Transcontinental Gas Pipe Line Company, LLC

Submittal Attachment 1D

Resource Report 1 – Additional Information

Regional Energy Access Expansion

April 2022

Regional Energy Access Expansion

prepared for

Transcontinental Gas Pipeline Co.

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Disclosure

This report has been commissioned by Transcontinental Gas Pipe Line Company, LLC (Transco), a subsidiary of The Williams Companies, Inc. This study has been funded in full by Transco. Levitan & Associates, Inc. (LAI) has performed an independent assessment of the need for the Regional Energy Access Expansion (REAE) project, how gas transported by REAE will be used, and the net impact of REAE on reasonably foreseeable GHG emissions of natural gas infrastructure. The methods, findings and recommendations set forth in this report are strictly those of LAI. The findings and conclusions reached in this report are independent of any other work undertaken for other clients.

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Executive Summary

The purpose of this report is to provide information regarding the need for the Regional Energy Access Expansion (REAE) project, how gas transported by REAE will be used, and the net impact of REAE on reasonably foreseeable GHG emissions.

- Section 1 of this report contains a market study in which Levitan & Associates, Inc. (LAI) assesses available pipeline capacity, design day requirements for New Jersey and Southeastern Pennsylvania, and the ability of other transportation providers to meet incremental demand with existing capacity.

- In Sections 2 and 3, LAI uses electric system dispatch and hydraulic modeling to analyze how gas transported by REAE will be used by natural gas-fired or dual fuel electric generators, as well as local distribution companies (LDCs).

- In Section 4, LAI estimates reasonably foreseeable direct and indirect net greenhouse gas (GHG) emissions accounting for offsetting reductions in PJM's and New York's consumption of other fossil fuels and natural gas transported by other pipelines in the study region.

The main observations and findings for each section are addressed briefly in this Executive Summary. More detail underlying LAI's study approach and findings are presented in the individual sections.

Section 1: Market Study of the Need for REAE

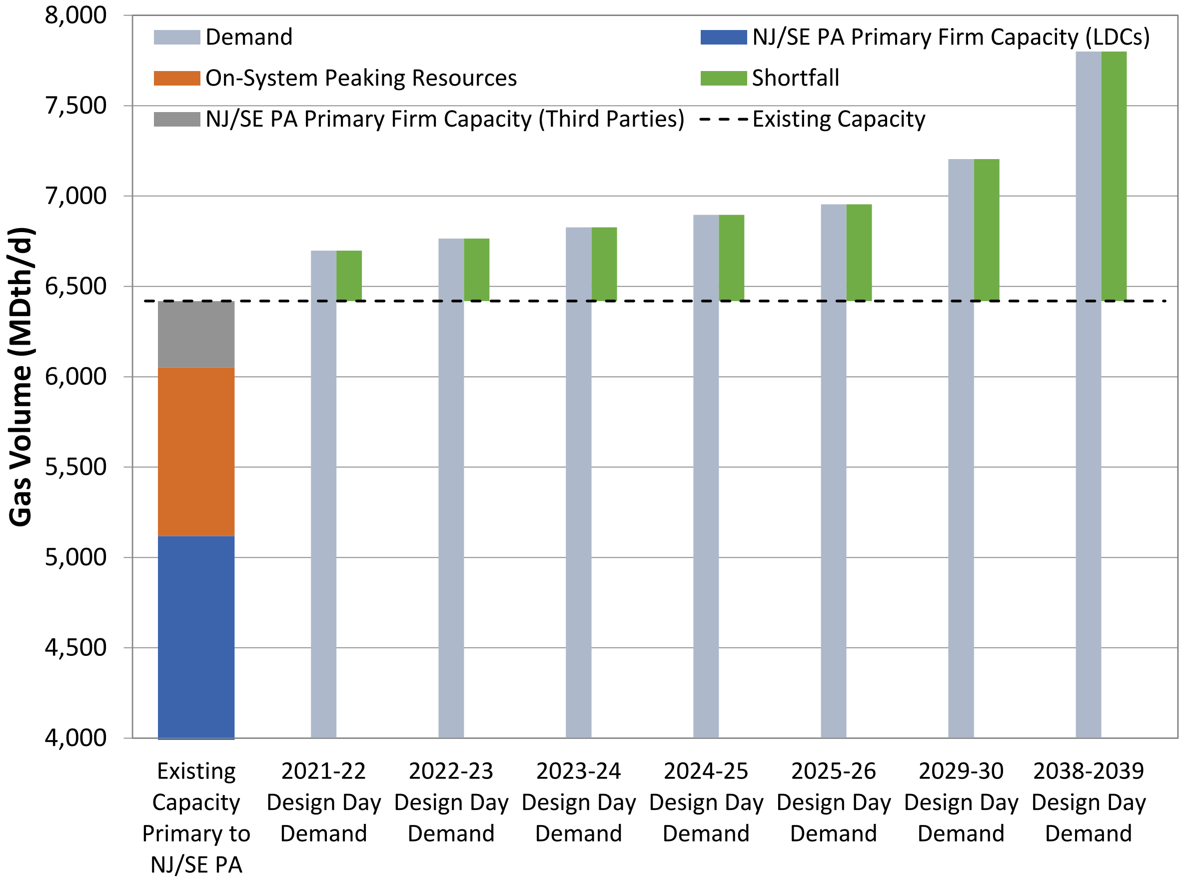
In assessing the market need for REAE capacity LAI performed a regional assessment analyzing factors including demand projections underlying the capacity that has been subscribed, local distribution company (LDC) statements regarding the need for REAE capacity, and LDC state regulatory commission filings. Review of these key determinants support LAI's conclusion that ***without REAE capacity*** there will not be sufficient pipeline capacity available to meet LDC customer requirements in New Jersey and Southeastern Pennsylvania under design day criteria.

In performing this analysis, LAI has not relied on the executed Precedent Agreements Williams has entered into with various shippers for at least 15-year terms, instead relying on public market data and state regulatory filings. LAI reviewed existing pipeline capacity in New Jersey and Southeastern Pennsylvania to identify the primary delivery points associated with each firm transportation contract. LAI used the primary delivery points to account for downstream customers in New York and New England that have firm contractual rights on pipelines operating in New Jersey and Southeastern Pennsylvania. Accounting for the firm delivery rights held by downstream customers, the firm capacity with primary delivery in the study region falls short of the LDCs' current design day requirements.

LAI separately assessed pipeline capacity available to the REAE shipper in Maryland. The Maryland LDC's territory is geographically separated from the service territories of LDC shippers subscribing to REAE capacity in New Jersey and Southeastern Pennsylvania and is not subject to the same pipeline capacity constraints and operational considerations observed in New Jersey and Southeastern Pennsylvania. The Maryland LDC has elected to use REAE capacity to meet its growing design day demand requirements because it provides the best combination of scheduled in-service date, reliability, and access to diverse supplies.

The capacity deficit in New Jersey and Southeastern Pennsylvania increases significantly over time. The vertical green bar located above the dashed horizontal line represents the LDC capacity shortfall on a design day. As shown in Figure ES-1, design day demand of LDC-served customers in New Jersey and Southeastern Pennsylvania currently exceeds the volume of existing firm supply from pipeline capacity with primary firm delivery in the region and LDC on-system resources. The capacity deficit in 2021-22 increases steadily, reaching 774 MDth/d by the 2029-30 winter heating season. After 2029-30, three scenarios are evaluated. The Low Demand scenario conservatively assumes no demand growth after 2029-30, the High Demand scenario assumes that demand continues to grow at the same average annual rate, and the Average Demand scenario assumes demand grows at the average of the rates in the High Demand and Low Demand scenarios. Even under the Low Demand scenario the 2038-39 capacity deficit is large, and under the High Demand and Average Demand scenarios, the deficit increases throughout the planning horizon reaching 1,346 and 1,060 MDth/d, respectively, by 2038-39. The design day demand of LDC-served customers in New Jersey and Southeastern Pennsylvania currently exceeds the volume of existing firm supply from pipeline capacity with primary firm delivery in the region and LDC on-system resources.

Figure ES-1. Supply/Demand Comparison for New Jersey and Southeastern Pennsylvania LDCs[1]



The annual supply shortfall is shown in Table ES-1. The same values apply for all three scenarios through 2029-30 and are differentiated thereafter to address uncertain annual demand growth rates.

Table ES-1. Supply Shortfall to Meet Forecasted Demand

Demand Scenario	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2029-30**	**2038-39**
High							1,345.6
Average	278.8	345.2	407.5	476.8	534.7	774.4	1,060.0
Low							774.4

<u>Sections 2 and 3: Modeling of the Use for REAE Transportation and Any Resultant Displacement of Fossil Fuels</u>

In Sections 2 and 3, LAI uses electric system dispatch and hydraulic modeling to provide information detailing how gas transported by REAE will ultimately be used and the resultant displacement of other fossil fuels and natural gas transported by other pipelines. To compute the

[1] The Demand and Shortfall shown in 2038-39 represent the High Demand scenario.

displacement effect, LAI used Aurora, an electric system dispatch model, to estimate the impact of REAE on the power sector. LAI concluded REAE capacity will loosen constraints that limit the utilization of gas-fired generators in New Jersey and Southeastern Pennsylvania on cold winter days. The addition of REAE will also help to alleviate constraints that may arise over the non-heating season when pipeline maintenance is scheduled. Hydraulic modeling results show that Transco can deliver LAI's estimated total peak day demands downstream of Station 190 in 2029/30 without REAE, but gas-fired generator ramping causes delivery pressures in multiple locations to drop close to the minimum pressures required under Transco's shipper contracts.

When REAE is added to the modeled infrastructure, not only is Transco able to deliver significantly more gas to generators, but delivery pressures trend higher in most areas, reflecting improved resilience and greater operating flexibility to accommodate the dispatch schedule of gas-fired generation in New Jersey and Southeastern Pennsylvania. The simulation modeling shows how REAE increases the supply available to combined cycle plants and peakers in New Jersey and Southeastern Pennsylvania that Transco would not otherwise be able to serve on very cold winter days. While these generators do not have firm transportation entitlements, REAE capacity is sure to improve the quantity and scheduling flexibility of the secondary firm and interruptible transportation upon which these generators usually rely.

Section 4: Estimates of Reasonably Foreseeable GHG Emissions Associated with REAE

In Section 4, LAI provides an estimate of REAE GHG emissions that are a reasonably foreseeable and causally connected result of the project, accounting for offsetting reductions in the consumption of other fossil fuels and natural gas transported by other pipelines.[2] LAI has estimated reasonably foreseeable direct and indirect net GHG emissions attributable to REAE taking into account the net reduction in GHG emissions from the displacement of other fuels, including natural gas delivered by other pipelines. For direct emissions, LAI relied on the estimated net GHG emissions from REAE construction and operation reported by Transco in its Supplemental Filing.[3] LAI's estimate of reasonably foreseeable indirect net GHG emissions reflects downstream power sector emissions and downstream emissions from increased natural gas use by residential, commercial and industrial customers. Direct emissions from project construction may result in 0.044 million metric tons of net CO2e in 2024. Direct emissions from REAE operations will result in 0.088 million metric tons per year (mtpy) of CO2e. Additional capacity ascribable to REAE will result in 0.033 million mtpy of net indirect CO2e. Table ES-1 reports REAE GHG emissions as a percentage of total US emissions.

[2] REAE Draft Environmental Impact Statement, FERC Office of Energy Projects, March 2022, Docket No. CP21-94-000.(REAE DEIS), page 4-167.

[3] Transco Supplemental Filing.

Table ES-1. REAE CO2e Emissions as a Percentage of 2019 U.S. Emissions (millions of tons)

	Incremental CO2e Emissions	U.S. CO2e Net Emissions, Based on 2019 Levels[4]	Percentage
REAE Construction	0.044	5,769	0.0007%
REAE Operation	0.088	5,769	0.0015%
REAE Indirect	0.033	5,769	0.0006%

Key Conclusions

LAI has reached primary conclusions for each Section:

1. REAE is needed to meet the reliability requirements of LDCs in New Jersey and Southeastern Pennsylvania under design day criteria, and will allow BGE to meet its design day requirements with cost effective firm pipeline capacity.

2. REAE increases the natural gas available to generators during cold winter conditions when LDC demand is high. During these periods, combined-cycle generators within the study area displace less-efficient generation, reducing GHG emissions from power generation.

3. REAE improves fuel security and operational flexibility for power generation, especially during the peak heating season, December through March. As more renewable generation is added to the resource mix to meet carbon reduction goals, REAE provides a vital operational hedge in extreme winter conditions when cold weather and high wind speeds reduce offshore wind production and snowstorms affect solar production.

4. Considered individually, REAE's reasonably foreseeable GHG emissions resulting from the construction, operation and downstream use of the natural gas transported by the project will have an insignificant impact on regional GHG emissions, accounting for less than 0.1% of annual emissions in New Jersey and Pennsylvania. Direct emissions from project construction may result in 0.044 million metric tons of net CO2e in 2024. Direct emissions from REAE operations will result in 0.088 million metric tons per year (mtpy) of CO2e. The additional pipeline capacity provided by REAE will result in 0.033 million mtpy of net indirect CO2e, with 0.049 million mtpy increased residential, commercial and industrial natural gas consumption offset by 0.016 mtpy of reductions in CO2e ascribable to avoided emissions from fossil-fired generation in the region.

5. Prior market experience shows that the additional supply tends to put downward pressure on prices. The incremental capacity ascribable to REAE will likely have a significant impact on delivered natural gas prices in New Jersey and Southeastern

[4] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=uuA7i8WoMDBOc0M4ln8WVXMgn1GkujvD, page ES-9.

Pennsylvania in the winter, especially on days when current capacity is used fully. In light of uncertainties about technology change in the electric sector, the likely frequency and diminution of the price spikes over the study horizon is unknown, as well as how long such diminution may persist. Absent REAE, the extent to which delivered gas price spikes during the heating season will affect both retail natural gas and electric rates is also unknown.

1 Existing Natural Gas Capacity Cannot Meet REAE LDC Customer Needs

LAI has conducted an independent assessment of the pipeline capacity available to the six LDCs in New Jersey, Pennsylvania and Maryland that have entered into precedent agreements for Transco's REAE.[5] The goal of the assessment is to compare each LDC's forecasted customer requirements under design day criteria to the pipeline capacity and on-system storage available to meet those requirements. Each of the six LDCs uses its own specific criteria to define the design day.[6] The design day planning structure ensures that an LDC can reliably serve its customers under harsh winter conditions when the demand for natural gas for space heating is highest.

In conducting this assessment, LAI has evaluated the adequacy of pipeline capacity in New Jersey and Southeastern Pennsylvania to meet LDC demand through 2039. LAI first determined the maximum level of New Jersey and Southeastern Pennsylvania firm customer send out supported by existing on-system peaking resources (including liquefied natural gas (LNG) and propane) and pipeline capacity deliverable to New Jersey and Southeastern Pennsylvania. LAI then compared this delivery capability (deliverability) to the aggregated annual design day demand forecast of the LDCs in the region in order to identify the supply surplus or shortfall for each year. In assessing market need LAI considered the ability of other pipelines to meet the incremental demand with existing capacity, the potential to cover the capacity deficit with planned pipeline capacity and non-pipeline alternatives and found:

- Pipeline capacity within and through New Jersey and Southeastern Pennsylvania is nearly fully subscribed. Under FERC tariff doctrine, pipeline entitlement holders have the right-of-first-refusal (ROFR) to renew expiring capacity contracts. Due to the scarcity and value of capacity in the region, ROFR rights are almost always exercised by contract holders. It is highly unlikely that existing firm pipeline capacity will be decontracted by current contract holders for reuse by others in the near to intermediate term absent clear regulatory guidance. There is no known regulatory pressure from state commissions on LDCs to decontract all or a portion of their pipeline capacity entitlements.

- There are a number of planned pipeline projects to serve additional natural gas demand in the study region. None of the planned pipeline projects represent viable REAE alternatives. All projects are either fully subscribed or unlikely to confer additional capacity benefits in New Jersey and Southeastern Pennsylvania.

- Non-pipeline supply alternatives, including trucked compressed natural gas (CNG) and LNG, renewable natural gas (RNG) and incremental on-system peaking resources, are more costly than pipeline capacity, and are not sufficient to cover the forecast pipeline capacity deficit. The maximum potential design day volume available in New Jersey and Southeastern Pennsylvania from non-pipeline options is 216.5 MDth/d. This total is insufficient to cover the current shortfall and falls way short of the growing capacity

[5] South Jersey Resources Group LLC (SJRG) and Williams Energy Resources LLC, both gas marketing entities, have also executed binding precedent agreements.

[6] See filings referenced in footnote 8 for more information on each LDC's design day criteria.

deficit over the forecast period. Compared to non-pipeline alternatives, REAE is a lower cost conventional transportation option that provides more than triple the capacity available from non-pipeline alternatives.

- REAE gives LDCs in New Jersey and Southeast Pennsylvania a safe bridge to a secure energy future that satisfies the LDCs' design day sendout obligations through the end of the 2030s. REAE is needed to ensure that reliability goals are met. LAI is not aware of any other project that can cure the deficit over the forecast period. The Maryland LDC elected to use REAE capacity to meet its growing design day demand requirements because REAE capacity provides the best combination of scheduled in-service date, reliability, and access to diverse supplies.

A pipeline's deliverability to a particular location is based on the primary delivery points set forth in the shippers' Transportation Service Agreements for firm capacity. Contracts with primary delivery points at an end user's (LDC, industrial customer or generator) meter in New Jersey or Southeastern Pennsylvania represent firm capacity allocable on a primary (first-priority) basis to New Jersey and Southeastern Pennsylvania. Contracts with primary delivery points located in New York and/or New England, or at a pipeline interconnection linking to a contract on a downstream pipeline, represent capacity not allocable on a primary basis to New Jersey and Southeastern Pennsylvania. While the capacity path to downstream points may pass through New Jersey and/or Southeastern Pennsylvania, delivery points in these regions would be secondary under the terms of the transportation contracts, and thus subordinate to the primary capacity rights subject to operating and tariff limitations. Like the LDCs in the study region, downstream customers also have contractual rights to their pipeline capacity that reserve the capacity to the primary delivery points in the downstream markets. Therefore, while an initial high-level review might indicate that there is more than enough gas flowing through New Jersey and Southeastern Pennsylvania to meet the collective needs of the LDCs in the region, the LDCs cannot rely on having access to this capacity on a given day.

When capacity associated with contracts held by downstream customers is removed from the determination of pipeline adequacy, LDCs in New Jersey and Southeastern Pennsylvania are unable to meet their current obligations with existing entitlements. Over the forecast horizon the LDCs face growing capacity deficits, a noteworthy concern insofar as the LDCs' forecasts of design day sendout obligations incorporates planned energy efficiency and conservation.

LAI also undertook an assessment of pipeline capacity available to BGE, which is geographically separated from the service territories of the LDC shippers in New Jersey and Southeastern Pennsylvania that have signed contracts with REAE. BGE is subject to different pipeline capacity operational dynamics around flow directionality and constraints. BGE elected to use REAE capacity to meet its growing design day demand requirements because it concluded that REAE capacity provides the best combination of scheduled in-service date, reliability, and access to diverse supplies.[7]

The analysis of design day demand and supplies presented in this section provides information on how fully REAE capacity may be used under design day conditions. The extent to which LDCs and/or power generators utilize Project deliverability under non-design day conditions is addressed in Sections 2 and 3.

1.1 New Jersey and Southeastern Pennsylvania's Demand for Natural Gas is Growing

LAI has aggregated the design day gas demand forecasts of the New Jersey and Southeastern Pennsylvania LDCs to determine the region's total utility design day gas load. Five LDCs in the study region – ETG, NJNG, PECO, PSEG and SJG – have entered into 15-year or longer contracts with Transco for REAE capacity. Philadelphia Gas Works (PGW), a municipal utility, is included in the region under study, as its territory is surrounded by PECO and SJG, but PGW has not executed a precedent agreement with Transco for Project capacity. Design day gas demand is based on the New Jersey LDCs' Basic Gas Supply Service (BGSS) filings for 2021 and Pennsylvania LDCs' supporting data for their 2021 Purchased Gas Cost filings.[8]

The design day is the basis for planning gas capacity requirements. The design day therefore reflects the highest gas demand an LDC expects to be obligated to serve on an extremely cold

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[7] Exelon Corporation, Comments of Exelon in Support of the Application, Docket No. CP21-94-000, April 28, 2021, pp. 3-4.

[8] Elizabethtown Gas Company, Petition to Review its Basic Gas Supply Service Rate, June 1. 2021, https://www.elizabethtowngas.com/Elizabethtown/media/PDF/Regulatory%20Info/2021-ETG-BGSS-P-Filing.pdf (ETG BGSS Filing).

New Jersey Natural Gas Company, Petition for the Annual Review of its Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Rates for F/Y 2022, May 28, 2021, Docket No. GR210505860. https://www.njng.com/regulatory/pdf/NJNG-2022-BGSS-CIP-Filing-GR21050860.pdf (NJNG BGSS Filing).

PECO Energy Company, Information Submitted in Compliance with Section 1307(f) of the Public Utility Code Recovery of Purchased Gas Costs, April 30, 2021. https://www.puc.pa.gov/pcdocs/1701950.pdf (PECO Supporting Information Filing).

Philadelphia Gas Works, Computation of Annual Purchased Gas Costs For Twelve Months Ending August 31, 2022, February 1, 2021, https://www.pgworks.com/uploads/pdfs/GCR_2021-2022_-_Pre-Filing_Volume_2.pdf (PGW Supporting Information Filing).

Public Service Electric and Gas Company, Motion, Supporting Testimony & Tariff Modifications, June 1, 2021, In the Matter of Public Service Electric and Gas Company's 2021/2022 Annual BGSS Commodity Charge Filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge, https://nj.pseg.com/aboutpseg/regulatorypage/-/media/78C8191CD540477D9230DA056F9A675B.ashx (PSEG BGSS Filing).

South Jersey Gas Company Petition, Case Summary, Testimony and Schedules, In the Matter of the Petition of South Jersey Gas Company to Revise the Level of Its Basic Gas Supply Service ("BGSS") Charge and Conservation Incentive Program ("CIP") Charge for the Year Ending September 30, 2022, June 1, 2021, https://southjerseygas.com/SJG/media/pdf/pdf-regulatory/SJG-2021-2022-BGSS_CIP-Peition-06-01-21.pdf (SJG BGSS Filing).

winter day. Each of the LDCs in the region uses its own specific criteria to define the design day.[9] Hence, LAI did not endeavor to standardize or otherwise second-guess the specific criteria each LDC used in its respective quantification of design day send-out requirements. While weather conditions may not reach the design day temperature in a given year, planning to the design day criteria ensures that there will be sufficient capacity to meet customer needs when extreme temperature conditions do occur. Planning around milder temperature conditions could result in an LDC failing to meet its obligation to serve in the event of more severe weather.[10]

LAI's assessment of market need has been oriented around LDC requirements to ensure local reliability. To the extent other market participants, such as industrial customers and generators have an unmet need for firm capacity, LAI's analysis will understate the market need for REAE and the incremental firm capacity it will provide.

The composition of LDC supply portfolios, including contracts for pipeline transportation capacity from production fields and conventional underground storage and local LNG and propane storage capacity, is subject to regulation by the state utility commissions. Local regulation ensures for the provision of reliable service to LDC customers. State commissions are also responsible for setting the cost of service for each LDC, including rate of return. The four LDCs in New Jersey are regulated by the New Jersey Board of Public Utilities (NJ BPU), which has recognized the applicability of design day criteria in evaluating LDCs' portfolio of pipeline and storage assets.[11] The Pennsylvania Public Utilities Commission has likewise recognized the applicability of design day criteria in evaluating the adequacy of LDCs' portfolios.[12] State utility commissioners in New Jersey, Pennsylvania and Maryland use the "prudent and reasonable" standard in determining which utility investment costs may be recovered from ratepayers.[13] This provides utilities in each state with an incentive to avoid making investments and entering into long-term capacity contracts that regulators might deem imprudent. In the context of design day

[9] See filings referenced in footnote 8 for more information on each LDC's design day criteria.

[10] State regulators frequently define design day as "the 24-hour period of the greatest theoretical gas demand." *See*, e.g., https://www.dps.ny.gov/glossary.html and https://mn.gov/commerce-stat/pdfs/natural-gas-utility-standard-forms-instructions.pdf. See, also, National Gas Council, Natural Gas Systems: Reliable & Resilient, July 2017, https://www.aga.org/sites/default/files/ngc_reliable_resilient_nat_gas_white_paper.pdf, page 21: "LDCs are regulated by most states as local gas utilities that have an obligation to serve their firm core customers … on a 'design day' (a forecasted peak-load day based on historical weather conditions)."

[11] See, e.g., In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846, Order dated May 20, 2020, at 1-2.

[12] See 52 Pa. Code § 69.11, defining "Design day conditions—the extreme weather conditions that an NGDC uses to project customer requirements."
http://www.pacodeandbulletin.gov/secure/pacode/data/052/chapter69/052_0069.pdf

[13] See, e.g.: NJBPU, Order in Docket No. ER20020146, April 7, 2021 (https://www.nj.gov/bpu/pdf/boardorders/2021/20210407/2C%20ORDER%20JCPL%20Reliability%20Plus%20Prudency%20Review.pdf); Maryland Public Service Commission, Order in Case No. 9645, December 16, 2020 (https://www.psc.state.md.us/wp-content/uploads/Order-No.-89678-Case-No.-9645-BGE-Multi-Year-Rate-Plan-Order-1.pdf); and Pennsylvania Public Utility Commission, Order in Docket No. M-2012-2293611, May 10, 2012 (https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.puc.pa.gov%2Fpcdocs%2F1186846.doc&wdOrigin=BROWSELINK).

planning, the prudent and reasonable standard requires that LDCs' design day demand forecasts are reasonable and that the supplies needed to meet design day demand are prudently procured. As a result, the design day demand forecasts of LDCs' in these states are a reliable forecast of LDC-served firm demand.

Figure 1-1 shows the aggregated design day gas demand forecast across the six LDCs that serve the study region. The values for each heating season correspond to the design day demand filed by each LDC. Not all of the latest filings, as listed in footnote 8, include design day forecasts extending through the 2029-30 heating season. In the cases of ETG, PSEG and SJG, their BGSS filings include forecasts that extend through the 2025-26 heating season, while PGW only provided information through 2023-24.[14] In these cases, LAI has extrapolated the overall trend for the period shown in the filing through 2029-30.

Many LDCs' design day demand forecasts are based on forecasts of customer counts and usage per customer. Changes in customer counts are driven primarily by fuel-switching and construction of new buildings with natural gas-fueled appliances and equipment, while changes in usage per customer are primarily driven by weather, economic growth and energy efficiency. New Jersey's Global Warming Response Act requires a reduction in New Jersey's GHG emissions to below the 1990 level by 2020 and 80% below the 2006 level by 2050.[15] Pennsylvania's legislature has not established a state GHG emissions reductions target.[16] While New Jersey's Global Warming Response Act does not require any further reduction in GHG emissions during the study period, meeting New Jersey's 2050 GHG reduction goal may require significant reductions in LDC customers' natural gas consumption. In addition, new legislation establishing binding GHG emissions targets may be enacted in New Jersey, Pennsylvania or nationally. To account for these downside risks to New Jersey and Southeastern Pennsylvania LDCs' customers' demand for natural gas, LAI has considered three demand scenarios that consider differing levels of building electrification.

The pace and timing of building electrification in New Jersey and Pennsylvania remains highly uncertain. As explained in a February 2022 study of LDC decarbonization in Massachusetts, achieving a significant level of building electrification "will require: (i) LDC or state sponsored programs that shift consumer economics in favor of electric technologies via incentives or higher gas commodity costs that reflect GHG externalities or compliance costs; (ii) LDCs or the state may need to impose mandates precluding natural gas as a fuel choice if incentives cannot provide

[14] See ETG BGSS filing, Schedule LJW-16, pages 2-3; PGW Supporting Information Filing, Form-IRP-Gas-1B: Peak Day Requirements; BGSS filing, Schedule F; and SJG BGSS filing, Schedule MCM-6.

[15] New Jersey Global Warming Response Act, P.L. 2007, Chapter 112, approved July 6, 2007, https://www.nj.gov/dep/aqes/docs/gw-responseact-07.pdf.

[16] Pennsylvania Department of Conservation and Natural Resources, Gov. Wolf Announces 'Pennsylvania Climate Action Plan 2021,' September 22, 2021, https://www.media.pa.gov/pages/DCNR_details.aspx?newsid=781.

enough impetus for customers to convert to electricity; and/or (iii) some combination of incentive, pricing and mandates."[17]

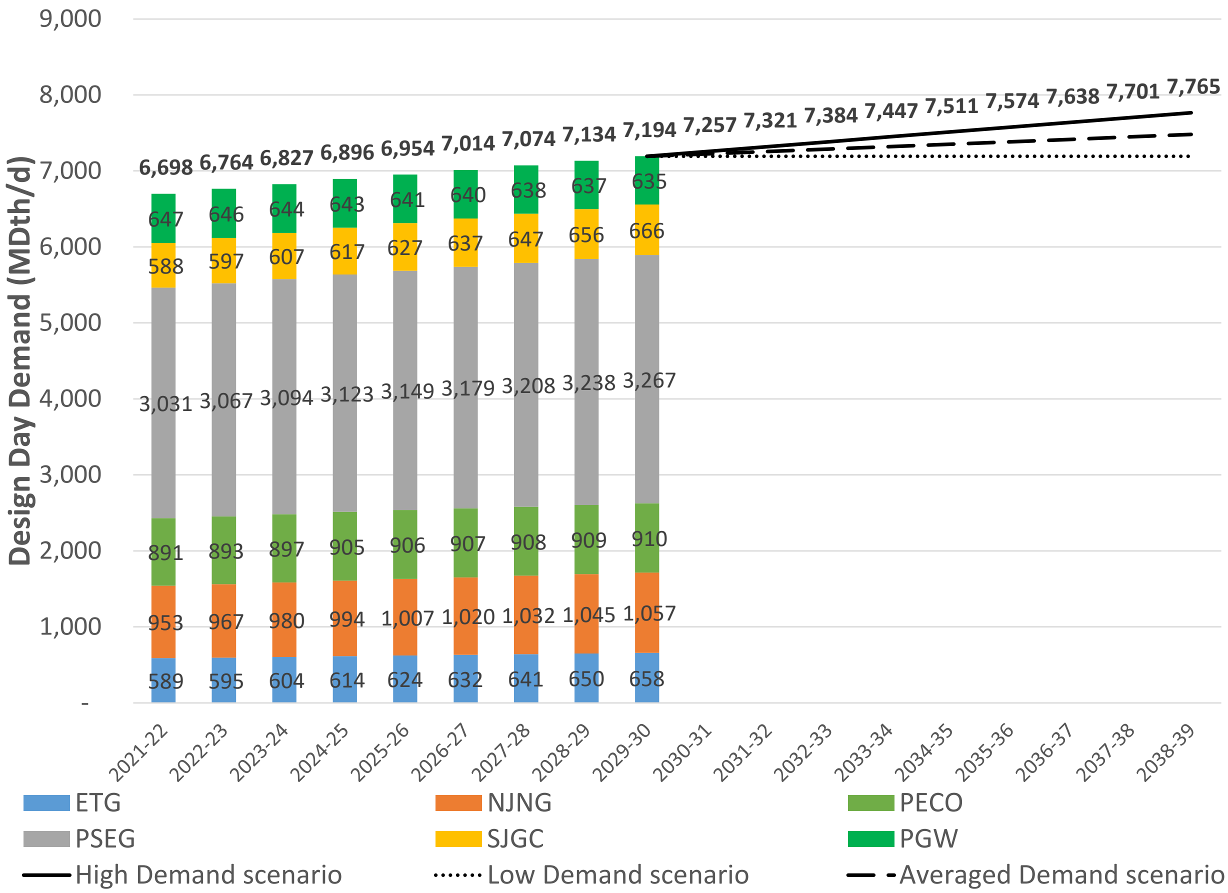
The High Demand scenario represents a future in which LDC-served natural gas demand in New Jersey and Eastern Pennsylvania continues along its forecast trend. This could occur if state and federal governments fail to enact policies that create incentives for consumers to switch from natural gas to renewable energy sources, if the incentives created are not strong enough to induce changes in consumer behavior, or if large cost-effective sources of renewable natural gas and hydrogen are developed. The Low Demand scenario represents a future in which LDC-served natural gas demand peaks sometime in the 2030s resulting in limited or no growth after 2030. As discussed below, the Low Demand scenario is broadly consistent with the goals set forth in New Jersey's 2019 Energy Master Plan and assumes no changes are made to the Energy Master Plan in subsequent years. The Average Demand scenario represents an intermediate future in which state and federal governments enact policies that lead to renewables replacing natural gas in newly built and renovated structures while natural gas use continues in existing buildings.

To estimate total design day demand for the period from 2030 through the end of the study period in 2039, LAI has prepared three demand scenarios:

- Continuation of the trend from 2021-22 through 2029-30, representing an annual growth rate of 0.9% (High Demand scenario);
- 2029-30 demand held constant through 2039, representing an annual growth rate of 0% (Low Demand scenario); and
- The average of these two scenarios, representing an annual growth rate of 0.45% (Average Demand scenario).

[17] Energy and Environmental Economics, Inc. and ScottMadden Inc. The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report – DRAFT, February 15, 2022, page 92.

Figure 1-1. Aggregated Study Region Design Day Gas Demand Forecast



As shown in Figure 1-1, growth continues at each of the LDCs that has committed to REAE as a result of new connections for newly constructed commercial and residential structures and customers switching from oil to gas. PGW, which not a Project shipper, is the only LDC in the study region with flat or declining demand. Each of the LDCs offers and promotes energy efficiency and conservation programs. PECO provides approximately $1.1 million per year in funding natural gas Energy Efficiency and Conservation programs offerings for residential and low-income customers, and proposed expansions to those offerings would increase funding to $4.5 million per year.[18] In 2018, New Jersey enacted the Clean Energy Act, which required that utilities expand upon their existing energy efficiency and conservation programs to achieve annual reductions in the use of natural gas of 0.75 percent of annual usage within five years of implementation. Under New Jersey's Clean Energy Act, utilities must ensure universal access to energy efficiency measures as well as serve the needs of low-income communities.[19] In order to

[18] Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division, Direct Testimony of Doreen L. Masalta, September 30, 2020, pages 5 and 9. https://www.peco.com/SiteCollectionDocuments/PECOSt9Masalta-Gas.pdf

[19] NJ P.L.2018, Chapter 17, An Act concerning clean energy, amending and supplementing P.L.1999, c.23, amending P.L.2010, c.57, and supplementing P.L.2005, c.354 (C.34:1A-85 et seq.), approved May 23, 2018. https://www.njleg.state.nj.us/Bills/2018/AL18/17_.HTM.

meet these goals, the New Jersey Board approved almost $1 billion of LDC energy efficiency and conservation programs, as shown in Table 1-1.

Table 1-1. New Jersey LDCs' Approved Energy Efficiency Budget: 2021-2024

($ millions)	**ETG**[20]	**NJNG**[21]	**PSEG**[22]	**SJG**[23]
Approved Budget	$83.4	$258.9	$496.4	$133.3

New Jersey LDCs' energy efficiency measures are reflected in their filed forecasts, to the extent applicable to the design day.[24] While New Jersey's Clean Energy Act requires that each utility adopt "energy efficiency and peak demand programs," the Board's study of potential energy savings did not consider natural gas peak demand programs, and each LDC has indicated that the potential for peak demand management is limited.[25]

[20] NJBPU, In re the Implementation of L. 2018, C. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, and In re the Petition of ETG Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act and the Establishment of a Conservation Incentive Program, BPU Dockets No. QO19010040 & GO20090619, April 7, 2021, page 7.

[21] NJBPU, In re the Implementation of L. 2018, C. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, and In re the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanism Pursuant to the Clean Energy Act, N.J.S.A.48:3-87.8 et seq. and 48:3-98.1 et seq., BPU Docket Nos. QO19010040 & GO20090622, March 3, 2021, page 6.

[22] NJBPU, In re the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis, BPU Docket Nos. GO18101112 & EO1801113, September 23, 2020. Based on total budget of $1,103 M and 45% gas share. Pages 13, 17.

[23] NJBPU, In re the Implementation of L. 2018, C. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, and In the Matter of the Petition of South Jersey Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act, BPU Docket Nos. QO19010040 & GO20090618, April 7, 2021, page 6.

[24] The LDCs account for energy efficiency programs on design day demand in a variety of ways. The forecasts used by SJG and ETG are based on actual historical use factors by customer class which capture actual (historical) energy efficiency trends. See SJI Utilities, February 8. 2022, Re: In the Matter of Natural Gas Commodity and Delivery Capacities In the State of New Jersey – Investigation of the Current and Mid-Term Future Supply and Demand, BPU Docket No. GO19070846, page 12. NJNG takes into account the impact of energy conservation savings embedded in historical data. PSEG accounts for the expected impact of state and utility energy efficiency programs. See, London Economics International LLC, *Final Report: Analysis of natural gas capacity to serve New Jersey firm Customers*, Prepared for New Jersey Board of Public Utilities, November 5, 2021. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1251860, page 46.

[25] See Optimal Energy, Energy Efficiency Potential in New Jersey, May 24, 2019, https://s3.amazonaws.com/CandI/NJ+EE+Potential+Report+-+FINAL+with+App+A-H+-+5.24.19.pdf, page 9; Comments from New Jersey Natural Gas Company Pertaining to Docket No. GO20010033, In the Matter of the Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-term Future Supply and Demand, Docket No. GO20010033, May 13, 2021, at 5;" Comments of South Jersey Gas and Elizabethtown Gas Companies, In the Matter of the Natural Gas Commodity and Delivery Capacities in the State of New Jersey – Investigation of the Current and Mid-term Future Supply and Demand, Docket No. GO20010033, May 13, 2021, at 10; PSEG Comments, In the Matter of the Natural Gas Commodity and Delivery Capacities in the State

New Jersey's current climate policies and Energy Master Plan recognize that electrification of space heating, cooking, hot water and other applications of natural gas in buildings may be required in order to reach the state's decarbonization and clean energy goals. New Jersey's 2019 Energy Master Plan also recognizes the risk that "poorly managed electrification could exacerbate peak load and greenhouse gas emissions and introduce capacity concerns."[26] This could occur if early building electrification leads to increases in electricity demand that are not paired with increases in renewable generation. Thus, while New Jersey's 2019 Energy Master Plan considers seven scenarios that would allow New Jersey to meet the clean energy goals set under the state's Global Warming Response Act, none of these plans call for substantial building electrification before 2030. Each of the scenarios, except for "Retain gas use in buildings" assumed that aggressive retrofitting and electrification of buildings would begin in 2030.[27] Pennsylvania does not currently have any programs to encourage or incentivize building electrification. Substantial building electrification in the study region would reduce consumer demand for natural gas and LDC design day forecasts. However, such electrification is not expected to have a significant impact on the study region before 2030 and may be delayed further, depending on the pace of growth in renewable generation, in particular, New Jersey's ability to realize the benefits of scheduled offshore wind generation.[28]

1.2 New Jersey and Southeastern Pennsylvania LDCs Already Hold Most of the Capacity with Primary Firm Delivery Points in the Study Region

There are five major interstate pipelines operating in New Jersey and Southeastern Pennsylvania.[29] Their locations relative to each of the study region LDCs' service territories are shown in Figure 1-2. Table 1-2 indicates which of the pipelines deliver gas to each of the LDCs.

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of New Jersey – Investigation of the Current and Mid-term Future Supply and Demand, Docket No. GO20010033, May 13, 2021, at 4.

[26] 2019 New Jersey Energy Master Plan: Pathway to 2050, https://www.nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf, page 38.

[27] 2019 New Jersey Energy Master Plan: Pathway to 2050, https://www.nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf, page 38, page 130.

[28] Presently, New Jersey's statutory mandate for offshore wind is 7.5 GW by 2035.

[29] In addition to the five major interstate pipelines, the region also includes the Eastern Shore Natural Gas (ESNG) and Adelphia Gateway pipelines. ESNG extends from Southeastern Pennsylvania through the Delmarva Peninsula. ESNG does not represent a potential source of supply for New Jersey and Southeastern Pennsylvania because the only available source of upstream supply are interconnects with Columbia, Transco and Texas Eastern (http://info.esng.com/about_pipeline_assets). Adelphia Gateway extends into Southeastern Pennsylvania where it interconnects with Texas Eastern, Transco and Columbia near the Marcus Hook Compression station. All three pipelines are fully subscribed. The only Adelphia Gateway subscribed capacity with delivery to the PECO or PGW systems is 22,500 Dth/d on the Tilghman lateral. This quantity is contracted for by Kimberly-Clark. *Adelphia Gateway, LLC*, 171 FERC ¶ 61,049 (2020), at PP 3-5, 58. https://cms.ferc.gov/sites/default/files/2020-05/C-6.pdf

Figure 1-2. Natural Gas Pipelines and LDCs in the Study Region

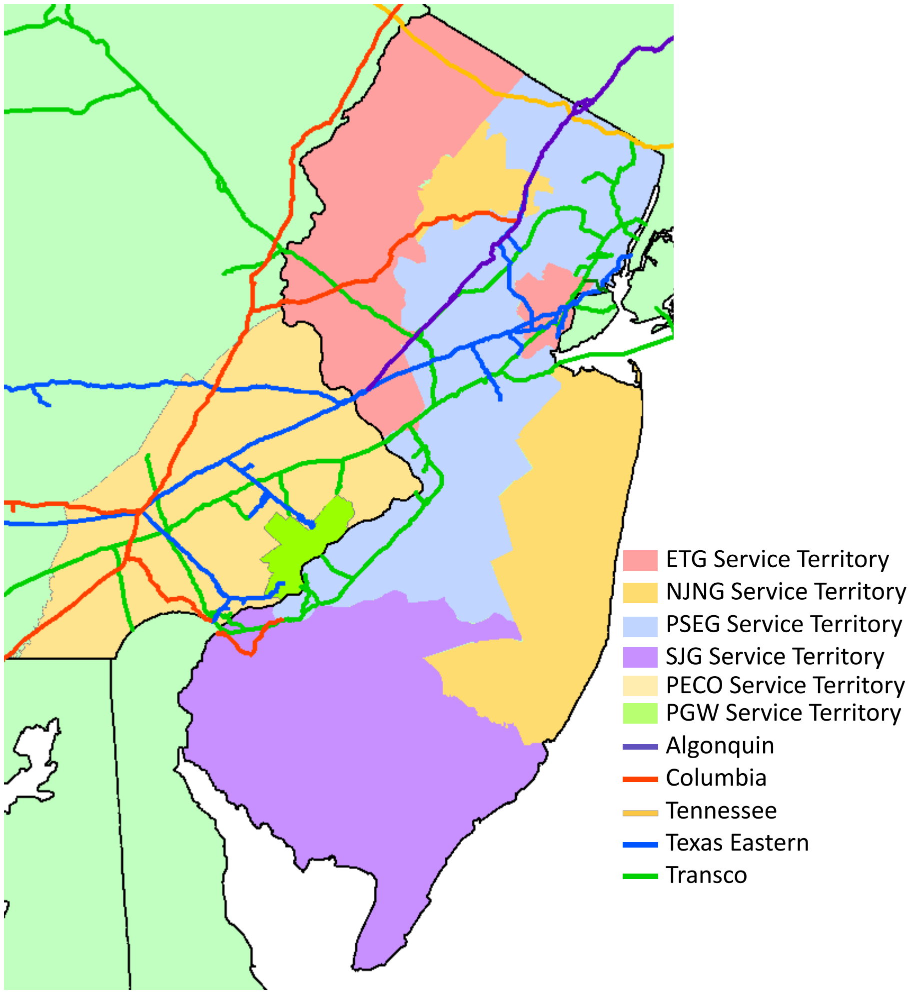


Table 1-2. Pipeline-LDC Connections in New Jersey and Southeastern Pennsylvania

	Algonquin	Columbia	Tennessee	Texas Eastern	Transco
ETG		X	X	X	X
NJNG	X	X	X	X	X
PECO				X	X
PGW				X	X
PSEG	X	X	X	X	X
SJG		X			X

As previously discussed, the LDCs plan their gas supply portfolios to satisfy their design day send-out requirements. The backbone of each LDC's portfolio is the long-term pipeline storage and transportation entitlements that support deliverability to the LDC's service territory. Because their full supply portfolios are not needed year-round, LDCs are able to recoup margin for the benefit of their customers by laying off or "releasing" a portion of their portfolio during the spring, summer, and fall, when residential, commercial, and industrial demand is lower. The transportation portfolio is also used during lower LDC demand periods to replenish storage inventory. Pipeline project additions are designed to transport all firm volumes under contract, regardless of how frequently the shippers' respective entitlements are used fully throughout the year. The addition of significant Project capacity in New Jersey, Pennsylvania and Maryland represents a valuable operational hedge to pipeline deliverability and resilience as extremely cold temperature conditions in the mid-Atlantic states are often coincident with like temperature conditions in downstream markets in New York and New England.

Available pipeline capacity with primary delivery points in the study region is based on each pipeline's Index of Customers as of October 1, 2021.[30] The Index of Customers lists the entities holding rights to firm transportation on the pipeline. The entitlement reserves a specific amount of transportation capacity expressed on a Maximum Daily Quantity basis between one or more primary receipt points and one or more primary delivery points. Pipeline customers can use their firm capacity rights to ship gas or use a capacity release to temporarily transfer their capacity rights to another shipper. Capacity release transactions are not reported in each pipeline's Index of Customers and are not accounted for in LAI's capacity analysis. In analyzing pipeline capacity, LAI assumed that LDCs and other market participants can procure sufficient volumes of natural gas to make full use of all firm capacity under contract with delivery in New Jersey or Southeastern Pennsylvania. Under this assumption incremental conventional storage capacity outside of the region, e.g., in Western Pennsylvania, does not increase firm supplies deliverable to New Jersey and Southeastern Pennsylvania without the addition of transportation capacity. If the limited availability of natural gas prevented some market participants from making full use of their firm capacity, then available supplies in New Jersey and Southeastern Pennsylvania would be even lower.

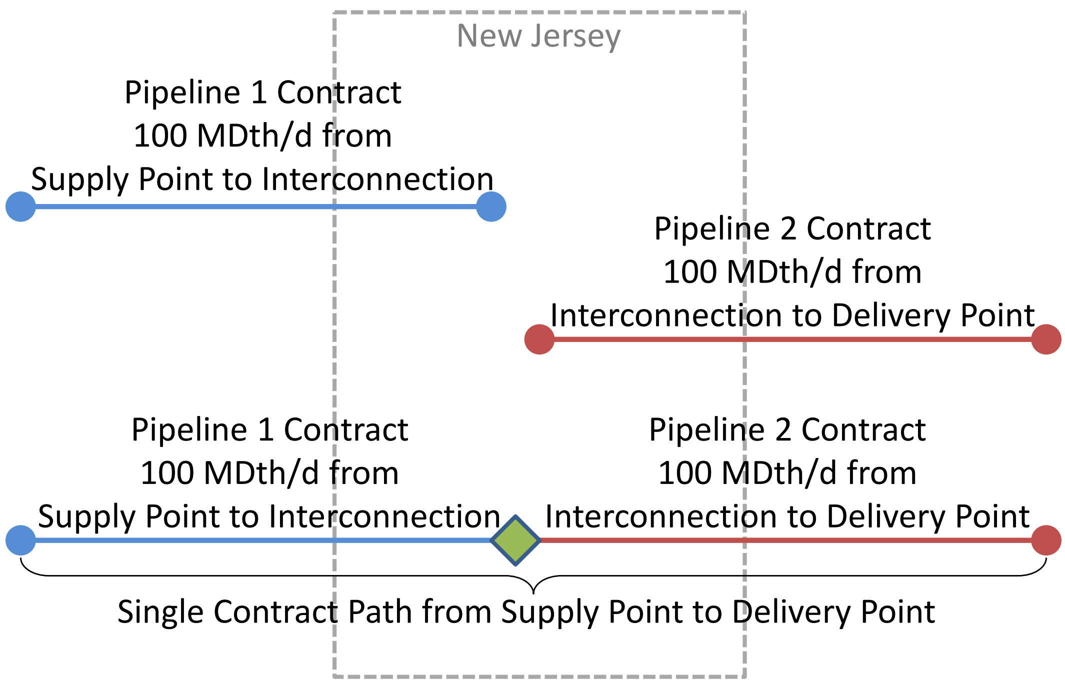
In each pipeline's Index of Customers an end date is reported for each capacity contract. The fact that an end date is reported does not mean the contracted capacity will be available to other shippers in New Jersey or Southeastern Pennsylvania upon contract expiration. Consistent with FERC precedent, entitlement holders typically possess a right-of-first-refusal (ROFR), which confers the right to extend the contract expiration date provided the entitlement holder agrees to match the rate and term offered by a competing bidder for capacity that would otherwise expire. In the absence of competing bidders, a shipper whose contract is expiring can exercise its ROFR by agreeing to pay the maximum rate allowed under the pipeline's tariff. When a shipper does not exercise its ROFR the capacity is available to third parties who can submit a bid offering a specified rate and contract term for the unsubscribed capacity, subject to the maximum tariff rate. If a downward price adjustment below the maximum rate is not accepted by the pipeline, the determining factor among rival bidders is often contract term. Based on these considerations, LAI has assumed that the LDCs will exercise ROFR for their existing pipeline contracts over the study period through 2039. Notably, there is no evidence of state regulatory pressure on LDCs

[30] Indices of Customers downloaded from: https://infopost.enbridge.com/Downloads/IOC/AG_IOC.txt; https://pipeline2.kindermorgan.com/IndexOfCust/IOC.aspx?code=TGP; https://ebb.tceconnects.com/infopost/; https://infopost.enbridge.com/Downloads/IOC/TE_IOC.txt; and https://www.1line.williams.com/Transco/info-postings/index-of-customers.html. Customer index data for bundled storage and transportation contracts is supplemented with information on Maximum Daily Withdrawal Quantity taken from LDCs' filings with state regulators.

doing business in New Jersey, New York, and Pennsylvania presently to decontract their interstate pipeline entitlements or otherwise relinquish their capacity rights by failing to exercise ROFR.

