation (DEC), pursuant to the Climate Act. Companies have indicated that the Companies' FLT Plan used emissions factors from the NYS GHG Inventory. Both Companies and Stakeholders can benefit from additional guidelines on GHG emissions accounting and PA understand multiple initiatives are underway to provide more guidance and clarity on this important subject.

[106] Source: FLT Plan.

The Companies have acknowledged Stakeholders' concerns of LCFs; however, they want to keep the door open for LCFs as an alternative for their difficult-to-electrify customers segments. In the next cycle of GSLTP updates, the Companies will further evaluate market developments for LCFs and revise their assumptions accordingly in modeling different pathways. The Companies will also analyze the cost of emission reductions made possible by the usage of LCFs in comparison to other options, such as electrification, as advised by NRDC.

The Hybrid pathway, a pipeline-based approach, relies heavily on RNG and certified natural gas, which is still in the development phase, and its true cost estimates, as well as emission reductions, are yet to be confirmed by independent third-party entities. This pathway also relies on hydrogen usage which has its own drawbacks, as leaking hydrogen can increase the amount of GHG gas, like methane, indirectly in the atmosphere. Given the expensive infrastructure upgrades and lack of concrete evidence for improving the H2 leakage potential and confirming certified natural gas's assumptions and outcomes, the Companies should be mindful of their customers as they will be the ultimate cost bearer, in case of lower-than-expected emission reduction achievements.

The Deep Electrification pathway relies much less on LCFs and some of the concerns raised above are less applicable to this pathway. In the last round of revised comments, PA found most stakeholders prefer the Deep Electrification pathway for these reasons, among others.

7.2 Recommendations

Recommendations for environmental are summarized below.

- Identify the pathway that is preferred to guide the Companies' actual investment plans. The Companies present Hybrid and Deep Electrification pathways as two potential pathways to meet CLCPA goals but do not identify a preferred plan. PA appreciates the challenges of a single point forecast when many variables are at play and finds a discussion on the range of possibilities is reasonable and useful. However, it is unclear which pathway is going to inform Companies' long-term planning and investment decision that need to be made in the near-term since there are clear tradeoffs between each pathway and it is inefficient and impossible to pursue all 3 pathways at the same time. In their RLT Plan, Companies "determined that many of the required actions are common to both the Hybrid and Deep Electrification Pathways, particularly prior to 2030". While that outcome may be the case to some extent, successful deployment of NPA and electrification solutions requires significant lead time, and the Companies would need to redirect some of the capital that is earmarked for pipe replacement toward electrification efforts and thus it is hard to imagine that Companies can successfully pursue both pathways and both strategies at the same time. Such process could lead to suboptimal allocation of capital to each strategy and inefficient utilization of scarce resources.
- Confirm the true cost estimates, emission reductions related to LCFs and whether advancement of LCFs will provide sufficient supply as per expectations; evaluate potential solutions for H2 leakage; weigh possible alternatives for LCFs. Given the importance of this subject, PA encourage the Stakeholders to review and discuss the assumptions made in the analysis that was recently shared by the Companies in the FLT Plan.
- Develop and share with Stakeholders a robust definition of hard to electrify customers and check that definition on a regular basis as developments in technology may change these assumptions. For example, the Companies have communicated that they are assuming dense high-rise buildings as hard to electrify given the space requirements and disruptions to day-to-day activities of residents for electrification. If new electric appliances are developed that could retrofit existing buildings, with minimal disruptions to day-to-day activities, the Companies may need to revisit this definition and account for the possibility of electrifying these buildings.
- Develop a list and geographical distribution of hard to electrify customers, coordinate with NYC Department of Buildings, and ensure Companies and Stakeholders have a long-term geographical view on where these hard to electrify buildings are located. This would be essential in developing a long-term view of which pipes are critical in supplying fuel to these buildings. This would help Stakeholders and regulators better understand which regions or neighborhoods are forecasted to remain on gas network and which regions/neighborhoods are forecasted to be potentially electrified.

