3. Natural Gas

Draft New York State Energy Plan

July 2025

Key Findings

- **While natural gas consumption may continue growing in the near term, State policy, a warming climate, and evolving customer preferences towards cleaner alternatives are expected to put downward pressure on long-term demand.** Diffusion of energy efficiency and electric technologies for space heating, water heating, cooking, and other energy services will drive down gas consumption.

- **State policies, regulations, and programs should increasingly support this transition to the fullest extent legally permissible while also safeguarding energy affordability.** The gas industry, policymakers, and regulators need to proactively adapt to this evolving energy landscape to ensure safe, reliable, and affordable service.

- **Gas system planners must continue to ensure safety and reliability, addressing persistent risks and hazards while also addressing emerging challenges.** Even as New York decarbonizes, the gas system will continue to play a large role in New York's energy system through the 2040 planning period, so it must remain reliable and resilient, for example, to risks posed by extreme weather and a shifting climate.

- **Proactive long-term and integrated planning are needed to ensure efficient investment in the natural gas system and to reduce stranded asset risk given the projected decline in gas system utilization.** Longer planning horizons, closer coordination with electric utilities, prioritization of non-pipe alternatives (NPAs), and more proactive demand management (especially in extreme conditions) are all needed to reduce gas system capital investment safely and strategically. Planning and investment standards need to be evaluated to ensure that they remain suitable as the climate and patterns of consumer demand change.

- **New approaches may need to be developed to give the PSC and gas utilities greater flexibility to proactively plan for safe, strategic reduction in gas system investment as customers adopt efficiency and electrification measures.**

- **Innovative cost recovery mechanisms may be needed to maintain the operational viability of gas utilities, ensure energy affordability, and improve alignment between cost causation and cost allocation, while supporting safe and reliable operation.** Potential approaches include accelerated depreciation of gas infrastructure, rate design reforms, securitization of legacy costs, and cost sharing with non-gas-ratepayer entities.

- **Alternative fuels can play a role in decarbonizing the gas sector and should be implemented strategically.** Renewable natural gas (RNG) sourced from sustainable feedstocks can reduce statewide emissions and support broader decarbonization of the agriculture and waste sectors. Clean hydrogen is also expected to have a role in New York's decarbonization specifically as clean, firm electric generation or for onsite industrial use. Claims that "certified" or "differentiated" gas reduce upstream methane emissions must be substantiated before these fuels can be incorporated into the State's strategy to decarbonize the gas sector.

- **A just transition for gas sector workers and businesses is a State policy priority.** The State should work closely with utilities and labor organizations to ensure gas sector workers have access to continued economic opportunities throughout the clean energy transition. Additional research is needed to determine the most effective workforce interventions.

- **The gas transition should be strategically managed to ensure disadvantaged communities (DACs) have equitable access to clean energy and are not unduly burdened financially or otherwise.** Proactive planning, including targeted deployment of clean energy technologies, will be essential to protect customers in DACs from adverse impacts and to ensure they benefit from the energy system transition.

- **The challenges facing the gas sector over the coming decades necessitate the development of a strategic gas system transition plan.** The State should work collaboratively with select utilities and other key gas sector stakeholders to develop a plan that sets utility-specific targets and evaluates changes to utility policy, investment, planning, and cost recovery.

Units: Measuring and Quantifying Natural Gas

- Natural gas is measured and quantified using both volumetric units and energy-based units depending on the context.
- Commonly used volumetric units include cubic feet (cf), hundred cubic feet (ccf), thousand cubic feet (Mcf), and billion cubic feet (Bcf).
- Commonly used energy-based units include British thermal units (Btu), therms (th), dekatherms (dth), million British Thermal Units (MMBtu), and trillion British thermal units (TBtu).
- Utility meters measure the volume of natural gas that customers consume. Utilities then apply a conversion factor—often referred to as the “heat content” or “therm factor”—to convert the metered volume into an energy value for billing purposes.
- Some unit conversions are provided below:
  - 1 Mcf = ~1.037 MMBtu or ~1.037 Dth (varies slightly by gas composition)
  - 1 MMBtu = 1 Dth = 10 th = 1,000,000 Btu
  - 1 MMBtu = 1 Dth = ~293.07 kWh
- For a general sense of scale, a typical residential customer in New York uses ~100 - 140 dth per year and ~1 dth on a peak day. A 350 MW combined cycle electric generating plant uses ~54,000 dth per day (assuming 100 percent capacity factor), and about 12,000,000 dth per year (assuming 60 percent capacity factor).

Key Terms

- **City Gate:** the point at which gas utilities or local distribution companies (LDCs) take operational responsibility for safely and reliably transporting gas to customers.
- **Demand Response:** programs that encourage gas customers to reduce consumption during periods of high demand, sometimes by shifting demand from high load periods to periods of lower demand. These programs are typically administered by natural gas utilities.
- **Design Day:** the specific extremely cold conditions that gas utilities use to plan for supply adequacy and reliability. Design day is typically based on the coldest actual day experienced in a gas utility's service territory and is often expressed in terms of "heating degree days."
- **Design Day Demand:** the expected consumption of natural gas by a gas utility's firm service customers on a design day.
- **Firm Service:** service for natural gas customers who lack alternatives to natural gas consumption and require uninterrupted delivery of gas. Residential and small commercial customers typically receive firm gas service.
- **Interruptible Service:** service for natural gas customers who can employ an alternative fuel or cease consumption of natural gas entirely when requested to do so by the gas utility (often at a particular cold temperature threshold). Customers receiving interruptible service pay reduced distribution rates.
- **Local Distribution Company (LDC):** a gas utility. LDCs are responsible for building and maintaining a local pipeline system that delivers natural gas to end use customers, such as businesses and homes, after receiving gas from a transmission pipeline at the city gate or another source.
- **Spot Market:** the market for buying and selling natural gas for immediate or very near-term delivery, usually for a period of 30 days or less. Transactions in the spot market reflect real-time supply and demand conditions and are not governed by long-term contracts.
- **Spot Price:** the current price of natural gas in the spot market. Spot prices can fluctuate daily based on weather, demand, supply availability, and other market dynamics.

1. Overview

New York residents and businesses currently use natural gas for many important end uses. In 2022, New York used 1,403 trillion British thermal units (TBtu) of natural gas, accounting for 39 percent of the state's primary energy consumption. Natural gas provided 75 percent of residential, 79 percent of commercial, 49 percent of industrial, 39 percent of electricity generation, and 3.8 percent of transportation energy consumption.[1] In 2024, natural-gas-fired generation accounted for 62 percent of New York's electricity generating capacity.[2] Over 5 million New York residents and businesses use natural gas for space and water heating, cooking, commercial and industrial processes, electricity generation, and as a raw material for manufacturing fertilizers, plastics, and petrochemicals.

New York's use of natural gas is expected to decline by 2040 in all scenarios of future energy pathways developed for the State Energy Plan, resulting from a combination of State and local policy as well as shifting customer preferences towards electric substitutes. While the extent of this decline varies depending on scenario, in all of them New York continues to meet a substantial portion of its energy needs with natural gas through at least 2040. As such, it is essential that the natural gas system remain safe, reliable, and affordable for customers.

To achieve these goals, New York must strategically manage the transition toward a reduced reliance on natural gas. This requires continued operational vigilance, particularly in response to emerging climate-related risks, as well as robust long-term and integrated planning and expanded use of non-pipeline alternatives to promote efficient gas system maintenance investment. New York will need to make dedicated efforts to ensure a just transition for gas sector workers and businesses, low- and moderate-income customers, and disadvantaged communities (DACs), ensuring that the benefits of the energy transition are shared equitably. The gas transition will also require the strategic use of alternative fuels to reduce greenhouse gas (GHG) emissions, policies to enable neighborhood-scale energy planning, and potentially, innovative cost recovery mechanisms that maintain the operational viability of gas utilities while supporting long-term energy affordability.

2. State of the Sector and Progress Report

2.1. New York Natural Gas Supply and Demand Overview

2.1.1. Production

New York's use of natural gas is situated within a broader regional, national, and international competitive market with corresponding industries for natural gas supply, storage, transmission, and distribution. U.S. production of natural gas increased over the past 15 years as new oil and gas production technology and horizontal drilling have increased the industry's ability to extract gas, especially from shale formations. The rapid increase in shale gas production from the Appalachian Basin, comprised of the Marcellus and Utica shale formations (especially in Pennsylvania, West Virginia, and

[1] "Patterns and Trends: New York State Energy Profile Dashboard." Accessed May 1, 2025. Available at: https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Patterns-and-Trends.

[2] NYISO 2025 Load & Capacity Data ("Gold Book") available at: https://www.nyiso.com/library. This number includes generation by both natural gas power plants and dual fuel (natural gas and oil) power plants.

Ohio), has become an important source of natural gas for the northeast. Figure 1 depicts the rapid growth in Appalachian shale production starting in 2010 and growing to over 30 billion cubic feet (Bcf)/day in the early 2020s.[3]

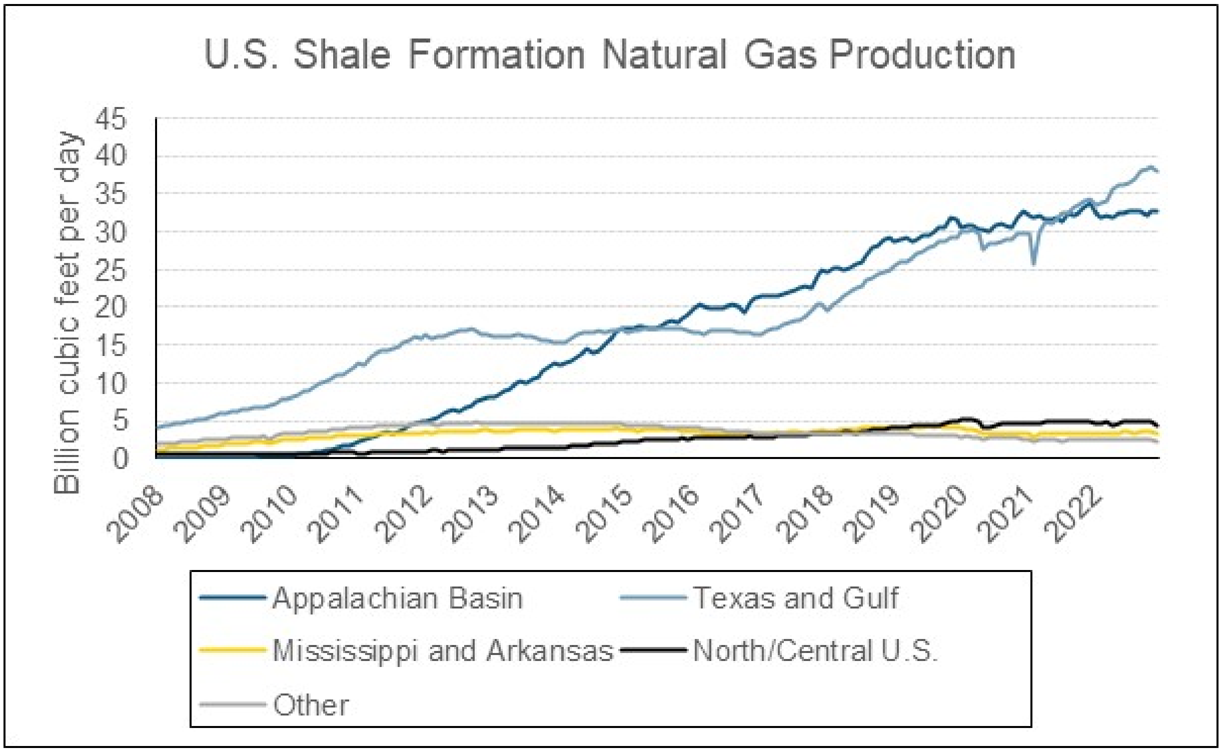

Figure 1. U.S. Shale Formation Natural Gas Production Estimates

New York is not a major producer of natural gas. In 2022 New York produced approximately 9.7 TBtu of natural gas, about 0.02 percent of US natural gas production or 0.7 percent of New York's annual gas demand.

2.1.2. Supply and Delivery

Because New York State produces a limited amount of natural gas in-state, its gas supply primarily comes from imports. Natural gas is delivered to New York through a network of interstate transmission pipelines.

The upstate region is served by the following gas utilities: Central Hudson Gas and Electric Corporation (CHGE), Corning Natural Gas Corporation (Corning), National Fuel Gas Distribution Corporation (NFG), Niagara Mohawk Power Corporation d/b/a National Grid (NMPC), New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RGE), Liberty Utilities (St. Lawrence Gas) Corp. (Liberty Utilities), and several small distribution companies and municipal utilities. These utilities primarily source gas from the following interstate pipelines: Columbia, Eastern, Empire, Iroquois, Millenium, National Fuel Gas Supply Corporation, Tennessee, and TransCanada.

[3] EIA, "Dry shale gas production estimates by play"

The downstate region (Long Island, New York City, and Westchester, Orange, and Rockland Counties) is served by the following gas utilities: The Brooklyn Union Gas Company d/b/a National Grid NY (KEDNY), KeySpan Gas East Corporation d/b/a National Grid (KEDLI), CHGE, NYSEG, Consolidated Edison Company of New York, Inc. (Con Edison) and Orange & Rockland Utilities, Inc. (O&R). These utilities primarily source gas from the following interstate pipelines: Iroquois, Millenium Tennessee, Texas Eastern, TransCanada, and Transcontinental (see Figure 2).