Capacity that has a primary firm delivery point at a pipeline interconnection in New Jersey or Southeastern Pennsylvania typically has its ultimate primary firm delivery at a point on the connecting pipeline (or downstream of a second interconnection). The capacity on both pipelines therefore represents a single contract path, even though it is composed of multiple contracts, i.e., one on each pipeline. As illustrated in Figure 1-3, this path consolidation avoids double counting capacity, as the upstream contract (Pipeline 1) with a delivery point at an interconnection in New Jersey does not represent capacity deliverable to New Jersey customers on a firm basis unless it is combined with a second contract with receipt at the interconnection and a delivery point at an LDC citygate or another end-user's meter. This is because upstream contracts are the only available source of supply at the interconnection. Without a corresponding downstream contract, LDC delivery points are not available on a primary firm basis for capacity with contractual delivery to an interconnection. LDCs therefore cannot rely on this capacity unless they hold a corresponding firm downstream capacity entitlement.

Figure 1-3. Path Consolidation Across Pipelines



In many cases, contracts have multiple delivery points. Examples of how such contracts were treated in the analysis are discussed below and summarized in Table 1-3 and Table 1-4. Total point-specific delivery quantities can be greater than the contract quantity, indicating that the shipper has options regarding where to deliver gas on a primary basis. For purposes of this assessment, LAI has allocated the contract capacity first to the contract holder's own delivery points. For example, if an LDC in the study region can deliver gas on a primary basis either to its own meters behind the citygate or a pipeline interconnection, the citygate meters are assumed to be primary. This is shown in Table 1-3. This assumption reflects the fact that LDCs use contracted capacity to supply their own on peak demand days.

Table 1-3. Example: LDC Contract with Multiple Delivery Point Options

Shipper:	**New Jersey LDC**		
Point Type	**Point Location**	**Point Volume (MDth/d)**	**Point Location Considered Primary for Analysis?**
Receipt	Pennsylvania Storage Field	50	Yes
Delivery	LDC Citygate in New Jersey	50	Yes
Delivery	Pipeline Interconnection in New Jersey	50	No

Where a third party, such as a marketer or producer, has a contract with a firm delivery in New York, LAI assumed that the third party moves the position to the highest and best use strictly on the basis of price. This is shown in Table 1-4. A third party's ability to realize option value is consistent with market dynamics. On peak winter days this capacity could be used to deliver gas to New Jersey, but it is not guaranteed to be available in New Jersey. The third party may exercise the option to deliver to gate stations in downstate New York. Due to Transco's system configuration, delivery points in southern New Jersey, where much of REAE's capacity is deliverable, are not in-the-path for capacity with primary delivery to downstate New York. Hence, even if this capacity were not scheduled to support deliveries to downstate New York on a given day, it might not be deliverable to New Jersey and Southeastern Pennsylvania due to infrastructure limitations.[31] In light of the high coincidence of heating degree days across the LDC service franchise areas doing business in New Jersey and Southeastern Pennsylvania, it is likely that each LDC facing a capacity deficit would seek discretionary supply at the same time to bolster their respective portfolios. Therefore, LDCs in New Jersey and Southeastern Pennsylvania cannot rely on any discretionary capacity from third parties holding primary downstream entitlements to meet peak day demand.

[31] The Trenton-Woodbury Lateral runs parallel to the Transco Mainline from Station 200 to south of Station 210. Exhibit F to the REAE CPCN Application shows the REAE delivery points that are located on this lateral and thus not able to schedule in-the-path secondary capacity with primary delivery to downstate New York.

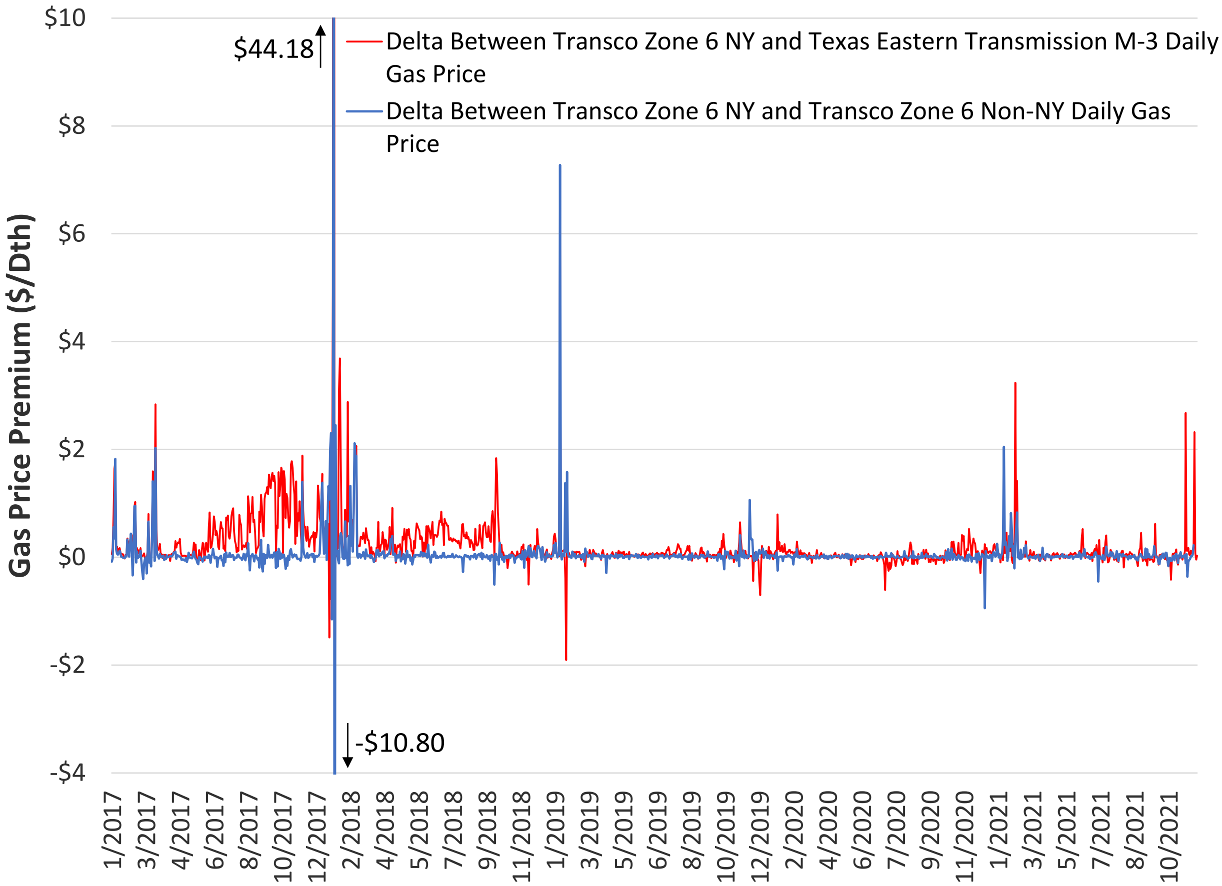
Table 1-4. Example: Third-Party Contract with Multiple Delivery Point Options

Shipper:	Marketer		
Point Type	**Point Location**	**Point Volume (MDth/d)**	**Point Location Considered Primary for Analysis?**
Receipt	Pennsylvania Production Field	50	Yes
Delivery	LDC Citygate in New Jersey	25	No
Delivery	LDC Citygate in New York	50	Yes
Delivery	Pipeline Interconnection in New Jersey	25	No

Marketers with primary delivery points in downstream markets respond to market prices that rationalize the highest and best use of such capacity rights. In relation to pricing points in New Jersey, Southeastern Pennsylvania and Maryland, the value of delivered natural gas in downstate New York frequently supports deliveries to the New York Facilities System serving Consolidated Edison (Con Ed) and National Grid in both New York City and Long Island. The difference between Transco Zone 6 New York and non-New York daily gas prices is shown in Figure 1-4 The (micro)basis differential between TZ6NY and TZ6NNY is frequently a large positive number. It is rarely a significant negative number during the peak heating season. Transco Zone 6 New York prices are usually at or above Transco Zone 6 Non-NY prices. Figure 1-4 also compares Transco Zone 6 New York to the Texas Eastern Transmission M3 price, another non-NY pricing point of commercial relevance to LDCs in New Jersey and Southeastern Pennsylvania as well as gas-fired generation in the mid-Atlantic portion of PJM. Transco Zone 6 New York also shows a frequent price premium over Texas Eastern Transmission M3.

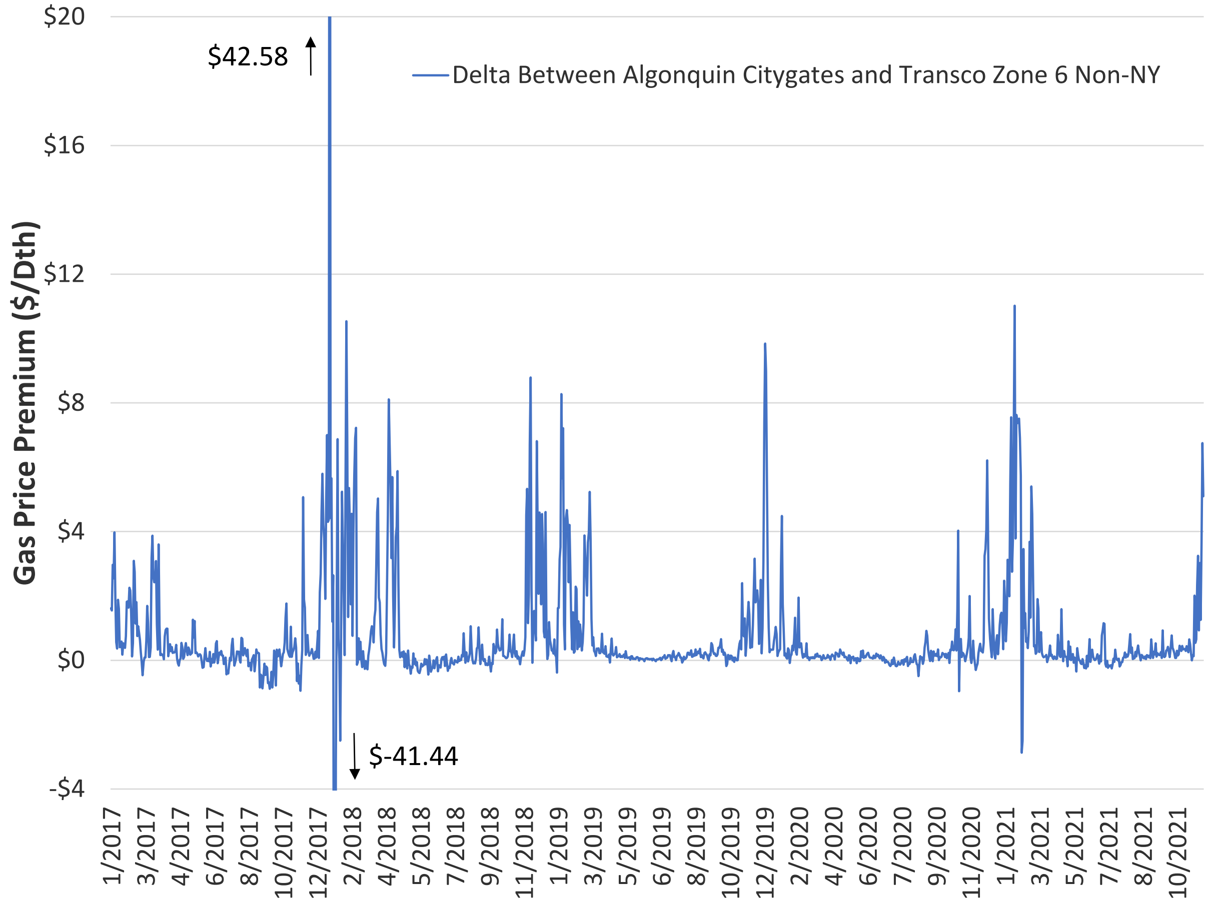
Despite primary delivery points in New Jersey and Southeastern Pennsylvania, the underlying capacity is not dedicated to these markets. Because entitlement holders retain the option to deliver to growing downstream markets for any capacity not under seasonal, annual or long-term contract(s), it is up to the LDCs in New Jersey, Southeastern Pennsylvania and Maryland to secure capacity to meet their obligation to serve in their territories.

Figure 1-4. Transco Zone 6 NY Price Premium over Transco Zone 6 Non-NY and Texas Eastern Transmission M3: 2017-2021



As shown in Figure 1-5, winter prices in New England are usually significantly higher than prices in New Jersey and Southeastern Pennsylvania, which makes New England a more attractive market for gas with flexible delivery points and a path that reaches into New England.

Figure 1-5. Algonquin Citygate Price Premium over Transco Zone 6 Non-NY: 2017-2021



Finally, in cases where a contract has multiple points with delivery rights that equal the total deliverability of the contract, the point-specific delivery rights are allocated to their respective locations, as shown in Table 1-5.

Table 1-5. Example: Contract with Discrete Capacity to Multiple Delivery Points

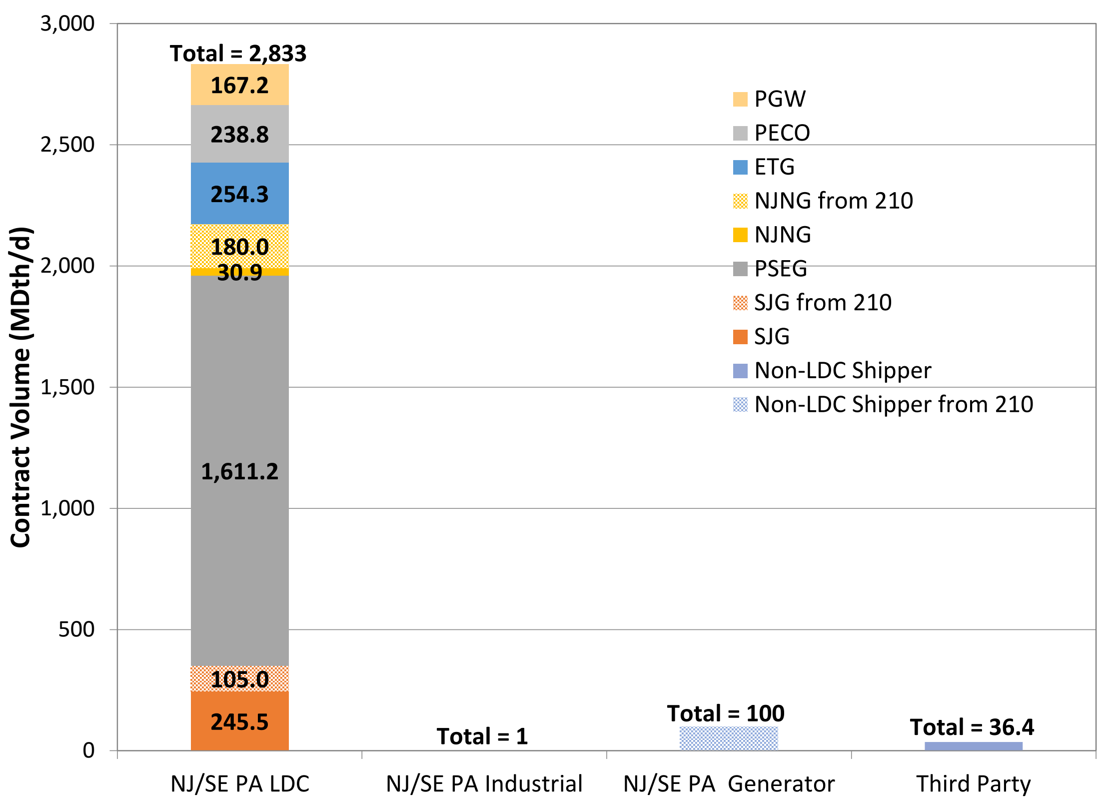
Shipper:	**Marketer**		
Point Type	**Point Location**	**Point Volume (MDth/d)**	**Point Location Considered Primary for Analysis?**
Receipt	Pennsylvania Production Field	50	Yes
Delivery	LDC Citygate in New Jersey	20	Yes
Delivery	LDC Citygate in New York	20	Yes
Delivery	Pipeline Interconnection in New Jersey	10	Yes

Lateral-only capacity is accounted for separately because it represents local short-haul capacity and does not provide access to gas supply. Firm contracts on laterals do not constitute a source of incremental deliverability supported by firm supply. Rather, lateral-only contracts are the funding mechanism for new pipeline laterals to be built without relying on subsidization from existing customers consistent with the FERC-established criteria for new pipeline facilities.[32]

Transco

Transco delivers more primary firm capacity to New Jersey and Southeastern Pennsylvania than any other pipeline operating in the study region, a total of 2,970 MDth/d, or about 3 Bcf/d. This does not include capacity delivered to Station 210, which is addressed separately below. LDCs located in Southeastern Pennsylvania and New Jersey hold 95% of this capacity, as shown in Figure 1-6. ETG, PSEG and SJG hold bundled storage and transportation contracts from Transco's 2-Bcf LNG storage facility in Carlstadt, NJ, which are included in the "NJ/SE PA LDC" category in Figure 1-6.[33] The "Third Party" category represents capacity held by marketers and producers, who can sell their capacity to other shippers through capacity releases, or sell delivered gas that bundles supply and transportation.

Figure 1-6. Transco Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania



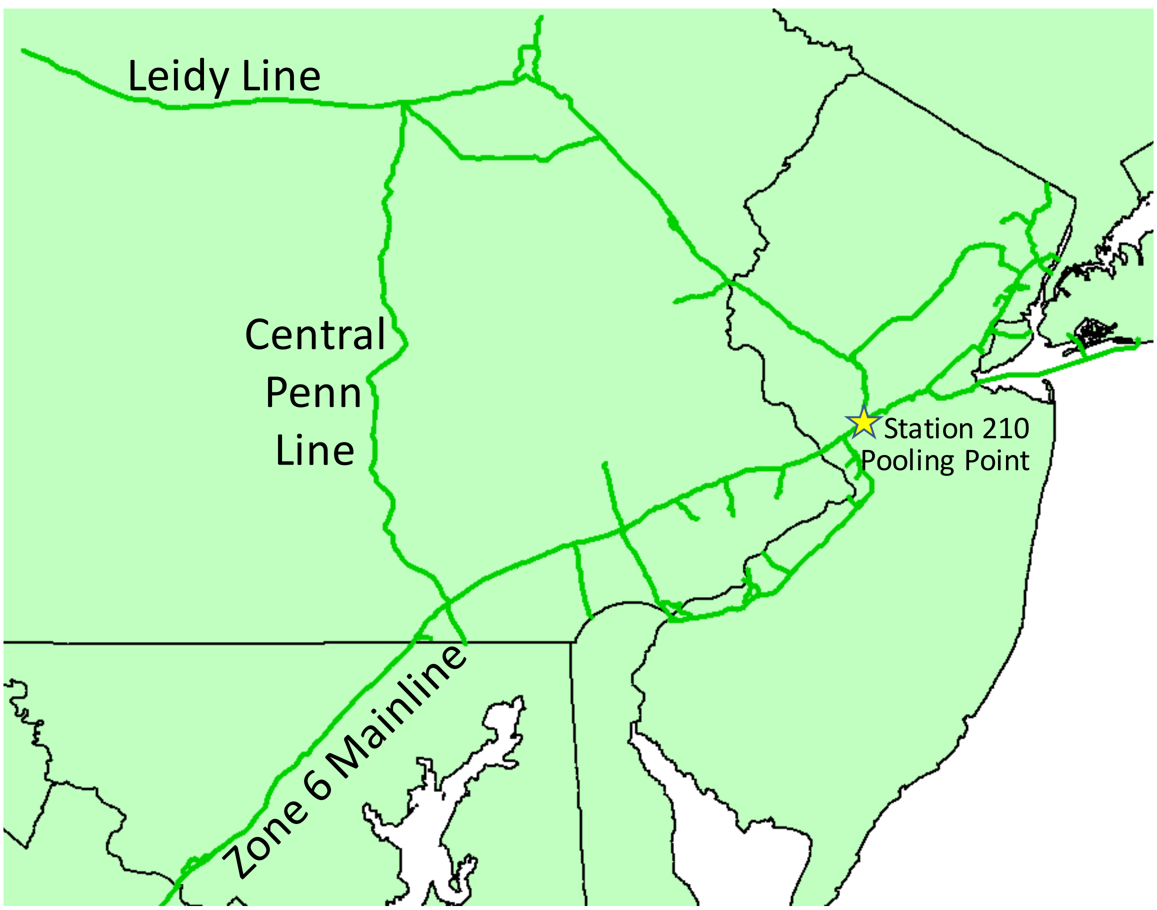
[32] Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227, corrected, 89 FERC ¶ 61,040 (1999), clarified, 90 FERC ¶ 61,128, further clarified, 92 FERC ¶ 61,094 (2000).

[33] Contracts held by ETG, PSEG and SJG represent 330 MDth/d of transportation capacity from the Carlstadt facility to delivery meters in New Jersey. Non-NJ LDCs hold an additional 69 MDth/d of bundled capacity deliverable from Carlstadt.

In addition to the capacity shown in Figure 1-6 above, Transco shippers hold 69 MDth/d of capacity deliverable to its interconnection with Algonquin in Centerville, NJ. Algonquin shippers hold 68 MDth/d of corresponding capacity sourced from Centerville, fully accounting for these delivered supplies. In addition to the capacity shown in Figure 1-6, Transco shippers also hold 535 MDth/d of lateral-only capacity deliverable to generators in New Jersey and Southeastern Pennsylvania.

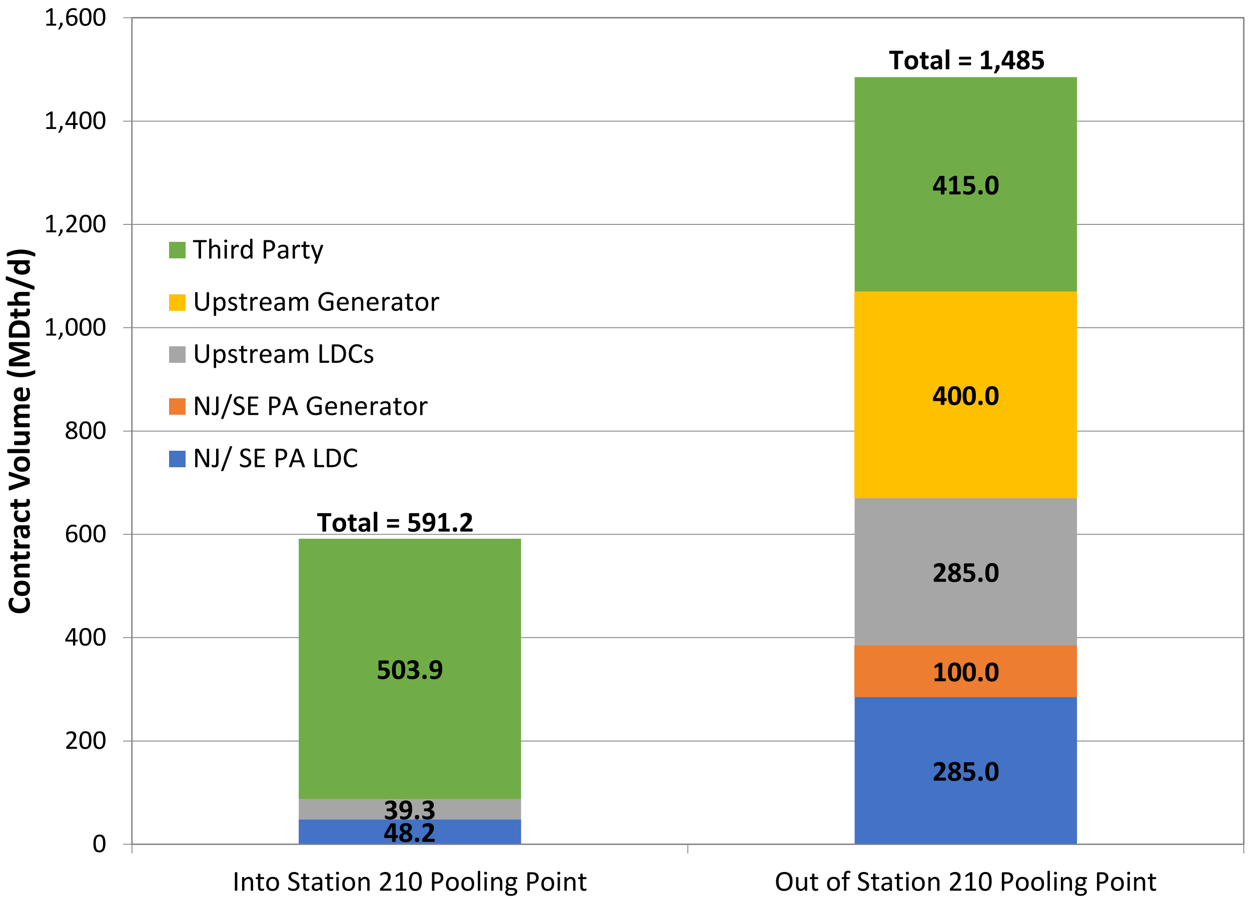
Access to gas supply is also an important consideration for capacity sourced from Transco's Station 210 pooling point, which includes the NJ/SE PA Generator capacity and 285 MDth/d of the NJ/SE PA LDC capacity in Figure 1-6. Pooling points on the Transco system represent locations where gas is aggregated and disaggregated among shippers. The Station 210 pooling point is located at the intersection of Transco's Leidy Line from storage fields and production in western Pennsylvania and the Zone 6 mainline between Maryland and New York City, as shown in Figure 1-7.

Figure 1-7. Transco Zone 6 System Configuration



Because there is no production or other local supply associated with the Station 210 pooling point, all gas contractually received at Station 210 must be transported from elsewhere on the Transco system before being aggregated in the pool. As shown in Figure 1-8, while Transco shippers have contracts with a portion of their paths passing through New Jersey, there are many more contracts that establish rights to receive gas from the pool than to deliver gas to the pool. Consequently, each shipper's ability to utilize capacity for deliveries out of Station 210 is limited by their respective holdings of contracted capacity with receipt at Station 210. Station 210 is therefore a key operational constraint point on the system. Even when capacity for receipts at Station 210 is made available, New Jersey's LDCs must compete for it with other shippers, including LDCs in *both* upstream and downstream markets on Transco's mainline on the eastern seaboard of the U.S.

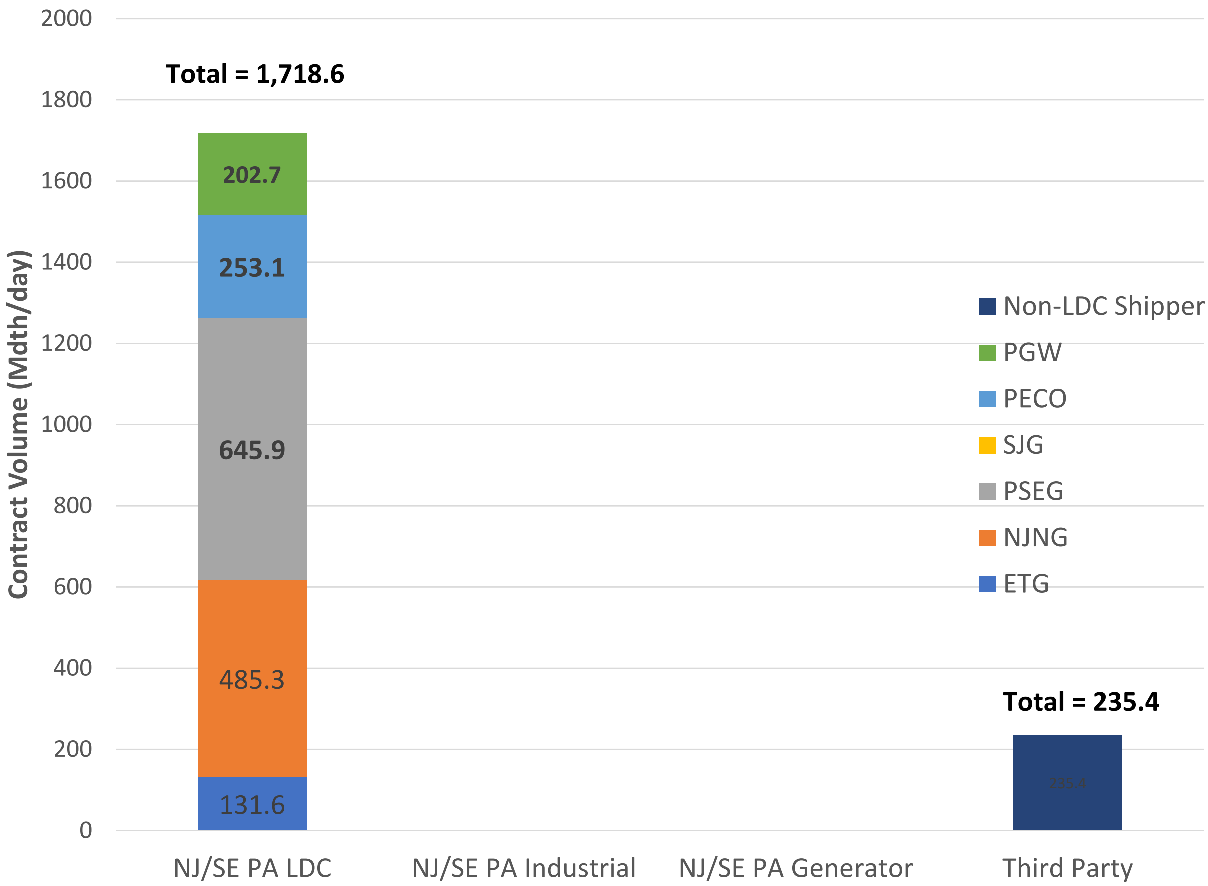
Figure 1-8. Transco Station 210 Pooling Point Contracts



Texas Eastern Transmission

The Texas Eastern Transmission system likewise represents a significant portion of New Jersey and Southeastern Pennsylvania's gas supply portfolio, transporting 1,954 MDth/d, or approximately 2.0 Bcf/d, of primary firm capacity to delivery points in the region. LDCs in New Jersey and Southeastern Pennsylvania hold 88% of this capacity, as shown in Figure 1-9.

Figure 1-9. Texas Eastern Transmission Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania



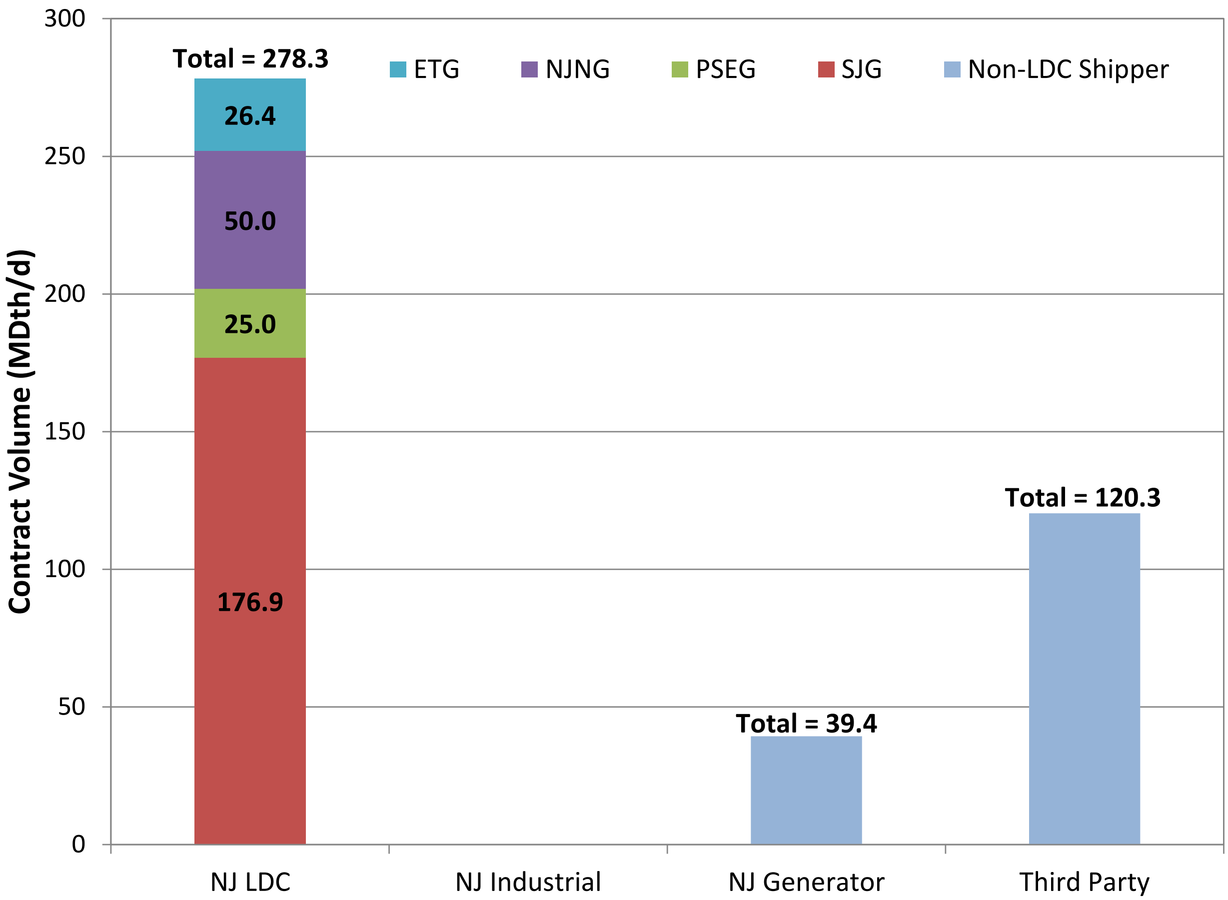
In addition to the capacity shown in Figure 1-9, Texas Eastern Transmission shippers hold 1,160 MDth/d deliverable to its Lambertville, NJ, and Hanover, NJ, interconnections with Algonquin Gas Transmission; 137 MDth/d of capacity deliverable to its Linden, NJ, interconnection with Transco; and 826 MDth/d of lateral-only capacity held by New Jersey LDCs, industrials and generators. Algonquin Gas Transmission shippers hold 1,056 MDth/d sourced from Lambertville and/or Hanover. 176 MDth/d of the Texas Eastern Transmission capacity deliverable to Algonquin has one or more additional primary delivery points. The remaining capacity deliverable to Algonquin Gas Transmission is potentially deliverable to New Jersey on a secondary basis, but competing downstream markets are also in the capacity path. The 136.5 MDth/d of capacity deliverable to the 1,300 MW combined cycle plant in Linden, New Jersey, is part of a bundled storage and transportation contract with transportation sourced from a Transco interconnection and is point specific. Its rate schedule type is not deliverable at any other points.[34] Moreover, Linden's lateral-only capacity does not include upstream transportation capacity or access to gas supply, and therefore does not represent incremental deliverability.

[34] Texas Eastern Transmission, L.P. FERC Gas Tariff, Second Revised Volume, No. 2, Part 4.5, Rate Schedule X-28.

Columbia Gas Transmission

The Columbia Gas Transmission system passes through Eastern Pennsylvania and has two laterals that deliver gas into New Jersey, but it does not have a direct connection with PECO or PGW. As a result of its limited footprint within the study region, it has significantly less capacity with primary firm delivery points in the region, as shown in Figure 1-10. New Jersey's LDCs hold 63% of this capacity.

Figure 1-10. Columbia Gas Transmission Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania

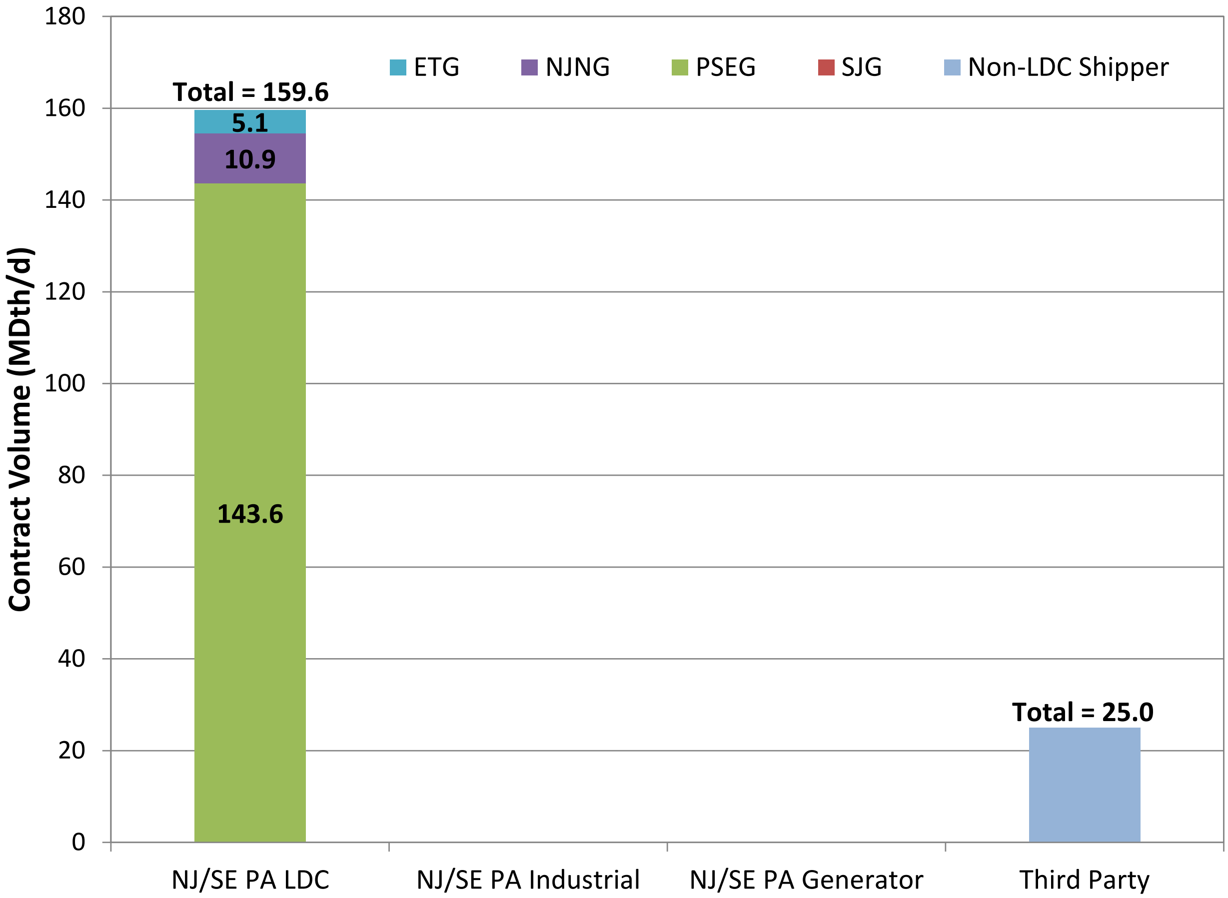


Columbia Gas Transmission's shippers additionally hold 53 MDth/d of contracted capacity with firm delivery to its interconnection with Algonquin Gas Transmission in Hanover, NJ. Algonquin Gas Transmission shippers hold 73 MDth/d of corresponding capacity sourced from the Hanover interconnection with Columbia to downstream delivery points in New York and New England.

Tennessee Gas Pipeline

New Jersey and Southeastern Pennsylvania's LDCs hold 86% of the Tennessee Gas Pipeline capacity with primary firm delivery points in the region, as shown in Figure 1-11.

Figure 1-11. Tennessee Gas Pipeline Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania

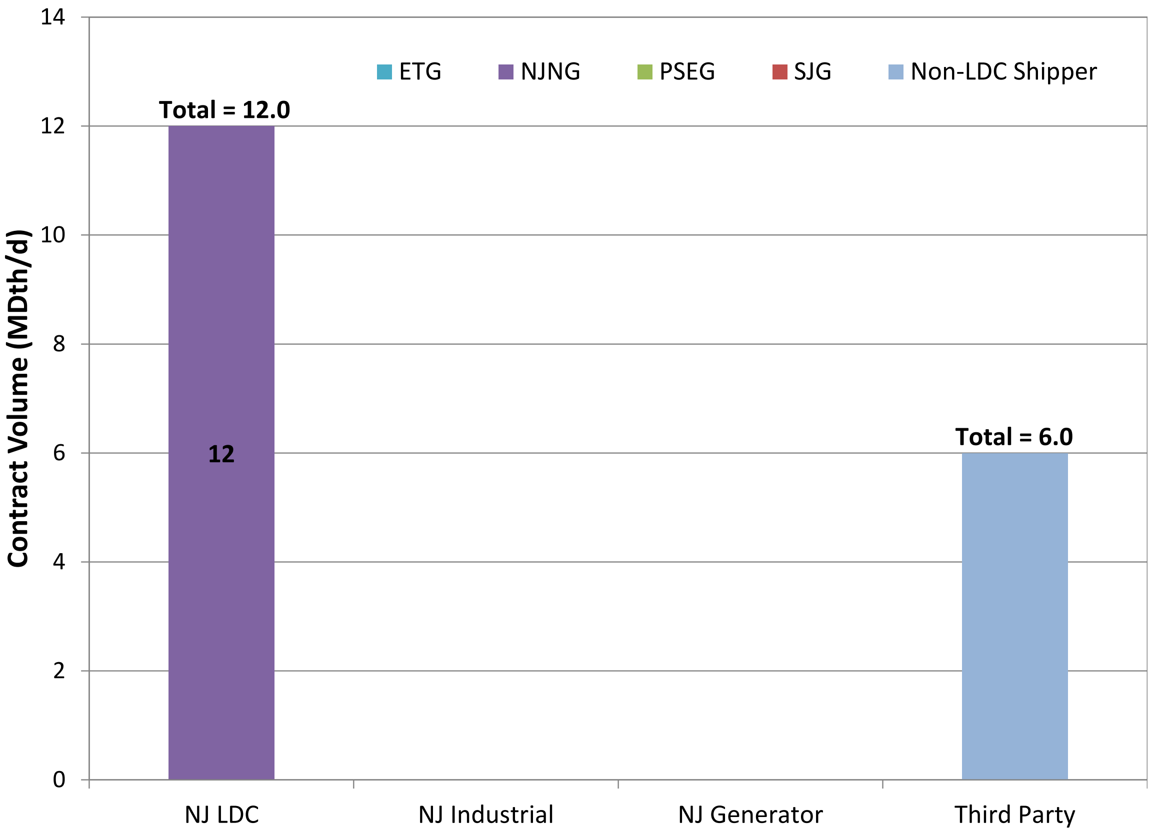


Tennessee Gas Pipeline shippers additionally hold 836 MDth/d of contracted capacity with firm delivery to Algonquin Gas Transmission at Mahwah and 116 MDth/d with firm delivery to Transco at Rivervale. The corresponding contractual receipts at these interconnections are 1,028 MDth/d and 72 MDth/d, respectively. All the capacity deliverable to Algonquin Gas Transmission has Mahwah as its only primary delivery point. Nearly all is sourced from points in Pennsylvania or Louisiana, resulting in a variety of available secondary delivery points. For the capacity deliverable to Transco, 18 MDth/d is sourced from LNG or a pipeline interconnection in New England. This amount is therefore deliverable on a secondary basis to New England, New York, or New Jersey.

Algonquin Gas Transmission

Algonquin Gas Transmission is primarily used to transport gas from pipeline interconnections in New Jersey, and to a lesser extent New York, to downstream markets in New York and New England. There are only two Algonquin Gas Transmission contracts with a primary firm delivery point in New Jersey and Southeastern Pennsylvania other than an interconnection, one held by NJNG and one held by a third-party marketer, as shown in Figure 1-12.

Figure 1-12. Algonquin Gas Transmission Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania

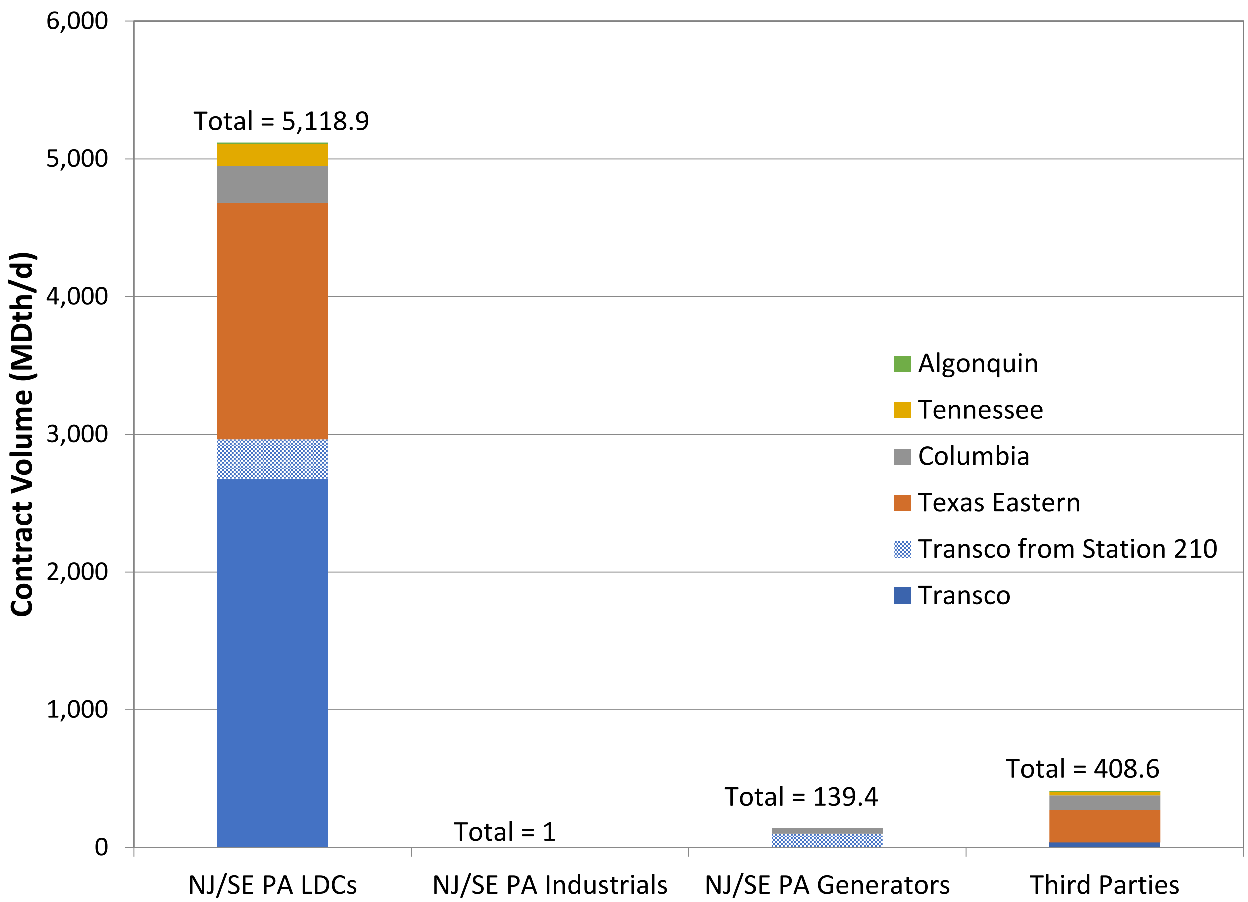


Algonquin Gas Transmission shippers additionally hold 246 MDth/d of capacity deliverable to interconnections: 27.5 MDth/d to Columbia Gas Transmission in Hanover, NJ, and 218.5 MDth/d to Texas Eastern Transmission in Lambertville, NJ. Columbia Gas Transmission shippers hold 18.5 MDth/d sourced from the Hanover interconnection, fully receiving the capacity delivered to the interconnection. Texas Eastern Transmission shippers hold 161 MDth/d sourced from Lambertville. The Algonquin Gas Transmission capacity delivered to Lambertville is sourced from LNG facilities at the east end of the Algonquin system. This means that New England is within the capacity path, and a more likely secondary destination for the capacity than New Jersey, given the pricing discussion above and the large amount of generation connected to the Algonquin Gas Transmission system.