- If and when possible, allow customers who may be interested in maintaining dual fuel options (e.g., maintain gas appliances)Given the rise in electric power grid reliability and resiliency concerns this can help customers get more comfortable with electrifying some of their use cases. We understand that in some cases customers are required to remove their gas appliances (e.g., distribution replacement NPA program) and in some cases customers are allowed to keep their gas appliances (e.g., load relief NPA). Dual fuel options help customers get more comfortable with the decision to electrify some use cases by providing a back-up option during extreme weather conditions and when power outages may take place. If customers are on sections of the gas network that are earmarked to remain on gas network they may be interested in retaining some of their gas appliances (e.g., gas furnace or gas stove) for days that the electric grid may be under stress or for cases of resiliency and reliability. We understand such an approach may to a minor extent negate the benefits of electrification, but in the long-term it will make customers more comfortable and provide resiliency value for extreme weather conditions.
- Update the analysis comparing the economics of different technologies used for space and water heating in various customers segments in New York. In the ILTP and RLTP Companies were relying on an economics comparison of various space heating technologies such as gas boilers, air-source heat pumps, etc. that was developed and filed in 2017.[107] Given the importance of this subject, PA encouraged Companies to update this assessment for the FLTP and Companies followed this recommendation. PA would encourage Stakeholders to review and further discuss the assumptions made in the FLTP to further improve this assessment and create alignment among Companies and Stakeholders' views on this crucial assessment.

[107] Source: Page 10, Case 16-G-0061 - ConEd Gas Peak Demand Reduction Collaborative Report, filled on December 22, 2017.

Appendix A

State and Local Laws

Natural Gas Ban in Buildings

Starting in 2026, New York will require new buildings to be zero-emission, effectively banning natural-gas hookups. The state's budget will ban fossil fuel combustion (i.e., gas furnaces and stoves) in most new buildings under 7 stories with larger buildings covered in 2029. Instead, buildings will use heat pumps, geothermal systems, and electric appliances. This will only apply to new buildings, and therefore existing gas stoves or furnaces can remain in use. There are exceptions too, as new gas connections will be allowed for manufacturing facilities, commercial food establishments, laboratories, car washes, laundromats, hospitals, crematoriums, agricultural buildings, and critical infrastructure. New gas hookups are also allowed for generators that serve as backup power supplies. New York will be the first state to take this step through legislative action. CA and WA have similar measures but have done so through administratively adopted building codes. NYC, however, already has a ban on new gas hook ups in place – new buildings up to 7 stories will be zero-emission by 2024 and larger ones by 2027.

Local Law 97

LL97 was passed in April 2019 by the New York City Council as part of the Mayor's Climate Mobilization Act. The purpose of the law is to help achieve the city's economy-wide GHG reduction goal, which is a 40% reduction of GHG emissions by 2030 and an 80% reduction by 2050 (relative to baseline year 2005).[108] The law applies to most buildings over 25,000 square feet and is up to the building owners to meet compliance. According to the LL97 definition of covered buildings, over 3.2 billion square feet of New York City buildings are covered under the law, which represents nearly 60% of New York City's total building area.[109] Given its customer base is almost exclusively large buildings in Manhattan, ConEd estimates that over 99% of the building square footage in its steam service area is covered by LL97.[110]

The law seeks to achieve GHG emission reduction targets by setting GHG emissions limits on the building sector, the highest contributing sector to GHG emissions in NYC. GHG emission caps become more stringent over a series of compliance periods: 2024-2029, 2030-2034, 2035-2039, 2040-2049, and 2050 onwards. Limits are in metric tons of CO_2- equivalent and depend on building class type, with standards already established for years 2024-2029 and 2030-2034. NYC estimates that about 20-25% of buildings will exceed their emissions limits in 2024, if they take no action to improve their building's performance, while about 75% of buildings will exceed their emissions limit by 2030.[111]

Covered buildings have a variety of compliance options for meeting their GHG emission limits. By May 1, 2025 (and every year thereafter), building owners will be required to submit a GHG emission report showing they are in compliance with their respective emissions limits. New York City's Department of Buildings may impose a penalty of $268 per metric ton for LL97 covered building emissions that are above the GHG emissions limits specific to those building classes.