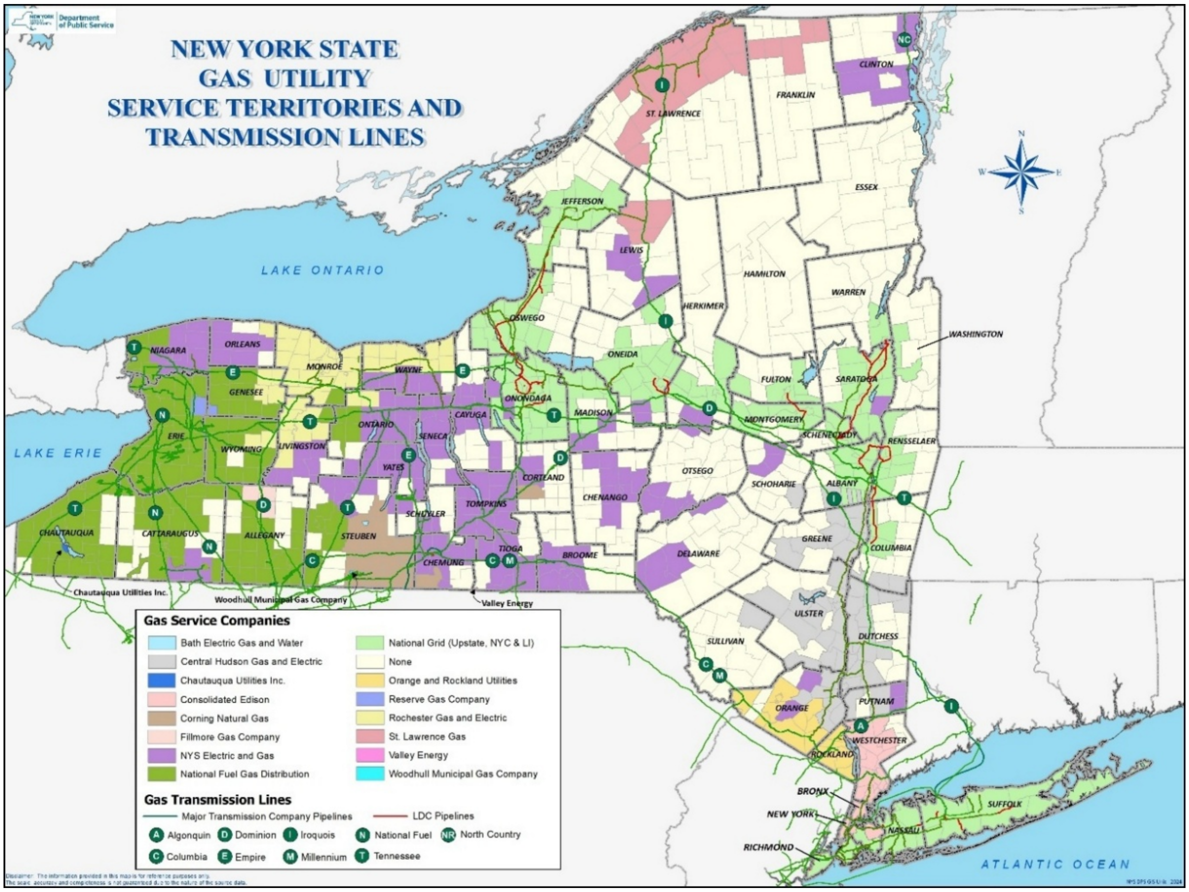

Figure 2. New York State Gas Utility Service Territories and Transmission Lines

The pipeline systems serving New York primarily source natural gas from production and storage regions southwest of New York, including from the Marcellus and Utica regions (primarily Pennsylvania, West Virginia, and Ohio), as well as the Gulf Coast states (Alabama, Florida, Louisiana, Mississippi, and Texas). Iroquois and TransCanada transport gas from the north, providing a reliability benefit through supply diversity.

Gas utilities or local distribution companies (LDCs) are responsible for procuring gas supply on behalf of their customers, delivering gas to customers from the city gate,[4] and keeping their distribution systems balanced by matching demand with supply. Each LDC's specific supply portfolio depends on factors that are unique to its service territory. Generally, supply portfolios are primarily comprised of firm capacity on interstate

[4] City gates designate the point at which gas utilities or LDCs take operational responsibility for safely and reliably transporting gas to customers.

pipelines and natural gas storage. Pipeline systems build up natural gas storage during the lower demand seasons, i.e., spring, summer, and early fall. Natural gas storage facilities are typically underground using caverns formed in old salt beds or depleted natural gas or oil wells. While some storage facilities used by New York's LDCs are located in western New York, the majority are located in the Marcellus and Gulf regions.

During periods of peak demand, LDCs often draw from a wider range of supply sources, referred to as "peaking services," that are typically purchased at a premium. These may include additional purchases from interstate pipelines, withdrawals from storage, compressed natural gas (CNG), or liquefied natural gas (LNG). Several of the State's gas utilities also currently receive local supplies of renewable natural gas (RNG) or conventional natural gas. If these sources are not sufficient to meet demand, LDCs can implement demand control measures such as directing tiered classes of interruptible customers to stop using natural gas in favor of pausing operations or switching to secondary fuels, such as fuel oil, until the service interruption ends. Peaking services and demand management are used to ensure reliability during cold weather or contingency events.

2.1.3. Demand

New York has approximately 5 million natural gas customers, 92 percent of which are residential.[5] In 2022, New York consumed approximately 1,400 Bcf of natural gas, accounting for 4 percent of gas consumption nationwide.[6] Demand for natural gas is greatest during the winter season due to demand related to space heating and a relatively low-demand summer season. Annual demand for natural gas in New York has historically peaked on the coldest days in winter.

Figure 3 shows a 15-year summary of natural gas consumption in New York State, by sector.[7] In recent years, natural gas consumption in the power generation sector has increased as New York's generation mix has shifted from coal to gas and, with the closure of the Indian Point generating station, from nuclear to gas. In the building sector, gas consumption has also risen as many buildings have switched from heating oil and other fuels to heating with gas, in part due to New York City policies that encouraged fuel switching. At the same time, growing investments in building energy efficiency, weatherization, and electrification are placing downward pressure on gas demand in the building sector, a dynamic that is expected to continue and likely accelerate in the years ahead.

Natural gas demand in the building sector currently peaks in the winter, driven by the use of gas-fired boilers and furnaces for space heating. By contrast, gas demand in the power generation sector currently peaks in the summer, corresponding to increased electricity consumption to serve air conditioning for space cooling. However, gas also continues to play a critical role in meeting electric demand in the winter months, providing fuel for generator demand. New York gas demand forecasts are discussed below in Section 3.

[5] EIA, "Natural Gas Customers"
[6] NYSERDA, "Patterns and Trends: New York State Energy Profile 2008 – 2022"
[7] *Ibid*.

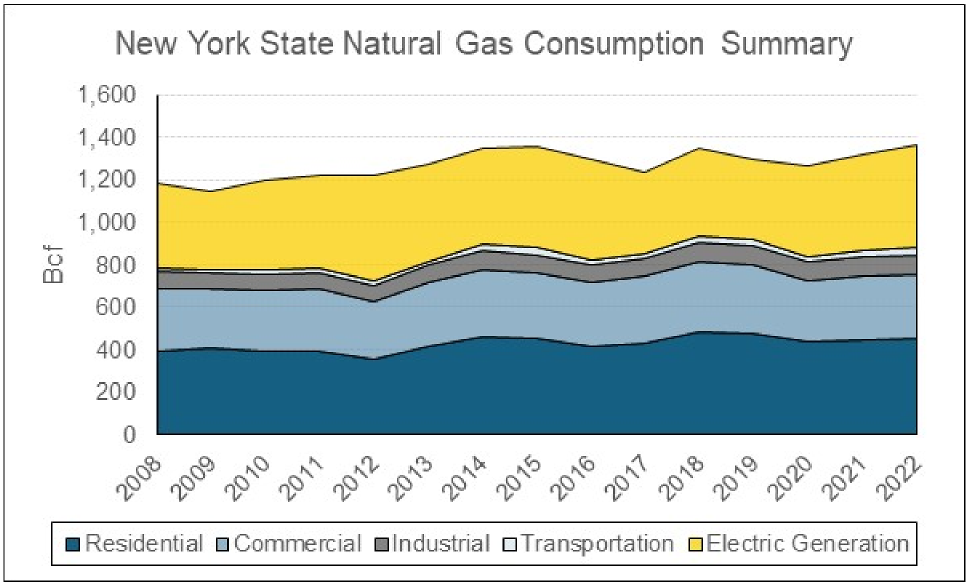

Figure 3. New York State Natural Gas Consumption Summary

2.1.4. Regulation and Oversight

The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines' siting and transportation rates, while the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration regulates interstate pipeline operations and maintenance. In New York, the Department of Environmental Conservation (DEC) issues the Clean Water Act Section 401 Water Quality Certification (WQC) and the Department of Public Service (DPS) monitors safety-related conditions and oversees system reliability, acting as an agent of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). DPS also works with the New York Division of Homeland Security and Emergency Services (DHSES) on winter preparedness and emergency response. NYSERDA collects, analyzes, and disseminates information on gas consumption and markets as part of its energy market intelligence function.

The New York State Public Service Commission (PSC) regulates gas distribution systems and the utilities that own and operate them. The PSC is responsible for ensuring that utilities provide safe and adequate service at just and reasonable rates, and that utility planning, investments, and operations align with State policy goals. For instance, as discussed below in Section 2.3.2, the PSC assesses whether its decisions may conflict with or impede the attainment of statewide GHG emission targets established under the 2019 Climate Leadership and Community Protection Act (Climate Act). The PSC also oversees a range of energy policies and programs that benefit New Yorkers, including those supporting weatherization, clean heat, and energy affordability.

In addition to the issuance of WQCs, DEC plays a key role in the oversight of natural gas sector emissions and environmental permitting. DEC is responsible for permitting new natural gas wells and regulating emissions of methane and volatile organic compounds from natural gas infrastructure. The agency's work is central to ensuring that emissions from the sector align with the GHG reduction targets established in the Climate Act, supporting the State's broader climate and environmental goals.

2.2. Gas Prices Overview

Retail natural gas prices paid by end users include two primary cost components—supply and delivery. The supply price, sometimes referred to as the commodity price, is influenced by a competitive market and includes the cost of the gas itself, interstate pipeline capacity contracts, storage facilities, and cost of transporting the gas to the LDC's city gate. As noted above, interstate pipeline transportation rates are set by FERC although many pipeline capacity contracts feature negotiated rates. Supply is typically priced at a particular gas hub, also known as a "liquid point." New York's gas utilities typically purchase supply (on behalf of their customers) which has its cost tied to a particular index, such as "first of month" or "liquid point" pricing, and deploy hedging strategies to reduce volatility seen in spot market prices.

The delivery or distribution price includes the cost of distribution pipelines ("mains" and "services") used to transport gas from the LDC's city gate to end users as well as the cost of supporting infrastructure like compressors, regulator stations, meters, and utility operational expenses. Delivery rates are specific to the gas distribution utility serving a given area. Distribution delivery rates are set by the PSC and can include the costs of efficiency and affordability programs as well as property taxes.

Retail prices—the final price paid by end users—include both supply and delivery costs as well as surcharges and credits associated with other costs. This section reviews historic supply prices at hubs that are relevant to New York and retail rates for New York's gas distribution utilities.

2.2.1. Supply Prices

Natural gas is a commodity bought in a competitive market. Like most markets, supply and demand directly influence prices. As customer demand increases, so do prices and the incentive for producers to ramp up production. Similar to how gasoline prices tend to increase in warmer months as people travel more, natural gas prices typically increase in the winter when demand for gas for heating is higher. Except for geopolitical global events that have impacted prices, such as the Ukraine war, natural gas futures have largely traded in the $2–$4/MMBtu range over the last 15 years.

The structural composition of the natural gas system and New York's diverse geography also impact natural gas retail prices. For example, the interstate pipelines serving the downstate region are constrained, so when demand increases, downstate commodity spot prices are significantly impacted. However, the interstate pipelines serving western New York are less constrained and, accordingly, their spot prices are less impacted by increases in demand.

Daily gas prices can be volatile, reflecting near-term changes in demand (which is frequently temperature-driven). LDCs engage in hedging to mitigate volatility for mass-market customers. Utility hedging programs are intended to mitigate dramatic spot market volatility especially during times of unexpected high demand. The PSC has a gas purchasing policy that requires gas utilities to mitigate price volatility experienced by core customers (i.e., customers who do not have alternatives to LDC-provided gas service). Price volatility can be managed through storing purchased gas supplies to deliver during future high price periods (a physical hedge), or through purchasing options that guarantee future delivery of gas at a set price that is not subject to subsequent price increases (a financial hedge).