Summary of Primary Firm Delivery Capacity in New Jersey and Southeastern Pennsylvania

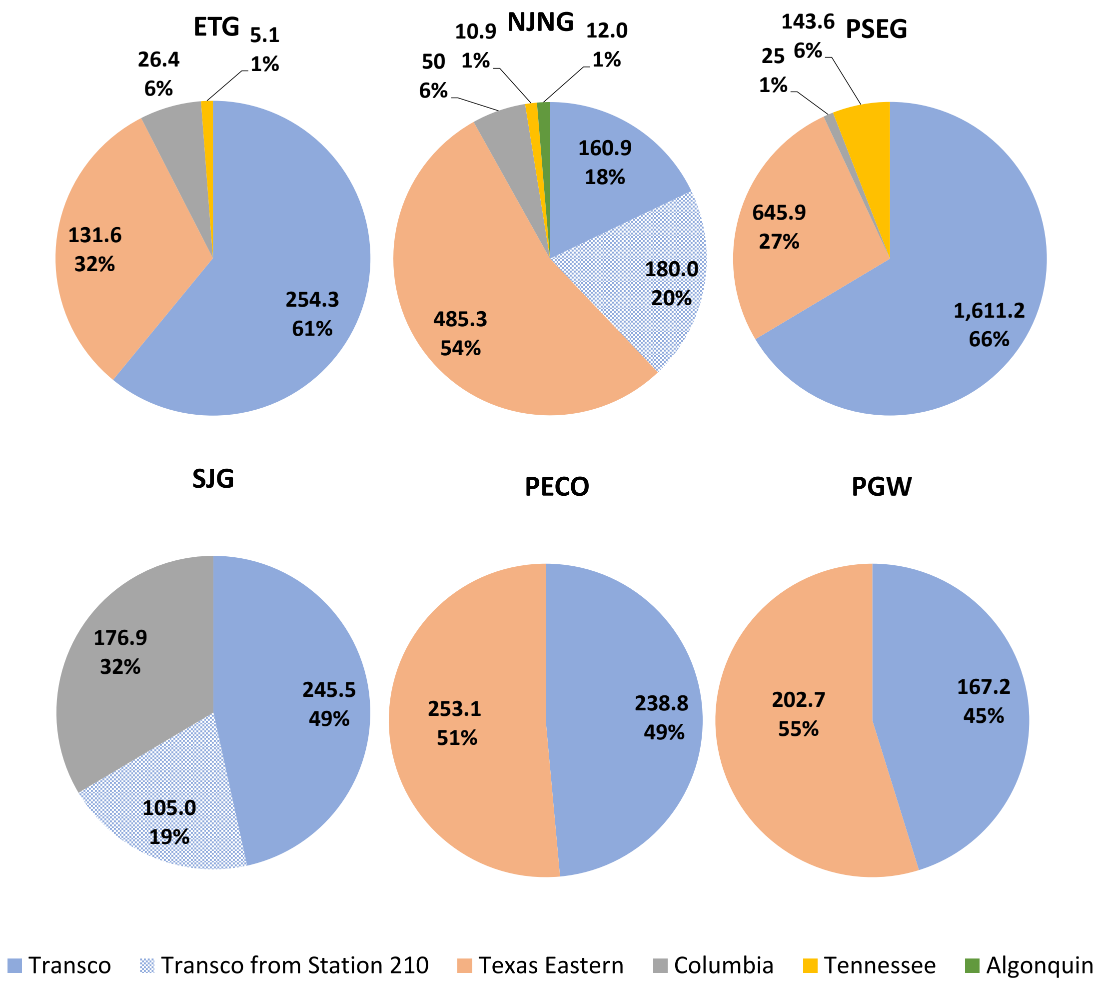
Figure 1-13 shows the total capacity contracted by each type of shipper to primary firm delivery points in New Jersey and Southeastern Pennsylvania. Of the 5,667 MDth/d with primary firm delivery in New Jersey and Southeastern Pennsylvania, 5,119 MDth/d, or 90%, is held by the LDCs in the study region. The capacity held by industrials and generators, 154 MDth/d in total, is deliverable to those shippers' specific delivery points and would thus not be available on a primary firm basis to the LDCs. Regardless of delivery point classification, those shippers are likely to be using their capacity fully on peak days. The availability of the third-party capacity to the LDCs is addressed in the following section.

Figure 1-13. Total Contracts with Primary Firm Delivery in New Jersey and Southeastern Pennsylvania



While there are five major interstate pipelines that serve New Jersey and Southeastern Pennsylvania, the locations of the pipelines relative to the LDC service territories result in each LDC having more than half of its capacity portfolio linked to a single pipeline – either Transco or Texas Eastern Transmission – as shown in Figure 1-14. All LDCs except SJG and PECO are dependent on Columbia Gas Transmission, Texas Eastern Transmission and Transco combined for more than 90% of their total contracted capacity. This dependence means that the LDCs are potentially susceptible to a pipeline maintenance or *force majeure* event that reduces system capacity or interrupts deliveries to a given point.

Figure 1-14. LDC Portfolios of Contracted Pipeline Capacity[35]



The figure also shows that Transco is the only pipeline that provides capacity to all six LDCs. An expansion of the Transco system, such as REAE, is therefore the only system expansion project that can provide incremental capacity to all shippers who have contracted for REAE capacity. Figure 1-14 also shows that contracting for REAE capacity will increase the diversity of NJNG's pipeline capacity portfolio, reducing NJNG's reliance on Texas Eastern Transmission. An added benefit of REAE capacity, in addition to meeting incremental demand, is that it will increase the study region's resilience when pipeline capacity is temporarily unavailable due to maintenance outages or other infrequent pipeline or storage disruptions. REAE will also provide reliability and system integrity benefits to NJNG by delivering firm capacity to NJNG's Southern Reliability Link

[35] NJNG's Transco capacity of 160.9 MDth/d includes both the 30.9 MDth/d reported in Figure 1-6 and the 130 MDth/d of capacity on Transco's Marcus Hook lateral discussed at page 69, below.

which would help to protect customers in Ocean, Burlington and Monmouth counties from the adverse effects of an interruption or limitation of deliveries to NJNG on TETCO.[36]

1.3 New Jersey and Southeastern Pennsylvania's LDCs Supplement Firm Pipeline Capacity to Meet Customer Needs

LDCs in New Jersey and Southeastern Pennsylvania Supplement Firm Pipeline Capacity with On-System Peaking Resources and Third-Party Supplies

An on-system peaking facility consists of LNG or propane storage tanks, vaporizers to convert the LNG or propane from liquid to gas and a connection to the local distribution system where the vaporized natural or propane gas can be injected. In New Jersey and Southeastern Pennsylvania, the larger on-system LNG peaking resources have liquefaction capacity onsite, while trucks deliver propane and LNG to smaller on-system LNG peaking resources. Historically, LDCs have not assumed that on-system peaking resources can be refueled by trucks under design-day conditions due to the risk that "transportation could be impacted by multiple events (e.g., road/bridge closures due to automobile accidents or construction, high winds, and inclement weather) with the risk of a customer service interruption if supply cannot be delivered on-time to meet the demand."[37]

New Jersey and Southeastern Pennsylvania's LDCs Utilize On-System Peaking Resources to Supplement Contracted Pipeline Capacity

Each of the six New Jersey and Southeastern Pennsylvania LDCs operates one or more on-system peaking facilities to support meeting supply needs on peak days. Each of these "peak shaving" facilities combines onsite storage of LNG or propane with liquefaction capacity and the ability to inject gas into an LDC system behind the citygate. Because of their onsite storage capacity peak shaving facilities are not impacted by pipeline constraints. All peaking facilities are subject to limited onsite storage capacity amounting to between one day and two weeks of sendout, depending on the facility. Replenishment logistics during the heating season may not be feasible during cold snaps. These facilities are listed in Table 1-6, along with their current design day sendout capabilities. PECO has begun work to increase the sendout capability of its West Conshohocken facility from 160 MMcf/d to 220 MMcf/d with a planned in-service date in the fourth quarter of 2022.[38]

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[36] Transcontinental Gas Pipe Line Company, LLC, Service Agreement Containing Non-Conforming Provisions, Docket No. RP21-800-000 April 30, 2021. New Jersey Board of Public Utilities, Order in Docket No. GO15040403, "In The Matter of the Petition of New Jersey Natural Gas Company for Determination Concerning the Southern Reliability Link Pursuant to N.J.S.A. 40:55D-19, dated March 18, 2016, https://www.state.nj.us/bpu/pdf/boardorders/2016/20160318/3-18-16-2C.pdf.

[37] https://www.nationalgridus.com/media/pdfs/other/aquidneckislandlong-termgascapacitystudy.pdf, page 35.

[38] https://www.peco.com/SiteCollectionImages/PECO%20Statement%20No.%202%20%28Carlos%20Thillet%29.pdf page 143.

Table 1-6. New Jersey and Southeastern Pennsylvania LDC On-System Peaking Facilities

LDC	Facility	Facility Type	Design Day Sendout Capability (MDth/d)
ETG	On-system LNG	LNG	25
NJNG	Howell	LNG	150
NJNG	Stafford	LNG	20
PSEG	Burlington	LNG	82
PSEG	LPG Total	Propane	199.7
SJG	McKee City	LNG	75[39]
PGW	Passyunk and Richmond	LNG	200[40]
PECO	West Conshohocken	LNG	156
PECO	Chester	Propane	25
		Total	932.7

New Jersey and Southeastern Pennsylvania's LDCs Utilize Third-Party Supplies to Supplement Contracted Pipeline Capacity

LDCs often supplement their storage and pipeline entitlements with third-party supplies purchased under monthly or seasonal contracts. Under New Jersey's retail choice program, the NJ LDCs also allow third-party supplies to serve local customers that elect to switch from the LDC. Third-party suppliers with customers in an LDC's territory must arrange for the delivery of gas to the LDC citygate. The third-party supply components listed in each LDC's filing for the 2021-22 design day are shown in Figure 1-15 relative to the capacity held by third parties with primary firm delivery points in New Jersey and Southeastern Pennsylvania, including those with alternative primary points in New York. The LDC third-party supplies shown in Figure 1-15 include LDCs' planned seasonal and spot market purchases and volumes arranged for third party suppliers with customers in the LDC territory.

The differential between the capacity held by third parties with primary firm delivery in New Jersey and Southeastern Pennsylvania and the LDCs' planned 2020-21 third party supplies is the result of planned spot market purchase arrangements for capacity which has primary delivery outside of the region to be delivered to New Jersey and Southeastern Pennsylvania on a secondary basis.[41] Again, secondary capacity has a lower scheduling priority than primary capacity and is differentiated by whether it is in-the-path (between the primary receipt and

[39] Corresponds to 110 MDth/d prorated to 20 hours of sendout.

[40] 200 MMcf of PGW's LNG is reserved to meet design day requirements, the remainder of PGW's 1.8 Bcf of annual liquefaction capacity is used to make interruptible LNG sales and displace higher priced winter supply options. https://kleinmanenergy.upenn.edu/wp-content/uploads/2020/08/PGW-LNG-Expansion-Efforts-FINAL-2-1.pdf; and https://www.pgworks.com/uploads/pdfs/GCR_2021-2022_-_Pre-Filing_Volume_2.pdf.

[41] South Jersey Resources Group, LLC ("SJRG"), a gas marketer that has entered into a precedent agreement for firm REA capacity, has indicated that it has "over 100,000 dt/day of firm commitments off the Transco system. However, SJRG currently has only 71,400 Dth/d. SJRG's participation in the Project will increase its overall capacity by 30,000 Dth/d and will allow SJRG to meet its firm obligations year-round." SJR's Motion for Leave to Intervene and Comments in Support of SJR Resources Group, LLC, Docket No. CP21-94-000, April 30, 2021, page 5.

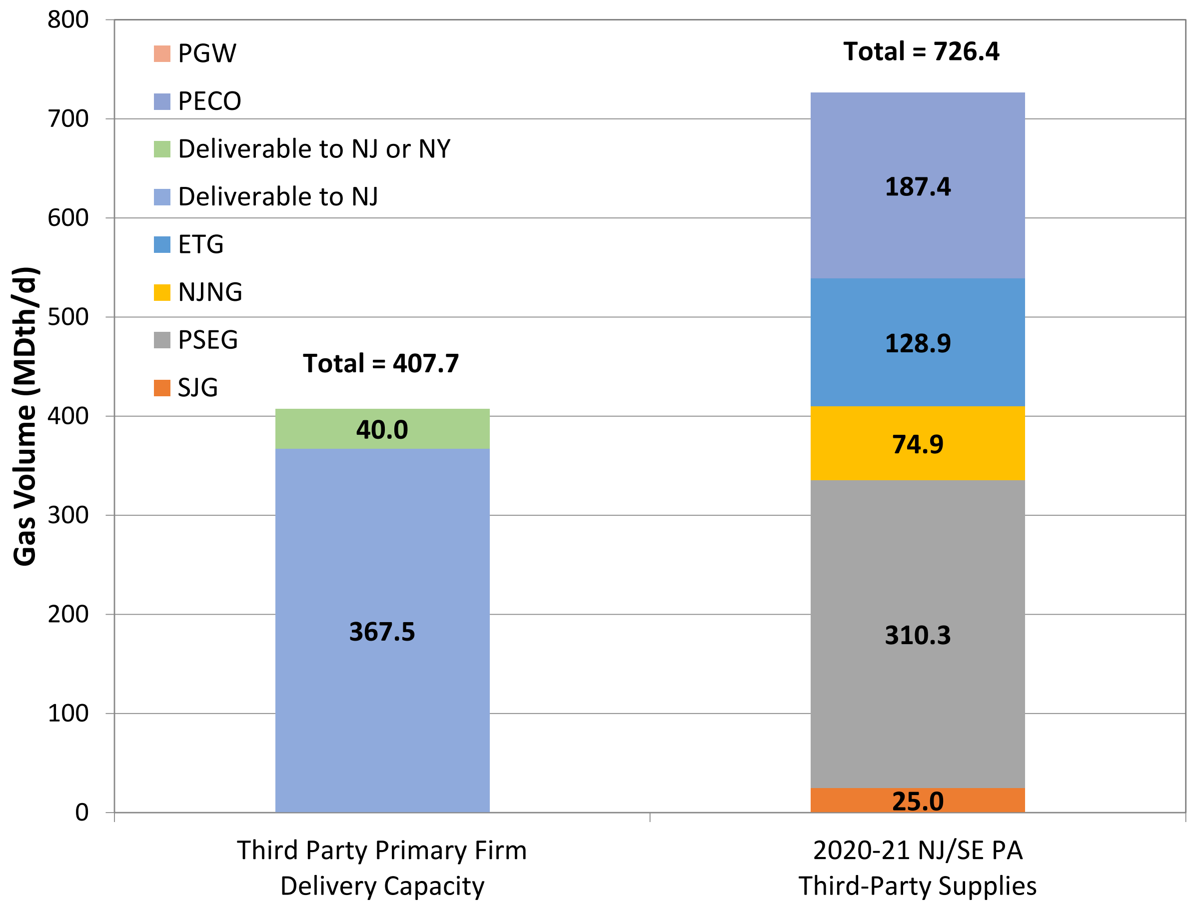
delivery points) or out-of-the-path. Secondary in-the-path has a higher scheduling priority than secondary out-of-the-path, but a lower priority than primary and is therefore subject to scheduling risk under high utilization conditions. The LDCs are not the only entities participating in the market for these supplies. Even within New Jersey and Southeastern Pennsylvania, there is competition from other entities for capacity with primary delivery in the region.

As shown in Figure 1-13 on page 30, generators in New Jersey and Southeastern Pennsylvania hold limited firm transportation capacity. They are therefore dependent on third parties to meet their supply needs.[42] Price spikes, such as those that have been seen in New Jersey, Southeastern Pennsylvania, New York and New England during cold weather or other periods of high demand and/or limited supply, are indicative of constrained pipeline infrastructure. LDCs, generators and other end users may scramble for discretionary tranches to support an LDC's obligation to serve or to help shield a generator in PJM or ISO-NE from costly penalties under Capacity Performance or Pay-for-Performance, respectively.

Robust competition among market participants requires the LDCs to likewise compete for third party supplies, either within the study region or with downstream shippers. Simply put, the LDCs cannot rely on the capacity unless and until a deal has been struck. Regardless of potential LDC willingness to pay, the outcome of such competition cannot be known *a priori* without parallel awareness of other market participants' willingness to pay.

[42] PJM's Capacity Performance (CP) attributes that are part of the Base Residual Auction pricing framework covering capacity resources can induce generators in New Jersey to incur a price premium to foster eligibility under CP. See, https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/cp-performance-assessment-intervals.ashx#:~:text=PJM%20implemented%20Capacity%20Performance%20to,Polar%20Vortex%20of%20winter%202014.

Figure 1-15. New Jersey and Southeastern Pennsylvania LDC Third-Party Supply Portfolio



1.4 LDCs in New Jersey and Southeastern Pennsylvania Cannot Rely Upon Capacity Contracted to Downstream Markets

Just as capacity contracted by industrials and generators in New Jersey and Southeastern Pennsylvania is not available on a primary firm basis to LDCs in the region, capacity contracted to delivery points downstream cannot be relied upon by LDCs in New Jersey and Southeastern Pennsylvania. Capacity under contract to marketers and other third parties may be available, but LDCs in the region would need to compete for discretionary tranches from liquid sourcing points, pooling points, or at citygates representing secondary delivery points along the primary contract path. Like New Jersey LDCs, LDCs in New York and New England have the same obligation to serve and so must ensure that their supply portfolios are sufficient to meet design day demand. To varying extents, these LDCs also rely on third-party peaking deals deliverable to their service territories, as do downstream generators subject to Commission-approved wholesale electric price incentives designed to improve fuel security in PJM, NYISO and ISO-NE by raising generators' willingness to pay.

Nearly all of the pipeline capacity passing through New Jersey and Southeastern Pennsylvania is under contract to LDCs and third parties that have primary firm delivery points in downstream markets. Generators in New Jersey, Southeastern Pennsylvania, downstate New York and New

England are largely reliant on secondary firm or interruptible transportation and therefore do not hold significant primary firm capacity in their own names.[43] Just as volumes with primary firm delivery in the study region are unavailable to LDCs and generators in upstream markets, this capacity with primary firm delivery in downstream markets is unavailable to the study region LDCs when downstream shippers are using it, even though the gas must flow through Pennsylvania and New Jersey to reach its destination. This is because pipelines will curtail secondary firm and interruptible deliveries to upstream points, including LDCs, if needed to prevent the denigration of firm transportation services provided to downstream customers.

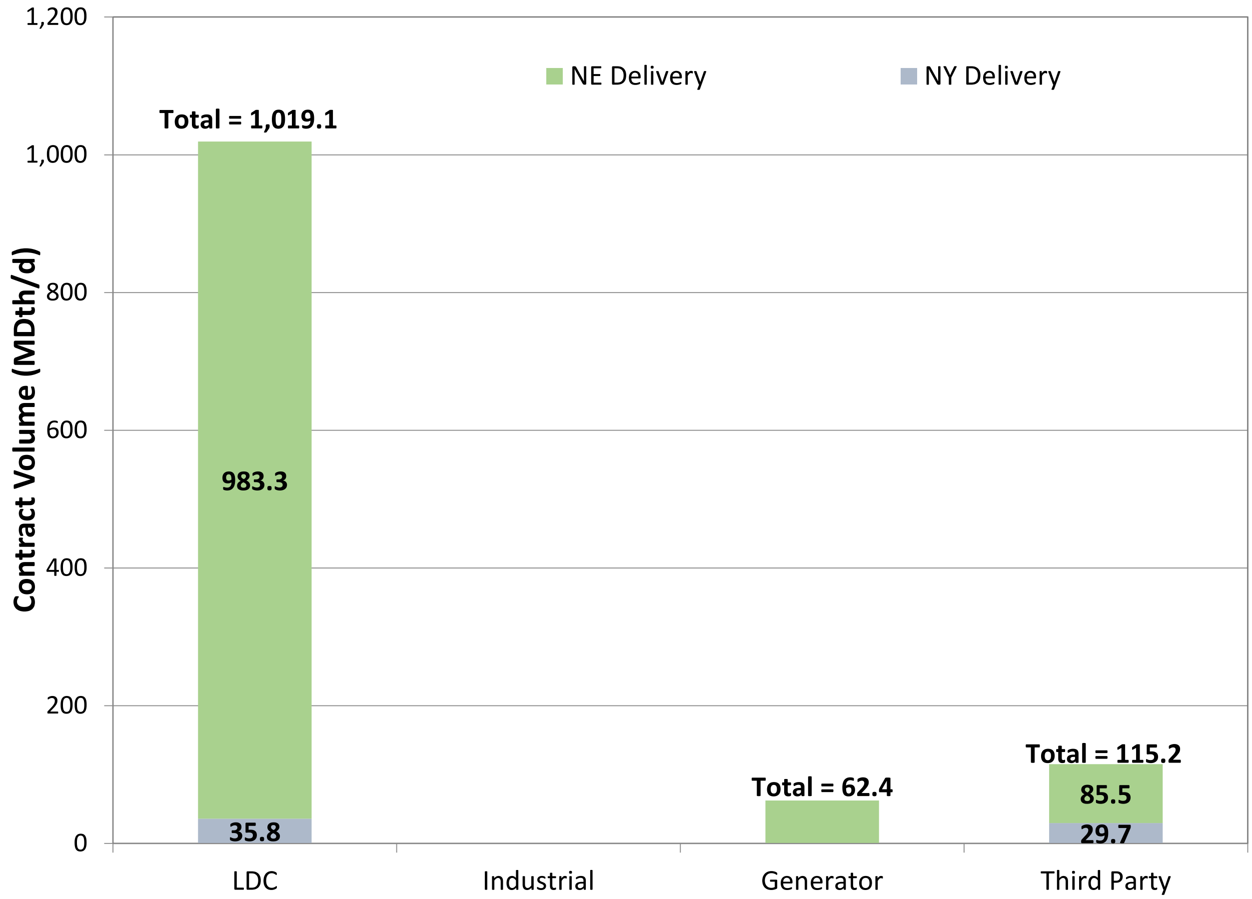
While third-party capacity may not be fully utilized in the downstream markets where the contract holder has primary delivery rights, the New Jersey LDCs represent only a subset of the potential secondary delivery points for the capacity. As previously addressed, competitive market phenomena and growing population centers along the system render uncertain and therefore unsafe any anticipated reliance by LDCs on third party capacity absent a confirmed supply arrangement.

[43] ISO-NE, 2021 Regional System Plan, November 2, 2021, page 12, https://www.iso-ne.com/static-assets/documents/2021/11/rsp21_final.docx "The majority of New England natural gas generators do not have firm gas contracts, and typically buy gas in the spot market. This has become an issue in the winter when gas supply available for generation is reduced by home heating natural gas demands." EIPC, Electric System Interface Study Existing Natural Gas-Electric System Interfaces, DOE Award Project DE-OE0000343, Final Draft, April 4, 2014. pp. ES-17 to ES-18. https://eipconline.com/s/73-Report-Final.pdf.

Algonquin Gas Transmission

Capacity held by Algonquin Gas Transmission shippers with receipt points in New Jersey and primary firm delivery points in New York and New England is shown in Figure 1-16. LDCs hold 90% of this capacity.

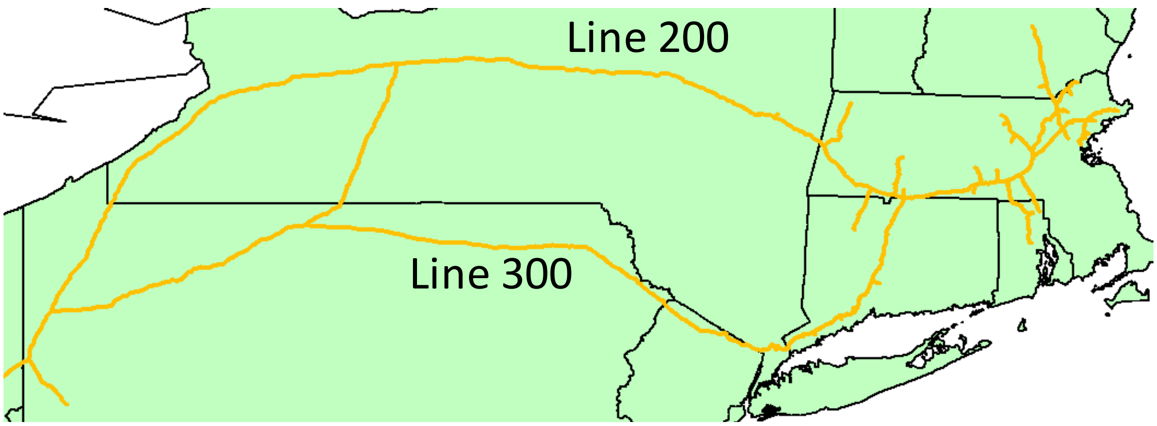
Figure 1-16. Algonquin Gas Transmission Contracts with Primary Firm Delivery in New York or New England



Tennessee Gas Pipeline

The Tennessee Gas Pipeline system has two west-to-east paths transporting gas between western Pennsylvania and New England, as shown in Figure 1-17. The northern path through upstate New York is Line 200. The southern path through Pennsylvania, New Jersey and downstate New York is Line 300. The path associated with a particular contract is based on the locations of the receipt and delivery points. With the exception of contracts sourced on Line 300 in eastern Pennsylvania, New Jersey, New York, or Connecticut, deliveries to Massachusetts, Rhode Island and New Hampshire are via Line 200, and do not pass through New Jersey and Southeastern Pennsylvania.

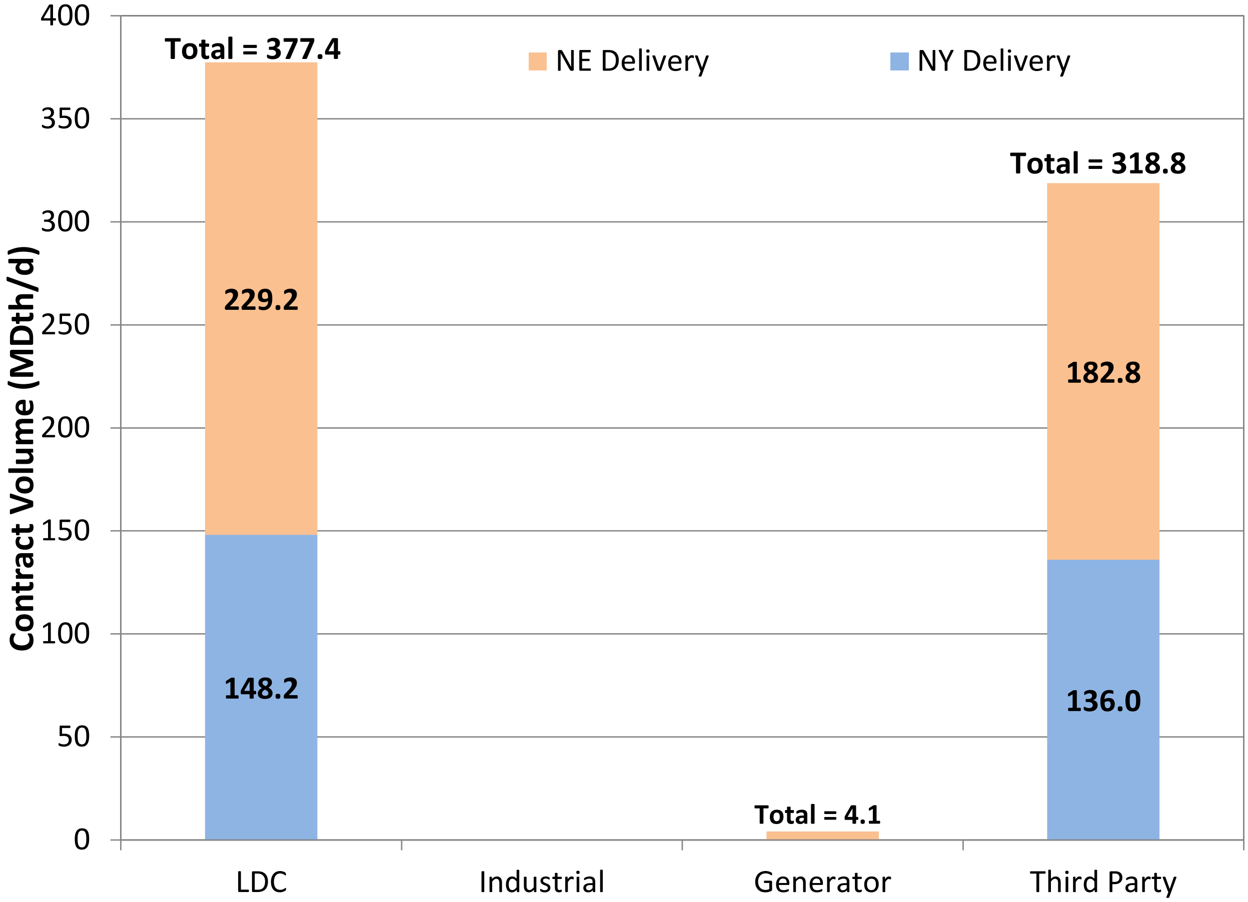
Figure 1-17. Tennessee Gas Transmission Paths Between Western Pennsylvania and New England



As identified based on Tennessee Gas Transmission's pathing rules, capacity held by Tennessee Gas Transmission shippers that uses the Line 300 path across northern New Jersey and has primary firm delivery points in New York and/or New England is shown in Figure 1-18.[44] LDCs in New York and New England hold 54% of this capacity.

[44] As posted to Tennessee Gas Transmission's informational postings: https://pipeline2.kindermorgan.com/Documents/TGP/Pathing_Rules-20210713070609.pdf (updated 7/13/2021).

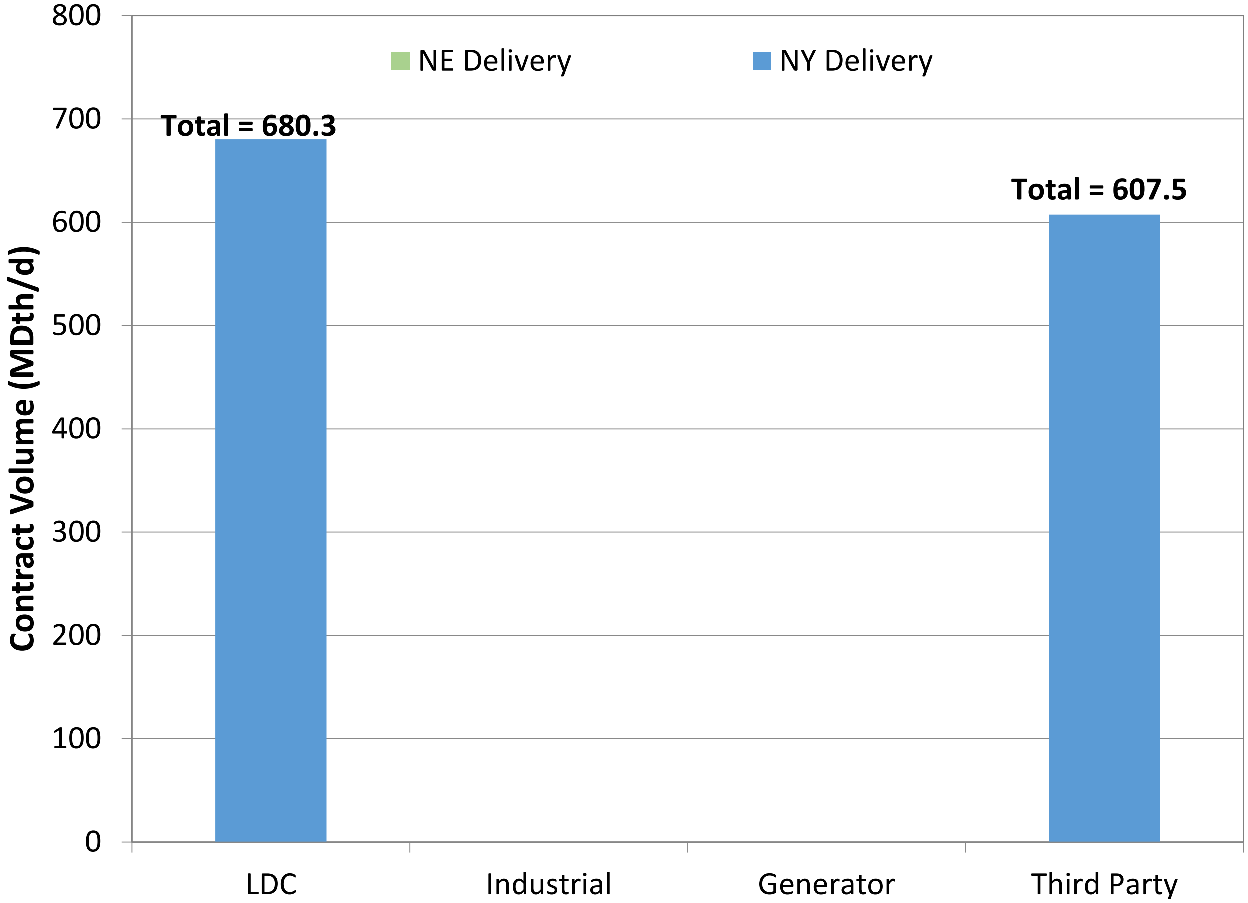
Figure 1-18. Tennessee Gas Transmission Line 300 Contracts with Primary Firm Delivery in New York or New England



Texas Eastern Transmission

Capacity held by Texas Eastern Transmission shippers with primary firm delivery points in New York is shown in Figure 1-19. New York LDCs hold just over 50% of this downstream capacity.

Figure 1-19. Texas Eastern Contracts with Primary Firm Delivery in New York[45]

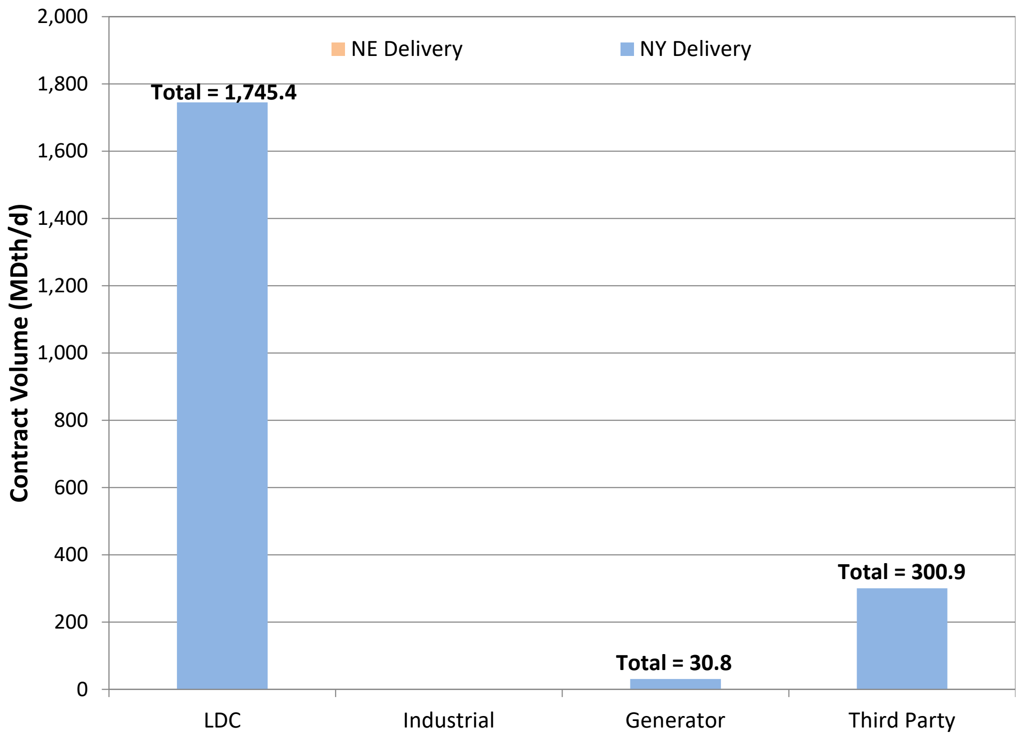


[45] Most capacity rights held by third parties – 582.5 MDth/d of 607.5 MDth/d – have a primary firm delivery point in Manhattan, and were added as part of the New Jersey-New York Expansion Project in November 2013. Peak deliveries to the Manhattan delivery point have been less than 500 MDth/d, relative to 800 MDth/d capacity, due to limited receipt capacity at the Con Edison side of the delivery meter.

Transco

Capacity held by Transco shippers with primary firm delivery points in New York is shown in Figure 1-20. New York LDCs hold 84% of this downstream capacity.

Figure 1-20. Transco Contracts with Primary Firm Delivery in New York



1.5 Existing Pipeline Capacity Deliverable to New Jersey and Southeastern Pennsylvania is Insufficient to Meet Forecasted Gas Demand

Again, as illustrated in Section 1.4, not all pipeline capacity in New Jersey and Southeastern Pennsylvania is earmarked for LDCs in the study region. On the contrary, a substantial portion is not available to New Jersey and Southeastern Pennsylvania's LDCs because it is contracted by other end users. To build a supply portfolio sufficient to meet design day demand, the LDCs are therefore reliant on their own contracted capacity, on-system peaking sources, and third-party supply arrangements.

Figure 1-21 shows the existing capacity held by LDCs and third parties with primary firm delivery in New Jersey and Southeastern Pennsylvania relative to the aggregated peak day demand forecast.[46] This analysis implicitly assumes that all third-party capacity with delivery in New Jersey and Southeastern Pennsylvania will be available to meet LDC design day demand, e.g., under

[46] The third party primary firm capacity, shown in grey in the Existing Capacity Primary to NJ/SE PA stack, is the amount of capacity held by third parties with primary delivery points only in New Jersey. It does not include capacity which is alternatively deliverable to New York, or capacity without primary delivery points in New Jersey that has been reserved by the LDCs (and LDC customers) through negotiation with third party suppliers.

short-term peaking contracts or through spot market purchases of gas delivered to the city gate. Because of the short-term nature of these contracts and spot market purchases, they can be very costly as LDCs in the region must compete for these supplies with other market participants, including gas-fired generators and downstream LDCs. For example, ETG and SJG have explained that they "must contract each winter for incremental supplies of peaking gas to ensure their ability to serve peak demand and peak hour demands … However, the availability of peaking supplies has tightened considerably in the last five years and the costs of incremental peaking supplies has increased significantly."[47] REAE capacity will allow its LDC customers to lower their costs by purchasing lower-priced Marcellus Shale gas at Leidy instead of peaking contracts or spot market purchases deliverable to the citygate. As NJNG has explained, REAE capacity "eliminates peak day shortfalls projected over the next ten years and provides access to attractive supply basin pricing."[48]

The horizontal dashed line compares the 2021-22 design day supply to the design day demand forecast. Each year's design day shortfall relative to existing capacity is shown in Table 1-7. As discussed above, LAI has developed three demand scenarios for the post-2030 period. The High Demand scenario assumes "business-as-usual," in which post-2030 design day demand growth follows the trend set by the LDCs' design day forecasts. The Low Demand scenario assumes no growth in LDC customer demand in New Jersey and Southeastern Pennsylvania after 2030 as a result of building electrification driven by new state and federal GHG emission regulations. The Average Demand scenario is an average of the other two scenarios and assumes that new state and federal GHG emission regulations reduce, but do not eliminate post-2030 growth. The supply shortfall in 2038-39 shown in Figure 1-21 represents the High Demand scenario, the 2038-39 shortfalls for the Average Demand and Low Demand scenarios are shown in Table 1-1.

[47] SJI Utilities, October 22, 2019, Comments of South Jersey Gas Company and Elizabethtown Gas Company filed in In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1221782, page 4.

[48] NJNG BGSS Filing, Pre-Filed Direct Testimony and Exhibits of Jayana S. Shah, page 8:28-29.

Figure 1-21. Supply/Demand Comparison for New Jersey and Southeastern Pennsylvania LDCs

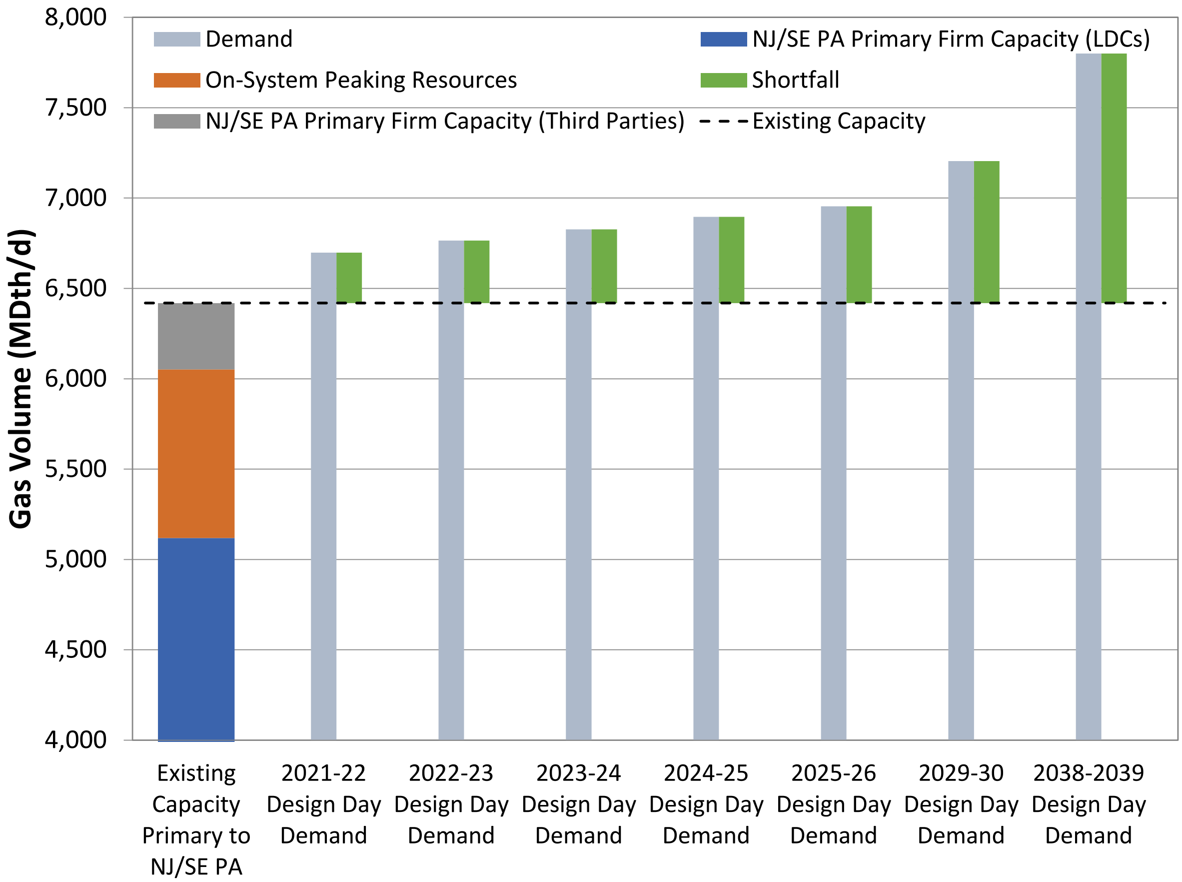


Table 1-7. Supply Shortfall to Meet Forecasted Demand

Demand Scenario	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2029-30**	**2038-39**
High							1,345.6
Average	278.8	345.2	407.5	476.8	534.7	774.4	1,060.0
Low							774.4

These values assume that all third-party capacity with primary firm delivery in New Jersey and Southeastern Pennsylvania is available to LDCs, and that supply can be procured to support all LDC-held transportation capacity, including that sourced from the Transco Station 210 pooling point. If either of these assumptions does not hold, the capacity shortfall would increase accordingly. The size of the shortfall in the later years of the forecast depends on the timing and scale of building electrification in New Jersey and Southeastern Pennsylvania driven by new state and federal GHG emission regulations. However, the high costs and absence of existing policies incentivizing building electrification create significant uncertainty regarding the timing and scale of building electrification. The cost of converting from natural gas-fired heat to an electric heat pump system represents a substantial barrier to adoption, with estimated costs of $22,000 per residence for air-source heat pump systems and even higher for ground-source.[49] In addition, building electrification would lead to significant increases in electricity demand, and reliably meeting this increase in demand would require much investment in primary and secondary distribution capacity upgrades, as well as generation and transmission capacity infrastructure in order to accommodate electrification goals in New Jersey and Southeastern Pennsylvania. LAI has not attempted to estimate the size of this investment due to the timing considerations and key uncertainty factors. One 2020 study found that 95% of distribution transformers would need to be upgraded just to meet the increased demand from electrification of single-family residences.[50] Another study estimated that U.S investment costs for residential electrification for 2023-2035 could range from $155 to $456 billion.[51]

Coupled with the lack of available existing capacity, the capacity shortfall results indicate that new gas infrastructure will be needed if the LDCs are to meet expected customer demand growth while maintaining system reliability.

1.6 Project Alternatives are Insufficient to Meet Forecast Demand in NJ and SE PA

Newly Built and Expanded Pipeline Capacity

As discussed above, no unsubscribed firm capacity deliverable to New Jersey and Southeastern Pennsylvania is currently available. Therefore, potential alternatives to REAE consist of newly built and expanded pipelines with unsubscribed firm capacity deliverable to New Jersey and Southeastern Pennsylvania. Potential alternative sources of supply were identified by reviewing the EIA's database of natural gas pipeline projects for projects in Pennsylvania, New Jersey, and New York that have a status of Announced, Applied, Approved, Construction, Pending Pre-Applied, and Requested in Service.[52] As shown in Table 1-8 there are twelve pipeline projects that meet the criteria, not including REAE.

[49] Diversified Energy Specialists, Case Study Massachusetts Air-Source Heat Pump Installations 2014-2019, November 19, 2019, https://www.senatenj.com/uploads/DES-Heat-Pump-Study-NORA.pdf.

[50] City of Palo Alto Utilities Advisory Commission, Discussion of Electrification Cost and Staffing Impacts on the City of Palo Alto's Electric and Gas Distribution Systems, November 4, 2020, https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilities-advisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2020/11-04-2020-special/id-11639-item-no-3.pdf, page 4.

[51] AGA, Implication of Policy-Driven Residential Electrification, July 2018, https://www.aga.org/globalassets/research--insights/reports/aga_study_on_residential_electrification.pdf, page 7.

[52] Projects listed as "On Hold" were not included in the review.

Table 1-8. Pending and Approved Pipeline Projects in PA, NJ, and NY[53]

Project Name	Status	State(s)
Adelphia Gateway Project	Construction	PA
East 300 Upgrade Project	Pending	PA, NJ
Iroquois Enhancement by Compression Project	Applied	NY, CT
Leidy North Project	Approved	PA, NY
Marcus Hook Electric Compression Project	Pending	PA
Mid-Atlantic Chiller Project	Applied	PA, VA
Supply Header Project	Construction	PA, WV
Tri-State Corridor Project	Pending	PA, WV
Yorktown Meter Station Upgrade	Construction	NY

In LAI's view, none of these projects represent viable alternatives to REAE. Each project is either fully subscribed or does not create incremental capacity deliverable to New Jersey or Southeastern Pennsylvania.

Three projects are fully subscribed:

- Tennessee Gas Pipeline's East 300 Upgrade Project is designed to create 115 MDth/d of firm capacity on the 300 Line and is fully subscribed under a binding precedent agreement with Con Ed.[54]
- Iroquois Gas Transmission System's Enhancement by Compression Project is designed to provide 125 MDth/d of firm capacity to the New York City metropolitan area, 62.5 MDth/d for Con Ed and 62.5 MDth/d for National Grid.[55]
- The Marcus Hook Electric Compression Project is designed to provide an additional 16.5 MDth/d of firm natural gas capacity from the Adelphia's interconnection with Texas Eastern Transmission in Bucks County, PA to the interconnection with Columbia Gas Transmission in New Castle County, DE under a firm transportation service agreement with South Jersey Gas.[56]

Six projects will not create capacity deliverable to New Jersey or Southeastern Pennsylvania:

- The Adelphia Gateway Project is designed to transport natural gas across Pennsylvania from Northampton County to interconnects with Columbia Gas Transmission, Texas

[53] Applied and approved projects reflect https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx, pending projects are listed in https://www.ferc.gov/industries-data/natural-gas/major-pipeline-projects-pending, both sources consulted April 4, 2022.