Local Law 154

LL154 was passed in December 2021 and aims to significantly limit fossil fuel service connections in new or gut renovated buildings in New York City. The law effectively bans most fossil fuel service connections for such buildings under seven stories beginning in 2024, and for such buildings greater than seven stories beginning in 2027. Buildings become covered under the law upon submission of an application either for new construction or gut renovation to the New York City DOB.

Specifically, and importantly, buildings covered under the law would be prohibited from emitting more than 25 kg of CO_2 per MMBtu of energy generated within a building. Although the first compliance date under the law

[108] Source: Local Law 97 of 2019 (nyc.gov).
[109] Source: Covered Buildings, NYC Sustainable Buildings.
[110] Source: Climate Leadership and Community Protection Act Panel Testimony, New York Public Service Commission, Case 22-S0659, November 2022, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service.
[111] Source: Compliance, NYC Sustainable Buildings.

remains in the future and the language is subject to some interpretation, the emissions limit established specifically for combustion of fuels *within* a building potentially creates tailwinds for customer connections to ConEd's steam system, given new or significantly renovated buildings that would connect to district steam would not be combusting fuel directly within their premises. This interpretation (and favorable treatment of district steam) would align with the more favorable GHG emissions coefficient of district steam, and the ability to incrementally decarbonize the centralized steam system, relative to direct consumption of natural gas and fuel oil.

Appendix B

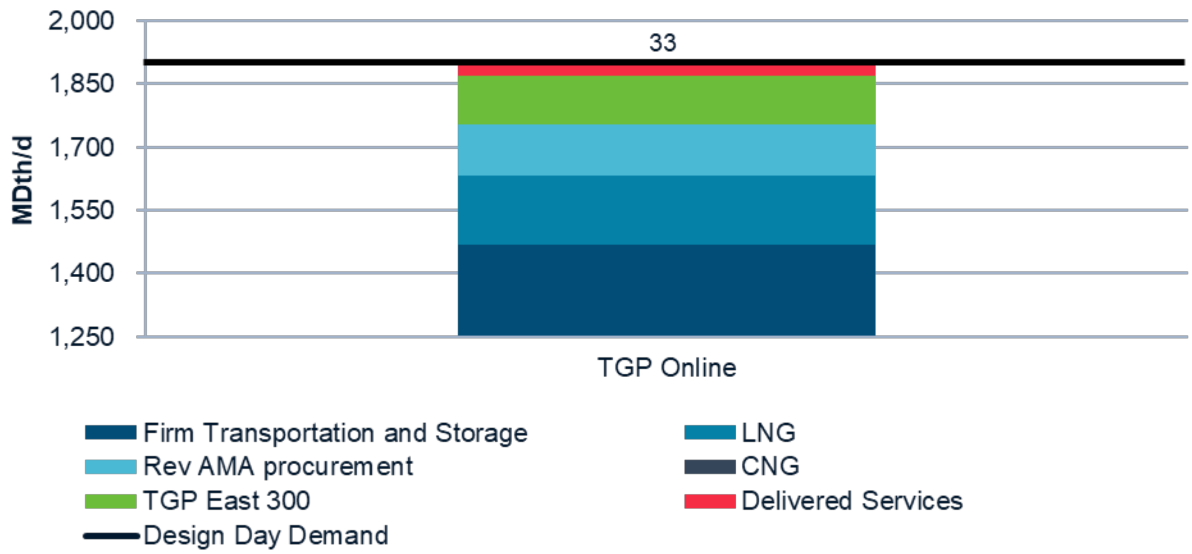
Required Delivered Services – Hybrid Pathway

The volume of Delivered Services necessary to meet demand varies depending on the components of the supply stack that are available in any given year and on the projected demand for a given year. PA evaluated the necessary number of Delivered Services under the 2023 Hybrid Pathway[112] between differing supply scenarios.