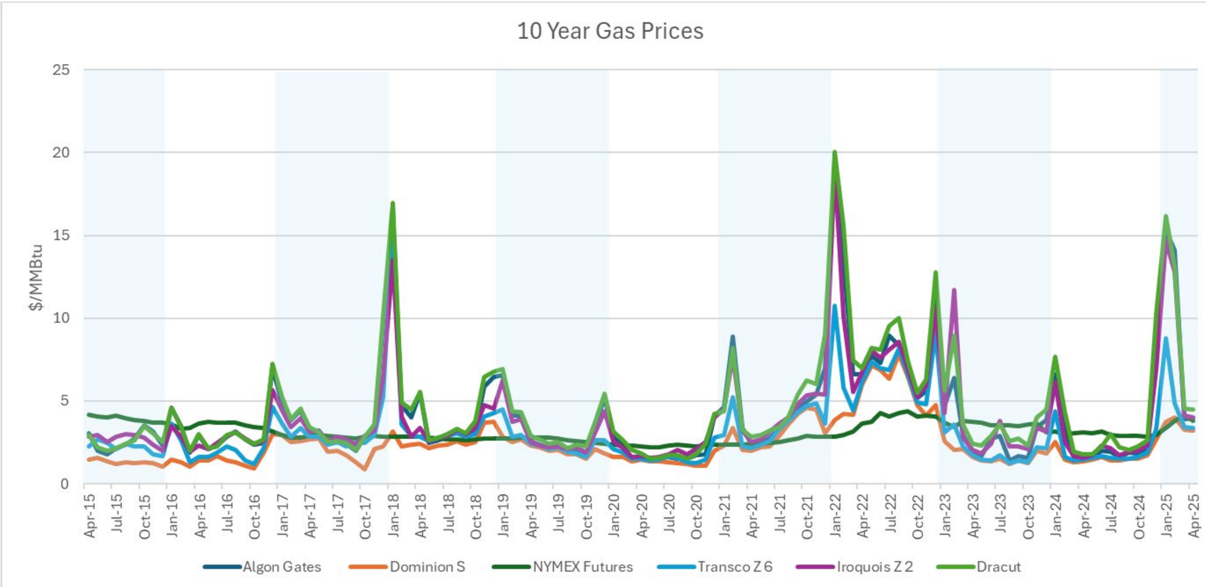

Figure 4. Historic Average Monthly Prices at Key Hubs Serving New York (2015-2025)

2.2.2. Retail Prices

As discussed above, natural gas retail prices include both supply and delivery costs as well as surcharges. The figures below show historical average monthly gas bills grouped by utility for upstate residential (Figure 5), downstate residential (Figure 6), upstate small commercial (Figure 7), and downstate small commercial (Figure 8) end users.[8] The figures show that average retail bills are generally higher downstate than upstate, reflecting several factors that include the higher costs of building and maintaining infrastructure in the more densely developed and populated downstate region and the higher commodity cost of gas downstate (which is a gas-supply-constrained region).

[8] Figures were developed using average bill data compiled from https://dps.ny.gov/gas-utility-ten-year-historic-average-monthly-bill-data-typical-customers.

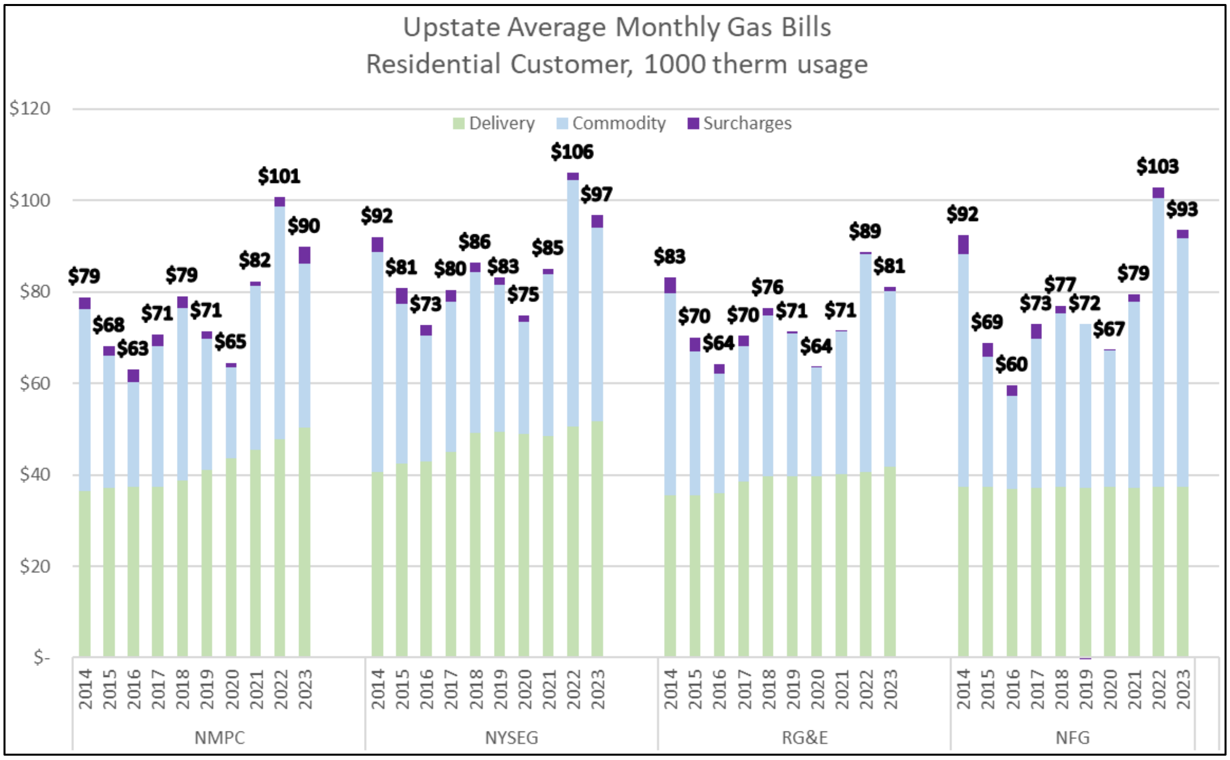

Figure 5. Upstate Average Monthly Residential Gas Bills (2014-2023)

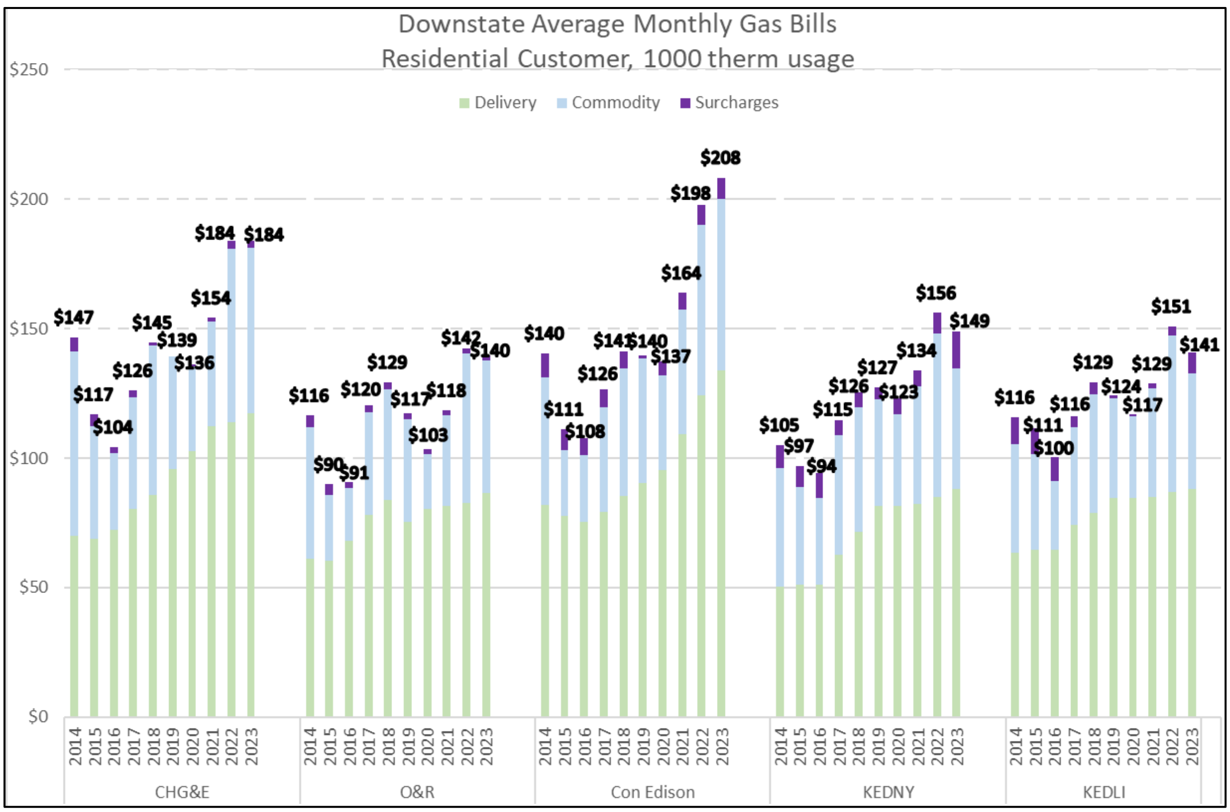

Figure 6. Downstate Average Monthly Residential Gas Bills (2014-2023)

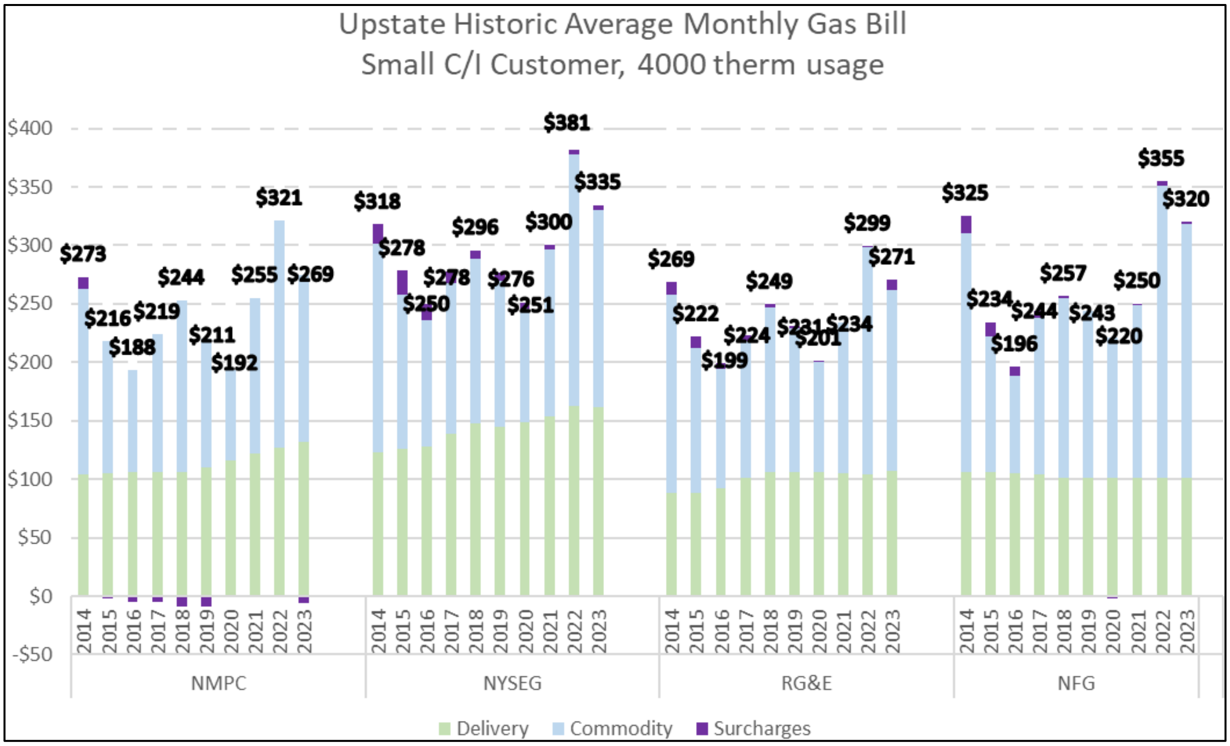

Figure 7. Upstate Average Monthly Small Commercial and Industrial Gas Bills (2014-2023)