[54] Comment of Tennessee Gas Pipeline Company on Draft Environmental Impact Statement, https://marcellusdrilling.com/wp-content/uploads/2021/08/20210823-5221.pdf

[55] Enhancement By Compression Project EA-CP20-48 0.pdf (ferc.gov) pp. A-1 to A-2.

[56] FERC Office of Energy Projects, Marcus Hook Electric Compression Project Final Environmental Impact Statement, October 2021, Docket No. CP21-14-000, page 4.

Eastern Transmission and Transco in Delaware County. Adelphia Gateway includes a new meter that will allow for 22,500 MDth/d of deliveries to PECO on the Tilghman Lateral in Chester, Pennsylvania.[57] This capacity will be used to supply the Kimberly-Clark gas-fired cogeneration facility in Chester and supply a portion of PECO's system in Chester County, meeting the "anticipated future need for additional delivered capacity to the Brookhaven and Chester/Tilghman Street gas stations."[58]

- Algonquin Gas Transmission's Yorktown Meter Station Upgrade will not create incremental capacity as it is designed to provide Algonquin Gas Transmission shippers with enhanced flexibility and reliability by allowing additional deliveries from the Yorktown meter station in the event service at one of Algonquin Gas Transmission's other delivery points is unavailable.[59]
- The Leidy North Project is designed to increase firm transportation capacity on Dominion Energy's system by 10 MDth/d on the segment from Clinton County, PA to the interconnection with Iroquois in Montgomery, NY.
- The Mid-Atlantic Cooler Project is designed to transport natural gas from the Leidy area in Pennsylvania to a natural gas-fueled power plant in Virginia.[60]
- The Supply Header Project is designed to transport natural gas from supply areas in Ohio, Pennsylvania and West Virginia to market areas in Virginia and North Carolina.[61]
- The Tri-State Corridor Project is a lateral designed to transport natural gas from Western Pennsylvania to a proposed natural gas-fueled power plant in West Virginia.[62]

Non-Pipeline Alternatives

In addition to on-system peaking resources, current and proposed alternatives to natural gas delivered by interstate pipeline include LNG and CNG transported via truck, renewable natural gas (RNG) produced locally, and hydrogen.[63] Each of these alternatives involves injecting

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[57] https://cms.ferc.gov/sites/default/files/2020-05/C-6.pdf

[58] https://www.peco.com/SiteCollectionImages/PECO%20Statement%20No.%202%20(Carlos%20Thillet).pdf Joint Petition for a Complete Settlement, Docket No. R-2018-3001568, August 2, 2018.

[59] Abbreviated Application - Certificate of Public Convenience and Necessity and Related Authorizations, Yorktown M&R Replacement & Reliability Project, CP19-13-000, Volume I, page 3

[60] Abbreviated Application of Eastern Gas Transmission and Storage, Inc. for a Certificate of Public Convenience and Necessity, Mid-Atlantic Cooler Project, CP21-97-000, Volume I, page 3.

[61] https://www.dominionenergy.com/projects-and-facilities/natural-gas-projects/supply-header-project

[62] https://www.tri-statecorridor.com/

[63] As indicated in Section 2.1, above, the present study includes demand scenarios that reflect the potential for new state and federal regulations and programs that reduce LDC customers' demand for natural gas. In contrast, some analysts define non-pipeline alternatives to also include reductions in lost and unaccounted for gas from leak detection, energy efficiency, demand response and building electrification. See, e.g., London Economics International LLC, *Final Report: Analysis of natural gas capacity to serve New Jersey firm Customers*, Prepared for

incremental supply directly into the LDC's system avoiding the need for incremental pipeline transportation capacity. While important components of the overall energy mix, these non-pipeline resources would not provide the same volume of incremental deliverability as REAE. In the short to intermediate term, the non-pipeline resources have policy and regulatory hurdles of their own, in addition to higher costs. In estimating the incremental design day supply potentially available from non-pipeline resources LAI has relied on National Grid and Con Ed's experience procuring non-pipeline supplies for New York City and Long Island and an assessment on non-pipeline supply alternatives prepared for the NJ BPU.[64]

Due to the limited availability of firm pipeline capacity deliverable to New York City and Long Island, National Grid and Con Ed have both investigated non-pipeline alternatives for meeting peak day demand. In response to its December 2017 Non-Pipeline RFP, Con Ed received twelve non-pipeline solutions utilizing RNG, CNG/LNG trucking, LNG liquefaction and propane-air.[65] After evaluating the proposals, Con Ed determined that the credible supply side proposals consisted of 5.1 MDth/d of RNG and 149.7 MDth/d of CNG/LNG trucking.[66] The lack of credible LNG and Propane-Air proposals submitted to Con Ed likely reflects the long lead times and permitting challenges associated with the construction and expansion of large-scale LNG and propane facilities. PECO has been working since at least 2018 to increase the sendout capability of its West Conshohocken facility for a planned in-service date in the fourth quarter of 2022.[67]

Con Ed then further reduced the amounts of CNG/LNG proposed to 40 MDth/d "to reflect the siting, permitting, and system integration hurdles associated with a very large volume of trucked supplies."[68] Since 2020, National Grid has expanded its use of CNG trucking in New York City and Long Island from 17 MDth/d to 62 MDth/d, creating the largest CNG operation of its kind in the

New Jersey Board of Public Utilities, November 5, 2021. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1251860.

[64] London Economics International LLC, *Final Report: Analysis of natural gas capacity to serve New Jersey firm Customers*, Prepared for New Jersey Board of Public Utilities, November 5, 2021. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1251860.

[65] Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, September 28, 2018.
https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7C3D0CD-E2B3-4B42-807C-82B553AE63F9}

[66] Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, September 28, 2018.
https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7C3D0CD-E2B3-4B42-807C-82B553AE63F9}

[67] https://www.peco.com/SiteCollectionImages/PECO%20Statement%20No.%202%20%28Carlos%20Thillet%29.pdf, Advance Information Filing Section 20.

[68] Case 17-G-0606 – Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, September 28, 2018.
https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A7C3D0CD-E2B3-4B42-807C-82B553AE63F9}

United States.[69] Planned additions will bring this total up to 80 MDth/d and would exhaust "National Grid's ability to further expand reliance on portable CNG due to siting operational and market constraints."[70] Design day volumes available from each of the non-pipeline resources considered is summarized in Table 1-9, below. The maximum potential design day volume available from all non-pipeline options, 216.5 MDth/d are insufficient to cover the 2022-23 supply shortage and provide less than a third of REAE's incremental firm capacity.

Table 1-9. Estimated Non-Pipeline Volumes

	Con Ed & National Grid NYC and LI	Report Prepared for NJ BPU	Assumed Range
CNG/LNG Trucking	120 MDth/d	53 MDth/d	53-120 MDth/d
On-system Peaking	-	-	67 MDth
RNG	5.1 MDth/d	37 MDth/d	5.1-37 MDth/d
Other	-	12.5 MDth/d[71]	12.5 MDth/d
Total	125.1 MDth/d	102.5 MDth/d	137.6-216.5 MDth/d

Non-pipeline supplies also have higher costs than natural gas delivered with firm pipeline capacity. According to New Jersey's Division of Rate Counsel "renewable natural gas is several times more expensive than natural gas."[72] Similarly, National Grid has estimated a cost $22.5 million per year for the operation of its CNG injection sites and a commodity cost of $12.75/Dth for trucked CNG, and $100 million per year for a 100 MDth/d LNG peaking facility.[73] Trucked CNG also has significantly higher GHG emission rates than gas delivered by pipeline.[74]

1.7 Maryland's Demand for Natural Gas is Growing

The purpose of this section is to present BGE's design day gas demand forecasts as reported in the 2021 BGE Annual Gas Capacity Plan.[75] BGE's planned gas requirements reflect expected

[69] https://millawesome.s3.amazonaws.com/NationalGrid-LTC-Longform-Report-Digital_ADA.pdf page 53.

[70] https://millawesome.s3.amazonaws.com/NationalGrid-LTC-Longform-Report-Digital_ADA.pdf page 53.

[71] Reflects assumed reduction in leaked or lost and unaccounted for gas due to advanced leak detection. London Economics International LLC, Final Report: Analysis of natural gas capacity to serve New Jersey firm Customers, Prepared for New Jersey Board of Public Utilities, November 5, 2021, page 81.

[72] New Jersey Division of Rate Counsel, Comments RE: A5655, https://www.nj.gov/rpa/docs/Ltr_to_Assbly_A5655_Renewable_Gas_12-17-21.pdf.

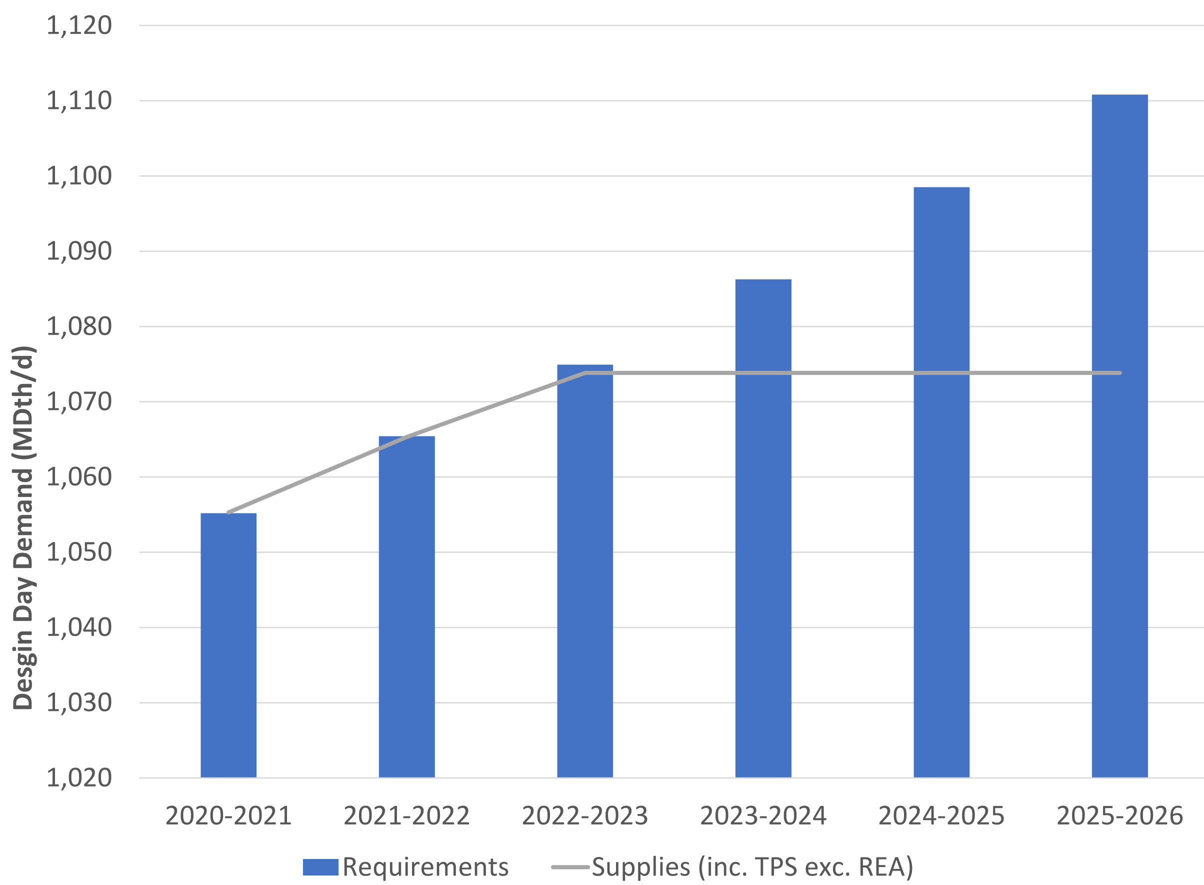
[73] National Grid, Natural Gas Long-Term Capacity Report, February 2020, https://millawesome.s3.amazonaws.com/Downstate_NY_Long-Term_Natural_Gas_Capacity_Report_February_24_2020.pdf, page 65.

[74] See, e.g., National Grid, Natural Gas Long-Term Capacity—Third Supplemental Report, August 2021, https://ngridsolutions.com/docs/DIGITAL_NationalGrid-LTC-Longform-Report.pdf, page 19.

[75] https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/Casenum/8900-8999/8950/85.pdf. BGE submitted errata on November 17, 2021 and January 26, 2022, https://webapp.psc.state.md.us/newIntranet/Maillog/submit_new.cfm?MaillogPath=238756&DirPath=//Coldfusion/Admin%20Filings/200000-249999/238756&maillognum=238756.

demand on Design Day as well as a Design Day Series. BGE's Design Day requirement is based on the highest gas demand BGE expects to be obligated to serve on an extremely cold winter day, while the Design Day Series requirement is based on expected demand during four consecutive days of extremely cold weather. BGE's design day calculations are regulated and have been approved by the Maryland Public Service Commission.[76] As shown in Figure 1-22, BGE's design day demand is expected to continue growing over the next five years, increasing 56 MDth/d over the period, substantially more than BGE's 40 MDth/d contract commitment to REA.

Figure 1-22. BGE Design Day Demand[77]



[76] See, e.g., Maryland Public Service Commission Order No. 79472 in Case No. 8950, Phase II, approving a settlement providing that BGE maintain capacity sufficient "to meet its design day requirements as a provider of last resort … The settlement also provides an agreement that the manner in which BGE calculates design day demand is appropriate." https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=//Coldfusion/Casenum/8900-8999/8950/Item_038\8950%20Ph%20II%20Settlement_final.doc

[77] BGE Gas Capacity Plan Winters 2021/2022 through 2025/2026, https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/Casenum/8900-8999/8950/\85.pdf. BGE submitted errata on November 17, 2021 and January 26, 2022, https://webapp.psc.state.md.us/newIntranet/Maillog/submit_new.cfm?MaillogPath=238756&DirPath=//Coldfusio

Retail choice regulations in New Jersey, Pennsylvania and Maryland allow for programs under which consumers in LDC territories are able to purchase natural gas from third party suppliers (TPSs). In New Jersey and Pennsylvania regulations, LDCs rely on TPSs to deliver volumes to the LDC citygates to meet the needs of TPS customers in LDCs' territories. However, because TPSs in New Jersey and Pennsylvania are not required to make informational filings or otherwise document their firm supply under contract, it is uncertain whether each TPS holds firm supplies and is capable of meeting design day requirements.[78]

In contrast, Maryland regulations allow LDCs to hold capacity over and above the design day requirements of their own customers to cover the LDCs' projected obligation as a Provider of Last Resort (POLR) for TPS customers in their territory. Under BGE's tariff, for example, TPSs operating in its territory must either hold capacity that BGE "deems is firm with primary deliverability to BGE's City Gate" or pay BGE for a portion of the firm capacity that BGE holds to meet the design day requirements of TPS customers.[79] BGE has confirmed that during the winter 2021-2022 56,264 Dth/d of third-party supplier deliverability and firm delivered gas design day capacity was committed to meeting the demands of TPS customers in BGE's territory.[80] Assuming constant third-party supplier deliverability and firm delivered gas, BGE is able to meet its design day requirements through 2022-23.

BGE Utilizes On-System Peaking Resources and Fixed Price Gas to Supplement Contracted Pipeline Capacity

BGE operates two on-system peaking facilities to support meeting supply needs on peak days. These facilities are listed in Table 1-10, along with their maximum daily sendout capabilities.

n/Admin%20Filings/200000-249999/238756&maillognum=238756. BGE Gas Capacity Plan Winters 2020 / 2021 through 2024 / 2025, https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=//Coldfusion/Casenum/8900-8999/8950/Item_84\2020CapacityPlanwApp_final.pdf

[78] See, e.g., PSEG October 22, 2019 comments filed in In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846 https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1221787.

[79] https://www.bge.com/MyAccount/MyBillUsage/Documents/Gas/GasRiders5thru8.pdf

[80] BGE Gas Capacity Plan Winters 2021/2022 through 2025/2026, https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/Casenum/8900-8999/8950/\85.pdf. BGE submitted errata on November 17, 2021 and January 26, 2022, https://webapp.psc.state.md.us/newIntranet/Maillog/submit_new.cfm?MaillogPath=238756&DirPath=//Coldfusion/Admin%20Filings/200000-249999/238756&maillognum=238756. BGE Gas Capacity Plan Winters 2020 / 2021 through 2024 / 2025, https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=//Coldfusion/Casenum/8900-8999/8950/Item_84\2020CapacityPlanwApp_final.pdf

Table 1-10. BGE On-System Peaking Facilities

LDC	Facility	Facility Type	Daily Sendout Capability (MDth/d)
BGE	Spring Gardens	LNG	322.1
BGE	Notch Cliff	LPA	85
		Total	407.1

As shown in Table 1-11, over the last several years BGE has increased capacity available from, pipeline contracts, and fixed price gas and has avoided the use of peaking contracts. In 2023-24, pipeline contract capacity increased by 9.3 MDth/d BGE secured as the successful bidder in a Columbia Gas Transmission open season for a term expiring in March 2025 Securing 40 MDth/d of REAE capacity may allow BGE to increase operational flexibility and supplier diversity.

Table 1-11. BGE Design Day Available Capacity[81]

Available Capacity from	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**
Pipeline Contracts	663.6	663.6	663.6	672.9	672.9	672.9	712.9
Peak Shaving	318.6	318.6	329.2	329.2	329.2	329.2	329.2
Third-Party Suppliers[82]	38.6	49.9	45	43.3	43.3	43.3	43.3
Fixed Price Gas[83]	-	10	17.5	20	>20	>20	-
Peaking Contracts	-	-	-	-	-	-	-
Total Available Capacity	1020.8	1042.1	1055.3	1065.4	>1065.4	>1065.4	1085.4

Role of REAE Capacity in Meeting BGE's Incremental Needs

BGE's REAE capacity will allow it to meet its design day requirements and reduce BGE's future dependency on request for proposals for peaking contracts delivered to its citygates or non-pipeline alternatives. REAE capacity offers greater reliability and less price risk due to the potential for such requests to go unfilled or be at increased cost.[84] BGE committed to using REAE capacity to meet its growing design day demand requirements because it concluded that REAE capacity provides the best combination of scheduled in-service date, dependability, and access to low-cost supplies.

[81] BGE 2018-19 Annual Capacity Plan, Case No. 8950; BGE 2019-20 Annual Capacity Plan, Case No. 8950; and BGE 2020-21 Annual Capacity Plan, Case No. 8950.

[82] Third Party Suppliers' volumes are reported net of OSS/Capacity Release. LAI has assumed that volumes for 2022-23 and later years will be equal to reported volume for 2021-22.

[83] LAI has assumed that Fixed Price Gas volume in 2022-23 and 2023-24 will be equal to reported volume for 2021-22.

[84] Comments of Exelon Corporation in Support of Application, Docket No. CP21-94-000, April 28, 2021.

1.8 Conclusion

Over 90% of the incremental capacity provided by REAE has delivery in New Jersey or Southeastern Pennsylvania. REAE capacity will cover the existing design day supply deficit and meet future growth of LDC-served demand in New Jersey and Southeastern Pennsylvania so that gas reliability can be maintained under design day conditions. In addition to the benefits provided by ensuring reliability under design day conditions, ETG's, NJNG's, PSEG's, PECO's and SJG's respective REAE capacity will provide dependable access to low-cost natural gas supplies which helps keep customers' gas rates low. While natural gas deliveries to Maryland are not subject to the same pipeline constraints as New Jersey and Southeastern Maryland, REAE capacity will allow BGE to meet its design day requirements with cost effective firm pipeline capacity.

2 Reliable Gas-Fired Generation Supported by REAE Will be Needed During the Power Sector's Clean Energy Transition

LAI used Aurora, an electric system dispatch model, to estimate the impact of REAE on the power sector. First, LAI used a capacity expansion module to identify market-driven generator additions and retirements to develop a forecast of the available generation fleet over the study period. Next, all-hours production cost simulations were conducted to estimate output and fuel consumption for generators within the study area. To analyze the impact of REAE on the power sector, LAI set a daily fuel limit on gas available for generation served by Transco that would benefit from REAE based on the pipeline capacity remaining after subtracting LDC gas consumption. LAI also accounted for expected volumes delivered to downstate New York by Transco. LAI ran Aurora with differing daily fuel limits based on the existing natural gas pipeline capacity and then with the addition of REAE. This but-for test did not include other changes. LAI compared the electric dispatch with and without REAE to estimate the impacts of REAE on power generators' demand for natural gas and other fuels, and associated GHG emissions, in both PJM and NYISO, and found:

- Wind and solar generation will provide an increasing share of the electricity produced in the PJM zones in New Jersey, Southeastern Pennsylvania, and Eastern Maryland, the area served by REAE. These renewable resources represent 12% of total electric production in 2025 but increase to 37% in 2039. The share of natural gas-fired generation falls from 29.2% to 23.3% over the same period. The area served by REAE will be increasingly reliant on offshore wind (OSW) generation, which will account for 22.3% of generation in the REAE area in 2039, compared to 6.2% for PJM as a whole.

- The increasing penetration of intermittent renewable generation in the area served by REAE increases the need for dispatchable, flexible attributes that gas-fired generation provides to supplement variable output from wind and solar. Existing gas-fired generation in the REAE area will be needed to provide capacity to meet peak demand, particularly at times when weather conditions limit the availability of wind and solar. LAI projected that the existing 19.2 GW of natural gas-fired generation capacity currently in service in the REAE area will remain in service through the end of the study period in 2039. However, the capacity factor of the incumbent fossil fleet will steadily decline as new wind and solar resources are added to the resource mix.

- Absent REAE the daily fuel limit for Transco-served generators within the REAE area will bind, on average, about four times a year. However, these limitations occur much more frequently in the second half of the fifteen-year study horizon. LDC demand growth in the REAE area coupled with increased flows to downstream markets in New York and New England reduce available pipeline capacity to generators, the majority of which lack firm pipeline entitlements for daily fuel requirements.

- The addition of REAE increases the daily fuel limit for gas-fired generators served by Transco in the area served by REAE. The lion's share of incremental gas burn is utilized by combined-cycle plants, as more fuel-efficient generation from Transco-connected gas-fired generation displaces less-efficient gas-fired generation elsewhere in PJM and NYISO. Displaced generation includes older vintage combined-cycle units, as well as some steam turbine generators and peakers. REAE capacity also allows gas-fired generation to displace coal-fired generation to a limited extent.

The area served by REAE, i.e., the PJM zones in New Jersey, Southeastern Pennsylvania, and Eastern Maryland, is still in the early stages of a transition from fossil-fueled to renewable generation. This transition may not be completed until 2050, perhaps later. While wind and solar generation will provide an increasing share of the electricity produced each year, natural gas-fired generation will be needed to meet peak demand and when weather conditions limit the availability of wind and solar. As New Jersey's 2019 Energy Master Plan concluded, under the least cost path to achieving 100% clean energy by 2050, New Jersey's existing natural gas power plants will be retained to provide reliable electricity to New Jersey homes and businesses when the sun is not shining, and the wind is not blowing, or blowing too hard, or when OSW projects deliver less energy during periods of extreme cold. Retained gas-fired generation may transition to biogas, hydrogen, or alternative zero-emission fuels around 2045.[85]

The increased natural gas burn caused by REAE takes place on the coldest days of the year when LDC "core" demand peaks. Over the study period, LAI finds that the power sector's natural gas burn in the REAE area increases by an average of 1,698 MDth per year, roughly a 3.8% increase in January and February usage. However, gas burn for generation outside the REAE area falls by 1,817 MDth per year for a net reduction in gas burn of 119 MDth per year, a 0.03% decrease across the larger Study Region (made up of all of PJM and NYISO, as discussed below). Non-gas fuel burn decreases by 97 MDth per year, primarily due to displacement of coal generation.

REAE's net impact on power sector GHG emissions reflects both increased emissions from increased natural gas consumption in the REAE area and the reduction in emissions from any offsetting changes in power generation inside or outside of the REAE area. Historically, petroleum products have been the marginal fuel for power generation in the REAE area on cold winter days. Hence, an increase in gas-fired generation in the region would allow for an offsetting reduction in oil-fired generation. Substituting gas for oil reduces emissions as oil-fired generation has higher rates of CO2 and particulate matter emissions relative to natural gas-fired generation.[86] However, LAI's analysis indicates growth in electric transmission capacity and natural gas-fired power generation capacity in Pennsylvania have changed this dynamic. Hence, the increased gas-fired power generation at combined cycle plants served by Transco in New Jersey and Pennsylvania will be offset primarily by less efficient gas-fired plants outside of the area. GHG emissions in the REAE area increase by an average of 0.087 mtpy while emissions in the rest of the Study Region fall by 0.103 million mtpy. Total GHG emissions fall by 0.016 million mtpy. To

[85] 2019 New Jersey Energy Master Plan: Pathway to 2050, https://www.nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf, page 49.

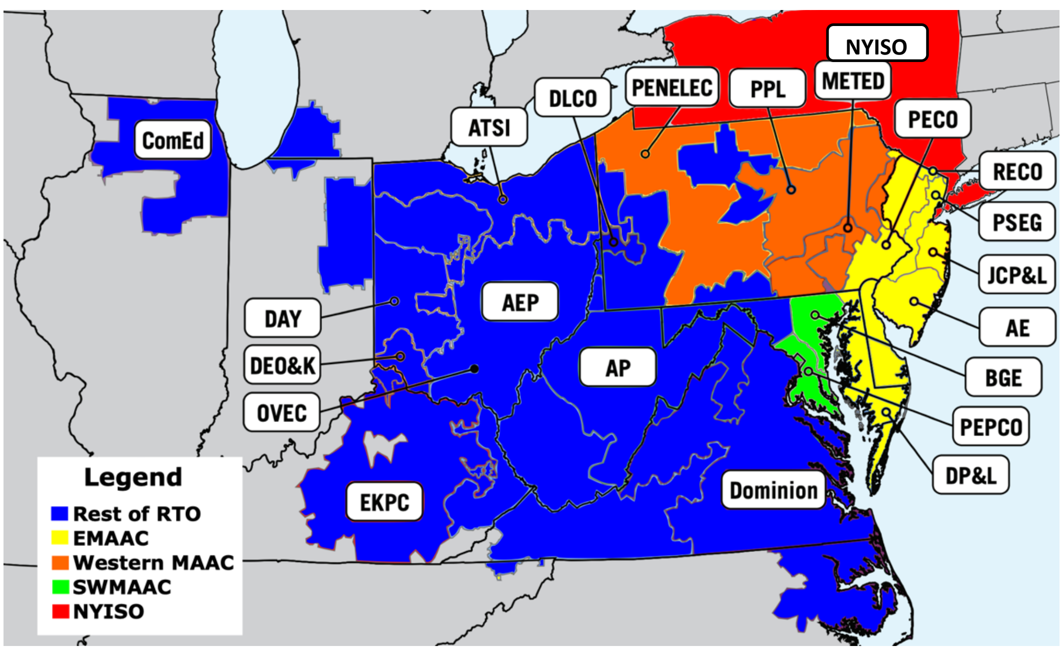
[86] In particular. See, e.g., EPA, Estimating Particulate Matter Emissions for eGRID, July 2020, https://www.epa.gov/sites/default/files/2020-07/documents/draft_egrid_pm_white_paper_7-20-20.pdf, page 6.

the extent oil-fired generation continues as the marginal fuel for electricity generation on cold winter days LAI's results will understate the reduction in power sector GHG emissions.

2.1 Capacity Expansion Modeling Shows the Increasing Market Penetration of Renewables in the Study Region

The Aurora model projects efficient commitment and dispatch of power generators given model inputs. These model inputs include electric power demand, fuel prices, emissions allowance prices, transmission limits, and generator operating characteristics. LAI has augmented Energy Exemplar's database with extensive customization based on public data sources, proprietary calculations, and professional judgment. As shown in Figure 2-1, the power sector Study Region consists of PJM and NYISO. While REAE will not create capacity with primary firm delivery in downstate New York, the strong electric and gas transmission ties between the two neighboring Regional Transmission Organizations (RTOs) necessitate the inclusion of NYISO in the study footprint. REAE's incremental gas deliverability benefits will be realized largely in New Jersey, which shares on-shore and marine electric transmission connections with New York, particularly to the import-constrained New York City and Long Island zones.

Figure 2-1. Map of Study Region for Aurora Power Sector Modeling



LAI relies on peak and annual energy forecasts from RTO planning documents including PJM's Load Forecast Report[87] and NYISO's Gold Book.[88] RTO forecasts that include energy efficiency are utilized. Behind the meter (BTM) solar, which is also forecast in planning documents, is defined as a supply-side resource in order to reflect the changes to the hourly shape of net load that solar creates, as solar generation does not track demand. Boundary flows with other neighboring RTOs, ISO New England (ISO-NE), the Midwest Independent Service Operator, the Tennessee Valley Authority, Ontario's Independent Electricity System Operator (IESO), and Hydro-Quebec, were modeled based on an average weekly profile for each month using three years of historical flow data (168 hours by 12 months, 2018-2020).[89,90]

For Delaware, Maryland, New Jersey, New York, and Virginia (i.e., the states in the study region that currently participate in the Regional Greenhouse Gas Initiative (RGGI)), and Pennsylvania[91] the carbon allowance price is set per the 2022 prompt year futures pricing. LAI has then escalated the prompt year carbon allowance price per the growth rates found in the RGGI Model Rule Policy Scenario forecast prices prepared during the Second Program Review conducted by the RGGI Stakeholder Group.[92] The solid blue line in Figure 2-2 shows the allowance price forecast. The dashed lines represent the RGGI Cost Containment Reserve (CCR) and Emissions Containment Reserve (ECR). The CCR and ECR represent price guardrails that allow for an injection or withdrawal of allowances into the RGGI auctions when the allowance price rises above the CCR or falls below the ECR, respectively.[93] LAI assumed that following the end of the current program

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[87] PJM Load Forecast Report, January 2021, https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx. The 2022 Load Forecast Report was released on December 31, 2021, after the capacity expansion runs were completed.

[88] NYISO, Gold Book: Load and Capacity Data Report, 2021. Available at https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/b08606d7-db88-c04b-b260-ab35c300ed64.

[89] PJM Actual/Schedule Summary Report provides hourly tie line flows and is updated annually. See: https://dataminer2.pjm.com/feed/act_sch_interchange.

[90] Imports into New York from Ontario were reduced to reflect the impending refurbishment schedule of IESO's nuclear units. IESO, Annual Planning Outlook, December 2020, https://ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Dec2020.ashx, page 26.

[91] Pennsylvania's Environmental Quality Board has approved regulations that would include Pennsylvania in RGGI, but those regulations will not take effect until they have been published. AP, Governor sues to force carbon-pricing plan to take effect, February 3, 2022. https://apnews.com/article/climate-business-environment-legislature-state-governments-34f9972a7652c43ac2b3cea69ad8e116

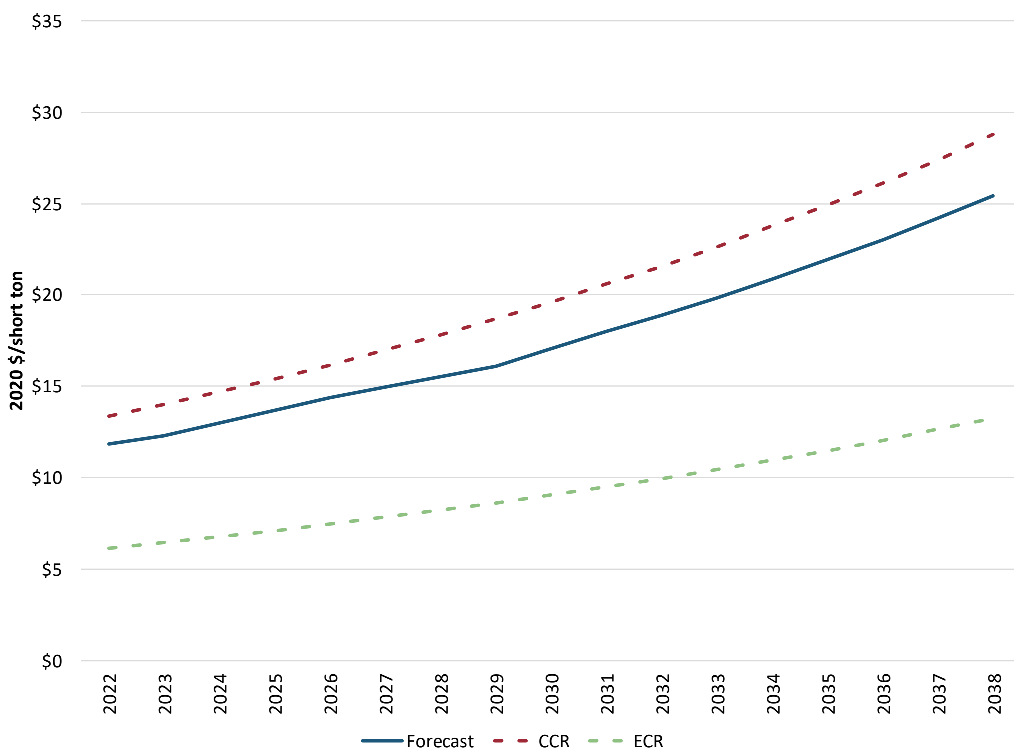
[92] Materials from the Second Program review are available at:
https://www.rggi.org/program-overview-and-design/design-archive/2016-materials.

The Third Program Review is in progress, and the release of an updated Model Rule is expected in Fall 2022. RGGI Preliminary Timeline for Third Program Review, September 13, 2021,
https://www.rggi.org/sites/default/files/Uploads/Program-Review/9-13-2021/Third%20Program%20Review_Timeline_Public_2021-09-07.pdf.

[93] The CCR and ECR Trigger Prices were set at $13.00/short ton and $6.00/short ton, respectively, under the Second Program Review. Each price is escalated at 7% a year through the current program period, which ends in 2030. https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf.

period in 2030, the RGGI real price escalates per the growth rate forecasted over the Second Program Review forecast period and the CCR and ECR prices continue to escalate at the same constant rate.

Figure 2-2. CO_2 Allowance Price Path



LAI's projection of new resources utilizes Aurora's Long Term Capacity Expansion functionality to determine an "equilibrium path" of annual resource additions and retirements beyond scheduled additions and retirements. Scheduled additions include:

- Renewable and clean energy projects, including OSW, that have approved contracts and/or have been selected for long-term contract under a state-mandated procurement;
- So-called "generic" solar, OSW and storage resources that represent projects that will be developed in the future per each state's technology-specific development goals;
- Conventional combined-cycle and combustion turbine generation that has cleared a forward capacity auction or reached construction milestones; and
- Renewable and battery storage projects that have met milestone thresholds within PJM's and NYISO's interconnection queue processes.

Scheduled retirements reflect:

- Tightening environmental regulations, such as New York's nitrogen emissions limits for combustion turbines;[94]
- Nuclear plant license expirations;
- Planned retirements reported in PJM's and NYISO's respective deactivation lists; and
- Plant owner announcements of planned deactivations.

Generation additions and retirements in PJM and NYISO are value-driven and reflect the efforts of generation owners and developers to maximize revenue while reducing overall system costs. The equilibrium path of value-driven additions therefore identifies a cost-efficient set of new resources taking into account factors including the specified fuel and emission allowance price, locational resource requirement forecasts, generation characteristics and state environmental policy goals.

The capacity expansion optimization is subject to resource adequacy and renewable portfolio constraints. Resource adequacy constraints reflect the amount of supply needed to meet planning reserve requirements in NYISO, PJM, and the import-constrained regions and subregions of each RTO. These regions include PJM's Mid-Atlantic Area Council (MAAC), Eastern MAAC (EMAAC) and Southwestern MAAC (SWMAAC). Renewable portfolio constraints reflect long-term clean energy targets that have been mandated in some states via Renewable Portfolio Standard (RPS) requirements. In states with RPS requirements, utilities and other load-serving entities must procure Renewable Energy Credits (RECs) that represent environmental attributes associated with prescribed technology types. New York and a number of PJM states set RPS goals for Class 1 or Tier 1 RECs as a portion of electricity sales which grows over time to a prescribed target percentage. Though many states in PJM allow for incumbent landfill gas, waste-to-energy, and other "brown" technologies to generate Class 1 or Tier 1 RECs, growing RPS requirements will generally be met with wind and utility-scale solar additions.

Aurora determines the equilibrium path through an iterative process. In each iteration the model evaluates the economic performance of all candidate new resource options and candidate resources for retirement using projected market prices taking into account the set of candidate new resources and retirements selected in the last iteration. To evaluate candidates for retirement, the capacity expansion function calculates the present value of forecast net revenues for each existing resource and selects the existing generators with the lowest value.[95] Similarly, the new resource options with the best economic performance are selected. At the end of each

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[94] NY Department of Environmental Conversation, "Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines," State Implementation Plan Revision, May 14, 2020, https://www.dec.ny.gov/docs/air_pdf/siprevision2273.pdf.

[95] LAI restricted the candidates for retirement to conventional fossil generation with no combined heat and power component, with age-out restrictions to reflect typical life cycles and expirations of long-term service agreements for gas-fired generation.

iteration, the long-term logic decides how to adjust the current set of new builds and retirements, or it determines that the model has "converged" on an optimal solution.

LAI created candidate resources which Aurora considered for new additions. The candidate resource types considered were gas-fired Combustion Turbine (CT) and Combined Cycle (CC) units; Photovoltaic Solar (Solar PV); Onshore and Offshore Wind; and Battery Energy Storage (BES). The candidate resources considered in each zone reflect the zone's characteristics.

- CC and CT units are modeled as candidate resources in western PJM but are not available as candidate resources in New Jersey or New York. Given recent decisions by New York's Department of Environmental Conservation denying generator repowering applications, LAI assumed that no new conventional gas-fired generation will be built in New York.[96] While New Jersey environmental laws and regulations do not contain any categorical limits on the development of fossil fueled generation, LAI assumes no new conventional gas-fired generation will be built in New Jersey.[97]
- Utility solar PV and BES are considered as candidate resources in every zone, save utility solar PV in New York City and Long Island.[98]
- OSW is considered as a candidate resource only in zones with scheduled OSW additions, and only following the last scheduled resource to be procured by states in the zone.
- Onshore wind is considered as a candidate resource in western PJM and upstate NYISO.

The generation capacity additions and retirements projected in the capacity expansion modeling determine the available generation fleet in each year. Then, forecast electricity generation is based on the efficient commitment and dispatch of power generators given the available generation fleet, electric power demand, fuel prices, transmission limits, and generator operating characteristics. Annual electricity generation is reported by fuel type in Figure 2-3.

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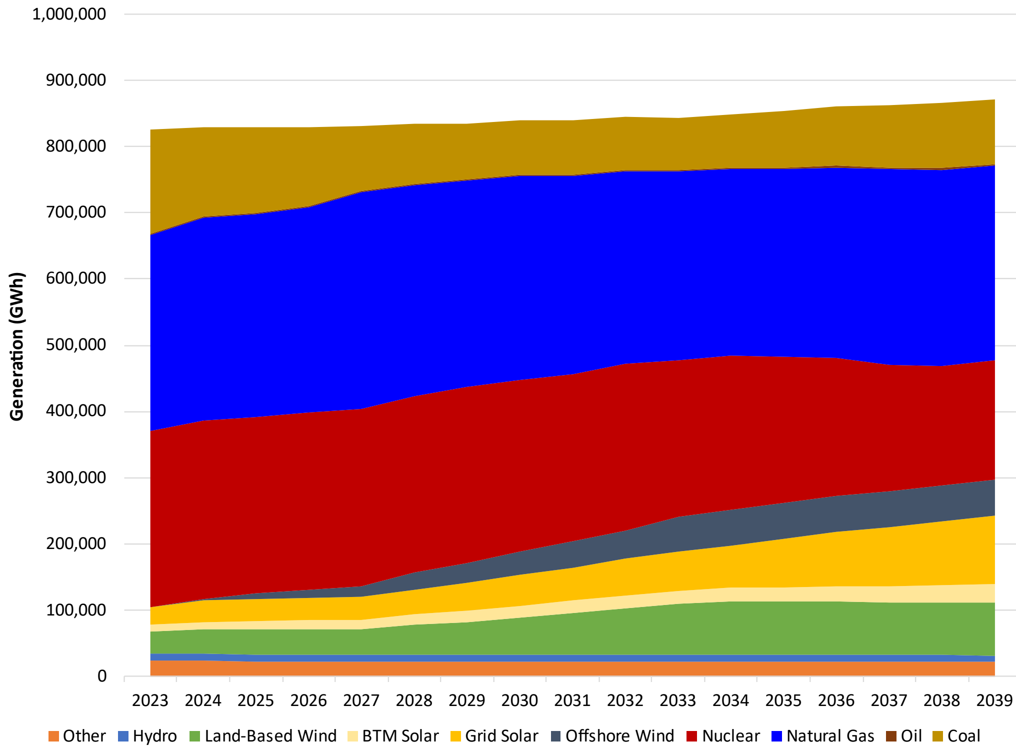
[96] New York State Department of Environmental Conservation, Re: Notice of Denial of Title V Air Permit, DEC ID: 2-6301-00191/00014, Astoria Gas Turbine Power - Astoria, Queens County, October 27, 2021, https://www.dec.ny.gov/docs/administration_pdf/nrgastoriadecision10272021.pdf.
New York State Department of Environmental Conservation, Re: Notice of Denial of Title V Air Permit, DEC ID: 3-3346-00011/00017, Danskammer Energy Center – Town of Newburgh, Orange County, October 27, 2021, https://www.dec.ny.gov/docs/administration_pdf/danskammer10272021.pdf.

[97] See, e.g., NJ Department of Environmental Protection, Notice of Action on Petition for Rulemaking, January 18, 2022, https://www.nj.gov/dep/rules/petition/pet20210721noa.pdf "it would be impractical for the Department to undertake the broad rulemaking requested by petitioners to categorically limit fossil fuel project development in the State. The Department will nonetheless continue and accelerate its efforts to establish regulations, policies, and programs intended to reduce the emissions of climate pollutants."

[98] Storage resources impose heavy computational requirements on capacity expansion modeling. Therefore, following screening analyses candidate BES options were limited to a subset of zones and in-service vintages.

Figure 2-3. Annual Generation in PJM[99]



As shown in Figure 2-3, the output of fossil fuel-fired generators, shown in blue and brown at the top of the figure, declines throughout the study period, from 436,318 GWh in 2025 to 392,891 GWh in 2039, a decrease of 10.0%. In contrast, natural gas-fired generation does not peak until 2027 when it reaches 327,171 GWh. Gas-fired generation experiences only a small decline in subsequent years. Hence, natural gas-fired generators still produce 293,872 GWh in 2039, a decrease of 10.2%. Over the same period, renewable generation, including behind-the-meter solar, grows from 102,959 GWh in 2025 to 276,113 GWh in 2039, an increase of 168%.

Figure 2-4 compares renewable generation in PJM to the amount of renewable generation required to meet the total RPS requirements in PJM. As such this figure provides detail on the composition of renewable generation in PJM. Growth in renewable generation is driven by OSW which grows from 9,352 GWh in 2025 to 54,166 GWh in 2039. The REC demand shown in Figure 2-4 reflects the clean energy required to meet Class 1 or Tier 1 (generally, the most strictly "clean") requirements in Washington D.C., Delaware, Maryland, New Jersey, and Virginia. As can be seen in the figure, renewable generation will substantially exceed requirements throughout the study period. Thus, renewable generation additions during the study period were not driven by RPS requirements and instead were the result of state procurements of OSW and market-driven entry.

[99] The "Other" category is mainly comprised of biofuels and waste-to-energy units.

Figure 2-4. RPS Balance in PJM

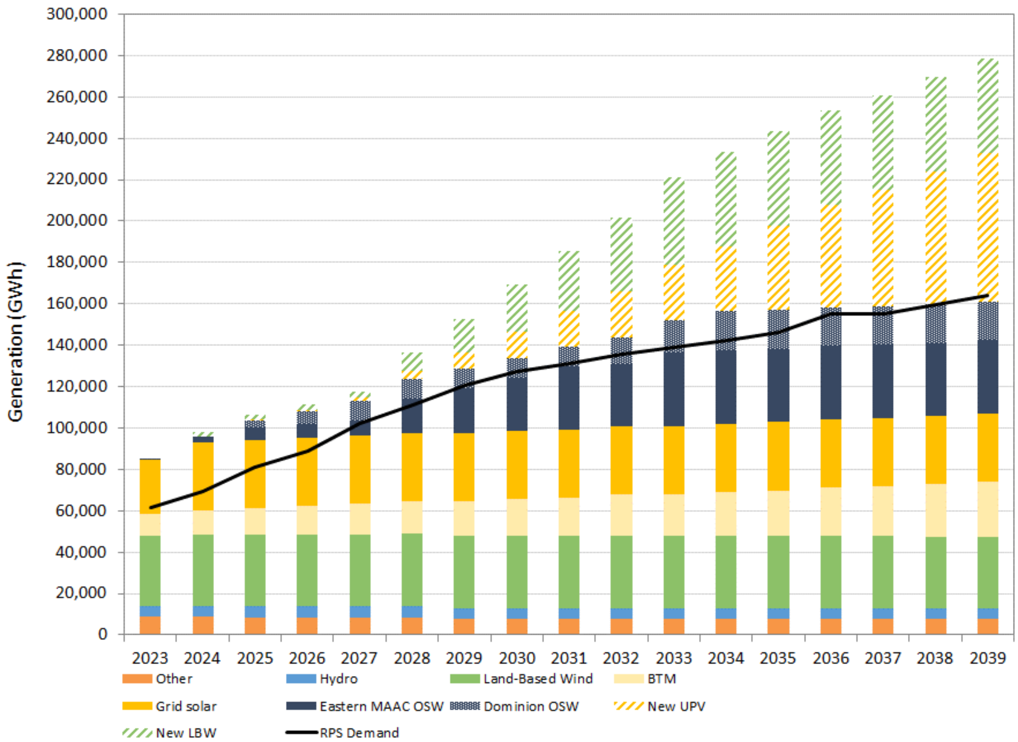


Figure 2-5. Annual Capacity in PJM

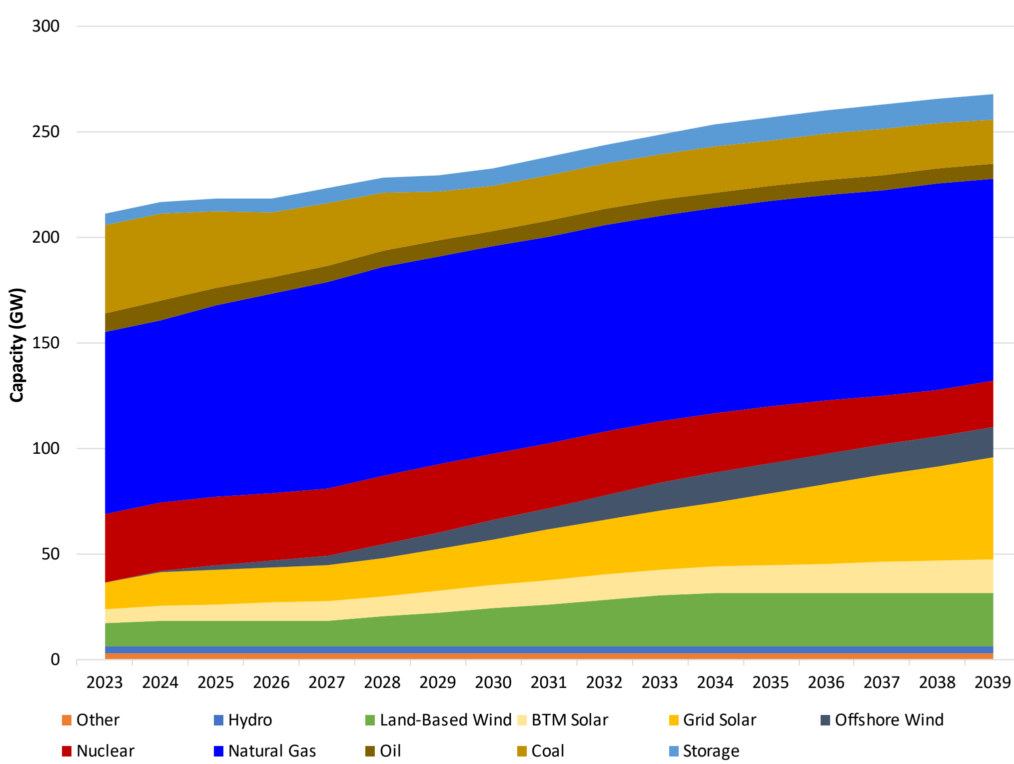
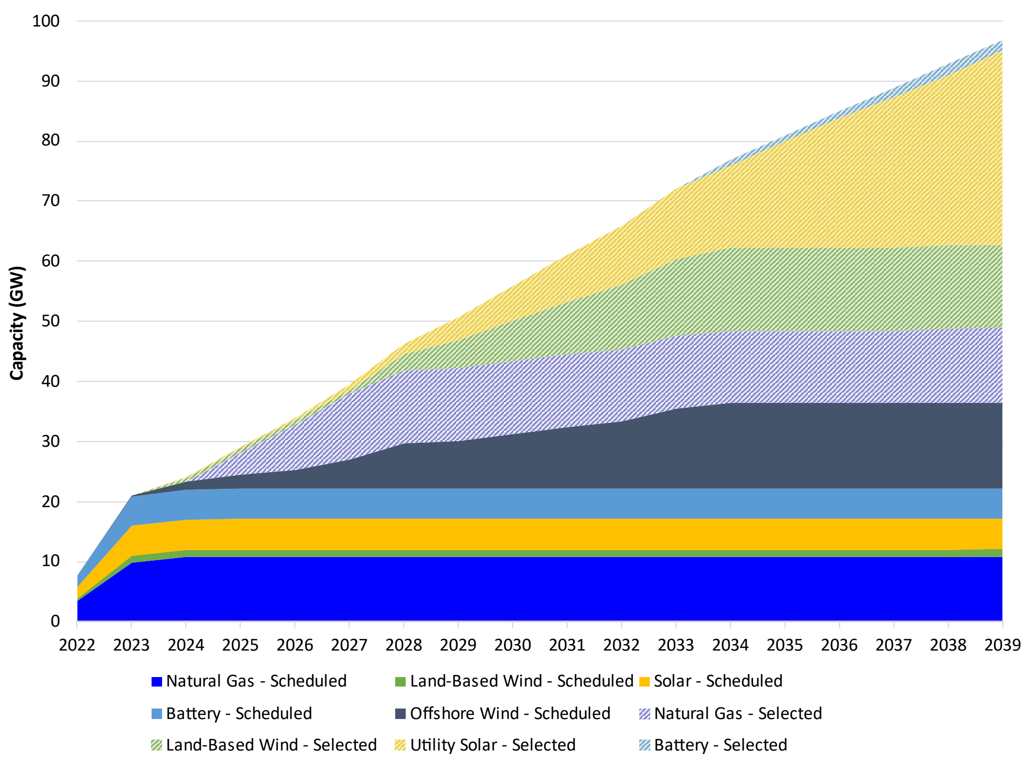


Figure 2-5 shows how generation capacity from renewable sources and natural gas substitutes for retiring coal, nuclear and oil-fired generation. LAI has assumed that nuclear units in the study region retire when their U.S. Nuclear Regulatory Commission license expires, which generally run 60 years. About a third of PJM's nuclear generation retires in the second half of the study period following 60 years of operation.[100]

Figure 2-6 provides a breakdown of the new generation capacity added to PJM during the study period. "Scheduled" capacity additions are fixed per threshold criteria discussed above. The "selected" capacity additions are generic resources included in the equilibrium path. As shown in Figure 2-6, all the non-OSW scheduled capacity additions are operational by 2025. Gas-fired generation accounts for most of the selected capacity additions in the mid-2020's. Later additions consist primarily of wind and solar generation. This transition is driven, in part, by projected increases in the prices of CO2 permits under RGGI. Notably, under the technology cost and performance assumptions posited, Aurora's capacity expansion module elected to build more renewable capacity than is necessary to meet PJM's RPS goals.