Winter 2023-24

In below, the volume of Delivered Services is 33 MDth/d if TGP East 300 is placed in-service.

Figure 34: 2023-24 Hybrid Pathway Supply Stack and Delivered Services

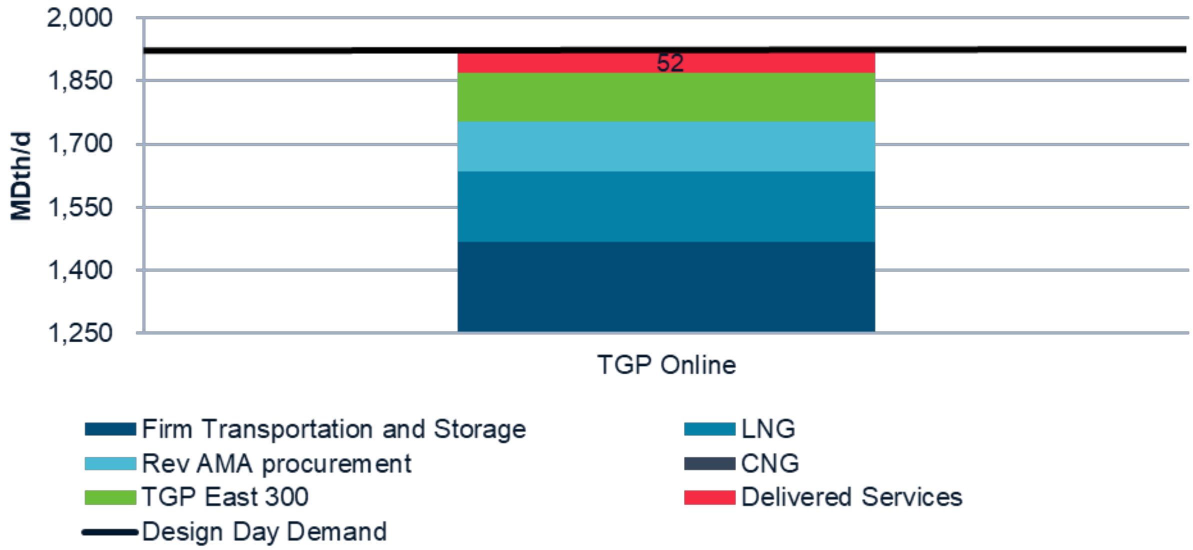


Winter 2024-25

In 2024-25, the design day demand grows slightly, increasing the need for Delivered Services. See Figure 35 below.

[112] As provided in the response to DPS 9-173

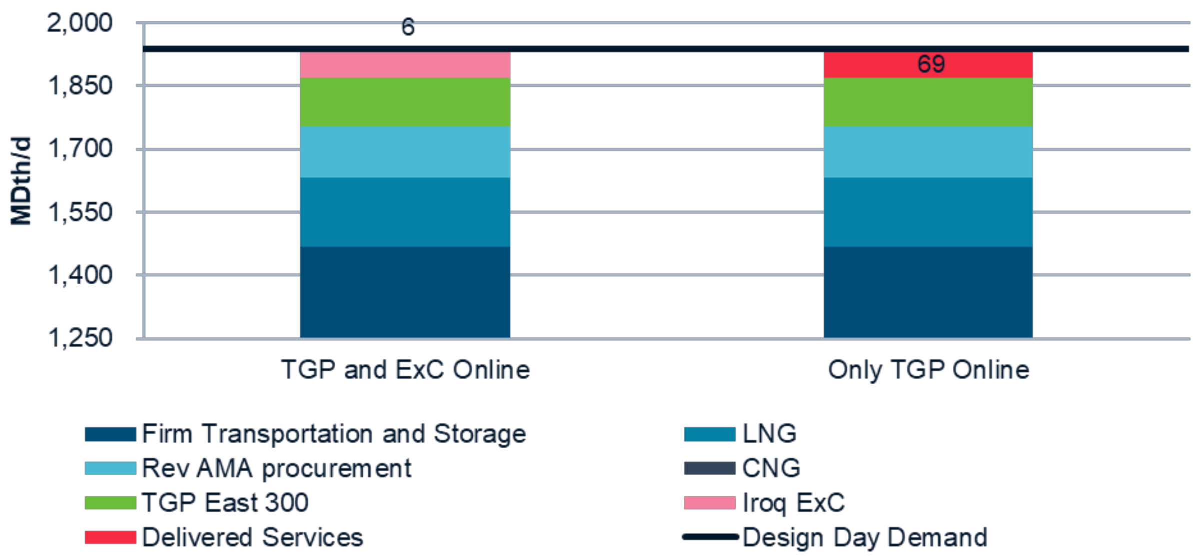
Figure 35: 2024-25 Hybrid Pathway Supply Stack and Delivered Services