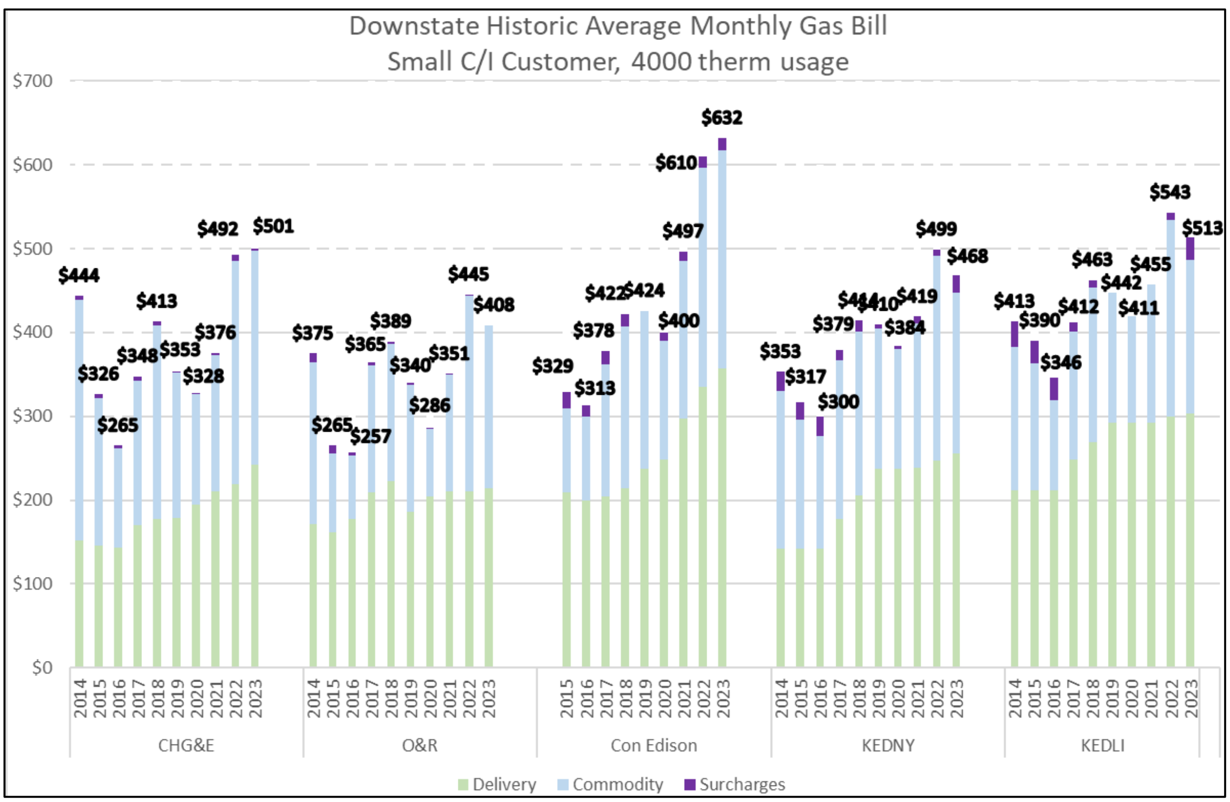

Figure 8. Downstate Average Monthly Small Commercial and Industrial Gas Bills (2014-2023)

2.3. Current Gas System Planning Practices, Laws, Regulations, and Programs

2.3.1. Gas Planning

Gas planning is necessary to ensure the provision of essential energy services to New York residents and businesses. Gas planning also helps evaluate progress towards and sets out actions needed to achieve New York's GHG limits, programmatic targets, and other policy priorities.

Gas planning occurs in multiple contexts and on multiple time and geographic scales. It generally involves forecasting gas demand, supply, and transmission and distribution capacity under various scenarios to ensure there is sufficient supply and infrastructure capacity to reliably meet forecast demand. Because gas demand currently peaks in winter months, corresponding with the heating season, many gas planning activities focus on winter reliability and preparedness planning.[9]

Gas planning may identify the need for investments to replace existing infrastructure that is aging or damaged or to meet demand growth with new infrastructure. Forecast demand can also be met through investment in alternatives to gas system infrastructure through demand-side measures or other competitive market solutions, often referred to as non-pipe alternatives (NPAs). LDCs can also actively manage demand during peak demand periods through the use of interruptible service classes, which limit certain customers' consumption, and issuing system alerts, which direct natural gas transporters to manage gas flows to prevent imbalances that can lead to system pressure issues or disruptions.

If an LDC forecasts that demand in a given area will exceed the system's capacity to meet that demand due to supply constraints, the LDC may impose a moratorium on new gas connections to help ensure that the LDC can continue to deliver gas reliably to existing gas customers. In such circumstances, utilities must comply with the PSC's moratorium management procedures, which are intended to ensure that moratoria are invoked, managed, and released in a fair, equitable, and transparent manner for all consumers, including those in DACs.[10]

Annual Winter Reliability and Preparedness Planning

Each year, DPS assesses the readiness of New York's natural gas system to meet customer energy needs for the upcoming winter. This includes reviewing the LDCs' forecasts of firm demand under extreme cold weather, or "design day" conditions, and their supply portfolios to ensure they have sufficient capacity to meet that demand. DPS also evaluates LDCs' hedging programs and provides estimates of average winter heating bills for gas customers across the state. DPS presents its findings to the PSC at its October monthly session.

Design day demand is the amount of gas that utilities or suppliers forecast their firm customers would need on an extremely cold day. The definition of design day generally reflects the coldest actual weather historically experienced in each region. As such, gas utilities' definitions of design day conditions vary

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[9] Because many power plants are gas-fired and electric demand peaks in the summer, there is also a seasonal summer gas demand peak for power generation—though this is lower than the winter gas demand peak. Gas demand for winter heating needs is generally considered firm demand whereas electric generators tend to rely on less costly interruptible capacity and supply, which is widely available in the summer.

[10] *Order Adopting Moratorium Management Procedures* issued May 12, 2022 in Case 20-G-0131. Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-G-0131.

throughout the state from average daily temperatures of between 0°F and -20°F. Design day demand is used for measuring the peak amount of gas that utilities must be prepared to deliver to ensure reliability. This makes design day demand the foundational engineering design criteria for reliable physical operation of the system and capacity planning at all levels—supply, transmission, and distribution.

Rate Cases

Gas utilities operate as regulated natural monopolies in New York. As described above, utility delivery rates include all the costs that the utility incurs to own, operate, and maintain its system to provide customers with utility service. Delivery rates are established through a formal legal process referred to as a rate case.[11] A rate case begins when a utility requests to increase the delivery rates it charges customers. The utility files expert testimony describing why its proposed rate increases are necessary. DPS performs extensive evaluations of the proposed capital investments, operating expenses, and resulting delivery rates proposed by utilities in their rate filings to determine what level of investment and rates are justified. DPS recommends to the PSC an appropriate balance of funding to ensure safe, reliable service while maintaining just and reasonable rates. Intervening parties, such as those representing customers, can also make recommendations in a rate case. Based on the evidence presented by the parties – DPS Staff, the LDC, and any intervenors, the PSC issues a final decision on the rate proceeding.

Gas Planning Order (20-G-0131)

On May 12, 2022, the PSC issued its "Order Adopting Gas System Planning Process" in Case 20-G-0131, which created the currently effective long-term gas system planning process and simultaneously closed its "Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service."[12] Both of these actions were, in part, in response to the enactment of the Climate Act. The Gas Planning Order established a process to modernize LDCs' planning practices to focus on maintaining reliability, ensuring affordability, and reducing emissions as the State transitions to alternative energy sources.

The Planning Order requires LDCs to file long-term gas plans (LTPs) every three years, covering twenty-year planning periods. The LTPs are staggered to ensure stakeholders adequate time to engage on each individual LDC. Each LTP involves significant effort to educate stakeholders on the design, operation, and planning requirements of natural gas systems. The first LTP was filed by NFG, and the PSC has now considered LTP filings by NFG, Con Edison/O&R, NYSEG/RGE, and CHGE.[13] The National Grid companies,

[11] Underlying commodity prices are set by the market, not regulated by the PSC. However, the PSC influences supply prices paid by retail customers through policies that apply to gas purchases utilities make on behalf of customers, like the hedging requirements described above.

[12] *Order Adopting Gas System Planning Process* issued May 12, 2022 in Case 20-G-0131. Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-G-0131. ("Gas Planning Order")

[13] *Order Implementing Long-Term Natural Gas Plan with Modifications* issued December 14, 2023 in Case 22-G-0610; *Order Regarding Long-Term Natural Gas Plan and Requiring Further Actions* issued September 20, 2024 in Case 23-G-0147; *Order Regarding Long-Term Natural Gas Plan and Directing Further Actions* issued January 23, 2025 in Case 23-G-0437; *Order Regarding Long-Term Natural Gas System Plan and Directing Further Actions* issued July 17, 2025 in Case 23-G-0676.

Corning, and Liberty Utilities have filed final LTPs that will be considered by the PSC in the coming months.[14]

The first round of LTPs generally outlined LDCs' strategies for advancing energy efficiency, building electrification, and demand response programs, such as residential "Bring Your Own Thermostat" initiatives, along with other NPAs, including targeted electrification efforts. The plans also address the potential integration of alternative fuels, such as RNG, into the LDCs' gas systems. In addition, the LTPs include long-range supply and demand forecasts, capital investment plans, gas peaking supplies, hydraulic modeling, potential bill impacts, and benefit-cost ratio analysis for various scenarios over a 20-year horizon.

2.3.2. Current Laws and Regulations

As outlined above in Section 2.1.4, the gas sector must adhere to regulations and oversight related to safety, reliability, cost, and environmental impacts—including impacts from GHG emissions. The key laws and regulations relevant to New York's natural gas sector are described in more detail below.

Federal

At the federal level, several agencies are involved in establishing and enforcing rules and regulations that apply to the natural gas system with the aims of safeguarding public health, environmental quality, worker safety, and market fairness. This section describes key agencies and current policies; however, future federal policy regarding regulation and oversight of the natural gas sector is uncertain.

PHMSA implements standards for pipeline safety, including requirements for periodic inspection, testing, and reporting to ensure the integrity of gas pipelines.[15] For example, in 2019, PHMSA promulgated a rule requiring pipeline operators to reconfirm (by 2035) the maximum allowable operating pressure of all gas transmission pipeline segments that do not have traceable, verifiable, and complete records.[16] This process is intended to ensure that pipelines continue to operate within safe limits over time and under varying conditions.

The U.S. Environmental Protection Agency (EPA) plays a role in regulating the environmental impacts of natural gas operations, such as methane emissions. For example, the EPA is responsible for developing regulations, establishing emissions measurement and verification protocols, and supporting enforcement related to the fee on gas system methane emissions established in the Inflation Reduction Act. In addition, the EPA's Supplemental Methane Emissions Rule enhances its existing requirements for

[14] Case 24-G-0248 In the Matter of a Review of the Long-Term Gas System Plans of The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, and Niagara Mohawk Power Corporation d/b/a National Grid; Case 24-G-0629 In the Matter of a Review of the Long-Term Gas System Plan of Corning Natural Gas Corporation; Case 24-G-0630 In the Matter of a Review of the Long-Term Gas System Plan of Liberty Utilities (St. Lawrence Gas) Corp.

[15] 49 USCA § 60101 et seq.; 49 CFR Part 190 et seq.

[16] 49 CFR §§ 191, 192. Available at: www.federalregister.gov/documents/2019/10/01/2019-20306/pipeline-safety-safety-of-gas-transmission-pipelines-maop-reconfirmation-expansion-of-assessment.

leak detection, repair protocols, and other emissions mitigation measures to reduce direct GHG emissions from the natural gas sector.[17] However, this rule is under review by the current administration.

As discussed in Section 2.1.4, FERC oversees the economic regulation and permitting of interstate natural gas pipelines.[18] FERC ensures pipelines are built and operated in a competitive and transparent marketplace, as part of this authority, it reviews and approves major investments in pipeline infrastructure and establishes tariffs (i.e., rates for gas transmission) and reliability standards. FERC is responsible for balancing the interests of consumers with those of gas pipeline owners and operators, while promoting accountability and market fairness.

State

Numerous provisions of the Public Service Law (PSL) and Transportation Corporations Law (TCL) guide the PSC and utilities' actions in relation to natural gas service and the recovery of the costs of providing that service. Certain provisions of the Climate Act also inform the regulation of gas service. Some important provisions from these portions of New York law are identified and summarized below.

Section 30 of the PSL declares that "the continued provision of all or any part of such gas, electric and steam service to all residential customers without unreasonable qualifications or lengthy delays is necessary for the preservation of the health and general welfare and is in the public interest."[19] This statement of policy does not, itself, create a right or obligation, but it does give a clear direction to the PSC to enable such service through its oversight of utilities.

Under current statute, Section 31 of the PSL and section 12 of the TCL establish an obligation on utilities to provide gas service to residential and commercial applicants that request it and not to charge applicants for the first hundred feet of whatever main or service line extensions are required to supply that service. Regulations implementing the "100-foot rule," codified at 16 NYCRR Part 230, spell out its features in detail.

16 NYCRR Part 229 describes standards related to the heating value, purity, chemical composition, and other characteristics of gas injected into the gas distribution system. This includes both conventional natural gas as well as RNG.

Section 65 and other provisions of the PSL require gas corporations to provide safe service. Section 66-u of the PSL establishes pipeline safety protocols and directs utilities to present an annual report on pipeline safety and performance measures. 16 NYCRR Part 255 discusses pipeline safety measures in greater detail.

Section 68 of the PSL requires utilities to seek a certificate of public convenience and necessity (CPCN) from the PSC before constructing gas plant or commencing operation pursuant to a previously unexercised local franchise. It also establishes conditions for the grant of such certificates.

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[17] 40 CFR § 60. Available at: https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

[18] 15 USCA § 717 et seq.

[19] PSL §30.

Article VII of PSL governs New York's process for reviewing and siting natural gas infrastructure projects within New York State, such as pipeline expansions or new gas storage facilities. The Article VII process requires that projects' potential impacts on the environment, safety, and community are evaluated to determine potential adverse effects prior to approval. The process also includes opportunities for public participation through hearings to ensure local community concerns can be identified.