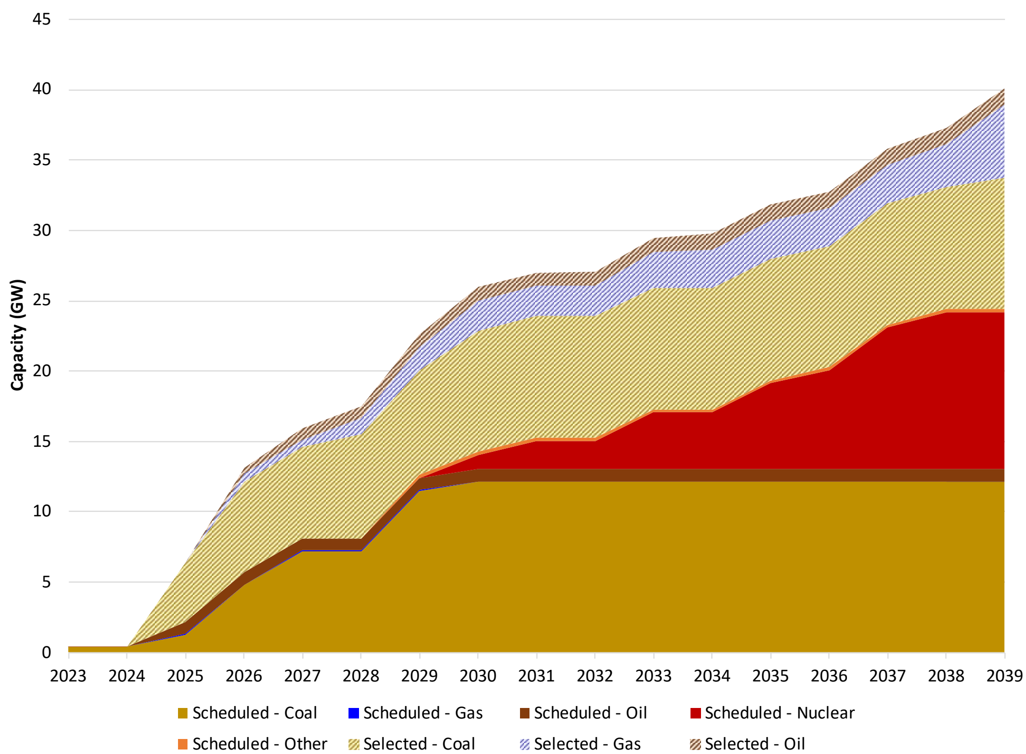
Figure 2-6. New Builds in PJM



[100] U.S. NRC, Reactor License Renewal, https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html, reviewed/updated January 12, 2022.

Figure 2-7 provides a similar breakdown of scheduled and selected generation retirements. Retirements are dominated by coal and nuclear which account for 53.4% and 27.9% of retirements during the study period, respectively.

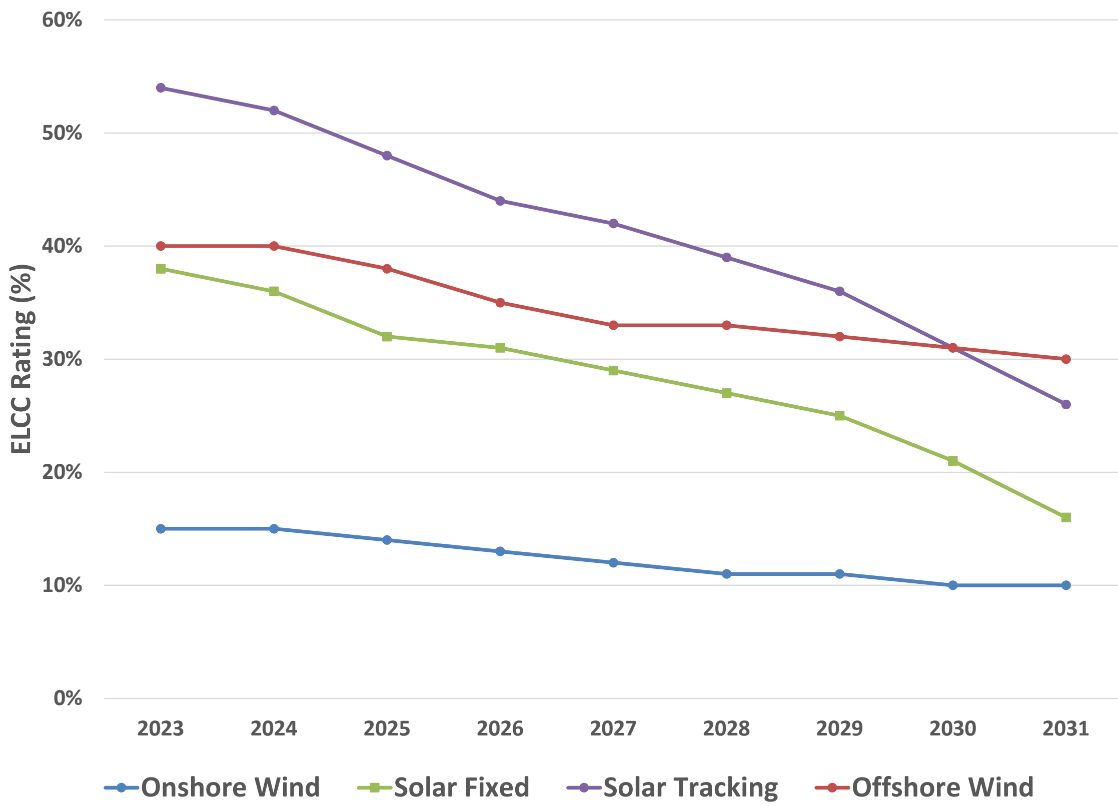
Figure 2-7. Retirements in PJM



Each generation resource's contribution to the reliability of PJM's system depends on the installed capacity of the resource and its outage rate. For resources with a limited duration, such as BES and non-dispatchable resources, the resource's reliability contribution also depends on the expected output of the resource during the shortage or near-shortage hours when the resource is needed to support reliability. Under PJM's Effective Load Carrying Capability (ELCC) mechanism, the reliability contribution of each resource is calculated by repeatedly simulating system reliability under varying weather conditions, identify the hours where the model predicts shortage and near-shortage conditions, and calculating average hourly simulated resource output during those hours.[101] Due to their intermittent nature, renewable generation resources can only be counted on to provide a fraction of their generation capacity when the system is stressed and their capacity is needed to support reliability. As shown in Figure 2-8, for 2023 OSW and onshore wind generation have ELCCs of only 40% and 14%, respectively, whereas tracking and fixed solar have ELCCs of 54% and 38%.

[101] PJM Interconnection, L.L.C., Effective Load Carrying Capability Construct, Docket No. ER21-2043-000 (June 1, 2021), https://www.pjm.com/directory/etariff/FercDockets/6152/20210601-er21-2043-000.pdf.

Figure 2-8. Annual PJM ELCC Factors for Wind and Solar Resources[102]

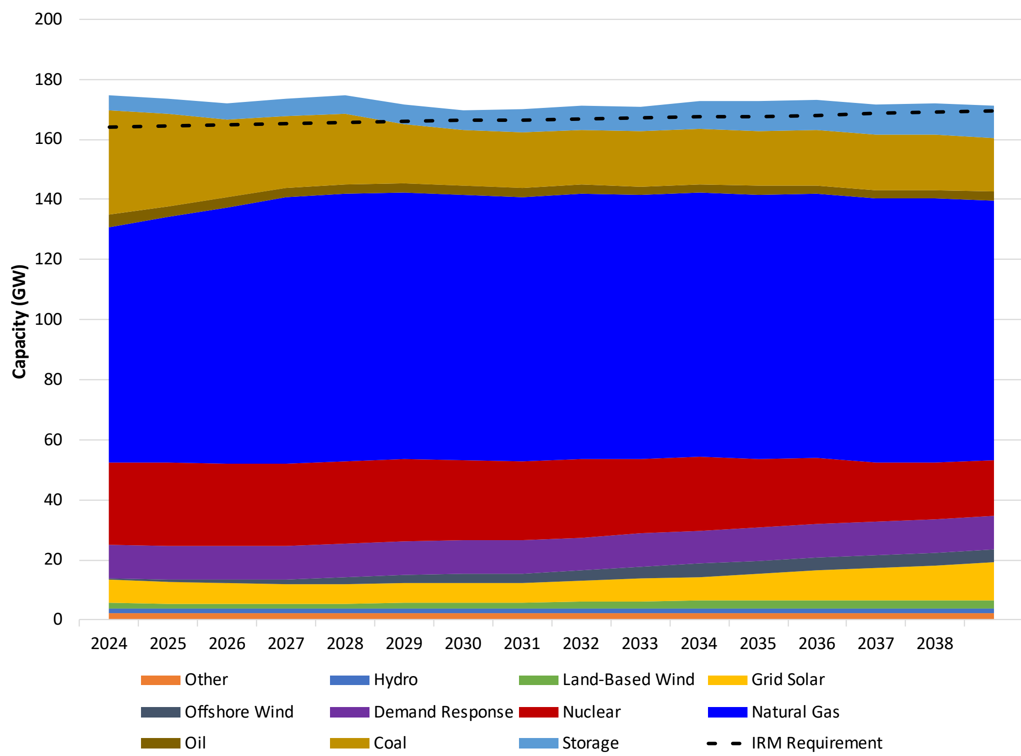


Furthermore, ELCC ratings for each class of renewable resources decline as more renewable capacity in that class is added. For example, the addition of new solar generation capacity will reduce the number of shortage or near shortage hours during daylight hours which will decrease the reliability contribution of existing solar capacity. As a result, the reliability contribution of wind and solar capacity resources is expected to decline over time as increasing quantities of renewable and storage resources are added to PJM. For 2024-2031, LAI has relied on PJM's forecast of ELCC factors, shown in Figure 2-8. From 2032 through 2039, the remainder of the study period, LAI has set ELCC factors equal to the 2031 values, the final year covered by the PJM ELCC projection. Each year, PJM develops a forecast of peak load and calculates the amount of unforced generation capacity required to ensure system reliability, known as the reserve margin. The Installed Reserve Margin (IRM) Requirement is the aggregate amount of capacity required to ensure system reliability. The IRM Requirement is equal to the sum of forecast peak load and the required reserve margin for the system. The most recent PJM reserve margin requirement

[102] See PJM July 2021 ELCC Report, Table 3: 2023 - 2031 ELCC Class Ratings and ELCC Portfolio Rating https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-for-july-2021-results.ashx. PJM has since released a December 2021 ELCC Report. Class Ratings for the 2024/2025 BRA did not change significantly relative to the Class Ratings for the 2023/2024 BRA, but solar technologies are forecast to continue to have declining ELCC Class Ratings in 2032.
https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2021.ashx.

for the study period was 14.7% of peak load.[103] As shown Figure 2-9, forecast unforced capacity exceeds the IRM Requirement in PJM throughout the study period, consistent with the modeled resource adequacy constraint.

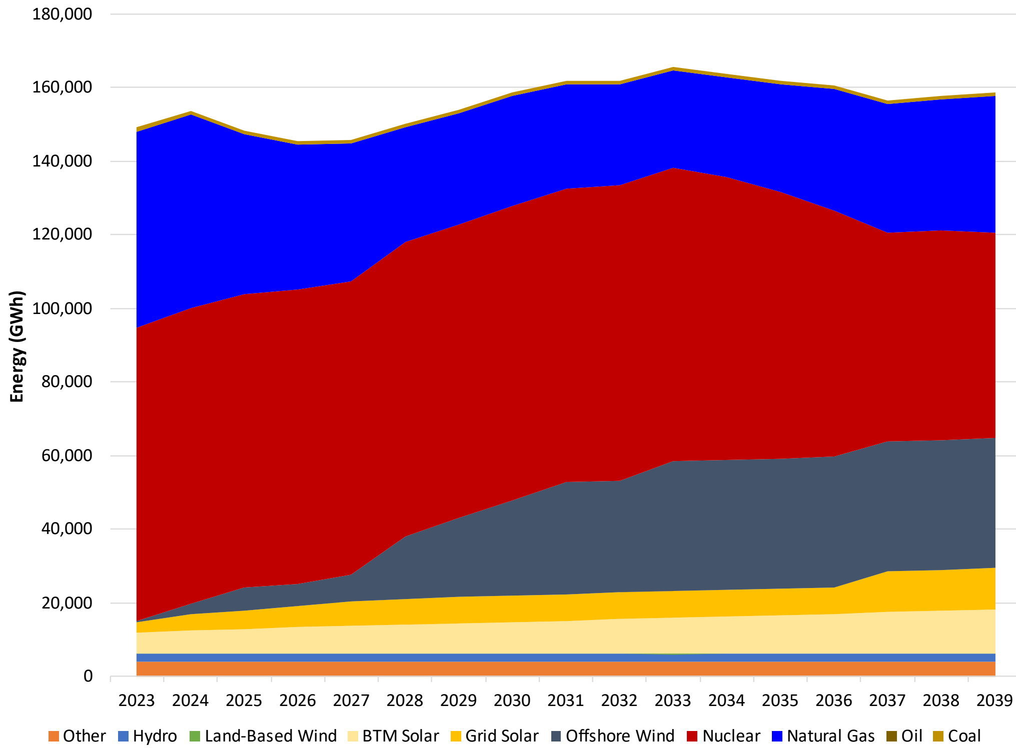
Figure 2-9. Annual Unforced Capacity and IRM Requirement in PJM



Taking a closer look at the PJM zones in New Jersey, Southeastern Pennsylvania and Maryland affected by REAE, i.e., EMAAC and BGE (REAE area), the introduction of new OSW and solar generation offsets the decrease in nuclear generation when NRC licenses expire and reduces energy from gas-fired generation. Renewable generation plays a greater role in the REAE area, where renewables will account for 38.3% of generation in 2039 as compared to 30.5% for PJM as a whole. Reliance on OSW is even more pronounced as OSW generation will account for 22.3% of generation in 2039 in the REAE area as compared to 6.2% for PJM as a whole. The greater concentration of variable renewable generation in the REAE area increases the need for dispatchable attributes that gas-fired generation provides to ensure reliability, increasing the importance of gas-electric coordination in the region.

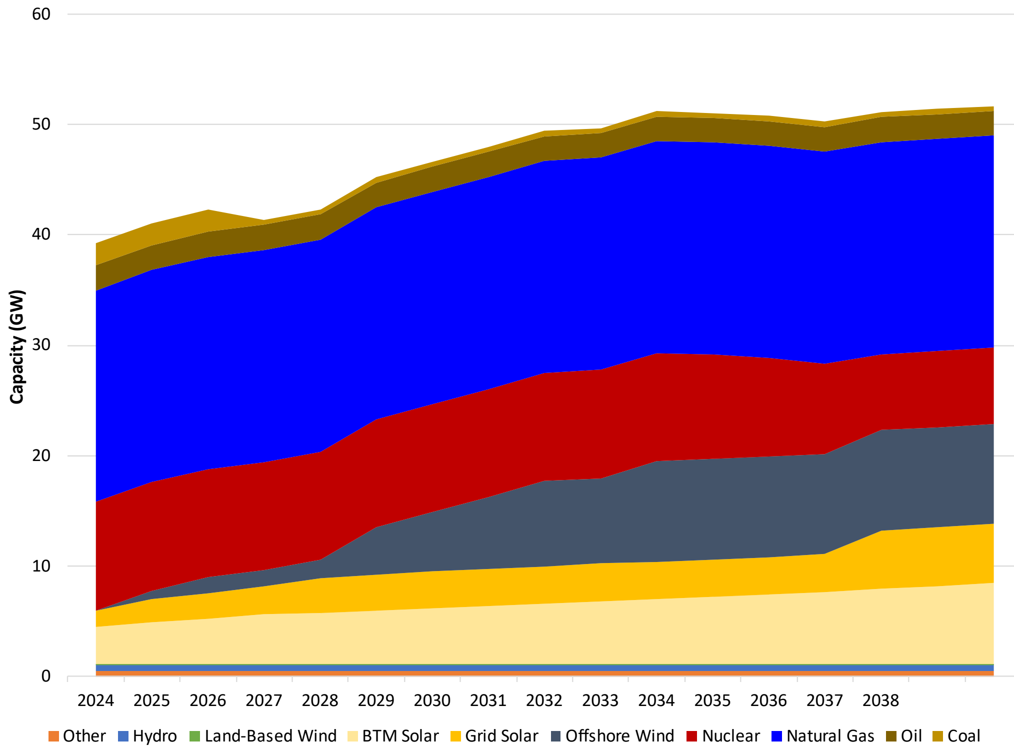
[103] PJM, 2021 PJM Reserve Requirement Study, https://www.pjm.com/-/media/planning/res-adeq/2021-pjm-reserve-requirement-study.ashx, page 15.

Figure 2-10. Annual Generation in REAE Area



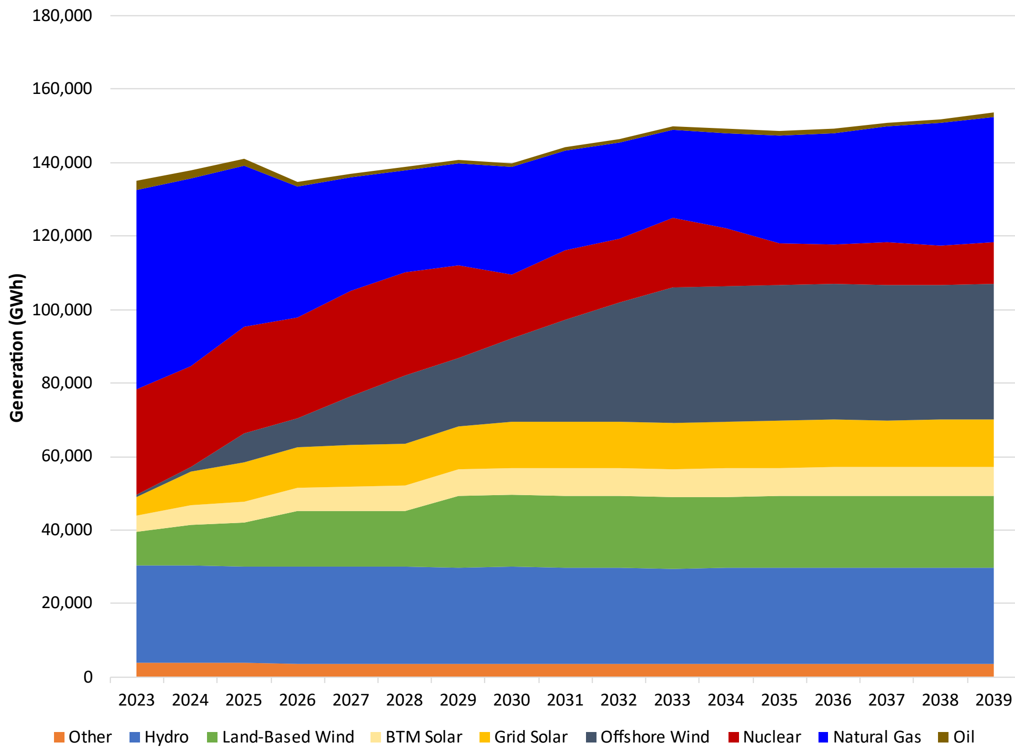
While gas-fired generation output is nearly halved by 2030, the amount of capacity available from the gas-fired fleet remains the same as shown in Figure 2-11. The increasing penetration of intermittent renewables will reduce the use of gas-fired capacity as baseload supply, while increasing the use of gas-fired capacity in a load-following or peaking role.

Figure 2-11. Annual Capacity in REAE Area



As shown in Figure 2-12, NYISO has a similar generation trend to PJM but manages to cut more fossil fuel use. New imports from Canada that will be procured through the Champlain Hudson Power Express contribute to the decline in NYISO generation in 2026.

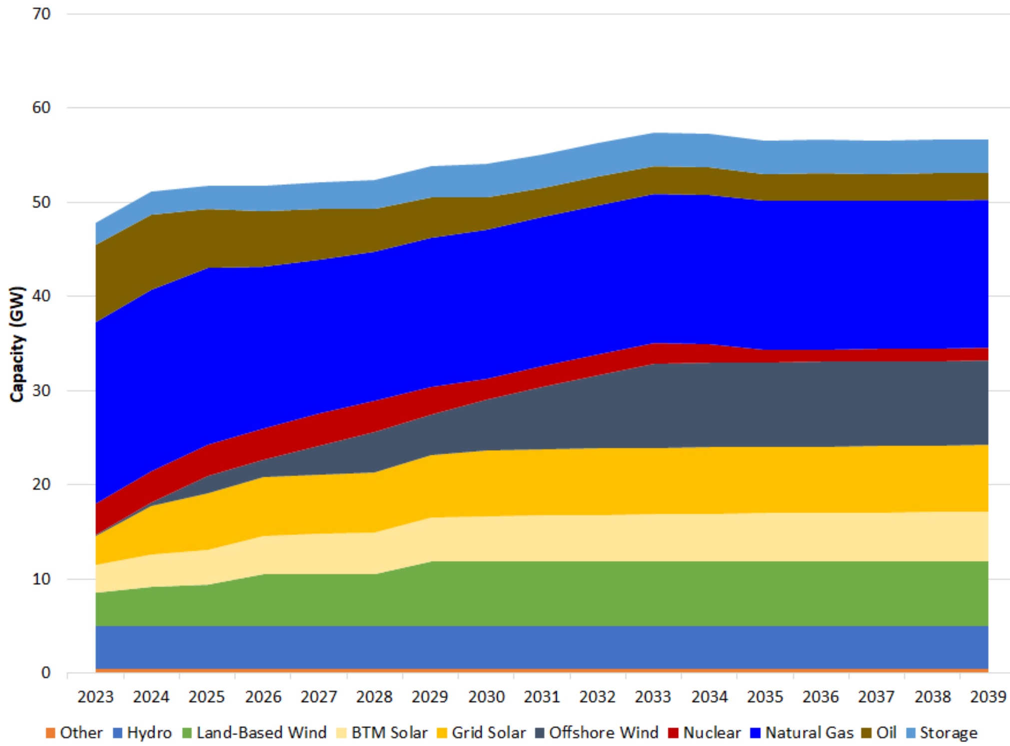
Figure 2-12. Annual Generation in NYISO



As shown in Figure 2-13, the adoption of renewables and OSW in NYISO will proceed even faster than in the REAE area as renewables will account for 67.3% of generation in 2039 as compared to 38.3% for the REAE area and 30.7% for PJM as a whole.[104] The concentration of OSW is even more pronounced as OSW will account for 24.1% of NYISO generation in 2039 as compared to 22.3% for the REAE area and 6.2% for PJM as a whole.

[104] NYISO also imports clean and renewable power from Canada through existing and scheduled new ties with Hydro Quebec. These ties help to ensure that New York's Clean Energy Standard is met.

Figure 2-13. Annual Capacity in NYISO



2.2 REAE Will Increase Natural Gas Supplies Available to the Power Sector in New Jersey and Southeastern Pennsylvania

REAE will enable Transco to provide an additional 829,400 Dth/d of firm transportation service from northeastern Pennsylvania to delivery points in New Jersey, Pennsylvania and Maryland.[105] The increase in capacity will come as a result of both new segments pipeline and new compression on existing segments. When it enters operation, it is expected that Adelphia Gateway will have higher operating pressure than Transco's Marcus Hook lateral at the interconnection point. Hence, the completion of the Adelphia Gateway will allow for increased firm capacity on Transco's Marcus Hook lateral.[106] From an operational standpoint it is like additional compression. Transco therefore held an Open Season for interim firm service on the Marcus Hook lateral so that shippers would be able to make use of this capacity before REAE is completed. As a result of a 2021 Open Season for interim service, NJNG has entered into a contract with Transco for 130,000 Dth/d of firm transportation service with delivery to NJNG system in Chesterfield, NJ, effective November 1, 2021, until REAE's in-service date.[107] While NJNG's use of this capacity is dependent on the relative operating pressures of the Adelphia

[105] Abbreviated Application for Certificate of Public Convenience and Necessity for Order Permitting and Approving Abandonment of Facilities (Regional Energy Access Expansion), Docket No. CP21-94-000, March 26, 2021, page 5.

[106] Transcontinental Gas Pipe Line Company, LLC Service Agreement Containing Non-Conforming Provisions, Docket No. RP21-800-000 April 30, 2021, page 2

[107] Ibid, pp. 1-2.

Gateway and Marcus Hook lateral, LAI has conservatively assumed that NJNG's use of this capacity is not dependent on REAE coming into service and does not represent incremental firm capacity. REAE is modeled as providing 699,400 Dth/d of new firm capacity to the region.

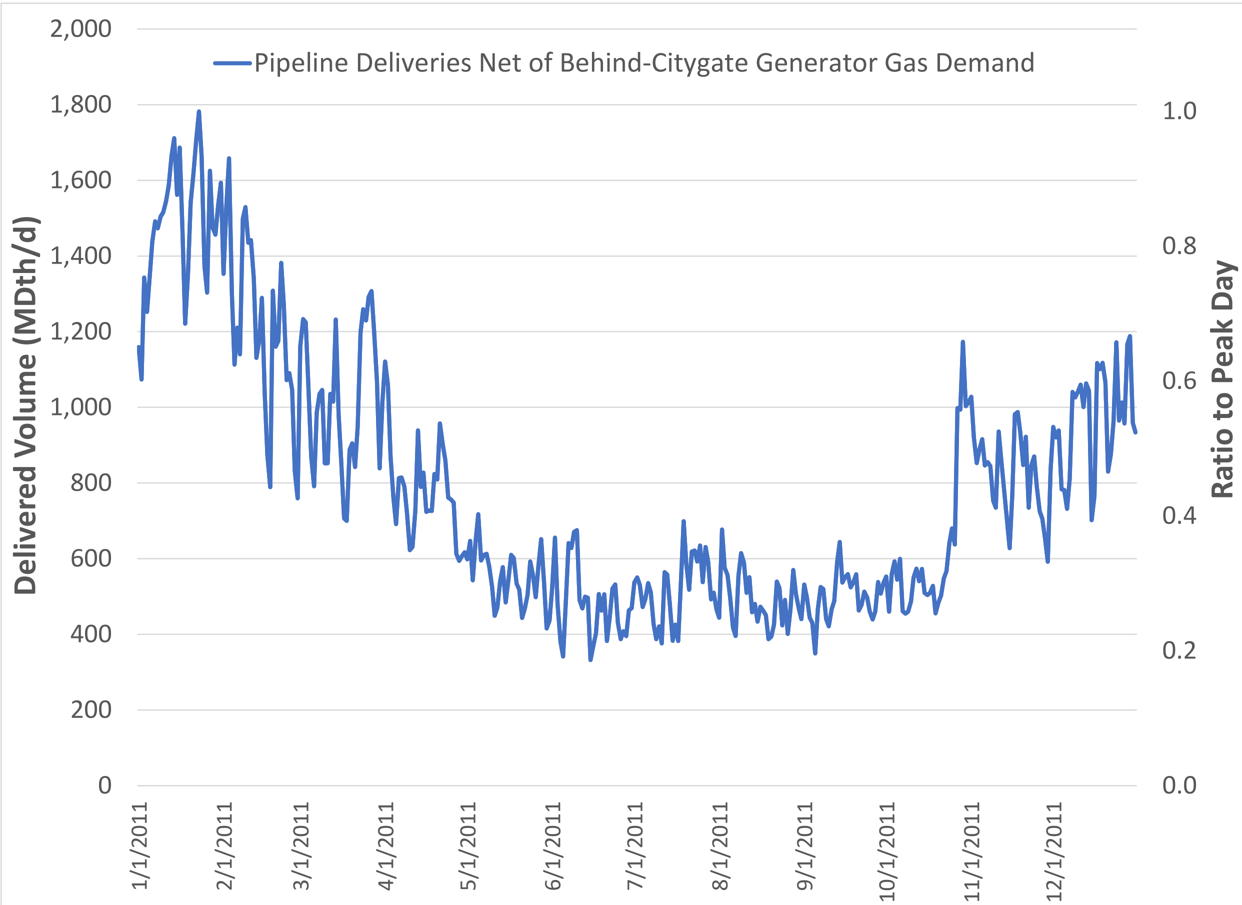
Per a review of pipeline customer indices, nearly all of the gas-fired generation in the REAE area lack firm entitlements to pipeline capacity. Fuel supply to these generators may be curtailed during tight winter conditions. In order to analyze the impact of REAE on the power sector, LAI limited daily natural-gas fired generation at power plants served by Transco based on the amount of capacity remaining after subtracting LDC retail gas consumption and downstream deliveries from the Transco capacity available in the region. NYISO uses the same basic methodology to estimate volumes available to generators for winter reliability assessments, as did the Eastern Interconnection Planning Collaborative (EIPC) in its DOE-funded assessment of gas-electric coordination, discussed in more detail in Section 3.1, below.[108] LAI estimated the impact of REAE by modelling the electric dispatch with and without REAE capacity and comparing the results. The first step in determining the amount of natural gas available for electric generation is to estimate the consumption of residential, commercial and industrial customers, including both LDC-served customers and industrial customers with firm entitlements served by laterals.

LAI estimated the daily profile of LDC-served demand based on the historical ratio of daily demand to the annual peak day demand in a given year for each LDC. This daily percentage is multiplied by the expected pipeline-served peak day demand for each year to calculate a daily demand, which is divided by pipeline based on 2021 delivery ratios. The expected pipeline-served peak day demand for an LDC is the design day demand (as discussed in Section 1) multiplied by a factor representing expected peak day demand as a ratio of design day demand given the heating degree days (HDDs) on the peak day in the representative weather year, minus the behind-citygate peaking capacity. The calculation of PSEG's demand served by Transco in 2035 is presented below.

Figure 2-14 shows PSEG's daily pipeline deliveries in 2011 (used as the representative weather year) net of gas consumed by behind-citygate generators. Generator gas demand is removed because it is forecasted separately through Aurora. The left-hand y-axis shows the total volume, and the right-hand y-axis shows the ratio of daily demand to peak demand on January 23, 2011.

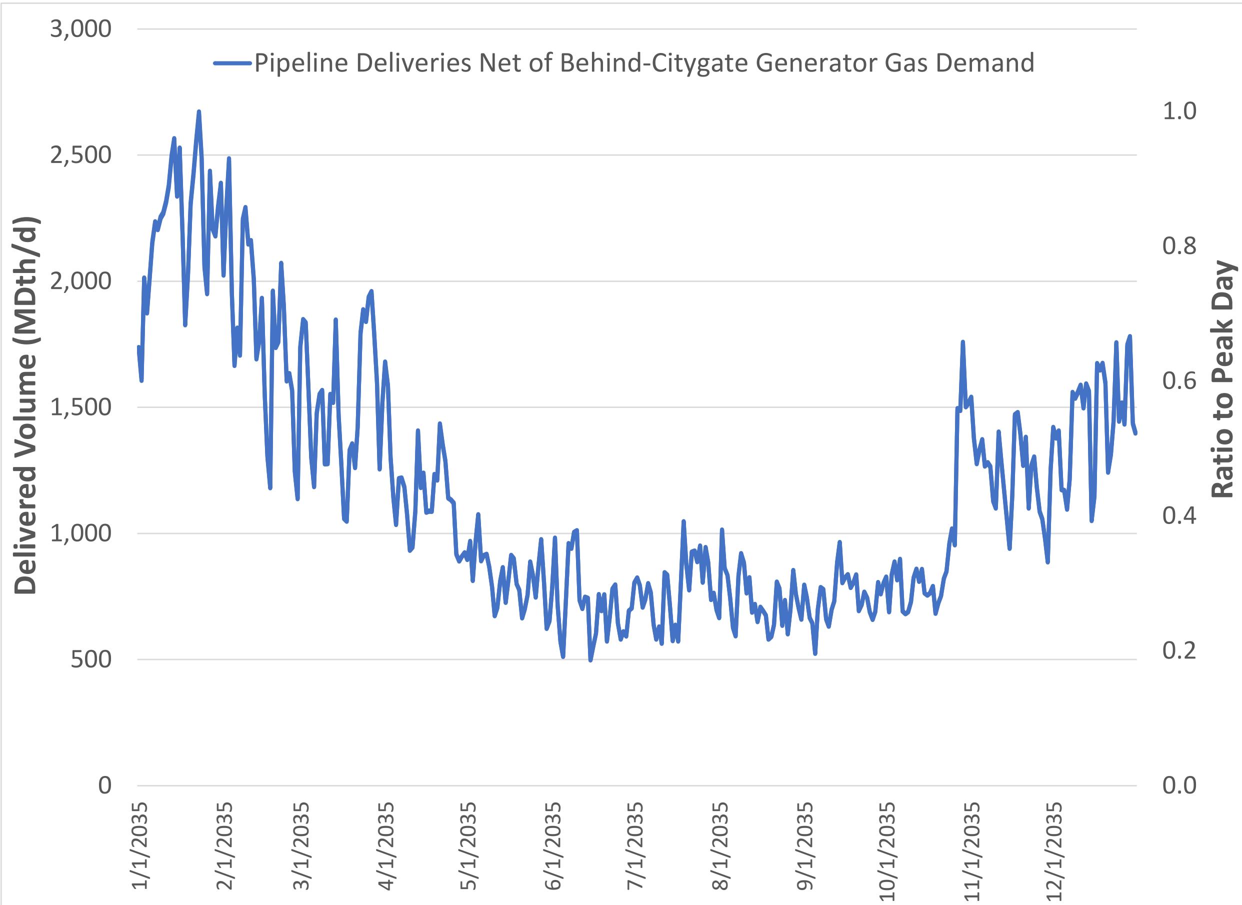
[108] Analysis Group, Final Report, Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, November 2019, pages 34-36. Available at https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf/cbecabaf-806b-d554-ad32-12cfd5a86d9e. EIPC, Final Draft, Gas-Electric System Interface Study Target 2 Report: Evaluate the Capability of the Natural Gas Systems to Satisfy the Needs of the Electric Systems, March 9, 2015, page 3. Available at https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cdecca552ef1200018509d9/1558105276098/Final+Draft+Target+2.pdf

Figure 2-14. PSEG Pipeline Deliveries Net of Behind-Citygate Generation in 2011



PSEG's design day demand in 2035 was extrapolated to be 3,415 MDth/d, with behind-citygate peaking resources of 282 MDth/d, resulting in expected pipeline deliveries on the design day of 3,133 MDth/d. An expected ratio of peak day demand to design day demand of 85% was utilized, based on the HDDs on January 23, 2011, relative to the HDDs assumed in PSEG's design day formulation. This results in a 2035 estimate of pipeline-delivered peak day demand of 2,663 MDth/d. Applying the daily profile shown in Figure 2-14 to this value results in the profile shown in Figure 2-15, which has the same shape, but a higher volume, reflecting load growth.

Figure 2-15. PSEG Pipeline Deliveries Net of Behind-Citygate Generation in 2035



For LDCs not served by REAE, the daily demand forecast is calculated using the same approach, except that the peak day demand is assumed to grow relative to the 2021 peak demand at an annual growth rate of 1%. Demand for industrial customers is held constant at the 2021 daily demand profile in each year. Interconnection volumes are also held constant at the 2021 daily flow profile in each year.

Finally, the sum of these scaled daily LDC retail gas demands and other volumes served by a pipeline is subtracted from the pipeline's total natural gas pipeline capacity available in the region to determine the amount of natural gas available on a daily basis available to support generation. For Transco, this capacity is defined by the throughput capacity at Station 190, production volumes transported west-to-east on the Leidy Line, and, where applicable, the incremental capacity associated with REAE.

LAI has made the simplifying assumption that pipeline operators are able to maintain scheduling flexibility through use of pipeline line-pack to serve firm customers without using Operational Flow Orders (OFOs) to impose daily imbalance or cash-out penalties or enforcing ratable take contracts provisions that require generators to burn approximately the same quantity of gas each hour throughout the day. When system conditions are not tight, Transco, like other pipelines, generally permit gas-fired generators significant flexibility in shifting gas burn between hours within a day or across days if needed to meet PJM's generator scheduling requirements. However, when operating conditions are tight Transco, like other pipelines doing business in New Jersey, New York and PJM, does in fact post restrictive Flow Day Alerts or OFOs that limit shippers' ability to schedule gas flexibly to accommodate variation in output levels especially in the early morning and late afternoon hours. The high utilization of Transco's system is reflected in both the lack of unsubscribed capacity and Transco's frequent use of imbalance OFOs. While Transco's tariff also allows for the use of scheduling OFOs, in 2020 and 2021 Transco relied extensively on imbalance OFOs. Transco imposed imbalance OFOs on 316 days in 2020 and 141 in 2021. As PJM observed in a recent statement on Natural Gas and Electric Markets Misalignment, because of the limited availability of pipeline capacity natural gas-fired generators in PJM face more restrictive gas pipeline operations with a greater frequency of OFOs and the resulting loss of flexibility significantly hinders natural gas-fired generators' ability to operate and provide regulation and reserves during critical events.[109]

LAI also made the simplifying assumption that gas scheduling over the weekend does not reduce generator flexibility by requiring that generators purchase or schedule the same volume of gas on Saturday, Sunday and Monday.[110] This issue is particularly acute over the holiday weekends in the winter (Martin Luther King Day, Presidents' Day, New Year's Day in some instances) when generators may need to make gas purchasing and scheduling decisions on Friday for deliveries on Saturday, Sunday, Monday and Tuesday. PJM noted that "During the [2014] Polar Vortex and Winter Storm, many generators that can typically operate very flexibly had to operate on significantly more restrictive parameters due to their contractual arrangements for natural gas."[111] This dynamic has persisted through more recent winters, with gas prices occurring during the four-day holiday weekend gas package over Presidents' Day in 2021 exceeding the monthly average by approximately 360%.[112] To the extent that limited generator flexibility over weekends and due to OFOs causes some pipeline capacity to go unused LAI's analysis will understate the need for and impact of REAE.

To model pipeline constraints in Aurora, LAI utilized the daily fuel limit functionality. In particular, LAI set the daily limit for gas-fired generators in the REAE area by taking the difference between firm capacity deliverable to the REAE area and LDC-served consumption in the REAE area. The

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[109] PJM, Natural Gas and Electric Market Misalignment Problem/Opportunity Statement, September 29, 2021, https://www.pjm.com/-/media/committees-groups/committees/mrc/2021/20210929/20210929-item-02-2-natural-gas-and-electric-markets-problem-statement.ashx.

[110] See, e.g., Dominion Energy Presentation to PJM Electric Gas Coordination Senior Task Force, November 5, 2021, https://www.pjm.com/-/media/committees-groups/task-forces/egcstf/2021/20211105/20211105-item-02-dominion-energy-presentation.ashx, page 12.

[111] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection, p. 47. May 8, 2014. See https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

[112] Winter Operations of the PJM Grid: December 1, 2020 – February 28, 2021, PJM Interconnection presentation to the Operating Committee, p. 19. April 8, 2021. See https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20210408/20210408-item-14-winter-operations-review.ashx

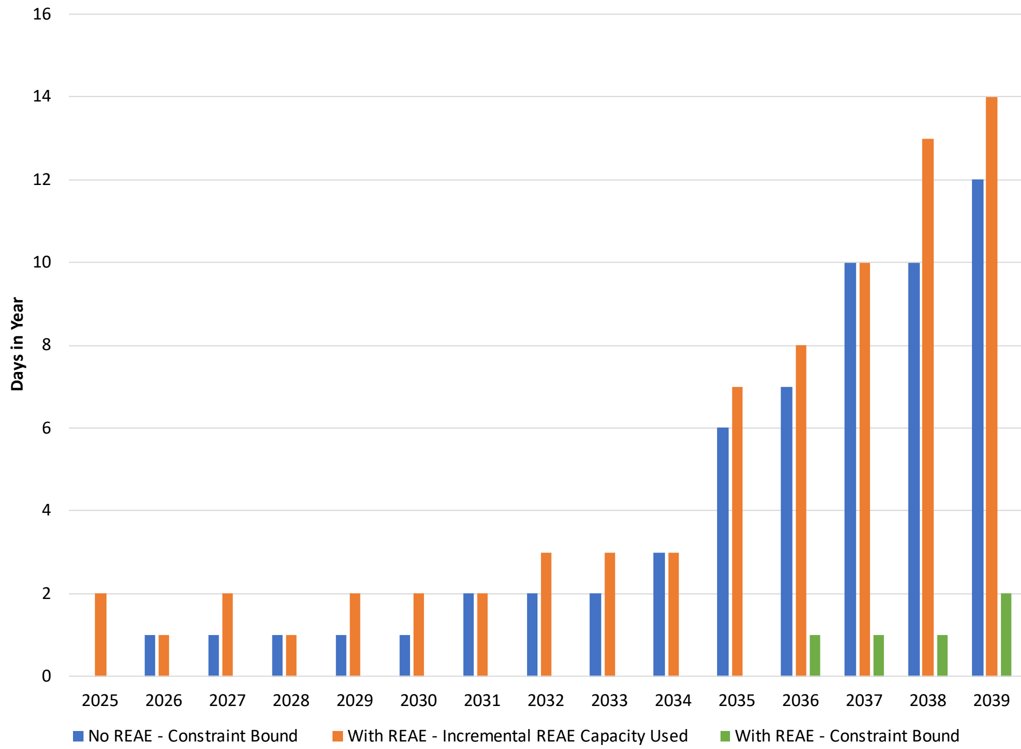
impact of REAE on the power sector is assessed by running the electric commitment and dispatch simulation with a daily gas constraint that reflects the existing gas infrastructure, then increasing the daily gas constraint to reflect incremental REAE capacity, rerunning the simulation and comparing the results.

2.3 REAE Results in Increased Gas Burn at Transco-Served Generators in New Jersey and Southeastern Pennsylvania and Decreases Emissions Elsewhere

REAE results in increased gas availability and gas burn at gas-fired generators served by Transco in the study region and decreased emissions elsewhere, as the lion's share of incremental gas burn comes from efficient combined-cycle generators. Incremental burn increases over the study period as the volume of gas available for gas-fired generation in the REAE area declines while demand for electric power grows. On the gas side, LDC demand growth in the REAE area and increased flows to downstream markets in New York and New England reduce the pipeline capacity available to generators over time. On the electric side, demand for electric power grows over time, nuclear retires, and more pressure is placed on natural gas to provide dispatchable generation. LAI created two Aurora study cases with different daily fuel limit settings: a no REAE case and a with REAE case. Based on testing without the daily fuel limit activated, January and February were the two months that the daily fuel limit was projected to bind. Aurora all-hours runs and results were therefore limited to those months. The Transco daily fuel limit bound, on average, about four times a year in the no REAE case, but gas burns were more heavily limited in the back half of the study period. There were fourteen additional days in the with REAE case where some portion of the incremental REAE capacity.[113]

[113] The daily fuel limit can constrain fuel usage even on days when fuel usage in the no REAE case does not reach the daily limit. This counter-intuitive result is due to the complex nature of the optimization problem that electric system operators face and that Aurora is used to replicate. Generator commitment and dispatch solve sometimes requires deciding between "lumpy" blocks of capability, each subject to different operating restrictions such as minimum operating limits and minimum up and down times.

Figure 2-16. Gas Burn Limited Days, All-Hours Cases



REAE increases the daily fuel limit for Transco-connected generators in the REAE area. Therefore, these generators run more in the With REAE case. Overall fuel demand for power generation drops in the with REAE case, mostly due to more fuel-efficient generation from units benefited by REAE substituting for less-efficient gas-fired generation elsewhere in PJM and NYISO. As previously mentioned, the lion's share of incremental gas burn provided by REAE units is associated with combined-cycle generators. While a significant portion of the other gas generation units that are dispatched down in response are also combined-cycle units, they are generally of an older vintage and therefore require more fuel to produce electricity relative to the superior heat rates characteristic of more recent vintage combined cycle plants. Also, some steam turbines and peaking units are also utilized less. REAE also allows gas-fired generation to substitute for a small portion of non-gas fossil fuel demand, largely coal-fired generation.

The reductions in fuel burn due to REAE translate into greenhouse gas emissions reductions at the global study region level. Displaced emissions are allocated fairly evenly between western PJM and NYISO. New Jersey shares several sub-sea cables with downstate New York, and a significant portion of the combined-cycle generation unlocked by REAE is exported from New Jersey to New York. Overall, addition of REAE results in about 0.016 million metric tons of greenhouse gas displacement annually, which is a tiny portion of the 42 million metric tons emitted during January and February annually within the PJM and NYISO modeling footprint. Criteria pollutants were also reviewed within the MAAC footprint. Due to the increases in gas-fired generation within MAAC, NO_X and $PM_{2.5}$ emissions increased by 59 and 4 metric tons, respectively, on an average annual basis. Gas-fired generation emits a minimal amount of SO_2

and some coal-fired generation is displaced in MAAC, therefore sulfur dioxide emissions were slightly decreased with the addition of REAE.