Winter 2025-26

Design day demand again grows slightly in 2025-26, but at this point the Iroquois ExC project may be placed in-service and alleviate some of the need for Delivered Services – shrinking those volumes to approximately 6 MDth/d if both TGP East 300 and Iroquois ExC are successful. This volume increases to 69 only TGP East 300 is placed in-service. See Figure 36.

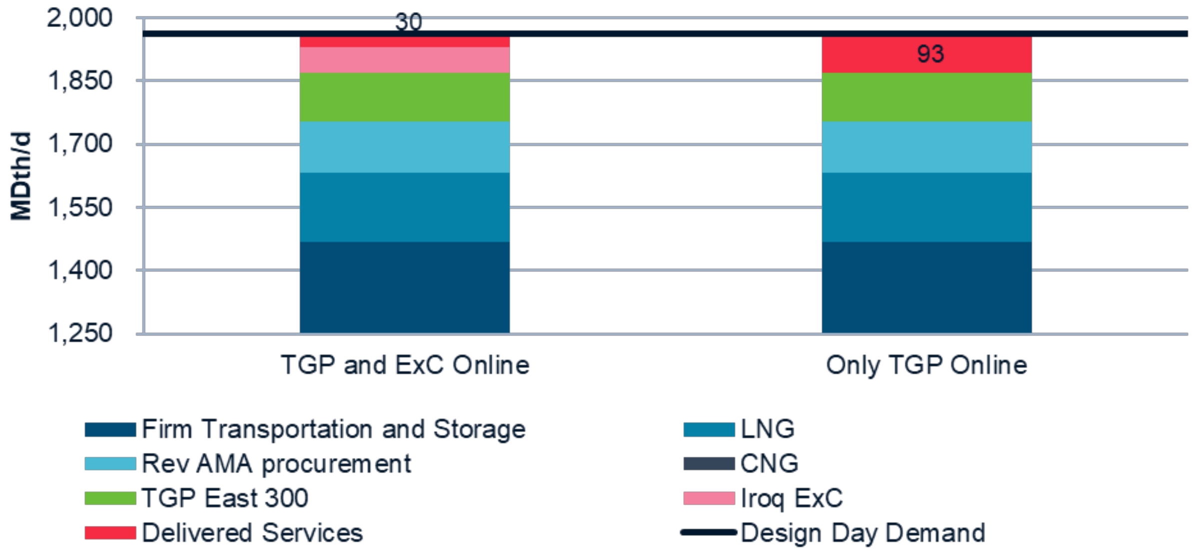
Figure 36: 2025-26 Hybrid Pathway Supply Stack and Delivered Services



Winter 2026-27

Under the 2022 Hybrid Pathway, demand peaks in 2026-27 and thereafter trends downward. At this peak, with both Iroquois ExC and TGP East 300 in-service, the Companies will require 30 MDth/d of Delivered Services. This value grows to 93 MDth/d if only TGP East 300 is successful. See Figure 37.