The Climate Act does not modify any of the foregoing provisions, but it does add GHG emission and local pollution impacts in DACs to the list of topics that the PSC is required to consider when it makes decisions about natural gas infrastructure and service. While the Climate Act does not say anything about the natural gas system specifically, §7(2) requires state agencies, including the PSC, to consider whether their decisions "are inconsistent with or will interfere with the attainment of statewide greenhouse gas emissions limits." §7(3) directs state agencies to not disproportionately burden disadvantaged communities and directs them to prioritize reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities. The PSC has determined that a §7 analysis is needed in a wide variety of decisions, notably including rate cases that authorize rate recovery of LDC investments. Where the PSC concludes that a decision would be inconsistent with the statewide emissions reductions under the Climate Act—meaning reductions from 1990 levels of 40 percent by 2030 and 85 percent by 2050—it offers a justification for that decision and identifies alternatives or mitigation measures.

DEC is also responsible for several regulations related to the natural gas sector. These include:

- 6 NYCRR Part 203, through which DEC regulates methane and volatile organic compound emissions (i.e., fugitive emissions) from natural gas sector sources. Emissions are controlled through requirements for maintenance, continuous leak detection, and repair if a sufficiently significant leak is identified;
- 6 NYCRR Parts 552 to 554, through which DEC regulates permits to drill, deepen, plug, or convert gas wells. DEC also regulates well drilling practices, spacing, and reporting requirements;
- 6 NYCRR Parts 555 and 556, through which DEC regulates operating practices for active natural gas wells and the plugging and abandonment of retired natural gas wells; and
- Clean Water Act, Section 401, WQC.

2.3.3. Laws and Programs that Affect the Gas System

Some policies and programs that target other sectors but have important interactions with or effects on the gas system are noted below. Additional policies and programs related to efficiency and building electrification are discussed in the Buildings chapter of this Plan.

The New Efficiency: New York program authorizes utilities to recover the costs of energy efficiency and weatherization investments at customer premises. By reducing overall energy use and natural gas consumption, the program plays a key role in supporting the State's decarbonization goals. The Climate Act codified the program's primary target, a reduction of 185 TBtus of end-use energy consumption by 2025, relative to a business-as-usual baseline.

The All-Electric Buildings Act of 2023 directs the State's Code Council to update the Energy Code for residential and small commercial buildings to prohibit the installation of fossil-fuel equipment and building systems in any new buildings starting in 2026 for smaller buildings (up to 7 stories) and in 2029 for larger buildings (over 7 stories). Because the All-Electric Buildings Act applies only to new construction, and buildings tend to have long lifetimes, the resulting reduction in gas demand is expected to be modest in the near term but grow over time. It is also important to note that select uses (e.g., manufacturing facilities, hospitals, agricultural buildings, emergency backup power, commercial food establishments, laundromats, wastewater treatment) are exempt from the Act's requirements.

The Utility Thermal Energy Networks and Jobs Act of 2022 aims to support the development of thermal energy networks by utilities—including gas utilities—using the same workforce that gas utilities currently employ to install, operate, and maintain pipes that deliver natural gas to customers. The PSC is implementing the Act's provisions through Case 22-M-0429. This implementation includes steering pilot projects through several stages of planning, design, and development, as well as the drafting of regulations, based on insights gleaned from the pilot projects, to govern the development and operation of thermal energy networks more generally.

3. Outlook (2025 –2040)

3.1. Pathways Analysis

This section describes expectations for how the gas sector may evolve over the next 15 years based primarily on the Pathways Analysis conducted for the State Energy Plan and informed by other studies regarding the future of New York's gas system, including gas utilities' long-term plans. Given the inherent uncertainty of forecasting over a multidecade horizon, the Pathways Analysis takes a scenario approach. These scenarios reflect a range of levels of State policy action to illustrate the impacts of different policy approaches, including interactions across sectors. A brief description of the core scenarios developed for the State Energy Plan is provided below (Table 1).

Table 1. Summary of Scenarios in the Pathways Analysis

Scenario	Description
No Action	Includes federal incentives (as of Q1 2025) and legacy New York State policies but excludes the Climate Act and more recent additional State and local policies.
Current Policies	Current progress toward achievement of enacted State and local policies (e.g., Clean Energy Standard, building code updates, Advanced Clean Cars/Trucks).
Additional Action	All actions included under Current Policies scenario plus additional progress toward adoption of clean technologies through a mix of future programs and investments aligned with recommendations in the State Energy Plan.
Net Zero A and B	Accelerates adoption of clean energy technologies in all sectors toward achievement of economywide net zero by 2050. Net Zero A emphasizes all electric space heating while Net Zero B assumes greater use of supplementary gas heating systems.

The discussion in this section focuses primarily on the Additional Action scenario which is intended to describe an ambitious but attainable level of achievement under foreseeable policy actions and market transformation. A more detailed description of the methodology, design, and results of these scenarios can be found in the Pathways Analysis chapter of this Plan.

3.2. Demand

The natural gas sector is entering a period of significant change. Over the next fifteen years, market forces, a warming climate, and policy advancing the state's GHG emission reduction targets are expected to induce a decline in gas system utilization. As discussed in Section 2.1.3, the electric generation, residential, commercial sectors use the most natural gas in New York. Each of these sectors will be subject to significant downward pressures on gas consumption.

In the electric generation sector, natural gas and dual fuel (natural gas and oil) generators currently account for nearly half of annual in-state electricity production. As described in greater detail in the Electricity chapter of this Plan, while aggregate demand for electricity is expected to rise significantly due to transportation and building electrification and the interconnection of new large electric loads, the role for natural gas-fired power plants is expected to decline over time as New York deploys renewable resources and advances towards the clean electricity targets set forth in the Climate Act.

In residential and commercial buildings, space heating comprises the largest use of gas. Demand for space heating is expected to decline over time as the climate warms.[20] For instance, Con Edison has projected that its natural gas business could experience an estimated 33 percent decrease in winter energy sales by 2050 as a result of a warming climate, (i.e., not from changes in demand due to electrification or efficiency).[21] In addition to the impact of a warming climate, shifting consumer preferences and State and local policy supporting efficiency and electrification are also expected to drive reductions in gas consumption. For example, new, zero-emission building and energy codes will prohibit the installation of fossil-fuel equipment and building systems in any new buildings starting in 2026 for smaller buildings (up to 7 stories) and in 2029 for larger buildings (over 7 stories). Federal appliance standards and State building codes promote improvements in energy efficiency. And State and federal incentives for heat pumps and energy efficiency will continue to drive reductions in gas consumption in buildings. The future of federal appliance standards and federal incentives is uncertain.

In the Additional Action scenario, the share of residential buildings with upgraded building envelopes is expected to rise from 6 percent currently to 45 percent (3.3 million households) by 2040. This scenario also sees the share of residential buildings with heat pumps rise from around 5 percent currently to 24 percent (1.8 million households) in 2040, the majority of which are full load heat pumps. While the specific level of clean energy deployment varies across the scenarios in the Pathways Analysis, all scenarios see a shift from gas-fired appliances towards electric appliances.

[20] Meier, S., et. al (2024). New York State Climate Impacts Assessment Chapter 06: Energy. *Ann NY Acad Sci.*, 1542, p. 358. https://doi.org/10.1111/nyas.15191

[21] Ibid., p. 359.

As shown in Figure 9 and Figure 10, these trends result in declining gas consumption across all State Energy Plan scenarios. The combination of declining gas system utilization with an ongoing need for significant investment in system maintenance and modernization creates challenges for affordability and necessitates thoughtful policy and planning approaches to strategically manage the gas transition. In the Additional Action scenario, gas throughput to non-electricity generation declines by nearly 20 percent by 2040. Notably, there may be significant regional variation in gas consumption trends, requiring gas infrastructure investments to be assessed on a case-by-case basis. For instance, under their LTP reference cases, Con Edison projects an 18 percent decline in throughput from 2025 to 2040, whereas NFG projects a 10 percent increase and NMPC projects a 6.9 percent increase over the same period.

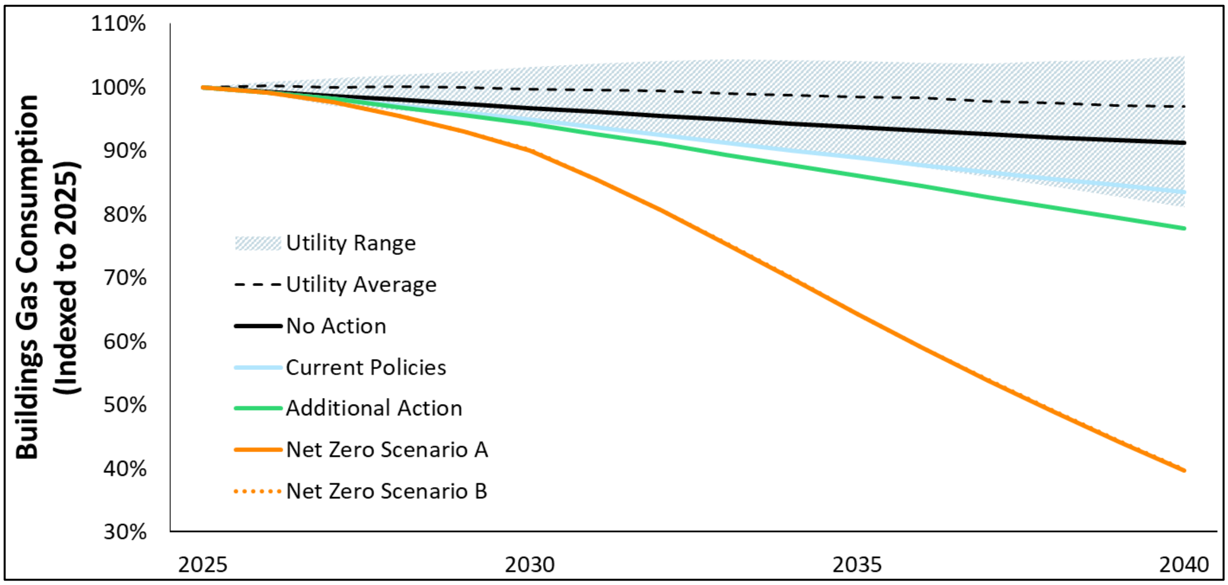

Figure 9. Gas Consumption by Scenario

Gas Throughput (TBtu) % Change vs. 2025 (excl. power sector)			
Scenario	2030	2035	2040
No Action	-2.7%	-5.2%	-7.2%
Current Policies	-4.2%	-9.3%	-13.7%
Additional Action	-5.4%	-12.4%	-19.4%
Net Zero Scenario A	-9.8%	-35.7%	-57.4%
Net Zero Scenario B	-9.7%	-35.6%	-57.3%

Figure 10. Gas Throughput Percent Change vs. 2025 (excl. power sector)

In addition to declining throughput or energy in the gas system, the number of customers connected to the gas system is also expected to decline as some customers fully electrify their end uses. This decline is expected to occur at a slower pace than the decline in gas system throughput. Consequently, the amount of gas used per customer will likely decline over time as customers adopt energy efficiency measures and partially electrify. As shown in Figure 11 and Figure 12, the number of residential gas customers is expected to decline by 13 percent by 2040 in the Additional Action scenario. However, as with throughput, the trend for customer count is expected to vary by region. For example, under their LTP reference cases, Con Edison projects that its customer count will decline by 11 percent from 2025 to 2040, while NFG projects that its customer count will increase by 4.7 percent and NMPC projects that its customer count will increase by 7.8 percent over the same period.