Table 2-1. Average Annual REAE Impact on Power Sector Fuel Consumption (Dth), All Hours

REAE Area Gas	Other Gas	All Gas	Non-Gas
1,697,839	-1,817,190	-119,352	-96,790

Table 2-2. Average Annual REAE Impact on CO_2 Emissions (mtpy), All Hours

NYISO & PJM	PJM	MAAC	REAE Area
-0.016	0.046	0.052	0.088

REAE would have a greater impact under extreme winter weather conditions. In addition to the improved electric and gas system reliability discussed in Section 3, REAE will also provide emissions benefits under extreme winter weather conditions. REAE allows for more efficient combined-cycle generation within the REAE area during high demand periods, and therefore non-REAE gas generation utilizes about 3.0 million less dekatherms during extreme weather conditions as further described in Section 3. REAE also displaces about 0.5 million dekatherms of oil and coal-fired generation in the extreme weather conditions modeling, largely due to heavy fuel switching on the two most severe days in the forecast period. This net reduction is reflected in a significantly larger carbon emissions impact relative to the all-hours annual average. REAE also provides benefits to PJM's MAAC region through reduced nitrous oxide and sulfur dioxide emissions of 120 and 169 metric tons. These criteria pollutant reductions are largely achieved by reducing the need for oil-fired generation. Since electric sector power demand is elevated in the extreme weather conditions modeling, REAE has greater benefits per dekatherm of gas delivered, as less-efficient units are offset relative to the all-hours cases.

Table 2-3. REAE Impact on CO_2 Emissions (Million Metric Tons), Extreme Weather Conditions

NYISO& PJM	PJM	MAAC	REAE Area
-0.094	-0.006	-0.0003	0.063

3 REAE will Improve Gas and Electric Reliability and Resilience Under Extreme Winter Weather Conditions

In this Section, LAI assessed the impact of REAE on the reliability of the electric and natural gas systems during severe winter weather conditions. As an illustrative scenario analysis, LAI analyzed the likely consequences on gas and electric reliability if harsh weather conditions experienced in 2014 were to occur in 2030. While the weather conditions tested in this study are harsh, they are surely plausible as they represent actual meteorological events in the recent past. LAI's analysis takes into account the reduction in energy production from wind generation resources due to cold temperatures as well as high wind speeds that exceed operating limits and the reduction in generation from solar PV resources due to snow cover. Under a sub-set of harsh winter conditions, wind and solar generation output would be likely be sharply reduced during the most critical days in the examined period, often for stretches significantly longer than the four to eight hours of storage capability that current battery energy storage systems provide.

Grid security requirements in most RTOs, including PJM and NYISO, typically require resource adequacy to ensure uninterrupted power supply under "n-1" and "n-1-1" contingencies, that is, the successive loss of the largest generation unit and/or transmission link on a day when electric demand is high. Resource adequacy also accounts for the probability that some resources will be unavailable or will have less than full capacity available during a contingency due to factors such as plant outages and maintenance, and the limited availability of wind, sunshine, natural gas and other fuels. Throughout most of the continental U.S., demand for electricity peaks on hot summer days due to the use of air conditioning. As a result, electric resource adequacy guidelines have traditionally focused on ensuring that sufficient generating capacity is available to meet the peak demand during the summer.

Since the mid to late 2000s, the shale gas boom coupled with the proliferation of natural gas-fired electric capacity has increased both the demands on the natural gas infrastructure and its importance in ensuring electric reliability across the U.S. In response, RTOs and other organizations charged with ensuring reliability have paid increasing attention to gas-electric coordination. Evaluation of grid reliability and resilience during winter weather conditions is an integral part of RTO's system planning capability, particularly considering the February 2021 ERCOT grid failure causing loss of life, massive human suffering, and billions of dollars of economic impacts due to unserved energy.[114] During the peak heating season, gas-fired generators compete for available pipeline delivery capability when traditional LDC obligations are scheduled first to serve residential, commercial and industrial customers. Going forward the replacement of coal and dual fuel oil and gas-fired capacity with renewable generation will

[114] Economic losses from lost output and damage are estimated to be $130 billion in Texas alone and over a hundred deaths have been documented, though this is likely an undercount. Joshua W. Busby, Kyri Baker, Morgan D. Bazilian, Alex Q. Gilbert, Emily Grubert, Varun Rai, Joshua D. Rhodes, Sarang Shidore, Caitlin A. Smith, Michael E. Webber, Cascading risks: Understanding the 2021 winter blackout in Texas, Energy Research & Social Science, Volume 77, 2021, https://www.sciencedirect.com/science/article/pii/S2214629621001997.

increase reliance on the remaining gas-fired capacity when weather conditions sharply limit solar and wind generation.

In order to assess REAE's impact on gas and electric reliability LAI has reviewed the frequency and duration of harsh winter conditions affecting the availability and performance of variable energy resources. To illustrate how severe, but plausible winter weather conditions could threaten gas and electric reliability in the study region, LAI has analyzed the likely consequences on gas and electric reliability if the severe weather conditions experienced in 2014 were to occur in 2030. Such severe winter weather conditions would be likely to materially reduce energy production from wind generation resources — both onshore and offshore — as well as solar PV resources. Under a sub-set of harsh winter conditions, there would likely be a coincident loss of both solar and wind generation.

LAI conducted Aurora simulation modeling which recreated January 2014 weather in conjunction with forecast 2030 electric system load and the generation resources projected for 2030 by capacity expansion modeling. In analyzing this scenario, LAI has been guided by the methods and practices that PJM and NYISO employ when performing their own analysis of system reliability to extreme winter weather events. LAI has reviewed the more conservative reliability analysis performed by ISO-NE regarding the scheduling and performance of wind and solar resources under harsh weather conditions but has not conducted like analysis in the present context.

Some of the issues PJM faced in 2014 have been mitigated by new transmission buildout or reduced temperature-related forced outages due to increased generator cold weather readiness. However, the grid of 2030 presents new challenges related to both large and small variances in the production from renewable resources, in particular, the potential vulnerability of wind and solar production under extreme cold and snowfall conditions. Incremental capacity from REAE was well-utilized during the two extreme weather event periods identified in January 2014 and found:

- Cold-weather curtailments of OSW could amount to approximately 5,000 MW being forced out in REAE area during the highest electric demand days under the Polar Vortex weather conditions. During the highest peak day of the Winter Storm Janus period, cold weather would force out 5,000 MW of offshore wind for both the morning and evening peaks, and solar generation would be limited by snowfall coverage, resulting in about 2,000 MW of lost generation on average during daytime hours. During the afternoon when solar output normally would peak, about 8,500 MWh of renewable generation was lost to cold temperatures and snowfall during a single hour.

- Increased penetration of wind and solar renewable resources, coupled with steep increases in load to meet morning and evening winter peaks, creates swings in the need for dispatchable resources with fast-ramping capabilities, such as flexible gas-fired generation and battery storage.

- REAE allows for about 3,800 MW of combined-cycle generation to run during the most stressed days of extreme weather, which displaces other fossil generation that is less efficient, reliable, and flexible and reduces GHG, NO_x, and SO_2 emissions.

Hydraulic modeling demonstrates that REAE enables increased gas deliveries to generators. System operating pressures and resilience are also improved.

3.1 Modeling of Weather Scenarios Represent Plausible Outcomes From History

To illustrate how severe, but plausible, winter weather conditions could threaten reliability in the study region, LAI first selected historical winter weather events. LAI then analyzed the likely consequences for electric and gas system reliability of a similar winter weather event during the study period. The 2029-2030 winter was selected as the representative year for this test of grid reliability and resilience. That winter is roughly halfway through the study period and is therefore more representative of average conditions. Also, by the 2029-2030 winter there will likely be many OSW plants as well as additional solar PV resources operational in accord with New Jersey's and other mid-Atlantic states' statutory OSW and decarbonization requirements.

Modeling grid reliability and resilience requires the use of a suite of gas and electric simulation models. To test gas infrastructure capability under steady state and contingency conditions, LAI used the Gregg Engineering WinFlow and WinTran models to assess residential, commercial, and industrial loads as well as the demand associated with gas-fired generation across the Study Area. To derive the demand for gas-fired generation, LAI used Aurora and the capacity expansion modeling results discussed in Section 3, above. Consistent with NYISO and PJM practice, LAI analyzed periods of extreme cold, as those weather conditions place the greatest strain on gas-electric coordination. Extreme cold can cause peaks in both electricity demand and in residential, commercial, and industrial gas consumption, which limits the supply of natural gas available for power generation. In consideration of the increasingly important role of wind and solar generation resources in the region and their correlations with extreme cold, LAI considered two types of extreme winter weather for which to model electric load, variable energy generation, and the commitment and dispatch of other generation resources.

- **Cold Snap Event**. This event combines very cold temperatures that may be below the minimum operating temperature of onshore and offshore wind energy resources in some locations.
- **Snowstorm Event**. This event combines cold temperatures with high cloud cover and snowfall accumulation, which reduce generation from photovoltaic (PV) resources.

After preliminary examination of hourly temperature, wind speed, and precipitation together with daily snowfall, and snowpack data from various sources for the period 2000-2020, LAI selected two January 2014 extreme weather event periods. Data availability drove the selection of 2000-2020 as the period for preliminary examination. This is also consistent with PJM's practice in analyzing winter fuel security, which calls for the use of recent load data which is more likely to be representative of the expected PJM hourly loads during the forecast year.[115] LAI selected January 2014 as the basis for the weather analysis, as follows:

- **January 5-7, 2014,** for the Cold Snap event. This weather event was known as the Polar Vortex and had record lows of −9° F in Pittsburgh and −11 F° in Cleveland on January 7.
- **January 21-23, 2014,** for the Solar Generation Stress event. This period was known as Winter Storm Janus and had 13" of snowfall in East Rutherford, NJ and record Snowfall in Central Park, New York City on January 21. This cold period retained substantial snowpack for the following three days.

The selection of the proposed extreme weather events in the same month was convenient for data management and modeling of the two adverse weather events, but it was not a selection criterion. In actuality, the extreme weather conditions associated with the Polar Vortex extended from late December 2013 through early March 2014. LAI has relied on the aforementioned 3-day temperature data for purposes of the winter weather contingency analysis. In addition to the Polar Vortex, as an extreme cold period coupled with substantial snowfall happened about two weeks apart in January 2014. Table 4-1 reports the average temperatures for weather stations in New Jersey and Southeastern Pennsylvania for both the selected weather events in January 2014 and five historical cold snaps identified by NYISO. As shown in the table, January 2014 temperatures in New Jersey and Southeastern Pennsylvania were similar to those experienced during other cold snaps in recent decades and do not approach the extraordinary cold of January 1994.

Table 3-1. New Jersey and Philadelphia Conditions During 3-Day Cold Snaps

Winter	3-day Period[116]	Average Temperature (°F) Atlantic City, NJ	Philadelphia, PA
1993 - 1994	1/18/1994 - 1/21/1994	9.5	8.2
2003 - 2004	1/13/2004 - 1/16/2004	20.7	20.0
2004 - 2005	1/20/2005 - 1/23/2005	19.1	17.3
2017 - 2018	1/04/2018 - 1/07/2018	13.9	14.2
1995 - 1996	1/04/1996 - 1/07/1996	20.6	18.8
2013 - 2014	1/05/2014 - 1/07/2014	27.2	26.8
2013 - 2014	1/21/2014 - 1/23/2014	15.5	17.0

[115] PJM Fuel Security Analysis Technical Appendix, December 17, 2018, https://www.pjm.com/-/media/library/reports-notices/fuel-security/fuel-security-technical-appendix.ashx, page 7.

[116] Because NYISO reported a 4-day period for each 3-day Cold Snap, it was assumed that each Cold Snap included half of the first and last days of the reported 4-day period. See, Analysis Group, Final Report, Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, November 2019, page 32. Available at https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf/cbecabaf-806b-d554-ad32-12cfd5a86d9e.

In addition to the extreme winter weather conditions modeled weather events tested in this evaluation, ISO-NE has also identified hurricanes and ice storms as high-impact, low-probability events having the potential to cause large-scale output reduction of wind resources. ISO-NE has recommended modeling hurricane events as having a 6% annual probability and resulting in OSW output reductions of 50% in week 1, 25% in weeks 2-4 and 10% for months 2-6. For ice storms, ISO-NE noted "there were 2 major ice storms (1921, 1998) in the region in the 20th century," recommends modeling ice storms as having a 2% probability of occurring each year and resulting in 50% reduction in land-based wind and 10% reduction in OSW during the ice storm and the following day, and a 10% reduction in land-based wind on days 2-7.[117]

ISO-NE also considered how extraordinary weather conditions could affect PV output. They identified hurricanes, ice storms, and hailstorms as high-impact, low-probability events having the potential to cause large-scale output reduction of PV resources. For hurricanes, they noted that "extremely strong wind and heavy rain … could damage the supporting structures and the panels of the large scale utility solar resources, resulting in extended outage for repair." ISO-NE recommends modeling hurricane events as resulting in a 90% reduction in utility and distributed PV utility in the first week after the storm, a 25% reduction in week 2 and a 10% reduction for the next six months. ISO-NE notes that "golf ball size hails with high speed could damage the solar panels, resulting in extended outage for repair." ISO-NE recommends modeling hailstorms as having a 1% probability of occurring in a given year resulting in a 50% reduction in solar PV output during the following week, and a 10% reduction for the next six months.[118] Similarly, ISO-NE recommends modeling ice storms as causing a 33% reduction in solar output the next day, and a 10% reduction in days 2-7.

3.2 Extreme Winter Weather Can Reduce Production from Variable Energy Resources' Generation

The output of wind and solar generation resources depends on weather conditions. In theory, wind and solar generation output from January 2014 could be used to forecast wind and solar generation under similar weather conditions in future years. However, because of the rapid growth and development of wind and solar resources that has occurred since 2014, the

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[117] See slides 19-20 of ISO New England's 2021 Economic Study: Future Grid Reliability Study Phase 1's Resource Adequacy Screen and Probabilistic Resource Availability Analysis Assumptions & Study Scenarios – Part 2 presentation, available at https://www.iso-ne.com/static-assets/documents/2021/10/a5_2021_economic_study_fgrs_phase_1_resource_adequacy_screen_and_probabilistic_resource_availability_analysis_assumptions.pdf. See slides 36, 38 and 39 of ISO-NE, Economic Study: Future Grid Reliability Study Phase 1's Resource Adequacy Screen and Probabilistic Resource Availability Analysis Assumptions & Study Scenarios – Part 3 presentation, https://www.iso-ne.com/static-assets/documents/2021/12/a6_2021_economic_study_phase_1_fgrs_probabilistic_resource_availability_and_resource_adequacy_screen_results_part_3.pdf.

[118] See slides 21-23 of ISO New England's 2021 Economic Study: Future Grid Reliability Study Phase 1's Resource Adequacy Screen and Probabilistic Resource Availability Analysis Assumptions & Study Scenarios – Part 2 presentation, available at https://www.iso-ne.com/static-assets/documents/2021/10/a5_2021_economic_study_fgrs_phase_1_resource_adequacy_screen_and_probabilistic_resource_availability_analysis_assumptions.pdf.

geographic distribution and unit characteristics present in 2014 are not representative of the existing and planned wind and solar generation in NYISO and PJM. To estimate the output of NYISO and PJM wind and solar generation resources existing in 2030 under January 2014 weather conditions, LAI identified wind and solar generation resources that will be in operation in 2030 per the capacity expansion modeling and then estimated output using hourly weather data from January 2014. As discussed below, LAI used the same methods and meteorological datasets to estimate solar and OSW output for the extreme winter weather modeling that was used in the capacity expansion and all-hours modeling in Section 2, but data limitations necessitated the use of a different methodology for land-based wind.

Offshore Wind

Over the next decade, OSW will play an increasingly important role in supplying electric energy in the Northeast and Mid-Atlantic. However, as no OSW has entered commercial operation in NYISO or PJM, OSW generation data for January 2014 is not available. To forecast OSW output in 2030, LAI began by forecasting the OSW generation resources present in 2030 using the capacity expansion modeling discussed in Section 2. To predict the generation produced by OSW capacity at each location, LAI used the OSW turbine simulation model developed and maintained by the National Renewable Energy Laboratory (NREL) and NREL's 2000 to 2020 meteorological dataset covering potential OSW project locations.

Each wind turbine manufacturer provides information on the operating conditions under which their products can operate. The maximum windspeed in which a turbine can operate is known as the "cut-out" speed, and the minimum windspeed as the "cut-in" speed. Consistent with the 2020 NREL ATB's reference facilities, LAI used a "cut-out" windspeed of 25 m/s and a cut-in windspeed of 3 m/s for OSW turbines.[119] Higher than cut-out windspeed events along the Atlantic coast are infrequent except during severe winter storms and the August-November hurricane season. Lower than cut-in windspeed occurs much more frequently and also requires other technologies for capacity backup. Lower than cut-in windspeed is less ramping issue as there is very limited generation when the windspeed is just above 3 m/s. The threat of OSW sudden cut-out due to excessive wind increases the need for gas-fired fast-ramping generation capacity. For example, the Block Island wind farm was generating at full output of 30 MW when winter storm Stella, a blizzard with heavy snowfall and wind speeds up to 74 mph, struck on March 14, 2017. With a cut-out speed of about 55 mph (25 m/s), the Block Island turbines had to suspend operation for several hours and did not produce electricity until the windspeed dropped below the cut-out limit and operations were restored.[120]

Wind turbine operating availability is also constrained by low and high temperature limits. International design standards for "standard" wind turbines are an operational temperature

[119] See https://nrel.github.io/turbine-models/Offshore.html. NREL's 12 MW and 15 MW reference turbines for OSW both specified a cut-out speed of 25 m/s, consistent with industry standards. The 2021 NREL ATB relied on identical power curves.

[120] North American Windpower, March 16, 2017. Available at https://nawindpower.com/winter-storm-stella-not-problem-block-island-wind-farm.

range of –10°C to +40°C and a pause or standby "survival" range of –20°C to +50°C.[121] The control system shuts the turbine down when the temperature in the nacelle falls below the operational lower temperature limit. The minimum operational temperature for a low temperature climate wind turbine option package varies from –15°C to –30°C. For a cold weather package turbine, when temperature is below the standard turbine lower limit, the power curve is derated due to heating of oil and certain components and limiting stress forces.[122] The PJM and NYISO study region is not cold enough to justify the additional capital and operating costs of adding a cold weather package to land-based or OSW turbines, given current market rules.[123] PJM market rules that influence this decision are further discussed in Section 1.1.

For the many years of data examined at an example New Jersey offshore location, extreme cold temperatures at rotor hub height (about 140m above mean sea level) are below the low temperature operating limit of current wind turbine models in some hours. The low temperature limit of Vestas offshore standard kit models is –10°C for its newest, 15 MW, model.[124] While information on the minimum operating temperature of comparable turbines from other manufacturers was not available, it is reasonable to assume that GE's 12-14 MW Haliade-X OSW turbine will have the same -10°C as GE's 6 MW Haliade OSW turbine.[125] For the example offshore location there were January or February hours in some years with hourly temperature below –15°C, and more hours, including some in March and December, below –10°C, as shown in Figure 3-1. LAI adjusted the generation simulated by the NREL wind power model to curtail generation for hours below –10°C, assumed to be representative of the operating limit for most large turbines models to be installed off the coast of New Jersey and New York.

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[121] In Fahrenheit, the operational temperature range is 14°F to 104°F and the pause or standby "survival" range is 4°F to 122°F.

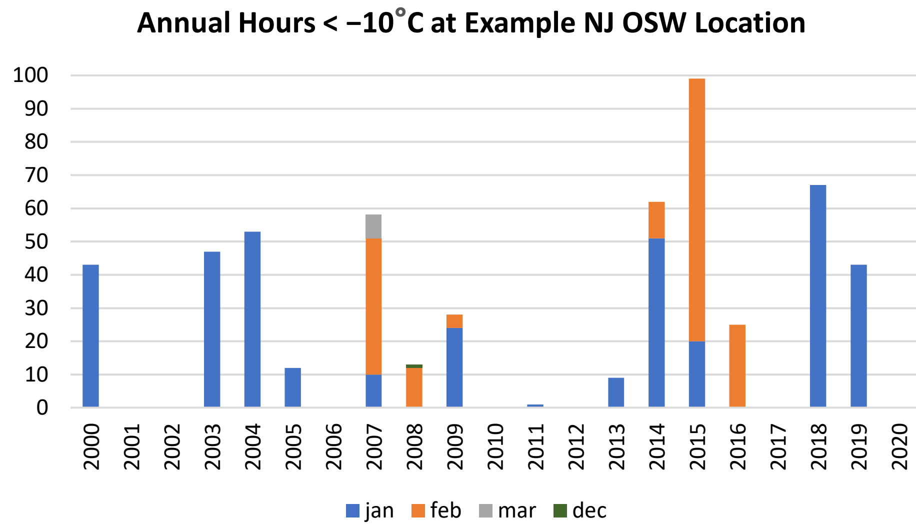
[122] Pieter Jan Jordaens, "Low temperature compliance testing of wind turbine applications for the 'cold climate' market," 2016 Wind Europe presentation, https://windeurope.org/summit2016/conference/allfiles2/76_WindEurope2016presentation.pdf.

[123] Adding a cold weather package can increase the cost of a wind turbine by 10-15%. See, e.g., https://www.turbomachinerymag.com/view/who-is-to-blame-for-the-texas-grid-outages.

[124] Vestas, Offshore Wind Model Product pages. Available at https://www.vestas.com/en.

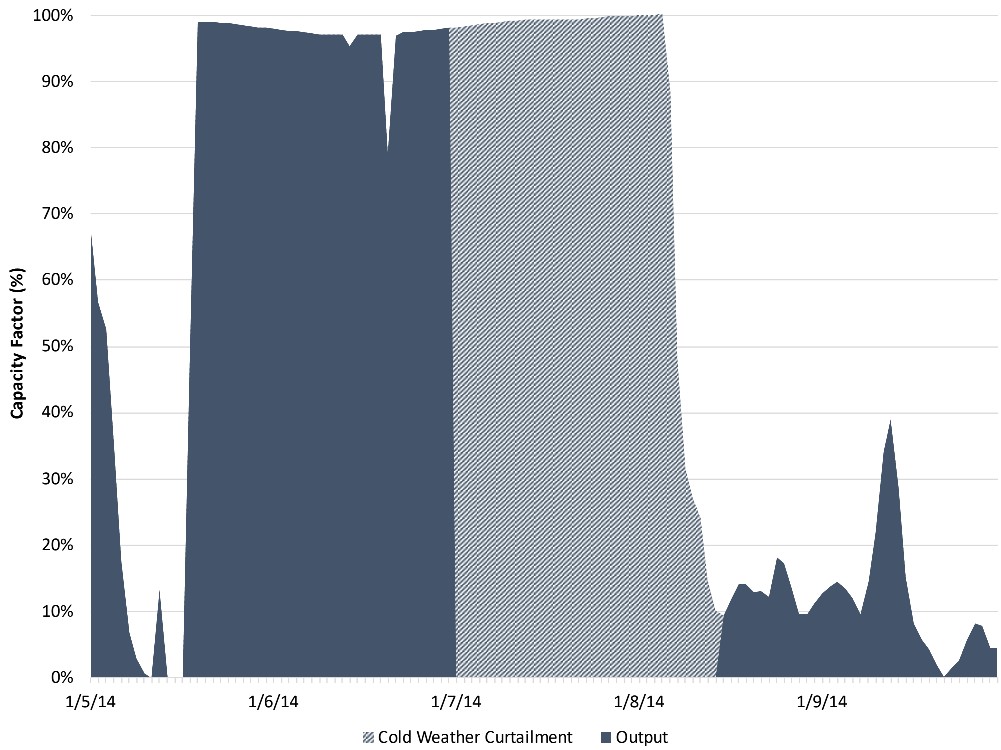
[125] GE, GE's Haliade 150-6MW High yield offshore wind turbine, page 4, https://www.ge.com/renewableenergy/sites/default/files/2020-01/wind-offshore-haliade-wind-turbine.pdf.

Figure 3-1. Annual Hours below Minimum Operating Temperatures of OSW Turbine Models



For the January 5-7, 2014, cold snap, the example OSW location had five consecutive hours below –15°C (starting 6am) and 33 consecutive hours below –10°C (starting 12am) on January 7. January 2014 had a total of 50 hours below –10°C. The 33 consecutive hours spell of sub-operating temperature would result in a lengthy outage during a time when windspeeds were strong enough to otherwise generate at full capability.

Figure 3-2. Example New Jersey Offshore Wind Hourly Capacity Factor, Jan. 5-9, 2014[126]

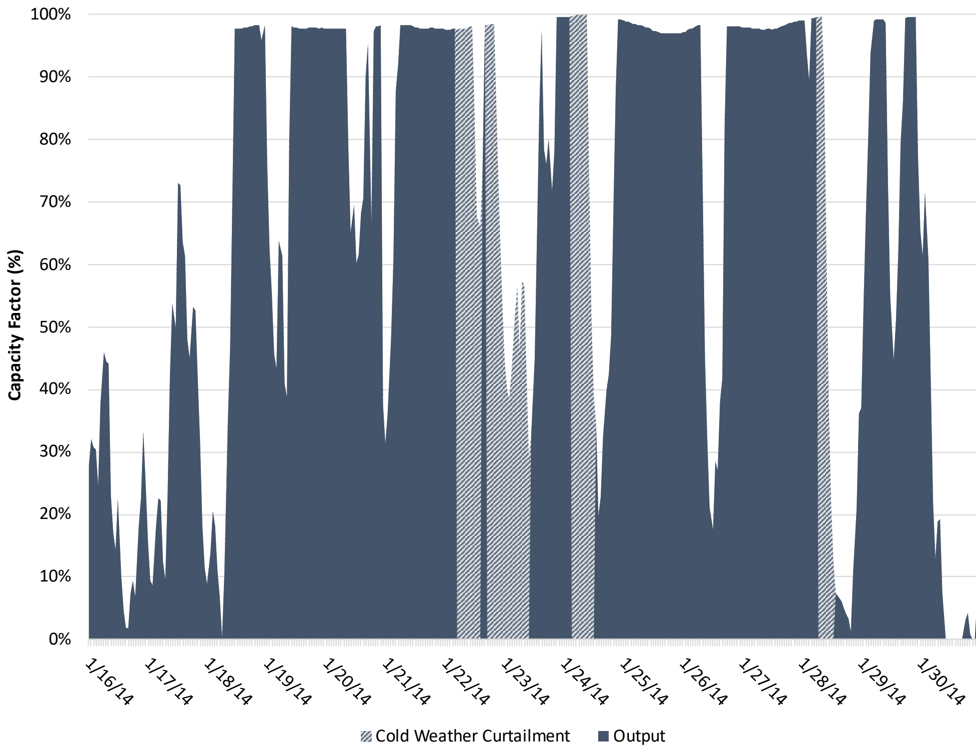


Cold weather conditions also occurred, albeit to a less dramatic extent, during the Winter Storm Janus period. Notably during January 22-24, when PJM experienced three of its top ten winter peak days in history through January 2014, offshore wind output would have been zero during more than half of those hours due to low temperatures.[127]

[126] Output produced using 15-MW turbine power curve. Capacity factors are calculated after netting a constant loss factor to account for losses such as wake losses, power conversion losses, and other factors that reduce wind turbine output.

[127] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection, p. 32. May 8, 2014. See https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

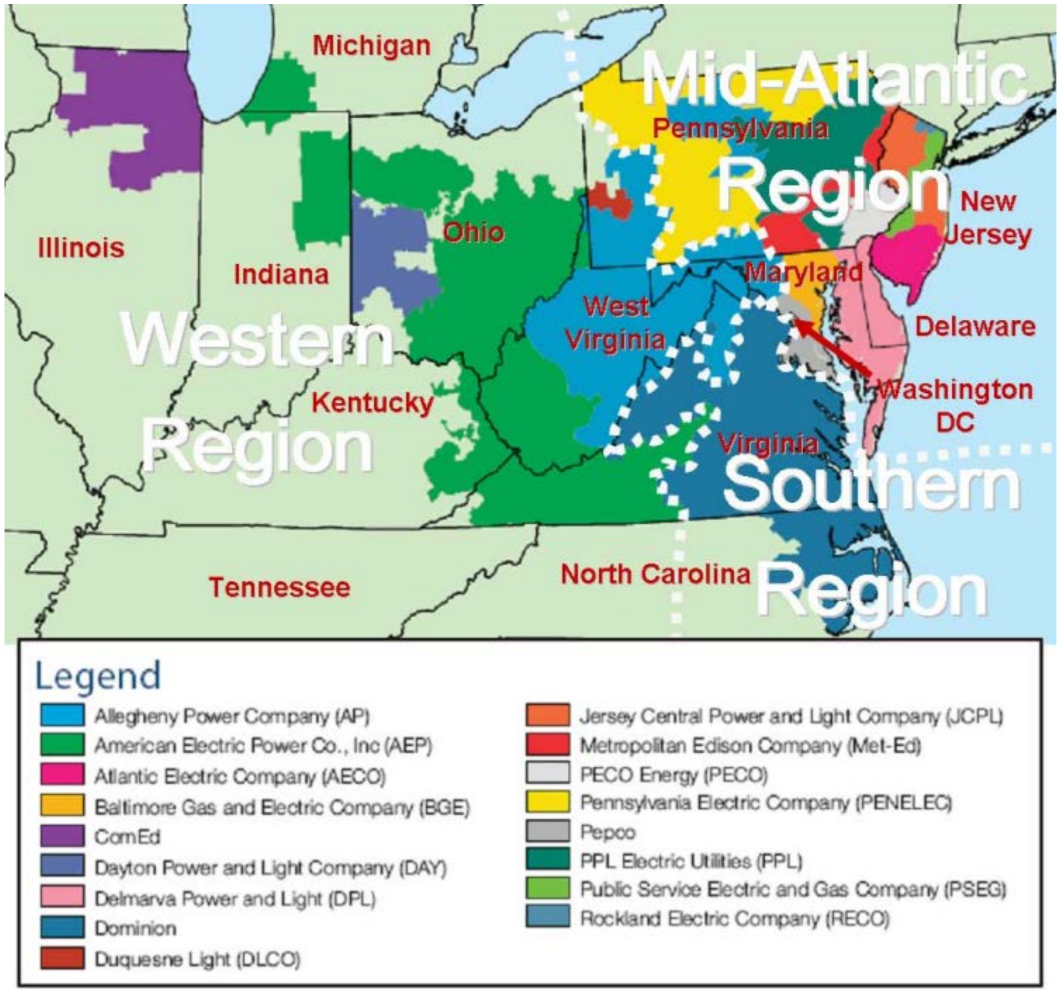
Figure 3-3. Example New Jersey Offshore Wind Hourly Capacity Factor, Jan. 16-31, 2014



Land-based Wind

NREL's meteorological dataset for onshore wind resource locations extends from 2007 to 2012. Hence, NREL's dataset could not be used for modeling onshore wind generation in January 2014. Therefore, instead of simulating wind generation based on observed conditions, LAI used actual land-based wind generation from January 2014 to estimate hourly capacity factors for wind generation resources operating in 2030 under January 2014 conditions. Specifically, LAI used PJM's reported actual hourly wind generation by reporting regions (Mid-Atlantic, South, West) and NYISO's reported hourly wind generation for its entire control area. As shown in Figure 3-4, PJM's Mid-Atlantic region includes the entire region served by REAE, as it encompasses New Jersey, Southeastern Pennsylvania and BGE's service franchise in Maryland.

Figure 3-4. PJM Control Area and Hourly Data Reporting Regions[128]



PJM began reporting hourly wind generation by each of three regions in January 2011. For PJM West, PJM Mid-Atlantic and NYISO LAI implemented the following procedure for estimating hourly capacity factor profiles. First, the hourly maximum generation capability of wind resource operational capacity in January 2014 was estimated by taking the maximum hourly generation over the surrounding three-month window (December 2013 to February 2014). A three-month period is sufficiently long to ensure that some hours will result in the maximum possible capacity factor, but only includes one month after January 2014, in order ensure that the period did not include any months in which new projects would not enter commercial operation in February. Second, LAI used the Mid-Atlantic region maximum generation hourly factor profile as a proxy for PJM South, which lacked wind generation data in 2014.[129] Third, LAI made the simplifying assumption that each LBW resource profile could be estimated by subtracting the maximum hourly capacity factor relative to nameplate capacity from unity for the capacity factor profiles

[128] Source: PJM

[129] This simplifying assumption has a limited effect on profile data, as there was only one LBW project in-service by 2014 in the Southern region.

simulated with the NREL WIND Toolkit meteorological data in 2011 for use in Aurora. The loss factors were applied to each of the profiles to represent hourly 2014 capacity factors by reducing the 2014 maximum generation hourly factors with the 2011 loss factors.

Solar PV

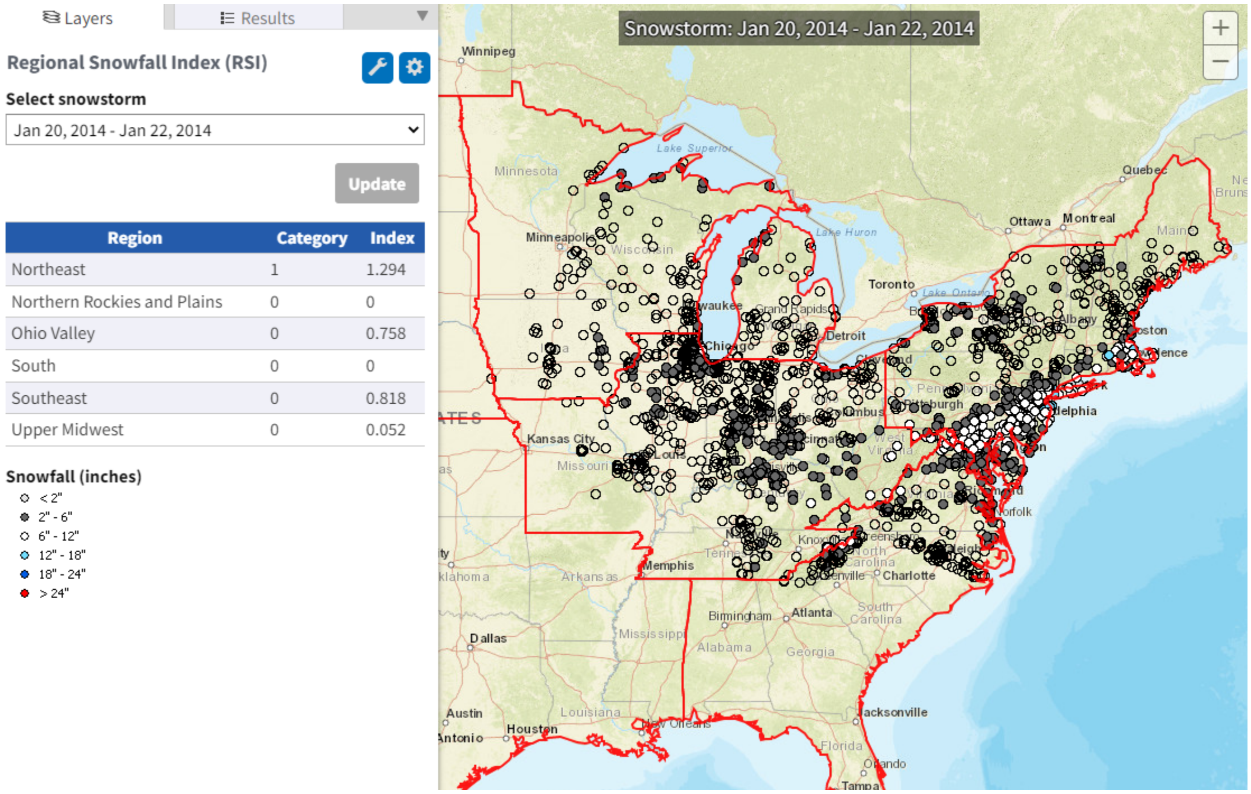
For modeling solar PV generation during extreme winter weather, including snowfall accumulation covering the PV arrays, a shortcoming of the available meteorological data in the NSRDB is that while it includes precipitation, it does not explicitly include snowfall. Although snowfall covering PV arrays is not a significant determinant of annual PV generation, it is important for accurately representing PV generation during short-duration winter weather events with significant snowfall and accumulation. The NREL SAM model for simulating PV generation includes an optional, simple snow cover sub-model, but using that model requires hourly or sub-hourly snowfall data, which is generally not available.

To model the effects of snowfall on PV generation, LAI obtained daily snowfall and snowpack data for 14 major airport locations in the study region. LAI explored the decremental effect of snowfall by testing several regression equations that used daily snowfall and hourly solar generation in the three PJM regions (Mid Atlantic, South, West). While LAI found an expected negative relationship between snowfall and solar generation at statistically and materially significant levels, the regression analysis results are inadequate for developing January 2014 hourly profiles for two reasons. First, daily snowfall data alone does not contain information on when over a 24-hour period snow fell, which affects the hourly profile of snow cover reductions of PV generation during daylight hours. Second, available timeseries of solar generation data are too limited, especially considering the small number of snowfall events each winter. PJM did not report solar PV generation prior to 2019 and NYISO has not yet put solar generation in its own reporting category. NYISO separates wind and hydro renewable resources, but solar is still reported in the "other renewable" category.

The National Centers for Environmental Information (NCEI) at NOAA produces the "Regional Snowfall Index (RSI)" for significant snowstorms across the eastern two-thirds of the U.S.[130] RSI values are binned into five categories, from Notable (1) to Extreme (5). The RSI is weighted by the population affected by a storm as well as the amount of snowfall. The RSI reports a separate index for each of six NCEI climate regions in the eastern two-thirds of the U.S. Because only part of the Northeast, Ohio Valley and Southeast regions are within the PJM and NYISO study area, LAI relied on the maps produced by the NCEI interactive viewer of snowstorms to identify a widespread snowfall event across much of the study area that occurred during a cold spell, resulting in slow snow melt. After viewing all snowstorms listed since the 2006-2007 winter, LAI selected the January 20-22, 2014, snowstorm event. That snowstorm was not as extensive in its geographic coverage across the study area as some other snowstorms, nor as deep as some of the other snowstorms. Hence, it does not represent the most crippling or severe snowstorm but occurred during a very cold period, another weather criterion for this study.

[130] See the "Regional Snowfall Index (RSI)" web page at https://www.ncdc.noaa.gov/snow-and-ice/rsi/.

Figure 3-5. NOAA Regional Snowfall Index, Snowstorm of Jan. 20-22, 2014[131]



The NOAA National Centers for Environmental Information website also reports the most severe snowstorms since 1956 in the Northeast, using a Northeast only index.[132] To date, it includes 66 snowstorms over the past 66 years, an average of one per winter. A disproportionately large number (25) of severe snowstorms occurred in the 11 years since 2011, more than 2.25 times the long-term expected number based on a simple average. Whether or not this upward trend is explained by the effect of climate change is outside the scope of this inquiry.

Because publicly available snowfall and snowpack data that LAI acquired was limited to daily observations, generally made in the morning, LAI was limited in how much statistical analysis could be performed to estimate the reduction in energy generation due to snow cover. As an alternative approach, LAI synthesized information from numerous field studies and models of the effects of snow cover on solar PV array output. Reports and publications with information that was useful for the purpose of representing typical energy output reduction profiles included

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[131] Source*: NOAA,* "Regional Snowfall Index (RSI)" web page at https://www.ncdc.noaa.gov/snow-and-ice/rsi/.

[132] NOAA, "Regional Snowfall Index (RSI), The Northeast Snowfall Impact Scale (NESIS)" web page at https://www.ncdc.noaa.gov/snow-and-ice/rsi/nesis.

Brench (1979),[133] Sandell (2012),[134] Marion et al. (2013),[135] Andrews, Pollard, and Pearce (2013),[136] Ryberg and Freeman (2015),[137] Anadol and Erhan (2019),[138] Pawluk et al. (2019),[139] and Øgaard et al. (2021).[140]

General findings from this literature include the following:

- The amount of snowfall is more important than ground-measured snowpack because snow tends to slide off tilted PV arrays.
- Snow slides off faster on more tilted arrays.
- Sliding of snow is much more frequent than melting of snow on the arrays as the mechanism of snow shedding.
- Some solar insolation gets through shallow snow cover (up to about 1 inch) to the PV arrays, resulting in faster sliding than for deeper snow cover.
- Sliding of snow begins to occur at ambient temperatures well below freezing because the PV arrays generate heat, causing the snow-array surface interface to melt, thereby reducing friction.
- Snow takes longer to slide off on cloudy days, which have much reduced solar insolation, than on clear sky days.
- Snow takes somewhat longer to slide off rooftop arrays than tilted ground-mounted arrays, primarily due to obstructions such as gutters and less optimized azimuths.
- Tilting PV arrays shed snow more quickly than fixed mount PV arrays because the tilt angle of single and dual axis arrays can be increased in advance of snowfall.

Based on these key functional relationships and measurement data from the various field tests, LAI developed a simple set of snow cover reduction factor hourly profiles to apply to the hourly energy generation simulated at each location and type of PV array facility modeled in Aurora.

[133] Brench, Bronwyn L. (1979). “Snow-covering Effects on the Power Output of Solar Photovoltaic Arrays.” December 1979. MIT Lincoln Laboratory. Prepared for the U.S. Department of Energy

[134] Sandell, Marni (2012). “The Effect of Snowfall on the Power Output of Photovoltaic Solar Panels in Halifax, NS,” Honours Thesis, Environmental Science, Dalhousie University, April 2.

[135] Marion, Bill et al. (2013). "Measured and Modeled Photovoltaic System Energy Losses from Snow for Colorado and Wisconsin Locations." *Solar Energy* 97, pp. 112-121.

[136] Andrews, Rob W., Pollard, Andrew, and Pearce, Joshua M. (2013). “The Effects of Snowfall on Solar Photovoltaic Performance.” *Solar Energy* 92.

[137] Ryberg, David and Freeman, Janine (2015). “Integration, Validation, and Application of a PV Snow Coverage Model in SAM.” NREL Technical Report NREL/TP-6A20-64260, September.

[138] Anadol, Mehmet Ali and Erhan, Erman (2019). “The Effect of Snowfall and Icing on the Sustainability of the Power Output of a Grid-connected Photovoltaic System in Konya, Turkey.” *Turkish Journal of Electrical Engineering & Computer Sciences* 27, pp. 4608-4623.

[139] Pawluk, Robert E. et al. (2019). “Photovoltaic electricity generation loss due to snow – a literature review on influence factors, estimation, and mitigation.” *Renewable and Sustainable Energy Reviews* 107, pp. 171-182.

[140] Øgaard, Mari B. et al. (2021). “Estimation of Snow Loss for Photovoltaic Plants in Norway.” 38th European Photovoltaic Solar Energy Conference and Exhibition.

These factors vary between light and heavy snowfalls and by type of PV array facility, as shown in Table 3-2.

Table 3-2. PV Facility Hourly Availability Parameters on Snow Days

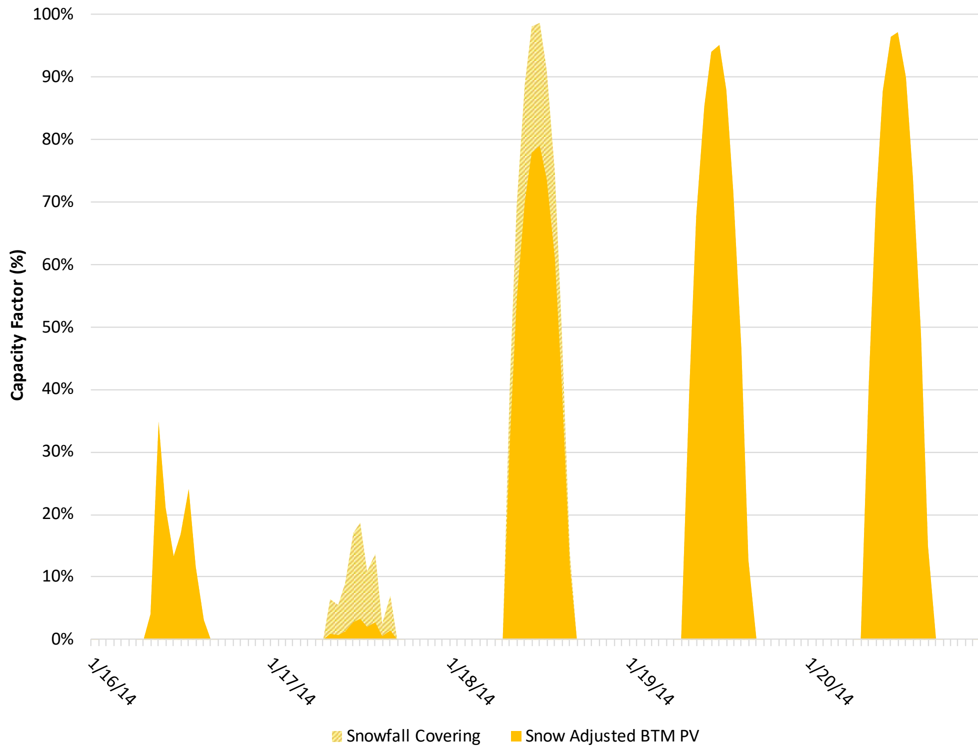
Snowfall Description	Daily Snowfall (inches)	Linear Parameter	UPV Fixed Tilt	UPV Tracking Tilt	BTM PV
Light	0 < SF ≤ 1	Constant	0.7091	0.7091	0.7091
		Hour Ending	0.0071	0.0071	0.0071
Heavy	SF > 1	Constant	0.0204	0.0245	0.0183
		Hour Ending	0.0134	0.0161	0.0121

The constant and hour-of-day parameters for utility PV fixed tilt resources were estimated from Ordinary Least Square regression results for PJM hourly generation, presumed to be almost entirely from fixed tilt PV arrays, for January and February in 2019, 2020, and 2021 regressed on snowfalls categorized into light and heavy. The hour ending coefficient is an intraday hourly change (trend) parameter. For each of the three PJM regions (including the South, which had some grid PV generation by 2019) LAI created a capacity-weighted average snowfall index for the region. The result of applying these two parameters is a linear upward trend over the daylight hours of PV array availability.

Parameters for UPV tracking tilt and BTM PV facilities are LAI assumptions based on review of several of the above-cited studies. For light snowfalls, LAI assumed no difference among array types for light snows. The accuracy of that simplifying assumption is not very relevant for this extreme weather analysis because the focus is on heavy snowfalls. For heavy snowfalls, LAI assumed that UPV tracking tilt array facilities would have constant and hour-ending parameters 1.2 times those of UPV fixed tilt facilities, and that BTM PV facilities would have constant and hour-ending parameters 0.9 times those for UPV fixed tilt facilities.

The Polar Vortex period did not include snow. During Winter Storm Janus, cloud cover and snowfall reduced solar generation. BTM solar comprises most of the installed solar capacity in the REAE area. Snowfall reduced solar output during five days during the Winter Storm, including leading into the most stressed part of the period on January 22nd.

Figure 3-6. Example New Jersey BTM PV Hourly Capacity Factor, Jan. 20-24, 2014



Load

To forecast PJM and NYISO load in January 2030 under January 2014 weather conditions LAI took load data from 2014 and rescaled it to account for actual and expected load growth. PJM's 2021 Load Forecast Report noted that "Winter peak load growth for PJM RTO is projected to average 0.3% per year over the next 10-year period, and 0.2% over the next 15-years. The PJM RTO winter peak load in 2030/31 is forecasted to be 135,568 MW, a 10-year increase of 3,541 MW…"[141] First, LAI obtained hourly metered load data by zone for the 2014 calendar year from the PJM Data Miner 2 and NYISO online databases. LAI then adjusted the PJM and NYISO load forecasts for 2030 to account for the impact of extreme winter weather conditions. LAI then used regression analysis to derive an adder and multiplier to scale each zone's 2014 load shape for each calendar month to the 2030 average and peak load forecast for that calendar month. The final load profiles consisted of the January 2014 load for each zone scaled by the estimated multiplier and shifted by estimated adder for that zone.

3.3 RTOs Have Studied Gas-Electric Coordination and Winter Weather Reliability

This section discusses how increasing reliance on gas-fired generation has increased the risks to electric reliability posed by extreme winter weather. The methods and assumptions that PJM and

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[141] PJM Load Forecast Report, January 2021, page 2. See https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx.

NYISO use to analyze fuel and energy security risks are discussed, as they inform LAI's extreme winter weather reliability analysis.