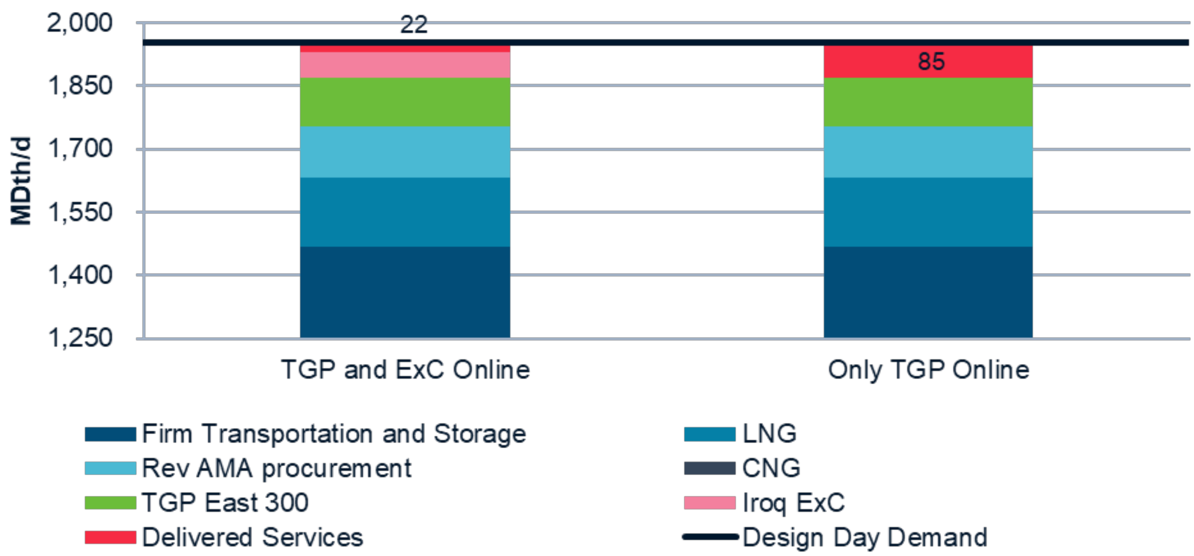
Figure 37: 2026-27 Hybrid Pathway Supply Stack and Delivered Services



Winter 2027-28 and Beyond

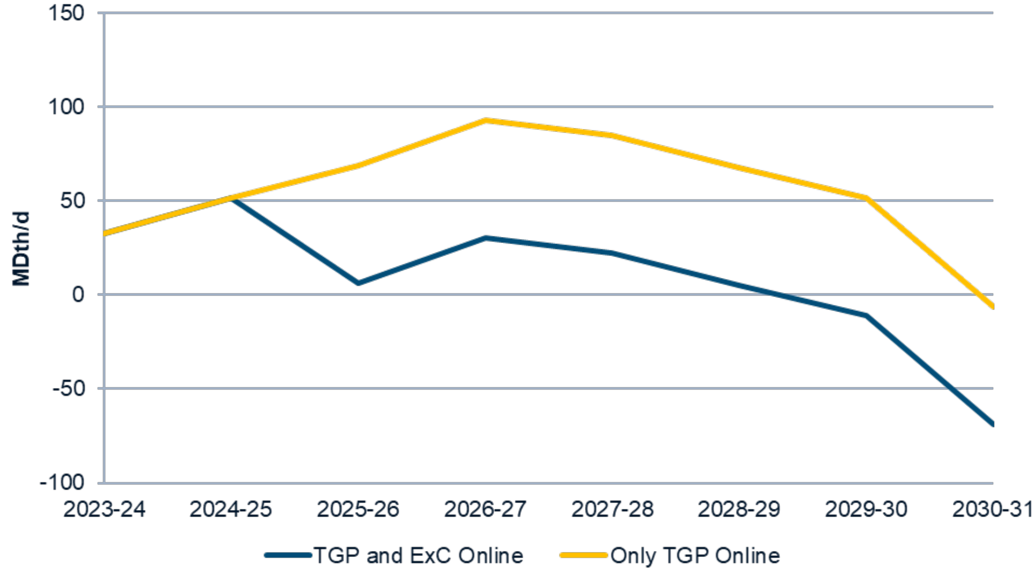
Under the Hybrid Pathway, from 2027-28 onwards, design day demand beings to trend down. In this year, if both Iroquois ExC and TGP East 300 are in-service, Delivered Services volumes shrink to 22 MDth/d. If only TGP East 300 is in-service, the required Delivered Services volumes grows to 85 MDth/d. See Figure 38.