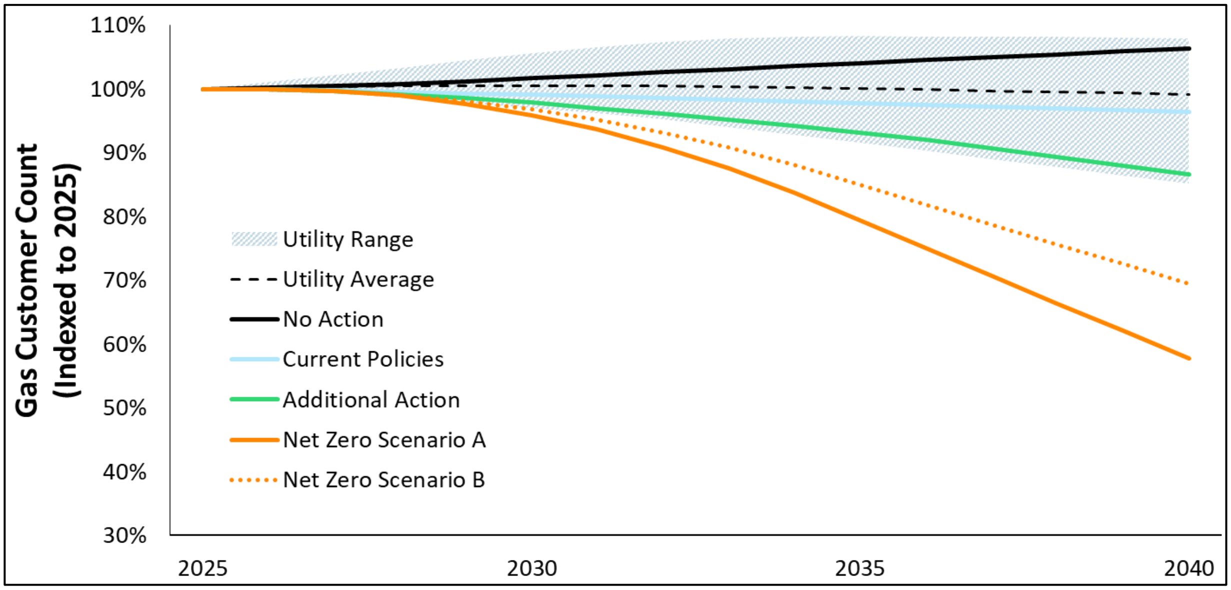

Figure 11. Residential Gas Customers by Scenario

Residential Gas Customers % Change vs 2025			
Scenario	2030	2035	2040
Baseline	2%	4%	6%
Current Policies	-1%	-2%	-4%
Additional Action	-2%	-7%	-13%
Net Zero Scenario A	-4%	-21%	-42%
Net Zero Scenario B	-3%	-15%	-31%

Figure 12. Gas Customer Count Percent Change vs. 2025

3.3. Alternative Fuels

The source of gas flowing through the gas distribution system is also expected to change over time in some certain scenarios. Currently, virtually all gas delivered by the gas distribution system is sourced from fossil fuels. While the supply of low-carbon alternative fuels is expected to be limited, necessitating a continued focus on efficiency and clean electrification as the pillars of the State's decarbonization strategy, renewable natural gas (RNG) can play a role in reducing emissions on the gas system. In the Additional Action scenario, incremental policies support the deployment of 24 Tbtu of RNG or 3.4 percent of the energy delivered by the gas distribution system in 2040. The production, delivery, and prioritization of alternative fuels is discussed in greater detail in the Low-Carbon Alternative Fuels chapter of this Plan.

RNG Energy (TBtu) and Blend %		
Scenario	2040	
	TBtu	% Blend
Baseline	0	0%
Current Policies	0	0%
Additional Action	24	3.4%
Net Zero Scenario A	109	33%
Net Zero Scenario B	109	33%

Figure 13. RNG in the Gas System by Scenario

4. Themes and Recommended Actions

4.1. Reducing Natural Gas Use

Under both already enacted policies ("Current Policies") and under a projection of potential increases in clean energy deployment through subsequent policy progress and technology improvement ("Additional Action"), statewide natural gas system throughput and customer counts are projected to decline by 2040 – though specific regions within New York may see growth in the near term. While overall decline is projected in all cases, natural gas will continue to be an important fuel source through 2040 and likely beyond (see Figure 14).

Range of Reduction	Current Policies & Additional Action	Net Zero Scenarios A & B
Residential Customer Count	4% - 13%	31% - 42%
Residential Throughput	21% - 29%	61%
Commercial Throughput	12% - 15%	58%

Figure 14. Range of Reductions in Gas System Use Under Pathways Analysis Scenarios by 2040

A reduction in statewide natural gas consumption, if realized, would end approximately two decades of expansion in system use. As discussed in greater detail below, the pivot requires a different planning, regulatory, financial management, and ratemaking paradigm than currently exists. The PSC's *Order Adopting Gas System Planning Process* and the resulting long-term gas planning process described above (see Section 2.3.1) constitute an important initial step toward creating this new paradigm.

Recommendations

- The PSC and supporting agencies should continue to reform the regulations that govern gas planning, investment, and ratemaking to facilitate a safe, reliable, and affordable gas system transition. Specific changes, discussed in greater detail in the following sections, include but are not limited to:
    - enhanced resiliency planning;
    - long-term planning;
    - integrated electric and gas system planning;

- innovative cost recovery mechanisms;
- evaluation of the potential expanded use of alternative fuels;
- continued exploration of whether "certified" or "differentiated" gas reduce emissions;
- strategically managing the gas transition for gas sector workers and businesses;
- strategically managing the gas transition for DACs; and
- developing a gas system transition plan.

4.2. Planning for Safety, Reliability, and Resiliency

As demonstrated in Sections 2 and 3, gas provides a wide range of essential energy services to New York residents and businesses and is expected to continue to do so through at least 2040 in all scenarios, even as decarbonization efforts continue. It is therefore imperative that the gas system remains safe, reliable, and resilient to both ongoing and emergent risks driven by climate change.

For a detailed discussion of the threats to and vulnerabilities of New York's energy sector (including the gas system), cross-sector interdependencies, and strategies to ensure resilience see the Energy Security Planning and Emergency Preparedness chapter and the Climate Change Adaptation and Resiliency chapter of this Plan. In 2024, the New York State Climate Impacts Assessment (NYSCIA) was released to investigate and document how climate change is affecting New York's communities, ecosystems, and economy based on the latest science, data, and models. The NYSCIA's Energy chapter contains a detailed discussion of how climate change is expected to affect the energy sector.[22] A limited discussion with a particular focus on the gas system is provided below.

Extreme cold. Extreme cold temperatures can affect the natural gas supply system by freezing fluid handling equipment, compressors, valves, and other equipment when gas demand is at its highest. Historically, major disruptions to New York's natural gas supply due to extreme cold temperature have been infrequent. However, recent Winter Storms Uri, Elliott, and Enzo all produced extreme cold weather events that led to disruptions in gas delivery systems. While extreme cold temperatures will continue to occur, extremely cold days are expected to occur less frequently.[23] New York's gas transmission and distribution system owners and operators can and do implement standard practices, such as insulating pipes, to protect gas infrastructure from freezing.

Temperature variability. Much of the gas system's infrastructure is underground, where it is partially insulated from variations in air temperature. While this provides a resiliency benefit, temperature fluctuations can still pose a risk to gas system infrastructure. For instance, increased variability in winter temperatures could increase the frequency of freeze-thaw cycles, as well as frost heaves in certain areas, impacting brittle underground infrastructure. In addition, some gas infrastructure is typically above-

[22] Meier, S., et. al (2024). New York State Climate Impacts Assessment Chapter 06: Energy. *Ann NY Acad Sci.*, 1542, 341-384. https://doi.org/10.1111/nyas.15191

[23] Ibid., p. 348.

ground and must be resilient to temperature extremes. For example, extreme heat may require greater cooling needs at compressor stations.

Precipitation, flooding, and sea level rise. Flooding associated with heavy precipitation is expected to occur more frequently and with greater intensity in New York over time.[24] Flooding can pose an increased risk of washouts or circumstances where water will infiltrate pipes and cause service interruptions by affecting the movement of gas through the pipes and by reducing system pressure. Infiltration is especially a concern with low-pressure systems that contain gas mains made from cast iron or uncoated/bare steel pipes that can be prone to leaks. Flooding can occur even in non-coastal regions. For example, in 2011, Hurricane Irene resulted in major flooding throughout the Catskill and Adirondack mountains as well as Vermont, causing approximately 1,300 customers to lose gas service. In addition, as sea level rises, groundwater levels may also rise, increasing the exposure of underground infrastructure to groundwater, which can lead to corrosion in unprotected systems.

High wind and tornados. High winds can damage above-ground facilities like compressor stations, metering, and regulation stations. In addition, power outages caused by wind-related damage may impact electric compressor operations.

Human error. Accidental strikes to underground pipelines during maintenance or construction activities can cause leaks. Valves that are left open accidentally or operated without proper adherence to safety regulations can increase the risk of leaks or explosions.

Cyber and physical attacks. There are interdependencies between the energy system and the information system. Attacks from malicious actors on information systems can disrupt operations that ensure safe and reliable energy delivery. Physical gas system assets, particularly those above-ground, can also be targeted for attack by malicious actors.

Potential exposure to disruptions that occur outside of New York. Because New York imports most of its natural gas supply from out-of-state, extreme weather events or other disruptions that impact "upstream" gas supply infrastructure can affect the state. For instance, in December 2022, Winter Storm Elliot affected New York as well as several nearby states and parts of Canada. During that storm, frigid temperatures caused outages at natural gas wellheads due to freezing equipment, leading to a 16 percent reduction in natural gas production in the United States.[25] The largest gas production declines (23 percent to 54 percent) occurred in the Marcellus and Utica Shale formation areas (primarily Pennsylvania, West Virginia, and Ohio). These conditions nearly resulted in a gas outage event in New York City with Con Edison and National Grid experiencing reliability-threatening low pressures on one of the interstate gas pipelines they rely upon for supply. The potential for upstream extreme weather events to impact the reliability of New York's energy system underscores the importance of maintaining a diverse energy portfolio—both in terms of geography and fuel types—as part of the State's strategy for energy reliability planning.

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[24] Ibid., p. 354.

[25] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*. FERC, NERC, and Regional Entity Staff Report (October 2023).

Recommendations

- DPS, DHSES, NYSERDA, utilities, and other stakeholders should continue to perform the actions described below to support a reliable and resilient gas system. Where appropriate and possible, efforts should also be enhanced.
    - Conduct emergency planning for hazards in advance. Processes like the State Comprehensive Emergency Management Plan (CEMP), the State Hazard Mitigation Plan (SHMP), the State Energy Emergency Plan (SEEP), and cross-sector coordination in advance of seasonal peaks in energy demand are essential for identifying, understanding, and developing and implementing risk reduction strategies for potential hazards to the energy system.
    - Coordinate between responsible parties. Close coordination among energy and telecommunication providers, emergency responders, and local governments can improve response time and effectiveness in the event of energy losses caused by extreme weather. Mobilizing logistics, supply chains, and personnel in advance can also increase resiliency.
    - Ensure continued compliance with pipeline safety regulations. Pipeline regulations promulgated by PHMSA, the PSC, and DEC are intended to ensure safe operation of the gas system.
    - Upgrade infrastructure and install on-system safety devices. Replacement of leak prone pipe can proactively reduce the risk of leaks and the risk of water infiltration from flooding. Installation of residential methane detectors (RMDs) can reduce the risk that leaks on customer premises go unnoticed. Excess flow valves on gas service lines reduce leakage and risks to customers in the event of a significant leak or damage.
    - Enhance demand management. Risks and impacts of disruptions to gas supply and delivery can be mitigated through solutions that increase end users' capacity to reduce their reliance on gas generally (e.g., energy efficiency, electrification, thermal energy networks) or during periods of disruption (e.g., demand response, backup fuels).
    - Maintain a diverse supply portfolio. This can include geographically diverse supply sources, gas storage, and avoiding over-reliance on interruptible supply contracts, which may not be available during extreme weather events. The State should also ensure supply portfolio and associated infrastructure is appropriately resilient to contingencies and other risks (see Section 4.3.4).
    - Study and plan for climate change vulnerabilities. Dedicated studies to evaluate utility systems' vulnerabilities to climate risks can be used to develop resiliency plans to address those vulnerabilities. Electric utilities and joint gas and electric utilities are required to complete climate change vulnerability studies to evaluate infrastructure,

design specifications, and operational processes at risk from climate change.[26] Gas utilities could also conduct climate change vulnerability studies and develop resiliency plans with a particular focus on how extreme events can affect upstream and midstream elements of the gas system.

- Use the best available climate models and weather data for energy planning. Incorporating weather forecasts into gas system operational planning and utility emergency response can ensure the appropriate range of conditions are evaluated as discussed below (see Section 4.3.4).

4.3. Planning for Efficient Investment

The gas sector is entering a period of significant change, driven by market forces (including the emergence of technically and economically viable electric alternatives for many services currently provided by gas) and policy supporting the achievement of statutory GHG emission reduction targets. These changes are expected to induce a decline in gas system utilization by 2040, thus reversing the continuous expansion of the gas system seen in past decades.

Declining gas system utilization, whether driven by market forces or policy imperatives, poses a threat to the State's goal of affordable energy. Multiple long-term gas planning studies have shown that scenarios in which gas system utilization declines significantly tend to result in large increases in gas distribution rates and correspondingly large increases in gas bills among customers remaining on the gas system.[27] Notably, in such scenarios, many of the customers remaining on the gas system may be those who cannot afford the upfront cost of electrification (even if they would be better off over time, financially, by electrifying). Thus, low- and moderate-income (LMI) customers and customers in DACs may be particularly at risk.

Declining gas system utilization also poses significant risks for businesses and employees who work, directly or indirectly, in the gas sector. If a significant number of customers depart the gas system and the customers who remain cannot bear the full cost of maintaining the gas system, there is a risk that utility investments in the gas system become "stranded," meaning the utility may not be able to recover the cost of those investments from its customers.

Enhanced gas planning practices (discussed below in Sections 4.3.1 through 4.3.4) are needed to help address these significant challenges, especially by enabling safe and strategic reductions in gas system investment.

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[26] See "Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans" (Case 22-E-0222).

[27] See, e.g., *NFG Final LTP* (Figure IV GHG Emission Reductions and Cost Impacts, p. 74), filed July 17, 2023 in Case 22-G-0610; *ConEd/O&R Final LTP* (Figure 60 Deep Electrification Pathway Gas System Rate, p. 91), filed November 29, 2023 in Case 23-G-0147; *NYSEG/RGE Final LTP* (Figure VI-7 Bill Impacts for Scenarios and LTP, p. 106), filed April 26, 2024 in Case 23-G-0437; *NGrid Final LTP* (Section 8.3 Bill Impact Analysis p. 144-153), filed March 7, 2025 in Case 24-G-0248.