A comprehensive study of gas-electric coordination was conducted by the EIPC over the three-year period, 2013 through 2015. EIPC was formed in 2009 by 25 of the major eastern utilities to carry out a DOE-funded project, "Resource Assessment and Interconnection-level Transmission Analysis and Planning." The DOE subsequently extended the project as the, then ongoing, discovery and development of new natural gas resources and the increasing reliance on natural gas for power generation raised questions about the sufficiency of the natural gas infrastructure to support the anticipated need for natural gas power production.[142] In Target 1, LAI developed a baseline assessment of the natural gas infrastructure and electric interfaces affecting the reliability of gas-fired generation.[143] EIPC found that the natural gas infrastructure across the Eastern Interconnection was not designed to meet the coincident gas requirements of the higher priority gas utility sendout to RCI loads, and the lower priority loads associated with gas-fired generators lacking primary firm transportation entitlements.[144]

In Target 2, LAI combined forecasts of gas demand in the power sector with forecasts of residential, commercial, and industrial demand in order to forecast seasonal coincident peak demand. Quantification of seasonal peak demand on a coincident basis among LDCs, other firm capacity holders and gas-fired generators supported the derivation of pipeline capacity limits constraining gas delivery to gas-fired generators across the Eastern Interconnection. On behalf of EIPC, LAI previously found that most gas-fired generation in NYISO is served under non-firm transportation agreements and are exposed to pipeline and/or local delivery constraints during cold snaps.[145] In PJM, the report identified pipeline and locational constraints during peak heating season in Maryland, Virginia, the Delmarva Peninsula, Eastern Pennsylvania, and New Jersey. To address gas system resilience a number of gas-side contingencies were postulated to

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[142] LAI performed similar analysis for EIPC members in: Steady State Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005, Levitan & Associates for ISO-NE, January 2001; Steady State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005, Levitan & Associates for ISO-NE, December 2001; Multi-Regional Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generation Sector, Levitan & Associates for ISO-NE, IMO, PJM, NYISO & NERC, February 2003/July 2003; and updates to those reports.

[143] EIPC, Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study, July 2, 2015, Volume 4, Section 8. Available at: https://eipconline.com/s/Vol-4-Section-8-Gas-Electric-System-Interface-Study.docx.

[144] EIPC, Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study, July 2, 2015, Volume 7, Section 9, page 1. Available at https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cb374540d929797d53ae506/1555264603155/08+Phase+II.pdf.

[145] EIPC, Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study, July 2, 2015, Volume 7, Section 9, page 1. Available at https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cb374540d929797d53ae506/1555264603155/08+Phase+II.pdf.

assess the responsiveness of the network of pipeline and storage facilities in PJM to withstand the loss of critical pipeline or storage segments.[146]

EIPC did not run electric side contingencies associated with harsh weather conditions affecting energy production from solar, offshore wind and land-based wind generators. PJM and NYISO have both identified and studied the potential threat to reliability from fuel and energy security risks during extreme winter operating conditions documented in the EIPC reports. However, the EIPC planning horizon was short- to intermediate-term and therefore did not examine the longer-term grid reliability and resilience issues ascribable to the then unanticipated buildup of solar and OSW generation in New Jersey, other mid-Atlantic states, New York and New England.

The Polar Vortex of 2013-2014 made it clear to PJM that stronger incentives were needed to encourage better generation performance year-round, rather than only during the summer peak. In response, PJM's Capacity Performance rules were implemented in June 2016 to create stronger incentives for generation resources to be available whenever they are needed. PJM's Capacity Performance rules impose significant financial penalties on generation resources that do not meet their capacity obligations at times when PJM relies on emergency actions and procedures to ensure reliability.[147] However, the Capacity Performance rules do not provide strong incentives for OSW winter reliability due to the low frequency of PJM emergencies and the capacity obligations PJM imposes on OSW and other intermittent and limited duration resources. In the first three years PJM's Capacity Performance rules were in place, there was only one emergency event that triggered financial penalties for non-performance. The event was in October 2019.[148] Moreover, the capacity obligations of OSW and other intermittent resources reflect the ELCCs reported in Figure 2-8, above. PJM's ELCC for OSW generation resources will be 40% in 2023 and is forecast to fall to 30% in 2031, so OSW generation's capacity obligation only reflects 30-40% of its nameplate capacity, depending on the year.

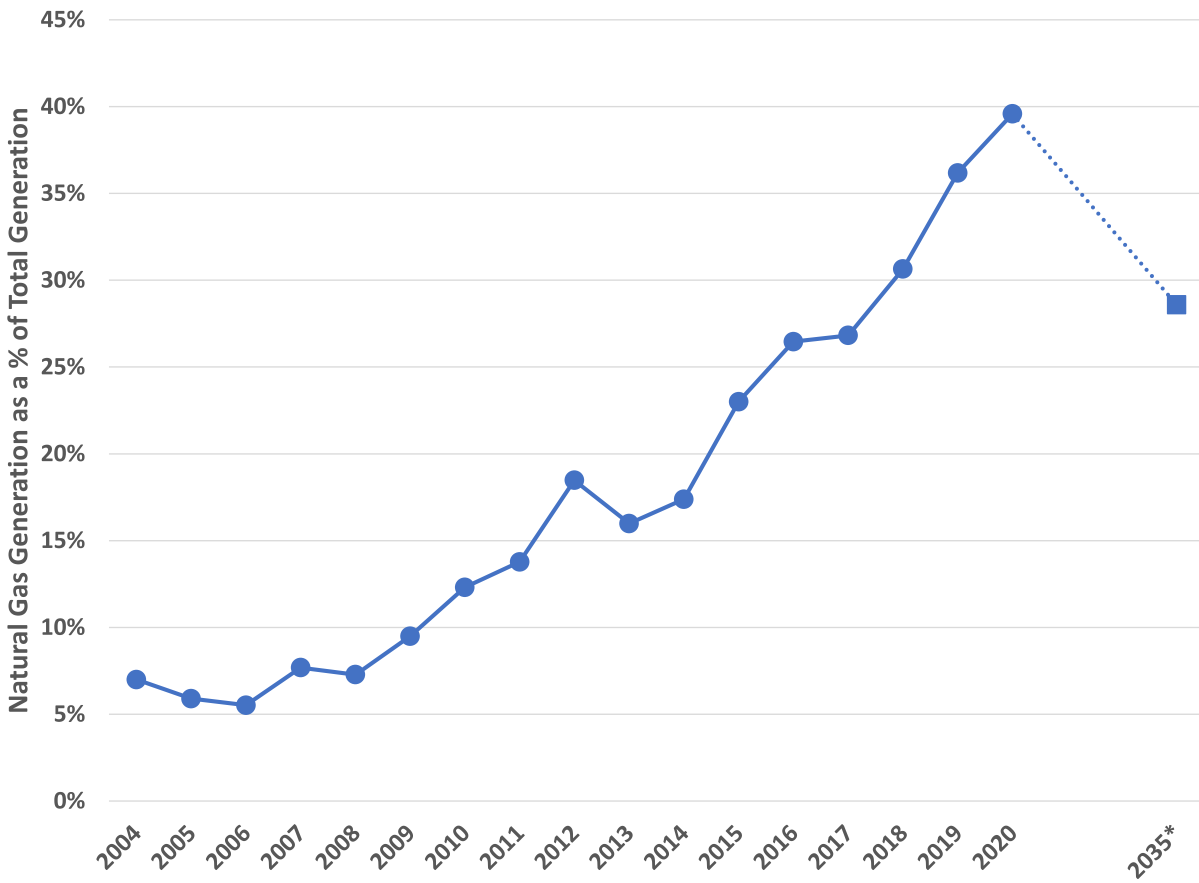
As shown in Figure 3-7, PJM's reliance on natural gas generation has increased dramatically over the last fifteen years. The gas share of total generation has grown from 5.5% in 2005 to 23.0% in 2015. Gas-fired generation reached 39.6% in 2020. PJM has forecast that the share of natural gas generation will fall modestly as production from wind and solar resources displaces fossil fuel generation over the forecast period. However, system reliability will continue to depend on natural gas, which will account for 28.6% of PJM generation in 2035.

[146] EIPC, Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study, July 2, 2015, Volume 10, Section 10. Available at: https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cb3750b7817f7173adae5e4/1555264781955/13+Phase+II.pdf.

[147] https://www.pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx, page 2.

[148] https://www.pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx, page 2.

Figure 3-7. Percentage of PJM Generation from Natural Gas[149]



PJM's reliance on gas-fired generation has increased, which has heightened concerns about the importance of fuel security and gas-electric coordination in ensuring electric system resilience when either supply or demand side contingencies arise. In 2018, these concerns prompted PJM to undertake an analysis of fuel security. PJM's fuel security analysis focuses on cold weather events because the risks to PJM generators' ability to procure fuel supplies are most prominent during the winter, when the delivery requirements of gas-fired generators often peak at the times when commercial and residential heating requirements are high. PJM found that approximately 16,000 MW of its generation resources were gas-only and did not have firm entitlements, other than on laterals from the mainline to the power plant.[150] Since 2020 PJM has

[149] PJM State of the Markets Reports for 2004-2020 available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml. 2035 forecast from PJM, Energy Transition in PJM: Frameworks for Analysis, December 15, 2021, https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx, page 10.

[150] Fuel Security Analysis: A PJM Resilience Initiative, PJM Interconnection, p. 18. December 17, 2018. See: https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx?la=en.

conducted an annual fuel security resource adequacy assessment. The assessment is focused on a 5-year ahead analysis of energy and fuel security risks in the face of extreme winter weather.[151]

Similarly, NYISO has found that:

> [T]he availability and consistent contributions of adequate amounts of natural gas-fired and oil-fired (or dual fuel) generating resources is necessary to maintain power system reliability in cold winter conditions. This is particularly true for Long Island and New York City. Simply put, avoidance of potential loss of load events in these load centers, under plausible adverse winter conditions, requires operation of natural gas and oil-fired units.[152]

NYISO's currently depends on gas-only and dual-fuel resources to ensure grid reliability. In downstate New York, the anticipated growth in renewable and clean energy resources has raised concerns about potential challenges to grid reliability. NYISO's concern regarding its continued dependence on oil-fired generation during winter months led to a 2019 study of fuel and energy security risks during winter operating conditions.[153]

The demand and supply inputs that PJM and NYISO use in their analyses of fuel and energy security risks during winter operating conditions are summarized in Table 3-3. Key demand inputs are peak demand by delivery year, modeled weather conditions and load shape. Supply reflects available generation and demand response resources, as well as fuel availability, assumed random forced outage rate, and additional modeled disruptions.

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[151] PJM, Fuel Security Monitoring Methodology, page 2. Available at https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20210610/20210610-item-13-fuel-security-monitoring-methodology.ashx page 2.

[152] Analysis Group, Final Report, Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, November 2019, pages 12-13. Available at https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf/cbecabaf-806b-d554-ad32-12cfd5a86d9e.

[153] *Id*, page 5.

Table 3-3. PJM and NYISO Winter Fuel and Energy Security Risk Modeling Inputs

Input	PJM[154]	NYISO[155]
Weather	Cold Snap (5 or more days in a row where the daily average PJM wind-adjusted temperature is below 21.5°F	Extended cold weather period including a three-day severe cold weather event
Load Shape	Historical Winter Load Shapes	Single-day hourly load shape scaled so that each day's modeled zonal total load reflects modeled weather
Delivery Year	5 Years from Now	4 Years from Now
Fuel Availability	Non-firm gas availability of 0% or 62.5%	Available Pipeline Gas – LDC/C&I Demand
Forced Outages	Historic unit-level non-fuel outage rate	Historic Winter Outage Rates
Additional Disruptions	Limited oil refueling, Pipeline disruptions, accelerated retirements	Limited oil refueling, limited natural gas availability, nuclear outage

Forced Outages and Fuel Availability

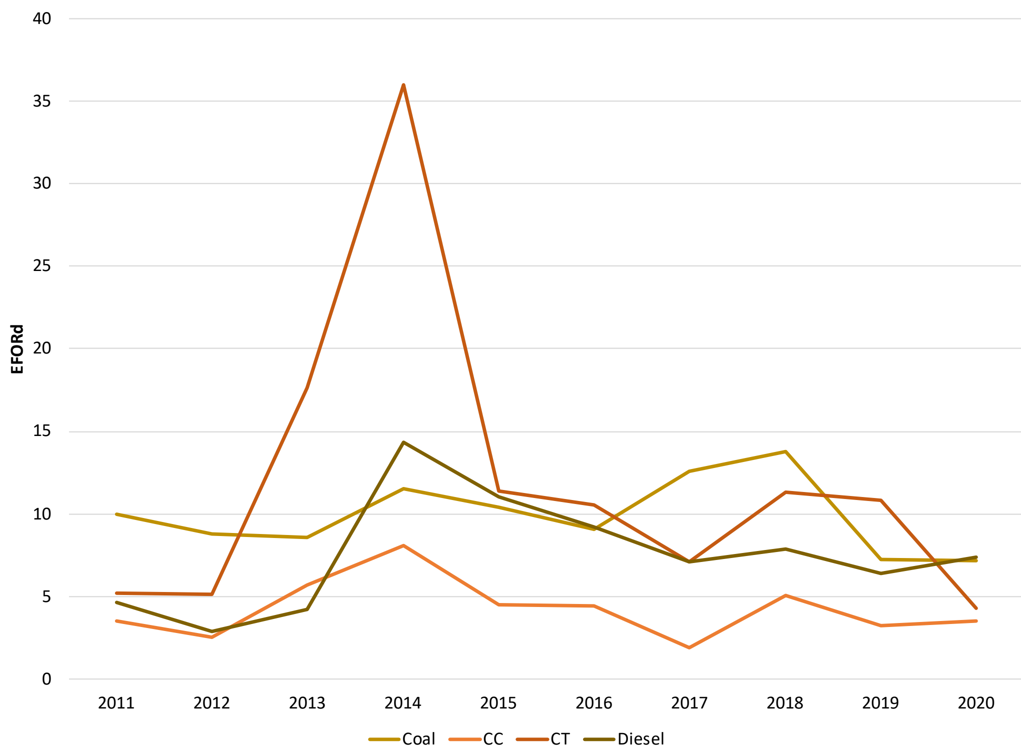
LAI utilized elevated forced outage assumptions for conventional generation in PJM which reflected the elevated outage risk during cold weather. However, data availability is limited; NERC GADS and PJM do not publicly release unit-level data, or data aggregated by unit type, at a daily granularity.[156] However, monthly Equivalent Forced Outage Rates (EFORd) by unit type and size have been reported since 2006.

[154] NJ BPU, In re the Implementation of L. 2018, C. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs, and In re the Petition of ETG Gas Company for Approval of New Energy Efficiency Programs and Associated Cost Recovery Pursuant to the Clean Energy Act and the Establishment of a Conservation Incentive Program, BPU Dockets No. QO19010040 & GO20090619, April 7, 2021, page 7.

[155] Analysis Group, Final Report, Fuel and Energy Security In New York State: An Assessment of Winter Operational Risks for a Power System in Transition, November 2019, pages 8, 11, 28-29, 37, and 40. Available at https://www.nyiso.com/documents/20142/9312827/Analysis%20Group%20Fuel%20Security%20Final%20Report%2020191111%20Text.pdf/cbecabaf-806b-d554-ad32-12cfd5a86d9e.

[156] PJM has started to report outage data for weekly forecast and actual by region here: https://dataminer2.pjm.com/feed/gen_outages_by_type/definition.

Figure 3-8. January EFORd Averages, Selected Unit Types[157]



All unit types had elevated forced outage averages in 2014. Detailed cause data is not available to link by unit or technology type. However, the Cold Weather Report indicates that 24% of all outages were caused by gas interruptions in the Polar Vortex snapshot.[158] It is difficult to identify the best way to avoid double counting outages for fuel supply interruptions while still employing a gas constraint. This is because non-gas generation may also be susceptible to curtailment due to lack of start fuel quantities. In some cases, gas supply may be a root cause that is obscured by another outage cause, as noted by PJM:

> PJM requested dual-fuel generation owners unable to secure gas to operate their units on oil during the extremely cold weather events. Even with this flexibility, generation owners encountered issues including run-time limits related to permit-defined environmental restrictions, resupply challenges and increased failure rates for unit startup.[159]

Per the 2018 Cold Weather Report, "PJM and its member companies have put [enhancements] in place in the years since the Polar Vortex, such as increased investment in existing resources, improved performance incentives, enhanced winterization measures and increased gas-electric

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[157] PJM Data Miner 2, Equivalent Forced Outage Rates – Monthly. https://dataminer2.pjm.com/feed/mnt_efor/definition.

[158] 2014 Cold Weather Report, p. 25.

[159] *Id*, p. 39.

coordination."[160] Given these enhancements, LAI adopted 2018 average monthly outage rates for input into the contingency case rather than 2014 outage rates. LAI utilized a derate (or "haircut") method rather than randomly determined forced outages because: (1) unit-specific data is not available, (2) a distribution of outage simulations would be required, and (3) results will not be disproportionately impacted by a particularly harmful draw.

LAI also adopted a daily fuel limit for gas-fired generation in the rest of MAAC that is not part of the REAE area, based on the assumption that fuel supply conditions would be tight across all pipelines during the 2014 contingency. LAI set the daily fuel limit at 62.5% of possible send out to reflect assumptions used in PJM's fuel and energy security modeling.[161] LAI also set a daily fuel limit for downstate gas-fired generation in the New York City and Long Island zones of NYISO, as nearly all of these generators are connected to LDCs rather than the bulk pipeline system and face bottlenecks within the New York Facilities System gas network. The daily fuel limit for this cohort was set based on a lookback at daily fuel usage from the EPA's Continuous Emissions Monitoring System.[162]

3.4 REAE Will Improve Power Sector Reliability and Resilience

LAI's Aurora analysis of the impact of extreme weather conditions on a 2030 resource mix shows that added pipeline capacity from REAE could improve regional reliability, the purpose of the project identified by the majority of the shippers.[163] This set of assumptions does not represent a precise forecast. Instead, it represents a plausible weather pattern for scenario analysis. As discussed above, generation from variable generation resources can be unreliable during winter storms. Figure 3-9 shows the gap between hourly renewable generation and demand (net of BTM Solar) during the Polar Vortex of the extreme winter conditions scenario.

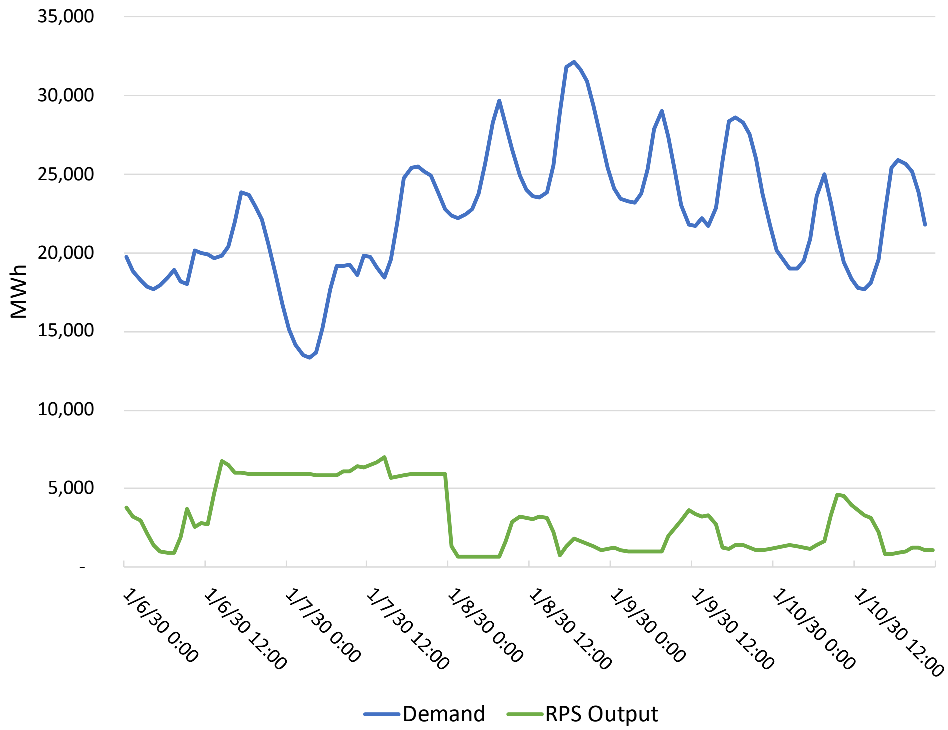
[160] 2018 Cold Weather Report, p. 2.

[161] Sendout assumed at heat rate efficiency of 7 Dth/MWh. This is similar to most combined cycle plants. While some gas-fired generators in the cohort group are less efficient simple cycle or steam turbine technologies, these technologies are unlikely to be dispatched.

[162] See EPA Air Markets Program Data: https://ampd.epa.gov/ampd/

[163] Transco Supplemental Filing.

Figure 3-9. Hourly Demand and Renewable Generation in REAE Area, Polar Vortex Period



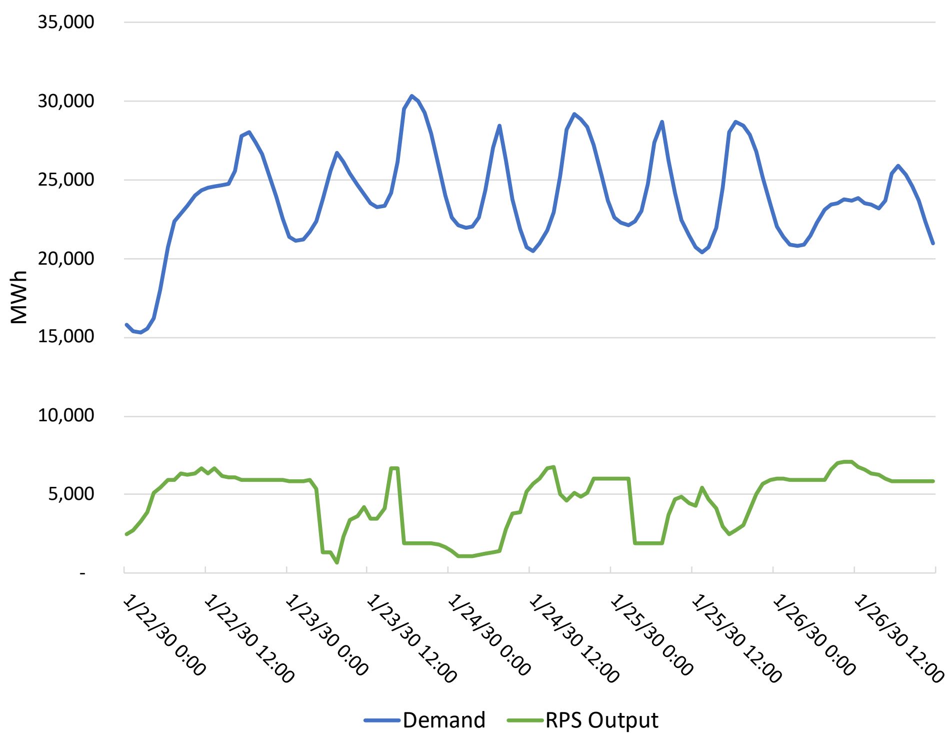
During the Polar Vortex, approximately 5,000 MW of OSW connected to EMAAC is curtailed due to cold weather conditions on the eve of January 8, 2030. The coincident weather and load profiles for that day are meant to replicate January 7, 2014, the day with the second-largest winter peak ever recorded in PJM.[164] The REAE area requires an early morning ramp of almost 7,000 MW over four hours, and an evening ramp of about 8,000 MW over four hours mainly to compensate for demand increases and the loss of BTM solar generation. No solar generation is lost to snow coverage on this day.

On January 23, 2030, offshore wind output is lost due to cold temperatures just hours before the morning peak. While solar output helps to meet the morning ramp, its output is diminished by about 20% due to snowfall, amounting to about 2,400 MW lost on average over daylight hours. During the noon hour, a total of about 8,500 MW of offshore wind and solar generation is lost due to cold temperatures and snowfall. Later that evening, renewable output drops almost 5,000 MW again due to cold-weather curtailment of OSW generation, just as the evening ramp into peak demand begins. Though onshore temperatures are not as frigid as during the Cold Weather Event, offshore temperatures still drop below the threshold for cold-weather operation. The sudden drop-off of OSW generation, combined with ramping needed to meet the evening peak, means that about 9,000 MW of dispatchable generation must quickly activate and ramp over a couple hours. Utility-scale solar cannot mitigate these changes in demand, and in fact may

[164] See 2022 PJM Load Forecast Report Table F-1, page 80: https://pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx.

exacerbate the need for dispatchable resources that can cycle up and down quickly by increasing the evening ramp. Battery storage helps mitigate some of the needs for ramping capability during extreme weather but burdens other resources with providing extra energy to account for efficiency losses. Storage resources reasonably available in 2030 also cannot compensate for a long-duration unplanned outage or low renewable output period.

Figure 3-10. Hourly Demand and Renewable Generation in REAE Area, Winter Storm Peak Period



REAE allows for about 5.0 million dekatherms of additional natural gas to be used for power generation in the REAE area. REAE enables more efficient combined cycle generation to be utilized. Over the course of the winter contingency period most of the benefits of REAE to power generation occur in a two-day block in the Polar Vortex Period and a four-day block in the Winter Storm Period. The incremental capacity from REAE effectively allows for about 3,800 MW of combined-cycle generation to run for the full day during these periods. In the highest electric sector demand day, January 8, the addition of REAE allows for about 4,000 MW of combined cycle capacity to be available. The additional capacity available through REAE is critical for supplying combined-cycle generation in the REAE area, as about half of the 14 GW of combined-cycle capacity in the REAE area does not have a backup fuel. Approximately 3,900 MW of gas-only capacity in MAAC does not run at all during January 8th peak day in the No REAE Case. REAE reduced oil use by about 1,550 MW on average over the course of the January 8 peak day. Loss of flexible and efficient combined-cycle resources supplied by REAE to provide energy, reserves, and ramping capability will increase reliance on simple cycle and steam turbines and/or oil-fired capacity. Having to rely on less flexible generators and fuel sources increases the potential for unforced outages which may lead to operational problems including loss of reserves, emergency actions, and loss of load. PJM noted that during the 2014 weather contingencies, "… [dual-fuel] generation owners encountered issues including run-time limits related to permit-defined environmental restrictions, resupply challenges and increased failure rates for unit startup."[165]

In conducting this simulation, LAI did not increase the need for spinning reserves on the PJM system or institute a requirement for additional ramping and flexible reserves due to forecast uncertainty associated with increased penetration of renewables, though PJM's simulations of renewable resource expansion have "… indicated an increased need for operational flexibility, with steeper ramps, frequent dispatch of generators to their economic minimum and lower capacity factors for natural gas and coal resources."[166] Increased needs for ancillary services may require gas-fired generation units to operate at lower efficiencies below their maximum capability and require more fuel to ensure that capacity headroom is available to respond to variable output of renewable generation.

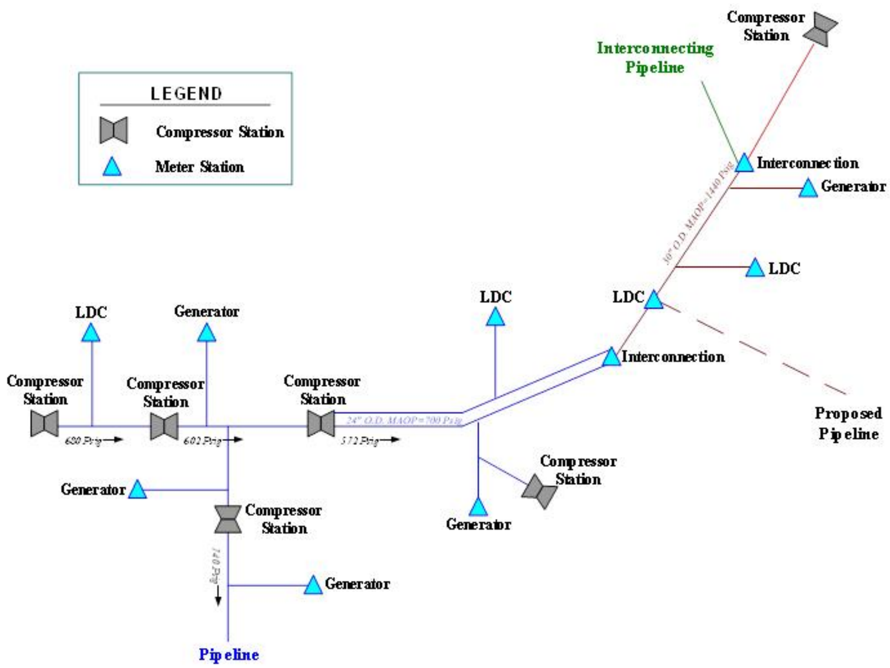
3.5 Hydraulic Modeling Demonstrates that REAE Satisfies the LDCs' Concerns for Reliability and Improves Gas-Grid Resilience

Based on documents filed at FERC, LAI constructed hydraulic models of the Transco Zone 6 system with and without REAE. Specifically, LAI relied on Transco's System Flow Diagram Report (Form 567) for the twelve months ended December 31, 2020and Exhibits G and G-II to the REAE Certificate of Public Convenience and Necessity (CPCN) Application. The hydraulic models were built using the WinFlow (steady-state) and WinTran (transient) software licensed by Gregg Engineering, Inc. This is the same gas simulation software suite LAI previously used to simulate gas-electric interdependencies for the multi-year study performed for EIPC. Whereas WinFlow represents system operations based on level deliveries over a 24-hour period, the transient flow model allows LAI to observe the change in pressure and flow associated with variable deliveries over the course of the day. Technical input parameters include pipeline diameters, segment lengths, compressor horsepower, discharge temperatures, velocities, maximum allowable operating pressures (MAOP), and elevation, among other factors. As shown in Figure 3-11, the models incorporate compressor stations, pipeline segments, interconnections, receipts from production and other supplies, storage injection/withdrawal points, and deliveries to LDCs, other commercial and industrial customers, and generators. Other model attributes pertaining to fluid flow in a pipe in relation to frictional losses require general flow equations.

[165] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection, p. 39. May 8, 2014. See https://www.hydro.org/wp-content/uploads/2017/08/PJM-January-2014-report.pdf.

[166] Energy Transition in PJM: Frameworks for Analysis, PJM Interconnection, p. 12. December 15, 2021. See https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx.

Figure 3-11. Example Hydraulic Model Schematic



The forecast of peak day gas demand was based on the analysis described in Section 2.2 for REAE LDC shippers and on historical deliveries for other LDCs served by Transco downstream of Station 190. Deliveries to meet the demand forecast were allocated by pipeline based on historical delivery ratios, with the ratios for REAE shippers adjusted to allocate more deliveries to Transco.

Transco deliveries were allocated to specific pipeline meters by applying each meter's share of the relevant customer's demand forecast, calculated as described in Section 2.2. The example in Table 3-4 illustrates how 200 MDth/d of forecast demand on a peak day in January 2030 was allocated *pro rata* to individual meters based on 2020 peak day meter demands as reported in Transco's Form 567.

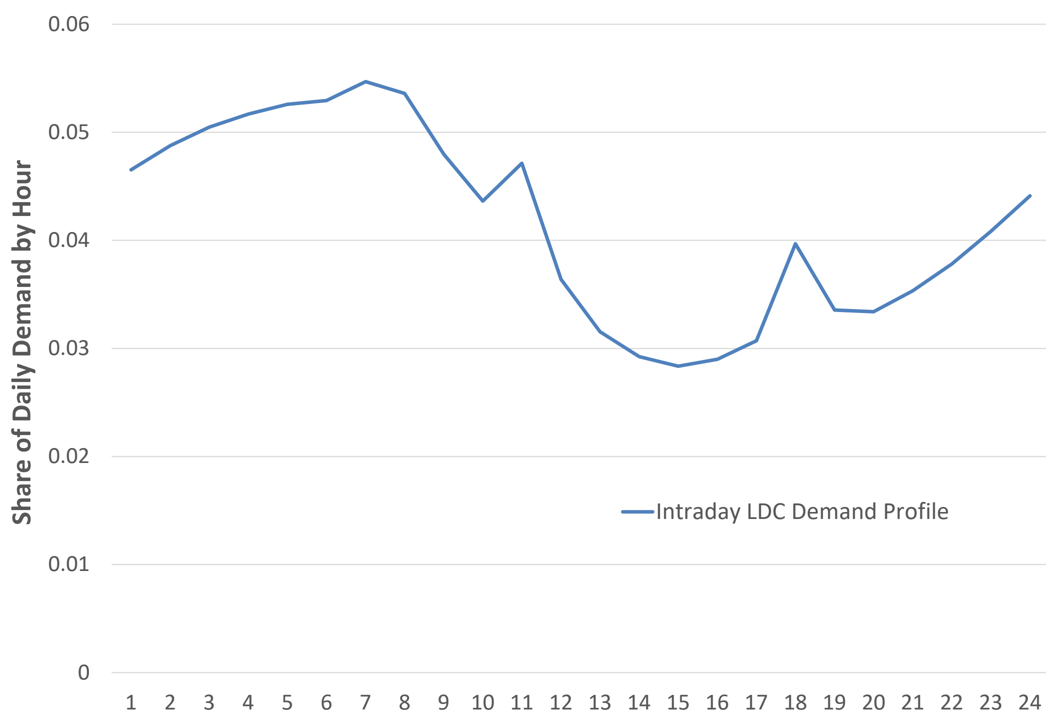
Table 3-4. RCI Demand Allocation Example

Meter	2020 Peak Day Deliveries (MDth/d)	% of Total Peak Day Demand	2030 Peak Day Deliveries (MDth/d)
A	29	18.1%	36
B	40	25.0%	50
C	14	8.8%	18
D	19	11.9%	24
E	22	13.8%	28
F	36	22.5%	40
Total	160		200

Demand associated with generators that are served by LDCs with multiple pipeline connections was allocated to an LDC delivery meter based on the proximity of the generator to the relevant gate stations, existence of dedicated laterals, contracted volumes and other factors.

To initialize each steady-state WinFlow run, LAI assumed that each gas-fired power plant, whether directly connected to an interstate pipeline or served by an LDC, received its respective scheduled fuel nominations, *i.e.*, the daily quantity derived in Aurora. Building on the steady-state runs, LAI applied intraday profiles to LDC and generator demand. The LDC intraday profile, shown in Figure 3-12 is based on an NREL meteorological dataset and peaks at approximately 130% of the average hourly value. Intraday profiles of generator gas demand were extracted from Aurora run results.

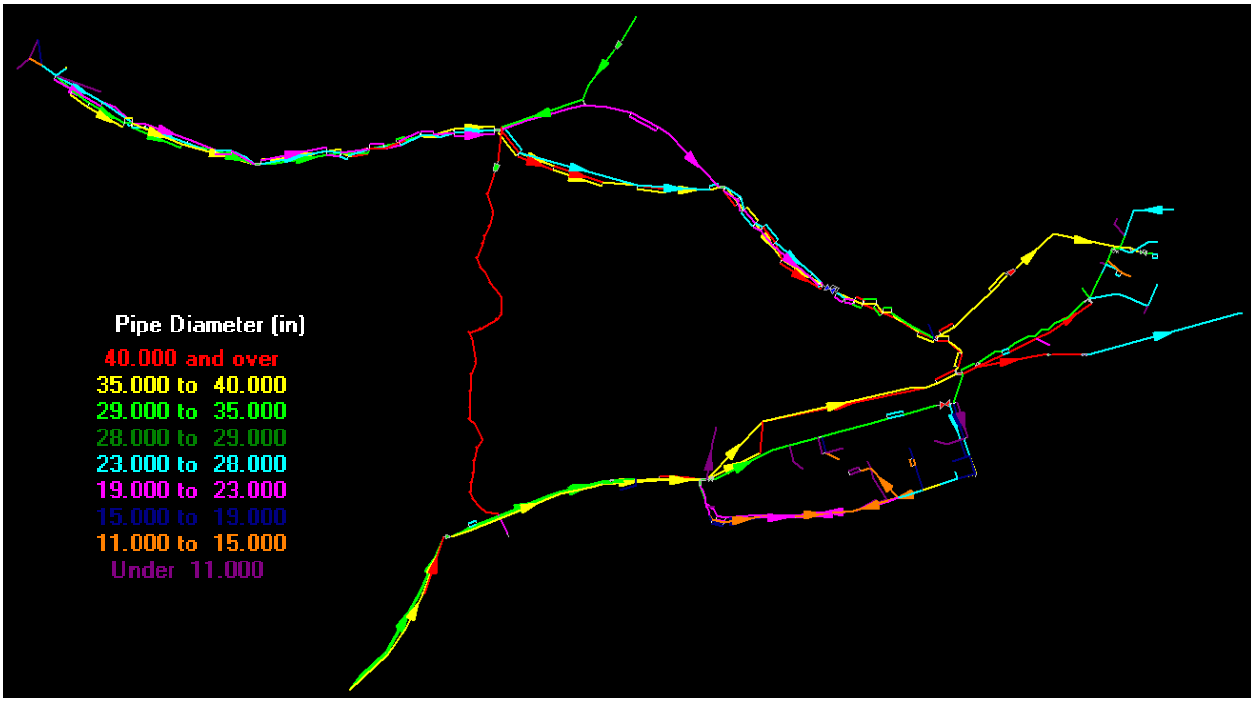
Figure 3-12. LDC Intraday Demand Profile



While the daily constraint input to Aurora estimates how much pipeline capacity is available volumetrically to serve gas-fired generation on a given day, it does not reflect generator pressure requirements or intra-day limitations. Interpretation of model solutions in WinFlow and WinTran requires assumptions regarding minimum pressure requirements at each delivery point. For LDCs, the models reflect minimum delivery pressure requirements are consistent with contractual minimum pressures as stated in contracts available from FERC, adjusted to account for pressure drop across the meter station. For generators, the models reflect minimum delivery pressure requirements based on the turbine technology and presence of on-site pressure boosters. If the delivery pressure to a generator drops below the assumed minimum delivery pressure, the plant is assumed to become unavailable. While Transco's MAOP is the same with and without REAE, the higher pressures that can be sustained by Transco's operators with REAE support greater operating flexibility to serve both LDCs and gas-fired generators in Southeastern Pennsylvania and New Jersey.

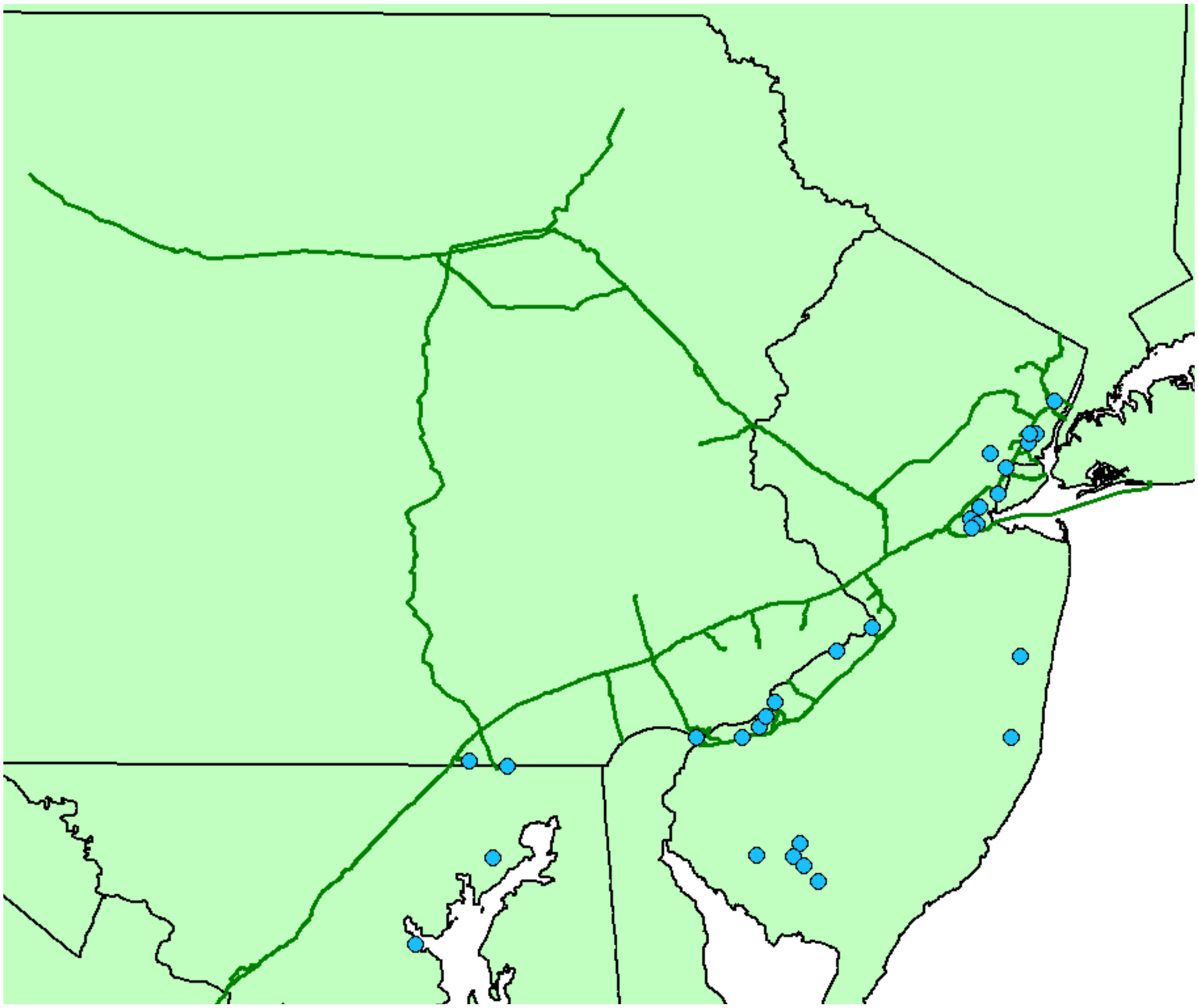
The footprint of the Transco hydraulic model is shown in Figure 3-13. The model includes mainline facilities north of Station 190, the Leidy Line, and the Central Penn Line.

Figure 3-13. Transco Hydraulic Model Footprint



The locations of generators served by Transco, either directly or behind the citygate via the LDC distribution system, are shown in Figure 3-14.

Figure 3-14. Study Region Generators Served by Transco



To test the pipeline's ability to supply the fuel needs of the generators during contingency weather conditions in 2030, as modeled in Aurora, the daily total (steady-state) and hourly (transient) gas demands by plant were loaded into a model reflecting a forecast of LDC gas demands under the same weather conditions. Each LDC's design day demand, less the volume served by behind-citygate peaking resources, was spread across the LDC's pipeline delivery meters pro rata based on Form 567 coincident peak day deliveries by meter. While 2021 peak day delivery volumes are not representative of a design day, relative meter station volumes have changed since 2014 in response to customer density, usage patterns, and the addition of new meter stations.

Detailed demand forecasts were not prepared for markets downstream of the study region, specifically downstate New York. Total peak day downstate New York demand delivered by Transco under contingency weather conditions in 2030 was estimated by increasing the 2021 peak day volume by 10% to reflect a more extreme weather condition, and then escalating at a

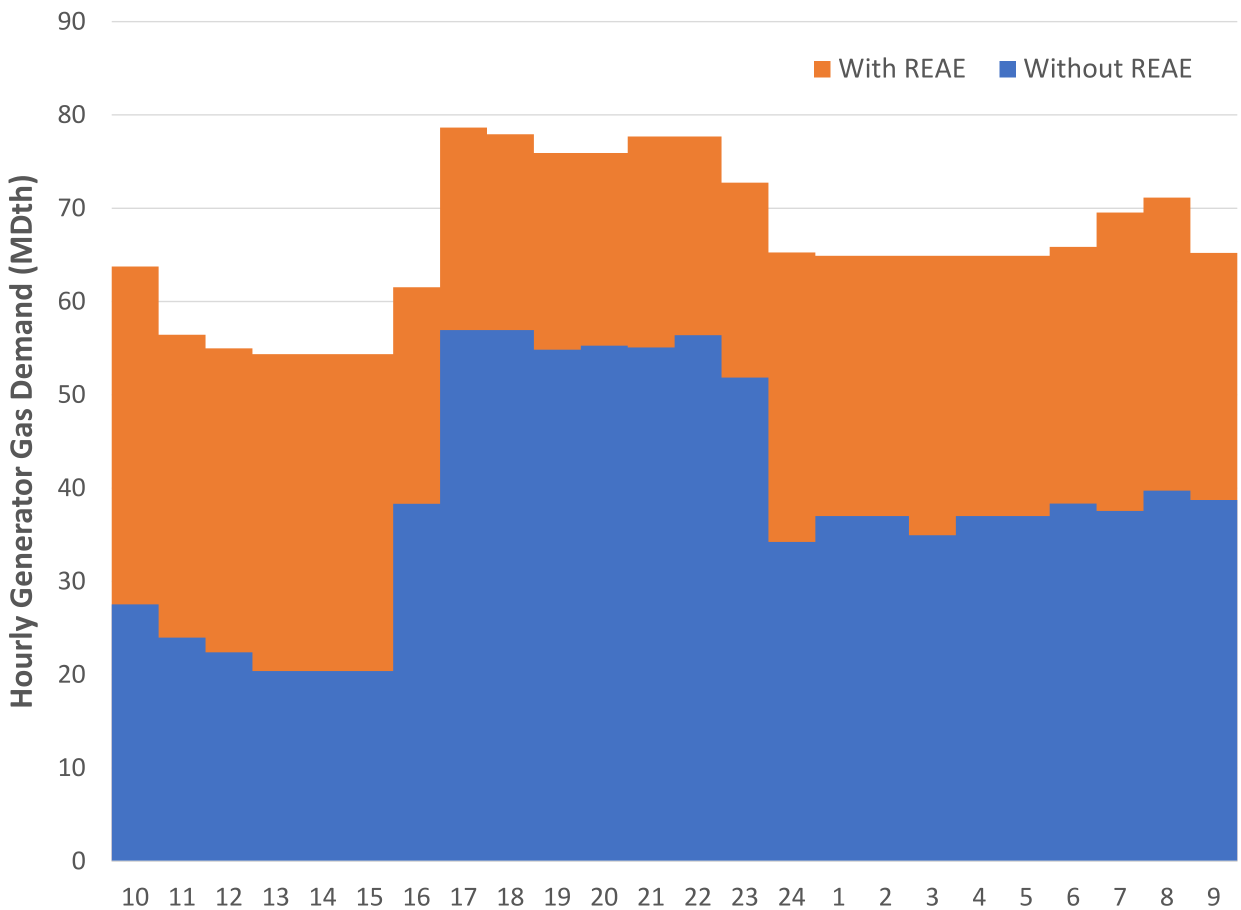
1% annual growth rate. Deliveries to downstate New York meters were similarly spread pro rata across the relevant meters.

On the peak day (January 8, 2030), without REAE, LAI estimates that deliveries on the Transco system downstream of Station 190 (including on the Leidy Line) will include LDC and industrial gas demand of 4,933 MDth/d and generator gas demand of 932 MDth/d, for a total of 5,865 MDth/d. Under these conditions, the mainline is flowing at capacity south-to-north and the Leidy Line is flowing west-to-east at a level consistent with production capability.

On the peak day with REAE, Aurora modeling results show that generator gas demand increases by 665 MDth/d to 1,598 MDth/d, an increase of 71%. Increased deliveries to gas-fired generators are based on the loosening of the daily constraint associated with the addition of REAE capacity, resulting in total demand of 6,531 MDth/d. The steady-state hydraulic model shows that Transco is able to fully deliver these volumes, with both south-to-north flows on the mainline and west-to-east flows on the Leidy operating at or near capacity. Transco's ability to serve increased gas-fired generator in the heart of EMAAC displaces less efficient generation in MAAC, including some coal-fired generation in the RTO, and also reduces PJM's reliance on oil-fired generation when gas deliverability constraints on Transco and other pipelines doing business in the study area are typically constrained.

The intraday demand profile is shown in Figure 3-15, based on Figure 3-12 for LDC and industrial deliveries and on Aurora outputs for generators.

Figure 3-15. Peak Day Intraday Generator Gas Demand Profile – 2030 Contingency Weather



Modeling hourly flows in the transient hydraulic model adds an additional layer of operational complexity, in particular, during the afternoon ramp to meet increasing electric load that slightly precedes but generally coincides with the late afternoon LDC gas demand increase shown in Figure 3-12. Under these conditions, the model shows that Transco is able to maintain deliveries throughout the gas day. Delivery pressures are reduced during the afternoon ramp, pushing both LDC and generator meters closer to contractual and required for operations, respectively, minimum pressures and limiting the ability of the pipeline to handle system disruptions.