Figure 38: 2027-28 Hybrid Pathway Supply Stack and Delivered Services



After 2027-28, Hybrid Pathway demand trends downward such that the need for Delivered Services disappears in 2029-30 if both TGP East 300 and Iroquois ExC are in-service. If only TGP East 300 is in-service, the need for Delivered Services disappears after 2030-31. See Figure 39.

Figure 39: Hybrid Pathway - Delivered Services Necessary Under Different Supply Scenarios



Required Delivered Services – Deep Electrification Pathway

Now that TGP East 300 has been placed in service, under the 2023 Deep Electrification Pathway, design day demand is fully satisfied without any additional reliance upon Delivered Services.

Appendix C

The Companies FLT Plan includes the following BCA Modeling Assumptions, within Appendix G.

BCA Modeling Assumptions

	Category	Baseline	Assumptions
	Avoided emissions	• 2023 emissions levels held constant through 2050 • Excluded emissions from transportation sector, and "baseload" electric sector	• Social cost of carbon based on New York DEC guidance, in line with other BCA's submitted • Lowest value of CO_2 reflected in BCA calculation (3% discount rate)
	Utility T&D investment	• 2022 revenue requirement (less purchased power/fuel and reg assets) • Escalated with inflation (3%) from 2023-2050	• Electric investments increase at the same CAGR as electric peak by pathway (excluded investments associated with EV adoption) • Steam investments increase below inflation • Gas investments as filed in GSLTP
	Supply	• Modeled 2023 supply costs and volumes • Per-unit costs escalated at inflation	• Electric CAGR based on NYISO policy cases • $/MMBTU gas costs aligned with GSLTP filing • Steam assumed to increase at same CAGR as gas • Oil prices escalated at 3% inflation, using 4-year historical average for starting value (2018-2021)
Customer Costs	**Buildings**	• Existing equipment replaced like-in-kind • No energy efficiency • Replacement costs escalated at 3% inflation	• $/sqft costs aligned with NENY filing, where possible • Range of costs developed based on CAC Integration Analysis • Includes space heating, water heating, cooking/drying, and EE • Growth in total floorspace, per CAC Integration Analysis
Industrial		• n/a	• Incremental industrial costs assumed to be 10% of incremental building costs, based on estimate of today's energy usage

Appendix D

The table below shows the Compound Annual Growth Rate (CAGR) analysis PA has conducted to offer an alternative method for demonstrating the rate impact of proposed decarbonization pathways over the forecast period.

ConEd		
Scenario	*Rate Impact (2023-43)*	*Rate Impact (2023-50)*
SC-1 Residential/Religious Firm Sales Service		
Reference	3.7%	2.9%
Hybrid	4.7%	3.9%
Deep Electrification	9.4%	9.3%
SC-2 Rate I General Firm Sales Service		
Reference	3.1%	2.5%
Hybrid	4.7%	4.7%
Deep Electrification	7.8%	11.0%
SC-2 Rate II General Firm Sales Service		
Reference	3.2%	2.6%
Hybrid	4.7%	4.6%
Deep Electrification	8.2%	11.4%
SC-3 Residential/Religious Heating		
Reference	3.4%	2.7%
Hybrid	4.6%	4.4%
Deep Electrification	8.0%	11.2%
O&R		
SC-1 Residential and Space Heating		
Reference	2.5%	2.5%
Hybrid	5.2%	6.2%
Deep Electrification	3.8%	6.2%
SC-2 General Service (small)		
Reference	2.2%	2.3%
Hybrid	3.7%	4.5%
Deep Electrification	6.2%	10.9%
SC-2 General Service (large)		
Reference	2.3%	2.4%
Hybrid	3.9%	4.7%
Deep Electrification	6.5%	11.3%