4.3.1. Long-Term Planning

As described above (see Section 2.3.1), the PSC's May 2022 Gas Planning Order initiated a process requiring gas utilities to develop LTPs covering a 20-year horizon. All utilities in the state have submitted final LTPs. The PSC has issued orders addressing LTPs from NFG, Con Edison/O&R, NYSEG/RGE, and CHGE and is still considering other utilities' LTPs.

These LTPs have consolidated several important planning functions, including:

- Modeling future demand under various scenarios;
- Identifying supply sources, including peaking services;
- Assessing supply constraints and investment needs to maintain supply adequacy;
- Highlighting opportunities for terminating supply contracts, where feasible;
- Projecting the effects of and need for energy efficiency, electrification, and demand response;
- Evaluating the potential role of alternative fuels;
- Estimating customer bill impacts under different scenarios; and
- Identifying barriers to achieving state policy goals such as decarbonization, including potential regulatory or policy changes needed.

While these planning functions are foundational, they can be augmented and improved upon to fully realize the PSC's vision for "a modernized gas planning process that is comprehensive, suited to forward-looking system and policy needs, *designed to minimize total lifetime costs*, and inclusive of stakeholders."[28] To adequately plan for the anticipated decline in gas system utilization, utilities should be required to identify which portions of their service territories will remain part of the gas network over the long term and which may transition away from gas service.

Making this differentiation is essential because it allows utilities, the PSC, and stakeholders to distinguish between:

(a) Areas where continued investment in the natural gas system presents low risk of stranded assets and may be appropriate for future deployment of alternative fuels; and

(b) Areas where the natural gas system may be reduced or eliminated allowing resources to be directed toward full electrification, thermal energy networks, or other solutions.

In short, this differentiation is necessary to support the type of multi-decade infrastructure investment prioritization necessary to ensure the safety and reliability of the State's energy systems.

Indeed, the PSC has underscored this need in LTP proceedings. For example, the PSC directed Con Edison and O&R "to develop a specific definition of hard to electrify customer sectors" and "to include pilot

[28] Gas Planning Order, p. 9 (emphasis added).

projects for directing low-carbon fuels to these customers in their next rate case filings and in their next long-term plan filing."[29] The PSC has emphasized that identifying where hard-to-electrify buildings are located is "essential in developing a long-term view of which pipes are critical in supplying fuel to these buildings and would help stakeholders and regulators better understand which regions or neighborhoods are forecasted to remain on the gas network and which regions and neighborhoods are forecasted to be potentially electrified."[30] Similarly, in PA Consulting's review of Central Hudson's LTP, it recommends that the Company "develop a holistic geographical view to determine which customers and use cases are most or least likely to remain on the gas network over time, and which areas could electrify between now and 2050."[31] PA notes that this would allow the company to develop "a directional view on the geographical footprint of the gas system over time" to identify "no-regrets" investments, and that this "would assist in [the Company's] multi-decade prioritization of gas system investment decisions."[32]

The second cycle of LTPs, which is expected to begin in December 2026 with NFG's second LTP, presents an opportunity to strengthen this approach. By clearly distinguishing areas where long-term investment in the gas system will be needed in the long-term from areas where it can be avoided, utilities can better align their planning and investment strategies with the policy goals outlined in this State Energy Plan.

Recommendations

- The PSC should continue to require New York's gas utilities to produce LTPs. In future LTPs, the PSC should require gas utilities to identify areas where the gas system will be necessary in the long-term and prioritize investment in those areas over others.

4.3.2. Integrated Energy System Planning

Historically, natural gas and electric utilities' planning practices have been largely independent from one another even in areas where electric and gas service is provided by the same parent company. This was adequate when demand for natural gas and demand for electricity were largely independent. The emergence of electrification—including of energy services met by natural gas like space heating, water heating, and cooking—as a primary strategy for reducing GHG emissions constitutes a fundamental change.

As electrification accelerates, demand for natural gas and electricity are expected to be much more closely linked. Accordingly, investment in both systems, at all scales, will also be more closely related. For instance, if customers on a particular section of the gas system electrify, this may enable the gas utility to reduce or avoid investment in that part of the gas system. However, this can only be achieved if the corresponding portion of the electric system is able to accommodate increased electric demand. As such, ensuring both reliability and efficient investment depends on closer coordination between electric

[29] *Order Regarding Long-Term Natural Gas Plan and Requiring Further Actions*, p. 44. Issued September 20, 2024 in Case 23-G-0147.
[30] *Ibid.*
[31] *Final Report on Central Hudson's Final Gas System Long-Term Plan*, p. 90. Prepared for NY Department of Public Service by PA Consulting. Filed January 14, 2025 in Case 23-G-0676.
[32] *Ibid.* p. 90-91.

and gas system planners. This is sometimes referred to as integrated energy system planning or integrated planning.

More integrated planning is essential to guide an efficient and equitable energy transition. Integrated planning is not a single action or tool. Rather, it requires reforming utility practices and analytical tools to incorporate relevant information from both the gas and electric systems, along with customer-level insights, across all planning scales.

Integrated planning will require the development of new data sets and analytical tools. Key components of this approach may include, but are not limited to:

- More robust data sharing between electric and gas utilities;
- Linking gas hydraulic analysis and electric power flow modeling;
- Improved mapping of gas and electric system assets;
- Restructuring utility planning teams to support joint responsibility for gas and electric planning; and
- Identifying priority electrification zones based on sections of the gas system that can be strategically downsized and sections of the electric system capable of supporting increased load.

Collectively, these and other strategies can help minimize total system investment by optimizing the entire energy system to maintain safe and reliable energy service rather than managing the gas and electric systems in isolation.

Existing Initiatives

Existing proceedings like the long-term gas planning proceeding (20-G-0131) and the proceeding on utility thermal energy networks (22-M-0429) are advancing progress on integrated planning. Other efforts include, but are not limited to, the following examples:

- Central Hudson LTP – identified areas where gas system investment may be needed in the next decade and overlaid projected winter electric system headroom to find where gas system investment could be avoided or deferred without straining the electric grid.[33] Central Hudson then developed proposed electrification and demand response portfolios to provide the necessary peak load reduction needed.[34] These analyses required the development of new data sets (e.g., locationally granular electric and gas demand forecasts) and analytical tools (maps overlaying gas and electric system load).
- NYSEG/RGE LTP – the PSC directed NYSEG/RGE to adopt a "joint-planning approach across their electric and gas companies to develop the most cost-effective and efficient solutions for

[33] *Central Hudson Final Gas System Long-Term Plan, Appendix A: 20-Year Historical Trend Gas Forecasts and Location-Specific Gas Distribution Costs* filed November 21, 2024 in Case 23-G-0676.

[34] *Central Hudson Final Gas System Long-Term Plan, Appendix C: Non-Pipe Alternative Assessment* filed November 21, 2024 in Case 23-G-0676.

customers and the Companies to support strategic downsizing and increase electrification."[35] NYSEG/RGE has a single team that works on both NPAs and non-wires alternatives (NWAs).

- National Grid – electric and gas planning asset management teams began exploring integrating energy planning in 2022.[36]
- Avoided Cost of Gas Working Group – the PSC established a working group in 2022 to develop best practices for calculating the avoided cost of gas. The working group may produce information useful for integrated planning, such as indices that can be used by gas utilities and stakeholders to evaluate the tradeoffs between investments in the gas system and investments that enable reductions in gas system usage.
- Utility Thermal Energy Networks (UTENs) – UTEN pilots will help New York utilities gain experience developing thermal networks and help the regulators establish a supportive regulatory framework for UTENs. UTENs may emerge as an integrated planning strategy because they can enable electrification with lower impact on peak electricity demand. UTENs are discussed more in the Buildings chapter of this Plan.

While these efforts represent important progress on integrated planning, more work is needed. In the coming years, electric and gas utilities will need to fully integrate planning practices to ensure coordinated and strategic investments in their systems. By enabling utilities and other stakeholders to consider interdependencies between the gas and electric systems, integrated planning can identify the infrastructure investments that maximize beneficial outcomes like avoiding or deferring investment, improving system reliability, improving customer choice, and reducing emissions. The PSC and DPS staff will have an essential role guiding the development of integrated planning practices.

Recommendations

- The PSC, with support from DPS staff and NYSERDA, should build on past progress to further advance integrated planning. This could include directing gas and electric utilities to develop standardized, locationally specific, and transparent joint planning practices that enable optimized energy system investments. Early efforts may focus on areas where gas and electric service are provided by the same company to ease integrated planning.
- NYSERDA and DPS staff should work with utilities, local governments, and other agencies and stakeholders to promote the development of data sets and analytical tools that can support integrated planning. These may include locationally granular forecasts of gas and electric system peak demand, models which link gas hydraulic analysis and electric power flow modeling, and tools that map physical components or assets of the natural gas and electric systems.

[35] *Order Regarding Long-Term Natural Gas Plan and Directing Further Actions*, p. 71. Issued January 23, 2025 in Case 23-G-0437.
[36] "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization." Whitepaper jointly published by National Grid and RMI, May 2022, p. 10. Available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf.

4.3.3. Non-Pipe Alternatives

Non-pipe alternatives (NPAs) refer to alternatives to traditional investments in the gas system. NPAs typically involve investments in energy efficiency, electrification, demand response, and/or alternative fuels or other peaking supplies. New York's utilities have established initial practices to evaluate NPA opportunities, but NPA implementation has been limited to date. For instance, as of November 2024, only three of the 290 sections of gas main that Con Edison identified as suitable for NPA feasibility and cost-effectiveness analysis have been completed as NPAs.[37] And only five of the 41 potential NPA projects Central Hudson identified between 2019 and 2024 have been completed as NPAs; 20 had insufficient customer interest, 11 were deemed unsuitable for NPA, and five are in progress or planning phases.[38]

More widespread deployment of NPAs is needed to enable safe and strategic reductions in gas system investments. Accordingly, utility planning practices should evolve to support NPA deployment. Indeed, the PSC's Gas Planning Order stated that "LDCs should integrate NPAs into their standard gas system planning processes, both in the context of specific avoidable projects in a particular area of the distribution system, and system-wide to reduce overall demand and the need for infrastructure investment."[39]

To successfully implement an NPA, utilities must ensure customers' energy needs can be met without additional investment in the gas system. NPAs can be categorized based on the type of gas system investment they are intended to avoid: system extension, capacity expansion, or pipeline replacements.[40] Each category requires a distinct planning approach, as outlined below.

NPAs to Avoid System Extension to New Customers

This type of NPA requires providing potential new gas customers with an alternative to gas service, thereby avoiding investment to extend the natural gas system. As noted in Section 2.3.2, the All Electric Buildings Act of 2023 will prohibit the installation of fossil-fuel equipment in new buildings starting in 2026 for smaller buildings (up to seven stories) and in 2029 for larger buildings (over seven stories). However, existing buildings can still request gas service. Notably, it is already common practice for New York's gas utilities to inform customers requesting gas service about the availability of electric alternatives and incentives to electrify. Nonetheless, gas utilities in New York State have been adding approximately 30,000 new customers per year in recent years, in a combination of new construction and conversions from other heating fuels.[41]

To improve the effectiveness of NPAs that avoid new customer connections, utilities and NYSERDA could identify those that are likely to request new gas service, such as those currently using oil or propane for heating, and proactively market electrification or electrification-readiness upgrades, highlighting opportunities for cost savings.

[37] Con Edison Non-Pipes Alternatives Implementation Plan, p. 8. Filed November 18, 2024 in Case 23-G-0147.
[38] Central Hudson Non-Pipeline Alternatives Annual Report, p. 13-14. Filed December 2, 2024 in Case 17-G-0460.
[39] Order on Gas System Planning Process, p. 6.
[40] See, *e.g.*, "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization." Whitepaper jointly published by National Grid and RMI, May 2022, p. 6. Available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf.
[41] Staff Straw Proposal Regarding Modification of 16 NYCRSS Part 230, p 9. Filed July 16, 2024 in Case 20-G-0131.

NPAs to Avoid Capacity Expansion to Meet Demand Growth

This type of NPA requires reducing forecast peak demand under design day conditions through demand reduction portfolios or alternative sources of peaking supply like CNG, thereby avoiding the need for investment to increase the capacity of the natural gas system.

To successfully implement this type of NPA, gas utilities must begin by identifying locations where additional capacity may be needed in the future. This assessment must be conducted with sufficient lead time to allow for the development and implementation of demand reduction portfolios before new capacity infrastructure is needed. Utilities must also ensure that the local electric system has sufficient capacity to support additional electric load resulting from these demand-side measures. As noted in Section 4.3.2, some gas utilities in New York have begun identifying this type of NPA opportunity by developing locationally granular demand forecasts.

Once utilities have identified locations where additional capacity may be needed, they must develop and implement demand management portfolios. These may be comprised of demand response, energy efficiency, electrification, and (if they are not delivered through the constrained portion of the gas delivery system) alternative or backup fuels. Notably, customers do not need to fully disconnect from the gas system for this type of NPA to be successful.