When the benefit of REAE's capacity is assessed in the transient model, Transco is able to deliver the higher level of generator demand in addition to LDC demand while maintaining higher delivery pressures, consistent with the project's CPCN Application. Hence, the addition of REAE satisfies LDC reliability concerns over the study horizon, significantly bolsters gas deliveries to gas-fired generators during the heating season, November through March, provides additional delivery capability to gas-fired generators during very cold winter days, and helps replace less efficient generation in EMAAC otherwise called on to meet PJM's daily scheduling requirements. REAE capacity will also lessen reliance on oil-fired generation that would otherwise be required by PJM under normal winter weather conditions or when electric-side contingencies are experienced. The simulation modeling reveals the availability of delivery capacity to gas-fired generators during very cold winter days when Transco would not otherwise be able to serve the intra-day scheduling requirements of gas-fired combined cycle plants and peakers in EMAAC without REAE. While the “bankability” of this capacity is not equivalent to firm transportation entitlements, REAE surely improves the quality and scheduling flexibility of secondary firm transportation rights, both in-the-path and out-of-path, as well as lower priority interruptible transportation. All Transco shippers who use these services will benefit.

The results of the transient simulation modeling also support recognition of a number of second-tier benefits. These include the ability to sustain gas-fired generation when unexpected harsh weather conditions disrupt offshore wind production, and, to a lesser extent, solar PV. It also includes improved gas-grid resilience in the event of a low probability, but highly disruptive gas-side contingency on Transco or upstream pipelines interconnected to Transco.

4 REAE Reasonably Foreseeable Direct and Indirect GHG Emissions are Insignificant

As the Commission noted in a recent order:

> The Council on Environmental Quality (CEQ) defines impacts as "changes to the human environment from the proposed action or alternatives that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives, including those effects that occur at the same time and place as the proposed action or alternatives and may include effects that are later in time or farther removed in distance from the proposed action or alternatives." An impact is reasonably foreseeable if it is "sufficiently likely to occur such that a person of ordinary prudence would take it into account in reaching a decision."[167]

In the Draft Environmental Impact Statement (DEIS), FERC Staff found that the construction emissions, operational emissions, and the emissions from the downstream combustion of the gas transported by the project are reasonably foreseeable emissions.[168] To aid the Commission in assessing the net effects that the project will have on GHG emissions, LAI has estimated reasonably foreseeable direct and indirect net GHG emissions attributable to REAE taking into account the net reduction in GHG emissions from the displacement of other fuels, including natural gas delivered by other pipelines. The analysis takes into account the net reduction in GHG emissions from the displacement of other fuels, including natural gas delivered by other pipelines. For direct emissions, LAI relied on the estimated net GHG emissions from REAE construction and operation reported by Transco in its Supplemental Filing.[169] LAI's estimate of reasonably foreseeable indirect net GHG emissions reflects downstream power sector emissions and downstream emissions from increased natural gas use by residential, commercial and industrial customers. Net power sector emissions based on the all-hours modeling results are presented in Table 2-2 of Section 2. GHG emissions from changes in gas demand in the residential, commercial and industrial sectors are calculated in this Section based on estimates of natural gas demand elasticity and REAE's impact on natural gas prices. LAI found:

- REAE construction could increase CO2e emissions by 0.044 million metric tons in 2024. In subsequent years, REAE operations will increase CO2e by 0.088 million mtpy. REAE will result in 0.033 million mtpy of indirect GHG emissions, with 0.049 million mtpy of emissions from increased residential, commercial and industrial natural gas consumption offset by 0.016 million mtpy of reductions in GHG emissions ascribable to avoided emissions from fossil-fired generation in the region.

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[167] Order Issuing Certificate, *In re Iroquois Natural Gas Transmission System, L.P.,* 178 FERC ¶ 61,200 (March 25, 2022), ¶ 49. *See also,* Order Issuing Certificates and Approving Abandonment, *In re Tennessee Gas Pipeline Company, LLC, et al,* 178 FERC ¶ 61,199 (March 25, 2022), ¶ 86.and Order Issuing Certificate, *In re Columbia Gulf Transmission, LLC,* 178 FERC ¶ 61,198 (March 25, 2022), ¶45.

[168] REAE DEIS, page 4-166.

[169] Transco Supplemental Filing.

- REAE's reasonably foreseeable GHG emissions resulting from the construction, operation and downstream use of the natural gas transported by the project will have an insignificant impact on regional GHG emissions, accounting for less than 0.1% of annual emissions in New Jersey and Pennsylvania, as shown in Table 4-8.

- LAI also compared REAE GHG emissions to the most recent year of GHG emissions reported by the EPA in its Inventory of U.S. Greenhouse Gas Emissions and Sinks.[170] LAI estimates that REAE construction could increase CO2e emissions by 0.0007% of 2019 U.S. emissions. In subsequent years, REAE operations will increase CO2e emissions by 0.0015% of 2019 U.S. emissions. Downstream emissions could increase CO2e emissions by 0.0006% of 2019 U.S. emissions.

The Commission requires that applicants provide estimates of construction emissions and potential operational emissions. Pursuant to this requirement, Transco estimated the impact of the project on air quality including GHG emissions in its Supplemental Filing.[171] Consistent with Transco's Supplemental Filing, LAI has defined reasonably foreseeable REAE direct GHG as emissions produced by REAE facilities during operations and by vehicles and equipment used in the construction of REAE. LAI estimates that REAE construction could increase CO2e emissions by 0.044 million metric tons, and, in subsequent years, REAE operations will increase CO2e by 0.088 million mtpy.

For a gas pipeline project, reasonably foreseeable upstream GHG emissions could include GHG emissions resulting from the production of natural gas transported by the project. However, as the Commission recently found:

> NEPA requires agencies to consider indirect effects or impacts that "are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." With respect to causation, "NEPA requires 'a reasonably close causal relationship' between the environmental effect and the alleged cause" in order "to make an agency responsible for a particular effect under NEPA." As the Supreme Court has explained, "a 'but for' causal relationship is insufficient [to establish cause for purposes of NEPA]." Thus, "[s]ome effects that are 'caused by' a change in the physical environment in the sense of 'but for' causation," will not fall within NEPA if "the causal chain is too attenuated." Further, the Court has stated that "where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect." Regarding reasonable foreseeability, courts have found that an impact is reasonably foreseeable if it is "sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision." Although

[170] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=uuA7i8WoMDBOc0M4ln8WVXMgn1GkujvD, page ES-9.

[171] Transco Supplemental Filing.

> courts have held that NEPA requires "reasonable forecasting," an agency "is not required to engage in speculative analysis" or "to do the impractical, if not enough information is available to permit meaningful consideration."[172]

In the DEIS, Commission Staff note that the source of the natural gas transported by REAE is "currently unknown and would likely change throughout the Project's operation. It is also unknown whether transported gas would come from new or existing production."[173]

Because there are no specific reserves or wells associated with REAE and none of the REAE shippers are producers, the environmental impacts of upstream production of natural gas transported by REAE "would not be caused by the Project or be a reasonably foreseeable consequence of the project"[174] are excluded from reasonably foreseeable indirect emissions.

The increase in volumes delivered on Transco will be offset by reduced deliveries on other pipelines serving LDCs in New Jersey and Southeastern Pennsylvania and reductions in other pipelines' deliveries to power plants. There will also be reductions in power plant emissions from other fuels. LAI has therefore estimated net indirect REAE GHG emissions as the sum of downstream GHG emissions from incremental shipments of natural gas to serve LDC demand, and net emissions from the use of fossil fuels for electric generation. LAI estimates net power sector CO2e emissions of -0.016 mtpy based on the all-hours modeling results presented in Table 2-2 in Section 2. GHG emissions from changes in gas demand in the residential, commercial and industrial sectors are calculated based on estimates of natural gas demand elasticity and REAE's impact on natural gas prices in New Jersey and Southeastern Pennsylvania. LAI estimates that downstream emissions will increase CO2e emissions by 0.033 million mtpy.

The Commission has recognized that comparing a proposed project's emissions to an inventory or goal "can be helpful to inform the Commission's analysis and the public, especially when presented using a consistent metric across proposed projects under consideration." LAI has therefore followed Commission precedent in comparing REAE GHG emissions to most recent year of GHG emissions reported by the EPA in its Inventory of U.S. Greenhouse Gas Emissions and Sinks.[175] LAI estimates that REAE construction could increase CO2e emissions by 0.0007% of 2019 U.S. emissions, and, in subsequent years, REAE operations will increase CO2e emissions by

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[172] Order Issuing Certificate, In re Iroquois Natural Gas Transmission System, L.P., 178 FERC ¶ 61,200 (March 25, 2022), ¶ 62

[173] FERC Office of Energy Projects, Regional Energy Access Expansion Project Draft Environmental Impact Statement, March 2022, (REAE DEIS), Page 4-167.

[174] REAE DEIS, page 4-167.

[175] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=uuA7i8WoMDBOc0M4ln8WVXMgn1GkujvD, page ES-9.

0.0015% of 2019 U.S. emissions, and downstream emissions could increase CO2e emissions by 0.0006% of 2019 U.S. emissions.[176]

4.1 Reasonably Foreseeable Direct Emissions

In Transco's Supplemental Filing, reasonably foreseeable net emissions for REAE emission sources are estimated based on the expected utilization of REAE facilities, as well as vehicles and equipment used during REAE's construction.[177] In Transco's Supplemental filing, reasonably foreseeable GHG emissions from operations are based on the expected utilization of each Compression Station. Estimated emissions from construction also reflect the expected utilization of vehicles and equipment. However, to accommodate potential construction schedule delays, conservative assumptions were used in estimating expected utilization. Adopting the reasonably foreseeable construction emissions from Transco's Supplemental Filing is therefore conservative.

Emissions from Construction

Consistent with Transco's Supplemental Filing, estimated GHG emissions from construction are calculated as the sum of fossil fuel combustion emissions from on-road and off-road construction worker commute vehicles, construction vehicles and construction equipment.[178] Transco expects to complete construction by the fourth quarter of 2024. LAI has therefore conservatively assumed that all construction emissions will take place in 2024.[179]

As can be seen in Table 4-1, the majority of GHG emissions from construction take place in Pennsylvania. This is primarily due to the fact that all of the approximately 22.3 miles of pipeline comprising the Regional Energy Lateral and approximately 13.8 miles of pipeline comprising the Effort Loop will be built in Pennsylvania.[180] The low level of reasonably foreseeable REAE construction GHG emissions in Maryland reflects the fact that the only REAE construction in Maryland relates to upgrades at a single delivery meter station.

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[176] Emissions in subsequent years are based on emissions in 2030 the same year used for the extreme weather analysis in Section 4.

[177]Transco Supplemental Filing.

[178] Transco Supplemental Filing.

[179] Transco Supplemental Filing.

[180] Transcontinental Gas Pipe Line Company, LLC., Resource Report No. 9, Air and Noise Quality, Regional Energy Access Expansion, March 2021, ("Resource Report 9"), page 9-1.

Table 4-1. Estimated 2024 GHG Emissions from REAE Construction (metric tons per year)[181]

State	**$CO2_e$**
NJ	10,186
MD	114
PA	33,247
U.S.	43,548

LAI anticipates that actual GHG emissions from construction will be significantly below the estimates in Table 4-1, because, as indicated in Resource Report 9,

> The emission calculations include the conservative assumption that construction equipment and worker commute vehicles will be operating over the full duration of the construction schedule anticipated for each Project area (six days per week and up to ten hours per day depending on equipment type); however, in actuality, such construction equipment and worker commute vehicles will only be operated for a fraction of this time.[182]

Emissions from Operation

Incremental GHG emissions from operations reported in Transco's Supplemental Filing are composed of increased emissions from new natural gas-fired compressors at Compressor Stations 505 and 515, new auxiliary generators at Station 201 and 515, reduced emissions due to the removal and abandonment of existing natural gas-fired compressors at Compressor Stations 195, 505 and 515, and increased emissions from pipeline fugitives, venting, and natural gas pigging operations on the sections of pipeline constructed as part of REAE.[183] For existing compressor stations, the net GHG emissions are the difference between new and existing total compressor station GHG emissions. For new compressor stations, the net GHG emissions are equal to total compressor station GHG emissions. For Compressor Stations 195, 505 and 515 projected utilization is set equal to each station's historical average utilization.[184] There is no historical utilization data for Compressor Station 201 because it is a new facility. In Transco's Supplemental Filing GHG emissions for Station 201 are estimated on a Potential to Emit basis, assuming that facilities operate at maximum capacity in all 8,760 hours of the year. Transco's Supplemental filing also contains reasonably foreseeable GHG emissions estimates for new pipeline segments and metering and regulation stations from incremental pipeline fugitives, venting, and natural gas pigging operations. Net annual GHG emissions from REAE operation are shown in Table 4-2.

[181] Transco Supplemental Filing.

[182] Resource Report 9, page 9-31.

[183] Transco Supplemental Filing. As part of REAE, Transco will also uprate the existing electric motor-driven compressor unit at Compressor Station 195.

[184] Transco Supplemental Filing.

Table 4-2. Estimated Net GHG Emissions from REAE Operation (metric tons per year)[185]

State	$CO2_e$	Percent of Total
NJ	6,394	7.3%
MD	1,052	1.2%
PA	80,423	91.5%
U.S.	87,868	100%

Approximately 91% of GHG emissions from REAE operation will occur in Pennsylvania.

4.2 Reasonably Foreseeable Indirect Emissions

LAI's estimate of reasonably foreseeable indirect net GHG emissions reflects downstream power sector emissions and downstream emissions from increased natural gas use by residential, commercial and industrial customers. As discussed in Section 2, above, REAE indirect power sector emissions are calculated by taking the difference between modeled emissions from electric generators across the study region, with and without the incremental pipeline capacity into New Jersey and southeastern Pennsylvania provided by REAE. Because generators in the study region generally do not contract for firm pipeline capacity, they are exposed to gas constraints and volatile prices during cold winter days when the LDCs utilize their capacity entitlements predominantly to serve heating load. Many dual-fuel generators in the Northeast commonly operate on natural gas and switch to petroleum products when natural gas pipeline capacity is constrained and/or gas prices are high.[186] On peak winter days dual-fuel generators therefore typically rely on oil in on-site tanks.

The incremental capacity from REAE will, for the most part, allow dual-fuel generators to avoid burning oil on peak winter days and will let gas-fired generators increase output displacing other fossil fuel-fired generation. The CO2 emission intensity of a generator (CO2 emissions per kWh of energy produced) is a function of fuel type and plant heat rate. For U.S. power generation in 2020, the EPA has estimated that natural gas-fired generation created 0.91 lbs. CO2 per kWh, versus 2.23 and 2.13 lbs. CO2 per kWh for coal and petroleum products, respectively.[187] The national averages provide some indication of the GHG emission reductions achieved when natural gas is substituted for coal and petroleum products. However, the emissions rates of individual plants will vary from these national averages as a result of differences in heat rate and fuel type.

[185] Transco Supplemental Filing.

[186] FERC, Winter 2018-2019 Energy Market Assessment, October 18, 2018, https://www.ferc.gov/sites/default/files/2020-05/2018%E2%80%932019WinterEnergyMarketAssessmentFullVersion.pdf, page 10.

[187] EPA, Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=74&t=11, updated November 4, 2021.

Net Power Sector GHG Emissions

As reported in Table 2-2 LAI estimates net power sector GHG emissions resulting from REAE will decrease by 0.016 million metric tons per year. LAI's estimate is conservative, as the 2011 weather year utilized in the all-hours modeling does not contain severe winter weather. Per marginal fuel postings from PJM's Market Monitor, oil products were the marginal fuel in only 0.4% of hours in January – February 2011. In contrast, over the last eleven years (2011-2021) of data available, oil products were the marginal fuel in 4.2% of hours or about 2.5 days.[188] If REAE allows gas-only combined cycle generation to run rather than less-efficient oil capacity, the net power sector GHG emissions reductions could be as high as 37,000 metric tons per day.[189] If all of the incremental gas burn enabled by REAE in the all-hours cases offset oil in this manner, emissions reductions could average as much as 81 metric tons a year.

Incremental Residential, Commercial and Industrial GHG Emissions

REAE will increase the available pipeline capacity to New Jersey and Southeastern Pennsylvania and reduce congestion on peak winter days, relative to congestion absent REAE. The retail natural gas prices that most residential and commercial consumers pay for natural gas in the study region tend to reflect the average cost of supplying natural gas during the month, season, or longer time period. No effort has been possible in this study to adjust for retail price effects resulting from the War in Ukraine. Absent adjustments to account for geopolitical events, it is expected that the reduction in prices on days when available pipeline capacity would have constrained consumption in the absence of REAE will be passed on to residential, commercial and industrial consumers in the form of lower average prices. To estimate the impact on natural gas consumption from the reduction in natural gas prices due to REAE, LAI takes the product of the estimated the percentage increase in consumption caused by reduced natural gas prices and estimated consumption in each sector. Estimated consumption in each sector is set equal to 2020 consumption in New Jersey and Southeastern Pennsylvania. The percentage increase in sectoral consumption reflects the change in price and the own price elasticity of demand. The demand elasticity is a measure of how much the volume of natural gas demanded changes in response to a change in price.

LAI estimated reasonably foreseeable GHG emissions from changes in energy consumption in the residential, commercial and industrial sectors based on 2020 consumption in each sector and estimates of sectoral own-price demand elasticity. This accounts for the impact of REAE on average annual natural gas prices in New Jersey and Southeastern Pennsylvania.

In estimating incremental emissions LAI does not account for the potential decline in residential, commercial and industrial consumption of electricity, heating oil and propane due to consumers switching to natural gas for space heating, water heating and cooking. In some applications, such

[188] Marginal Fuel Posting Data, Monitoring Analytics. See https://www.monitoringanalytics.com/data/marginal_fuel.shtml.

[189] Assuming full REAE capacity substitutes 7 Dth/MWh gas-fired combined cycle generation for 10 Dth/MWh heat rate simple-cycle or steam turbine generation running on distillate fuels.

as space heating and cooking, natural gas is a substitute for electricity, heating oil and propane, at least in the intermediate- to long-run. While various states' electrification objectives may support the substitution of air or ground source heat pumps, electric water heaters and electric cooktops for natural gas appliances, the time frame associated with realization of these electrification goals is uncertain. Even when they are supported by state and utility programs, it can take many years for building electrification to gain momentum as consumer acceptance of heat pumps and the number of trained installers grow slowly. Consequently, incremental residential, commercial and industrial GHG emissions resulting from REAE are equal to the product of the increase in natural gas consumption and the CO2e emissions rate for natural gas combustion of 54.87 kg/Mcf.[190]

Estimated Impact on Natural Gas Prices in NJ and SE PA

REAE will increase available pipeline capacity with delivery in New Jersey and Southeastern Pennsylvania, causing a decrease in price and an increase in consumption by LDC load and generation. On days when the available pipeline capacity with delivery into a region is not fully utilized, prices within the region do not usually rise significantly above upstream prices. When prices in the region rise above upstream prices, market participants use available capacity to increase deliveries into the region reducing prices in the region.[191] As a result, incremental pipeline capacity is not expected to have a significant impact on prices on days when existing capacity is not fully utilized. Similarly, the incremental pipeline capacity created by REAE is only expected to reduce prices in Maryland, New Jersey, and Southeastern Pennsylvania on days when all currently available capacity would be fully utilized in the absence of REAE.

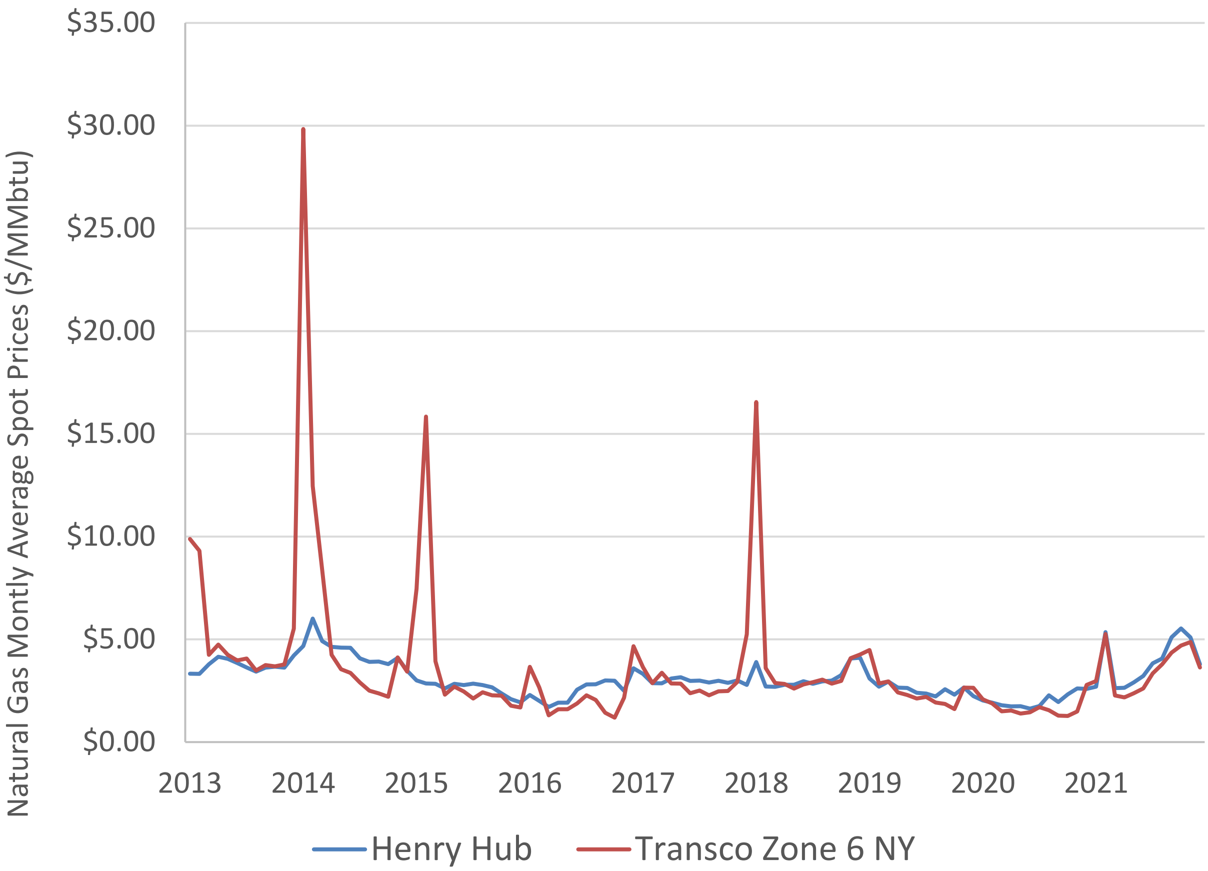
Experience has demonstrated that the provision of incremental capacity can reduce or eliminate the price premiums caused by pipeline constraints. For example, prior to 2014 available pipeline capacity limited the supply of natural gas to New York City. On cold winter days, pipelines delivering natural gas to New York City were constrained and prices would spike causing a large basis jump over the Henry Hub price. Then, as the Department of Energy (DOE) observed, "[i]n 2014, new capacity into New York City eliminated the historic price premium to Henry Hub" as "expansion projects to bring capacity to New York/New Jersey and Mid-Atlantic markets [brought] more than 2.0 Bcf/d of expansions for 2013–2014."[192] As shown in, since 2014, prices in New York City only spiked in one year, 2018. This demonstrates the ability of new capacity to limit price spikes resulting from pipeline constraints.

[190] EIA, Carbon Dioxide Emissions Coefficients by Fuel, November `8, 2021, https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[191] This discussion assumes that the variable costs of pipeline transportation are insignificant.

[192] Department of Energy, Appendix B to the Quadrennial Energy Review: Natural Gas Infrastructure, June 2015, https://www.energy.gov/sites/prod/files/2015/06/f22/Appendix%20B-%20Natural%20Gas_1.pdf, pages 30 and 35.

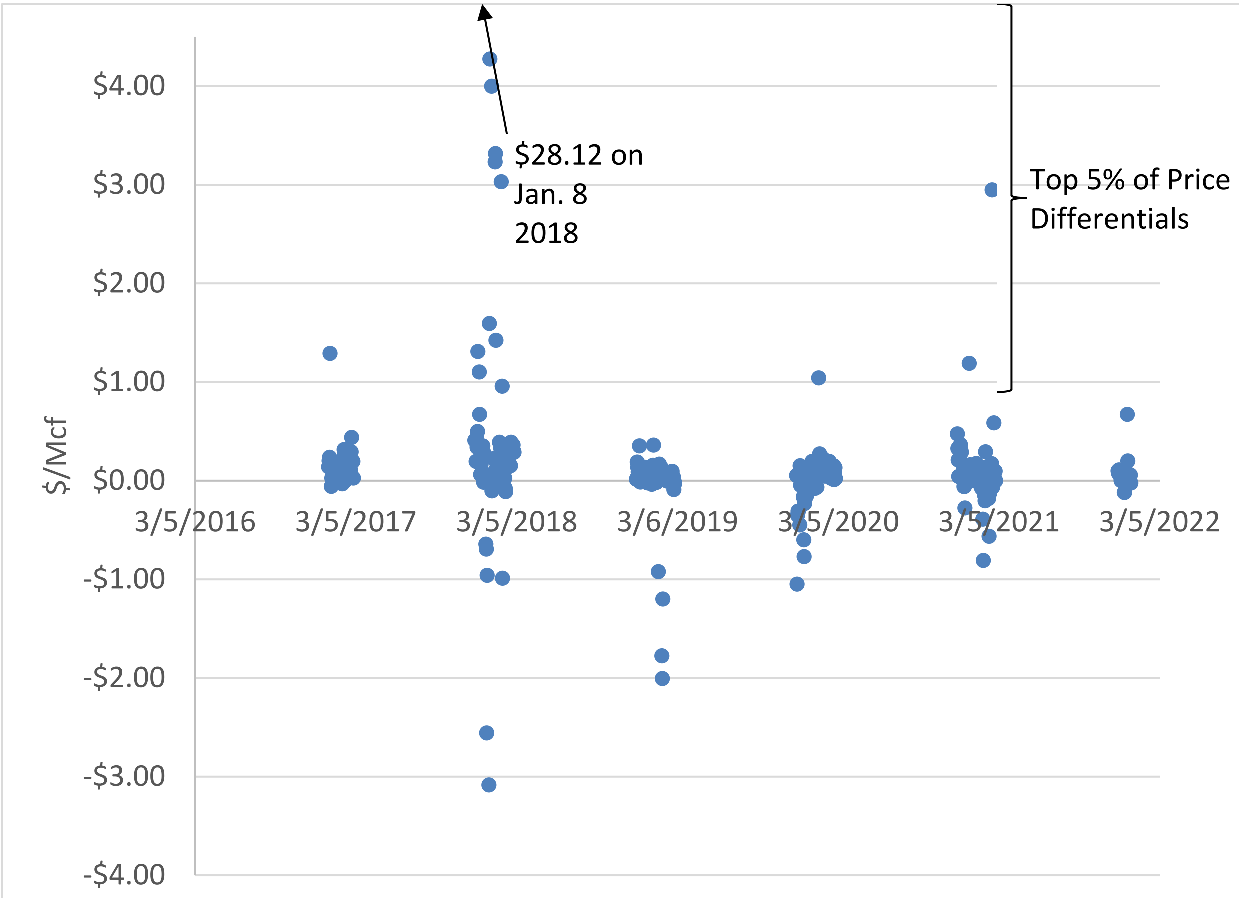
Figure 4-1. Henry Hub and Transco Zone 6 Natural Gas Spot Prices (2013 - 2021)



The reduction in delivered natural gas prices in New Jersey and Southeastern PA that may be induced by REAE depends on the number of days each year when the flow of gas into the study region is constrained as well as the average reduction in price attributable to REAE capacity on constrained days. In Section 2, LAI estimated that REAE will relieve pipeline constraints by an average of four days per year over the study period. Therefore, the estimated REAE impact is calculated by assuming there would be four fewer unconstrained days on average with REAE than without it.

To estimate the impact of REAE on constrained days, LAI assumed that approximately 5% of days in December, January and February of 2017-2021 were constrained. To identify days when the flow of gas into New Jersey and Southeastern Pennsylvania was likely constrained LAI calculated the difference in the Transco Zone 6 Non-NY and Texas Eastern Zone M3 daily gas prices for December, January and February of 2017-2021, as shown in Figure 4-2. For the purposes of estimating reasonably foreseeable emissions, LAI assumed REAE's average impact on prices on constrained days is equal to the average difference between the Transco Zone 6 Non-NY and Texas Eastern Zone M3 daily gas prices for the 5% of days with the highest differences, or $3.92/Mcf.

Figure 4-2. Difference Between Transco Zone 6 Non-NY and Texas Eastern Zone M3 daily gas prices, December, January and February of 2017-2021



To the extent that REAE causes a larger than assumed reduction in prices on constrained days the decrease in average annual prices would be larger than shown in Table 4-3. However, even if the actual impact of REAE on prices is larger than the estimates reported in Table 4-3, the impact on estimated GHG emissions would be offset by conservative assumptions employed elsewhere in estimating incremental LDC use. REAE reduces the estimated average annual constrained days by 4. Therefore, the estimated REAE impact is calculated by assuming there would be four fewer unconstrained days on average with REAE than without it.

Table 4-3. Estimated REAE Impact on Annual Prices

Impact on Constrained Days	Constrained Days Avoided	Annual Price Impact		NJ 2020 $/Mcf[193]	% Decrease in Price
$3.92	4	$0.043/Mcf	Residential	$9.92	0.43%
			Commercial	$8.79	0.49%
			Industrial	$7.54	0.57%

LDCs in the study region procure natural gas from the Marcellus Shale and Gulf Coast. Firm pipeline rights on Transco and other pipelines allow shippers to purchase at favorable pricing points in the upstream producing basins, while also allowing for timely storage withdrawals from conventional storage fields in Pennsylvania, Ohio and West Virginia. When pipeline throughput is at or near maximum delivery capability, constraints can result in price spikes in consuming in New Jersey and Pennsylvania, as well as New York and New England. Prices in the region served by REAE can rise to several times the prices at liquid sourcing points, such as Dominion South Point, or to even greater multiples. LDCs make most of their purchases at liquid sourcing points in the producing basin, and they are typically not adversely affected by periodic price spikes in the consuming region. The impact of natural gas price spikes is borne mainly by wholesale electric energy suppliers and marketers where pricing of wholesale energy across PJM reflects the daily delivered cost of natural gas. Retail electric customers ultimately bear the cost of price spikes in delivered natural gas prices, however.

Increased natural gas and electricity prices have the greatest impact on vulnerable and low-income populations. The DOE measures household exposure to energy costs using the energy burden—defined as the percentage of gross household income spent on home energy bills.[194] LAI used the DOE's Low-Income Energy Affordability Data (LEAD) tool to calculate the energy burden of low- and moderate-income households in Maryland, New Jersey and Pennsylvania based on the federal poverty guidelines. As shown in Table 4-4, home energy bills account for 21% of household income for those living below the federal poverty line in Maryland, whereas home energy bills averaged 17% and 22% of low-income households in New Jersey and Pennsylvania, respectively. Moderate income households in these states also face a substantial energy burden, with home energy bills accounting for between 6% and 11% of household income, depending on the state and income range.

[193] EIA, Natural Gas Price by Sector, New Jersey, 2020. Available at https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SNJ_a.htm.

[194] DOE, https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf.

Table 4-4. Household Energy Burden by State and Income Level[195]

	Average Energy Burden				
Household Income as a % of Federal Poverty Level	0-100%	100-150%	150-200%	200-400%	400%+
Maryland	21%	9%	7%	4%	2%
New Jersey	17%	8%	6%	4%	2%
Pennsylvania	22%	11%	8%	5%	2%

In PJM, energy prices are set by the marginal units – the highest cost generation resource needed to meet load. According to PJM's market monitor, natural gas-fired generation units accounted for 72.3% of marginal resources in 2020. Natural gas costs were the largest contributor to PJM energy prices, accounting for 41.5% of energy costs in 2020.[196] As a result, gas price spikes during extreme winter weather events can have a disproportionate impact on electricity costs. For example, it has been estimated that electricity retailers incurred $47 billion in charges during the extreme winter weather and resulting power outages experienced in February 2021.[197]

The impacts of electrical outages can fall disproportionately on low-income communities. This inequity is illustrated by the consequences of the February 2021 outage in Texas. The outages were especially hard on low-income families as they tend to live in older, poorly insulated homes, with worse plumbing, and limited resources to relocate, repair home damage, or replace spoiled food.[198] The lack of resources both prevented them from mitigating the effects of cold, food insecurity, and loss of public transportation during the power outages. Like other Texans, low-income minority Texas were also impacted by the increase in household energy bills caused by the price spike – just more so on a relative basis.[199]

Elasticity of Residential, Commercial and Industrial Demand for Natural Gas

For the demand elasticities, LAI used estimates of own-price natural gas demand elasticities for the residential, commercial and industrial sectors published and relied upon by the U.S. Bureau

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[195] DOE, Low-Income Energy Affordability Data (LEAD) Tool, https://www.energy.gov/eere/slsc/maps/lead-tool.

[196] Monitoring Analytics, 2020 State of the Market Report for PJM, Volume II, March 11, 2021, pages 176 and 180. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol2.pdf.

[197] Joshua W. Busby, Kyri Baker, Morgan D. Bazilian, Alex Q. Gilbert, Emily Grubert, Varun Rai, Joshua D. Rhodes, Sarang Shidore, Caitlin A. Smith, Michael E. Webber, Cascading risks: Understanding the 2021 winter blackout in Texas, Energy Research & Social Science, Volume 77, 2021, 102106, ISSN 2214-6296, (https://www.sciencedirect.com/science/article/pii/S2214629621001997).

[198] Joshua W. Busby, Kyri Baker, Morgan D. Bazilian, Alex Q. Gilbert, Emily Grubert, Varun Rai, Joshua D. Rhodes, Sarang Shidore, Caitlin A. Smith, Michael E. Webber, Cascading risks: Understanding the 2021 winter blackout in Texas, Energy Research & Social Science, Volume 77, 2021, 102106, ISSN 2214-6296, (https://www.sciencedirect.com/science/article/pii/S2214629621001997).

[199] The Texas Tribune, Already hit hard by pandemic, Black and Hispanic communities suffer the blows of an unforgiving winter storm, February 19, 2021, https://www.texastribune.org/2021/02/19/Texas-winter-storm-suffering-inequities/.

of Ocean Energy Management (BOEM).[200] As shown in Table 4-5, all three sectors have inelastic demand (i.e., an elasticity of less than one), indicating that the percentage change in the natural gas demand will be less than the percentage change in the price. Table 4-5 also reports the residential and commercial natural gas demand elasticities EIA used in its 2020 Annual Energy Outlook and estimated residential elasticity from a 2018 micro-data-based study.[201]

Table 4-5. Natural Gas Own-price Demand Elasticity Estimates

	BOEM 2021 Update	**EIA AEO 2020**[202]	**Auffhammer and Rubin (2018)**[203]
Residential	0.313	0.08 - 0.23	0.17-0.23
Commercial	0.296	0.03 - 0.28	
Industrial	0.468		

Table 4-5 shows that the residential and commercial demand elasticities reported by other sources are lower than the BOEM estimates. Relying on the residential and commercial elasticities reported by the BOEM results in larger estimates of incremental natural gas consumption and GHG emissions and is therefore conservative.

Incremental Emissions from Increased Residential, Commercial and Industrial Natural Gas Consumption

For New Jersey, natural gas consumption for the residential, commercial and industrial sectors is based the EIA's reporting of 2020 natural gas consumption by end use. For Southeastern Pennsylvania, residential natural gas consumption is equal to the sum of PECO and PGW's reported residential volumes for 2020. Commercial and industrial consumption reflect PGW's reported commercial and industrial sales, PECO's total reported 2020 non-residential volume, and the commercial and industrial shares of 2020 Pennsylvania natural gas consumption reported by the EIA. Residential, commercial and industrial consumption for New Jersey and Southeastern Pennsylvania is reported in Table 4-6, along with the percentage increase in natural gas consumption, increase in natural gas consumption and increase in GHG emissions REAE is expected to cause in each sector. The percentage increase in natural gas consumption is

[200] U.S. BOEM, Updated Market Simulation Model Elasticities, September 2021, https://www.boem.gov/sites/default/files/documents/renewable-energy/state-activities/MarketSim-Elasticities-Tables.pdf.

[201] Auffhammer, Maximilian and Rubin, Edward, Natural Gas Price Elasticities and Optimal Cost Recovery Under Consumer Heterogeneity: Evidence from 300 Million Natural Gas Bills (February 2018). NBER Working Paper No. w24295, Available at SSRN: https://ssrn.com/abstract=3219791.

[202] U.S. Energy Information Administration, Price Elasticity for Energy Use in Buildings in the United States, https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf, page 3.

[203] Auffhammer, Maximilian and Rubin, Edward, Natural Gas Price Elasticities and Optimal Cost Recovery Under Consumer Heterogeneity: Evidence from 300 Million Natural Gas Bills (February 2018). NBER Working Paper No. w24295, Available at SSRN: https://ssrn.com/abstract=3219791

calculated as the product of the BOEM demand elasticities reported in Table 4-5 and the percentage decrease in price calculated in Table 4-3

Table 4-6. Calculation of GHG Emissions from Incremental Residential, Commercial and Industrial Natural Gas Consumption

	2020 Consumption (MMcf)	Percentage Increase	Incremental Consumption (MMcf)	Incremental Emissions (CO2e thousands of metric tons)
Southeastern Pennsylvania[204]				
Residential	83,607	0.14%	113	6.2
Commercial	29,236	0.14%	42	2.3
Industrial	29,764	0.27%	79	4.4
New Jersey[205]				
Residential	223,370	0.14%	303	16.6
Commercial	138,105	0.14%	200	11.0
Industrial	58,710	0.27%	157	8.6
Total			894	49.1

Incremental CO2e emissions are converted from natural gas consumption using the carbon dioxide emission coefficient of 54.87 kg/Mcf.[206] Blending conventional natural gas with hydrogen or renewable natural gas reduces the effective carbon dioxide emission intensity. LAI's use of a fixed carbon dioxide emission coefficient reflects the conservative assumption that blending of hydrogen and renewable natural gas is either insignificant or infra-marginal.

4.3 REAE Incremental GHG Emissions are Insignificant

REAE CO2e Emissions as a Percentage of 2019 US Emissions

One method to measure significance of CO2e emissions for a project was illustrated in the Commission's March 2021 Order in Northern Natural, where the Commission assessed the significance of a natural gas pipeline project's GHG emissions and those emissions' contribution to climate change as a share of GHG emissions at the national level.[207] Table 4-7 compares

[204] https://www.peco.com/SiteCollectionDocuments/PECOExhibitJD6-Gas.PDF, page 3. EIA, Pennsylvania Natural Gas Consumption by End Use, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SPA_a.htm , PGW Advance filing, FORM-IRP-GAS-1A: Annual Gas Requirements.

[205] EIA, New Jersey Natural Gas Consumption by End Use, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SNJ_a.htm.

[206] EIA, Carbon Dioxide Emissions Coefficients by Fuel, November `8, 2021, https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[207] Northern Natural Order, paragraph 29

estimates for reasonably foreseeable annual GHG emissions from REAE's construction, operation, and impact to the total GHG emissions of the U.S. as a whole.

Table 4-7. REAE CO2e Emissions as a Percentage of 2019 U.S. Emissions (millions of tons)

	Incremental CO2e Emissions	U.S. CO2e Net Emissions, Based on 2019 Levels[208]	Percentage
REAE Construction	0.044	5,769	0.0007%
REAE Operation	0.088	5,769	0.0015%
REAE Indirect	0.033	5,769	0.0006%

Table 4-8 compares estimates for reasonably foreseeable annual GHG emissions in New Jersey, Pennsylvania and Maryland from REAE's construction, operation, and impact to total GHG emissions reported for each in the 2017 state inventories.

Table 4-8. REAE CO2e Emissions as a Percentage of PA, NJ and MD 2017 Emissions (thousands of metric tons)

	Incremental CO2e Emissions	State CO2e Net Emissions, Based on 2017 Levels	Percentage
REAE Construction			
Pennsylvania	33.3	236,210[209]	0.014%
New Jersey	10.2	96,700[210]	0.011%
Maryland	0.1	68,350[211]	0.0002%
REAE Operation			
Pennsylvania	80.5	236,210	0.034%
New Jersey	6.7	96,700	0.007%
Maryland	1.2	68,350	0.002%
REAE Indirect			
Pennsylvania	12.9	236,210	0.005%
New Jersey	36.2	96,700	0.037%

[208] EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=uuA7i8WoMDBOc0M4ln8WVXMgn1GkujvD, page ES-9.

[209] Pennsylvania Department of Environmental Protection, Pennsylvania Greenhouse Gas Inventory Report, September 2021, page 6. Available at https://files.dep.state.pa.us/Energy/Office%20of%20Energy%20and%20Technology/OETDPortalFiles/Climate%20Change%20Advisory%20Committee/2021/2021_GHG_Inventory_Report_2021-09-02.pdf.

[210] New Jersey Department of Environmental Protection, New Jersey

Greenhouse Gas Inventory Mid-Cycle Update Report, February 2021. Available at https://www.nj.gov/dep/aqes/ghgarchive/MCU%20GHG%20Inventory_2021.pdf, page 3.

[211] Maryland Department of Environmental Protection, Greenhouse Gas Emissions Reduction Act - 2030 GGRA Plan, page VI. Available at https://mde.maryland.gov/programs/Air/ClimateChange/Documents/2030%20GGRA%20Plan/THE%202030%20GGRA%20PLAN.pdf.

The Commission has also considered the impact of project GHG emissions on those state goals. Table 4-9 compares REAE GHG emissions for New Jersey and Maryland to each state's 2030 GHG emissions target. Pennsylvania's legislature has not established a state GHG emissions reductions target.[212] New Jersey's Global Warming Response Act requires a reduction in New Jersey's GHG emissions below the 1990 level by 2020 and 80% below the 2006 level by 2050.[213] While New Jersey has not set a GHG emissions target for 2030, or the other intermediate years, LAI has calculated an implicit target for 2030 assuming New Jersey's emissions target follows a linear trend between 2020 and 2050.[214] Maryland's Greenhouse Gas Emissions Reduction Act established state GHG emissions reductions targets of 25% by 2020 and 40% by 2030.[215] For 2017, the most recent year for which Maryland has performed a comprehensive GHG inventory, Maryland accounted for 68.35 million metric tons of net CO2e GHG emissions, 25.8% below the state's total for 2006 of 108.06 million metric tons.[216]

Table 4-9. REAE CO2e Emissions as a Percentage of PA, NJ and MD 2030 Emissions Targets (thousands of metric tons)

	Incremental CO2e Emissions	State CO2e Net Emissions, Based on 2030 Targets	Percentage
REAE Construction			
Pennsylvania	33.3	N/A	
New Jersey	10.2	91,800	0.011%
Maryland	0.1	53,000	0.0002%
REAE Operation			
Pennsylvania	80.5	N/A	
New Jersey	6.7	91,800	0.007%
Maryland	1.2	53,000	0.002%
REAE Indirect			
Pennsylvania	12.9	N/A	
New Jersey	36.2	91,800	0.039%

[212] Pennsylvania Department of Conservation and Natural Resources, Gov. Wolf Announces 'Pennsylvania Climate Action Plan 2021,' September 22, 2021, https://www.media.pa.gov/pages/DCNR_details.aspx?newsid=781.

[213] New Jersey Global Warming Response Act, P.L. 2007, Chapter 112, approved July 6, 2007, https://www.nj.gov/dep/aqes/docs/gw-responseact-07.pdf.

[214] New Jersey had 125.7 million metric tons of net GHG emissions in 1990, and 120.6 million tons in 2006. Therefore New Jersey's 2020 and 2050 emissions targets are 125.7 and 24.1 million tons, respectively. https://www.nj.gov/dep/aqes/ghgarchive/MCU%20GHG%20Inventory_2021.pdf, page 6. New Jersey's assumed 2030 target is 91.8 = 125.7 + (125.7 – 24.1) * (2050 – 2030) / (2050 – 2020) million metric tons.

[215] Maryland Department of Environmental Protection, Climate Change Program. Available at https://mde.maryland.gov/programs/Air/ClimateChange/Pages/index.aspx

[216] Maryland Department of Environmental Protection, Greenhouse Gas Emissions Reduction Act - 2030 GGRA Plan, page V. Available at https://mde.maryland.gov/programs/Air/ClimateChange/Documents/2030%20GGRA%20Plan/THE%202030%20GGRA%20PLAN.pdf.

LAI gives context to the GHG estimate by noting that 5.769 billion metric tons of CO2e were emitted on a net basis at a national level in 2019.[217] REAE construction could increase CO2e emissions by 0.044 million metric tons or 0.0007% based on 2019 levels and, in subsequent years, operations could increase CO2e emissions levels by 0.088 million metric tons or 0.0015% based on 2019 levels, and downstream emissions could increase CO2e emissions by 0.033 million metric tons or 0.0006% based on 2019 levels.

As shown in Table 4-8, Pennsylvania had 236.2 million metric tons of net CO2e emissions in 2017. REAE construction could increase net Pennsylvania GHG emissions by 0.033 million metric tons or 0.014% based on 2017 levels. In subsequent years, operations could increase CO2e emissions by 0.08 million metric tons or 0.034% based on 2017 levels, and downstream emissions could increase CO2e emissions 0.013 million metric tons or 0.005% based on 2017 levels. Similarly, New Jersey had 96.7 million metric tons of net CO2e emissions in 2017. REAE construction could increase net New Jersey GHG emissions by 0.01 million metric tons or 0.011% based on 2017 levels. In subsequent years, operations could increase CO2e emissions 0.007 million metric tons or 0.007% based on 2017 levels, and downstream emissions could increase CO2e emissions 0.036 million metric tons or 0.037% based on 2017 levels by 0.0036. In regard to Maryland, the state had 68.4 million metric tons of net CO2e emissions in 2017. REAE construction could increase net Maryland GHG emissions by 0.0001 million metric tons or 0.0002% based on 2017 levels. In subsequent years, operations could increase CO2e emissions by 0.0012 million metric tons or 0.002% based on 2017 levels.

When comparing results to future targets in Table 4-9 New Jersey estimates 91.8 million metric tons of emissions in 2030. REAE construction may potentially increase net New Jersey GHG emissions by about 0.011% based on the 2030 targets and operations could increase CO2e emissions based on the 2030 targets by 0.007%. In comparison, Maryland projects approximately 53.0 million metric tons of emissions in 2030, which means REAE construction could increase net Maryland GHG emissions by about 0.0002% based on the 2030 targets, operations could increase CO2e emissions based on the 2030 targets by 0.002%.

[217] In its North Natural Order, the Commission relied on 2018 GHG emissions, but 2019 values are now available. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=uuA7i8WoMDBOc0M4ln8WVXMgn1GkujvD, page ES-9.

5 <u>Conclusions</u>

LAI has reached five primary conclusions:

1. REAE is needed to meet the reliability requirements of LDCs in New Jersey and Southeastern Pennsylvania under design day criteria, and will allow BGE to meet its design day requirements with cost effective firm pipeline capacity.

2. REAE increases the natural gas available to generators during cold winter conditions when LDC demand is high. During these periods, combined-cycle generators within the study area displace less-efficient generation, reducing GHG emissions from power generation.

3. REAE improves fuel security and operational flexibility for power generation, especially during the peak heating season, December through February, when harsh weather conditions may arise that may impair energy deliveries from wind and solar plants. As more renewable generation is added to the resource mix to meet laudable carbon reduction goals, REAE provides a vital operational hedge in case extreme winter conditions occur when offshore wind production is much lower due to cold weather conditions and high wind speeds, as well as ice-build up. Snowstorms affecting solar production at the same time should be considered.

4. REAE's reasonably foreseeable GHG emissions resulting from the construction, operation and downstream use of REAE will have an insignificant impact on regional GHG emissions, accounting for less than 0.1% of annual emissions in New Jersey and Pennsylvania. Direct emissions from project construction may result in 0.044 million metric tons of net CO_2e in 2024. Direct emissions from REAE operations will result in 0.088 million metric tons per year (mtpy) of CO_2e. Additional capacity ascribable to REAE will result in 0.033 million mtpy of net indirect CO_2e, with 0.049 million mtpy increased residential, commercial and industrial natural gas consumption offset by 0.016 mtpy of reductions in CO_2e ascribable to avoided emissions from fossil-fired generation in the region.

5. Market experience shows that the additional supply lowers prices. How long lower prices prevail and for how long no one knows. The incremental capacity ascribable to REAE will likely, but not definitely, have a significant impact on delivered natural gas prices in New Jersey and Southeastern Pennsylvania in the winter, especially on days when current capacity is used fully. The duration and sustainability of these beneficial impacts is unknown. In light of uncertainties about technology change in the electric sector, the likely frequency and diminution of the price spikes over the study horizon is unknown, as well as how long such diminution may persist. Absent REAE, the extent to which delivered gas price spikes during the heating season will affect both retail natural gas and electric rates is also unknown.