Utilities and demand management service providers need to increase their capability to quickly develop portfolios that can reliably reduce demand during peak periods. To that end, it may be necessary to develop new strategies, programs, and enabling policies to limit customer gas demand during extreme cold weather events, for example, by temporarily and safely lowering temperature set points. In locations where these strategies are implemented, utilities could lower their estimates of usage-per-customer and, by extension, their design day demand forecasts enabling cost reductions via the deferral or avoidance of gas system investment.

To prevent inefficient investment in the gas system, utilities should continue to refine strategies to identify and implement this type of NPA. This will involve developing standardized, transparent analytical tools to identify these NPA opportunities and enhanced practices for deploying targeted demand management. The PSC, DPS staff, and NYSERDA should help guide and support this work.

NPAs to Avoid Pipe Replacements

Pipe replacement constitutes a large share of gas utilities' capital expenditures, with utility forecasts indicating that it will represent 40 percent of annual investment through 2028. The majority of this investment (79 percent) is to replace leak-prone pipe (LPP). In 2015, the PSC encouraged LPP replacement, stating that this "would increase gas safety and reliability, modernize gas transmission and distribution assets, and benefit the environment."[42] While the total amount of LPP has declined since then, substantial amounts remain, particularly in downstate regions. Fully replacing LPP is expected to

[42] *Order Instituting Proceeding for a Recovery Mechanism to Accelerate the Replacement of Leak Prone Pipe* issued April 17, 2015 in Case 15-G-0151, p. 2. Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-G-0151.

cost tens of billions of dollars, underscoring the value of NPAs that avoid the need for pipe replacement. Indeed, the PSC directed gas utilities to identify "locations of specific segments of LPP that could be abandoned in favor of NPAs" within their LTPs.[43]

However, implementing NPAs in place of LPP replacement presents significant challenges:

1. A pipe segment can only be abandoned if all connected customers fully electrify their gas uses or adopt another alternative to gas.
2. Some segments are hydraulically necessary to serve downstream customers, even if no customers are directly connected to the segment.
3. The corresponding electrical network must have sufficient capacity, or may require upgrades, to accommodate the additional load.

To address these challenges, utilities must identify LPP segments that may be suitable for this type of NPA. Segments on the edge of the gas network, with fewer customers or fewer customers per mile, and where the electric system has sufficient capacity are generally more technically and economically viable NPA candidates.

Historically, gas utilities have not accounted for these factors to prioritize which LPP segments should be replaced. Replacement priority has primarily been based on physical factors that impact the likelihood of leakage.[44] While these physical risk factors need to be considered, utilities should also incorporate NPA suitability into their prioritization framework to avoid unnecessary investment in gas infrastructure.

Advancing this approach will require new data sets and analytical tools to support the identification of this type of NPA. Research and innovation are already underway. For example a spatially granular analysis of alternatives to gas pipe replacement was recently conducted in Holyoke, Massachusetts,[45] and a study conducted for the California Energy Commission aimed to develop an analytical framework for targeted electrification and strategic decommissioning.[46] These studies both found that segment-level analysis using site-specific data can identify segments where targeted electrification and strategic decommissioning could generate cost savings (relative to pipe replacement), especially in sites with fewer customers per mile of gas main. While these studies offer a proof of concept, utilities will need to play a more active role in scaling up this type of work.

Once a utility identifies LPP segments as promising for this type of NPA, the utility must deploy a proactive and well-planned approach. Because full customer electrification is required before a segment

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[43] Gas Planning Order, p. 39.

[44] These physical factors include pipe material, age, diameter, pressure, length, coating type and condition, leak history, corrosion, soil type, and proximity to buildings. In addition, to reduce cost and the frequency of disruptions, utilities also often coordinate with municipalities to replace LPP segments when streets are already being opened up for other work.

[45] University of Massachusetts Amherst Energy Transition Institute, "*Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency*" (2023). ETI Reports. 2. Available at: https://doi.org/10.7275/enzr-5311.

[46] Gold-Parker, Aryeh, Claire Halbrook, Helen Mejia, Allison Lopez, Fangxing Liu, Jared Landsman, and Amber Mahone. 2024. *An Analytical Framework for Targeted Electrification and Strategic Gas Decommissioning: Identifying Potential Pilot Sites in Northern California's East Bay Region*. California Energy Commission. Publication Number: CEC-500-2024-073.

can be abandoned, project timelines may need to span a decade or more. A phased approach, beginning with site identification, customer relationship development, building assessments, electrification-readiness upgrades, and electric grid upgrades if needed, can lay the ground for gradual whole-building electrification and gas system decommissioning. Over time, this approach will enable a more strategic and cost-effective transition while maintaining safety and reliability.

Pipe Repair and Re-Lining

Another strategy for reducing unnecessary investment in the gas system is for utilities to pursue lower cost alternatives to pipe replacement, such as pipe repair or re-lining, when safe and technically feasible. For example, National Grid's 2024 Gas Distribution Integrity Management Plan for its Massachusetts service territory describes programs and technologies that "extend the useful life of large diameter distribution piping."[47] CISBOT (Cast Iron Sealing Robot), which has been used in New York for years, makes it possible "to seal more than 80 joints from one excavation without shutting down the main;" and re-lining "extends the life of the pipeline for more than 50 years" and can be "the most cost-effective way to recondition the existing pipelines, reduce costs and minimize disruptions to the public" in congested metropolitan areas.[48] Technologies that enable pipe repair and re-lining should continue to be evaluated and implemented when possible. Such strategies are most appropriate in areas with leaking pipe or LPP that may become suitable for decommissioning in the medium-term, but that still have customers connected to the gas system. While these alternatives may be temporary, they can serve as a lower-cost bridge until customers can migrate off the gas system and decommissioning becomes possible.

Capital investments in the gas system create long-term obligations to recover the costs of those investments, contributing to the risk that natural gas will become unaffordable for customers remaining on the gas system as the State decarbonizes. Utilities must avoid such investments as much as possible through proactive planning for NPAs as described above.

Recommendations

- The PSC should continue to require that gas utilities prioritize investments in NPAs.
- The PSC should direct utilities, with support from DPS staff and NYSERDA, to develop planning tools and practices to enable the successful identification and deployment of NPAs to avoid investments in system extension, capacity expansion, and pipe replacements.
- The PSC should direct utilities to continue to prioritize lower-cost alternatives to pipe replacement such as pipe repair and re-lining, where safe and technically feasible. DPS staff and NYSERDA should work with utilities to support innovation and commercialization of technologies that enable cost-effective pipe repair and re-lining.

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[47] National Grid Massachusetts Distribution Integrity Management Plan Revision 13, p. 145-146. Effective 08/02/2024. Available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19846034.
[48] *Ibid*.

4.3.4. Planning Standards

Utilities typically define design day conditions to reflect the coldest actual weather historically experienced in each region (see Section 2.3.1). Investments to expand natural gas system capacity become necessary in areas where forecast demand under design day conditions exceeds the system's ability to provide supply (see Section 4.3.3). Historically, these standards for planning and investment have helped ensure a very reliable gas system in New York. Gas system reliability is extremely critical both because the gas system provides essential services to New Yorkers (e.g., home heating) and because restoring service after a disruption to gas service is very complex, time-consuming, labor-intensive, and costly (substantially more so than an electrical outage affecting a similar number of customers). As such, it is appropriate to use conservative standards for planning and investment.

While a conservative approach is certainly warranted, investments required to ensure system reliability under extreme conditions have accompanying costs. Indeed, in the context of LTP proceedings, the PSC has noted that "employing design day criteria for reliability planning is conservative, in that design day conditions are unlikely to occur in a given winter. For this reason, employing a reserve margin on top of design day conditions may impose unnecessary costs on ratepayers."[49] Accordingly, it is also appropriate to consider whether the planning and reliability criteria utilities use strike the proper balance between the need for conservatism and the imperative to avoid imposing unnecessary costs on ratepayers.

Notably, the NYSCIA, which provides detailed projections of the impacts of climate change across the state through the 2080s, projects a declining incidence of extreme cold weather events (days below 0°F) across all regions statewide in the coming decades.[50] This suggests that the frequency of reaching design day conditions may decline over time, though further research in this area—including regarding how climate change may impact jet streams, which can create regional extreme cold weather ("polar vortex") conditions—is warranted. When forecasting demand under design day conditions for investment planning purposes, utilities should use up-to-date assumptions regarding usage-per-customer that reflect the impact of demand reduction measures (energy efficiency, building shell improvements, electrification, and demand response).

In addition to planning for potential peak demand through design day planning, gas system planners must also account for the potential disruptions to key sources of supply. As discussed above (see Section 4.2), disruptions that impact "upstream" gas supply infrastructure can affect New York. Also, parts of New York's gas system are particularly constrained and rely on peaking services that can be expensive, capacity constrained, or potentially less reliable than other sources of supply. For example, the downstate region has a high reliance on CNG trucking to meet design day demand. Gas system planners must evaluate whether current reliability standards adequately account for the risk of multiple points of failure or contingency.

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[49] *Order Regarding Long-Term Natural Gas Plan and Directing Further Actions*, p. 37-38. Issued January 23, 2025 in Case 23-G-0437.

[50] Lamie, C., Bader, D., Graziano, K., Horton, R. John, K., O'Hern, N., & Spungin, S. (2024). Chapter 2: New York State's Changing Climate, Figure 2-10, p. 20. New York State Climate Impacts Assessment [Interim version for public release]. Available at: nysclimateimpacts.org/explore-the-assessment/new-york-states-changing-climate.

Recommendations

- Gas utilities should transparently evaluate whether their planning and investment standards properly balance the need for reliability with the need to avoid imposing unnecessary costs on ratepayers. Definitions of design day conditions should be informed by the best and latest available climate science, and planning exercises should account for potential gas system contingencies.
- Gas utilities' methodologies for forecasting design day demand—including how they incorporate the impacts of demand reduction measures when calculating usage-per-customer—should be transparent.
- State policy decisions regarding proposed new gas supply assets should consider the asset's potential impact on reliability and resilience, including the possibility of reducing dependencies on short-term peaking services not controlled by New York's gas utilities.

4.4. Evaluate Approaches to Manage Gas System Affordability and Support NPA Viability

Existing policies limit the tools and flexibility available to the PSC to proactively manage gas system costs and safe operation as a potentially growing share of customers opt to switch from gas service to efficient electrification. If customer counts begin to decline, then existing limits on the PSC's latitude to direct and manage the gas system transition will create long-term affordability risks for customers. If capital investments in the gas system that might otherwise be avoided continue, the costs of those investments must be recovered from fewer remaining customers and reduced gas sales.

Recommendations

- The PSC should continue to evaluate and develop new approaches to strategically manage gas system affordability including costs borne by ratepayers resulting from system expansion or incomplete customer participation in NPAs.

4.5. Cost Recovery Mechanisms

Several of the utilities' LTPs have identified scenarios in which customer count and throughput are forecast to decline faster than annual utility revenue requirements—especially in scenarios with significant reductions in gas system use—resulting in steeply rising unit gas costs and compromising energy affordability.[51] In such scenarios, without proactive management, energy costs for customers with substantial remaining gas demand (i.e., customers that do not electrify all or part of their energy needs currently met using gas) will increase, potentially to unacceptably high levels. The high upfront cost of electric alternatives to gas appliances poses a barrier to electrification, especially for low-income customers—even in cases where the customer might otherwise be financially better off over time by electrifying. This could place an untenable cost burden on low-income customers.

Rising gas prices can also create risks for owners and operators of the gas system. If retail gas prices rise, the attractiveness of electric alternatives increases, driving electrification among customers who can

[51] *Supra* footnote 27, at 28.

afford to do so. Customer departures further increase rates and energy bills, encouraging more of the remaining customers to exit the gas system. If enough customers disconnect from the gas system, gas utilities' customer bases may no longer be large enough to recover costs needed to maintain the gas system while keeping gas rates affordable, creating stranded asset risk. This risk is particularly significant for gas-only utilities. This dynamic must be avoided to ensure a well-managed, gradual gas system transition that is not disruptive to remaining customers or the operational viability of gas utilities.

In addition to adopting practices to ensure that utilities only make necessary investments in the gas system, as described above (see Section 4.3), it will also be necessary to ensure that gas system costs are allocated in a manner that reflects cost causation principles[52] and ensures energy affordability. Innovative cost recovery practices can support gas utility operations while helping to protect customers, especially LMI customers, from unaffordable energy costs.

There are many potential cost recovery practices that can support equitable cost allocation, some of which are outlined below. The approaches listed below are not currently recommended for implementation, but a framework for further discussion and refinement. These mechanisms may not be necessary or advisable to implement under all potential gas system futures. Rather, they should be evaluated on an on-going basis to determine whether, individually or collectively, they can help address an emergent need. Novel cost recovery practices could include, and may not be limited to, the following:

Accelerated depreciation. If the number of gas customers declines over time, the remaining costs for investments in the gas system that have not yet been depreciated will be recovered from a declining pool of remaining ratepayers, increasing their rates and bills. Accelerated depreciation is a practice in which utilities depreciate assets more rapidly than the traditional straight-line methodology. This mitigates energy cost burdens for the future customers remaining on the system and reduces stranded asset risk. Tradeoffs accompany this approach, as it increases near-term costs for ratepayers. Accelerated depreciation can also improve alignment between cost recovery and system use by having utilities' annual depreciation expense gradually decline with gas system utilization. Notably, as part of its Gas Planning Order, the PSC directed New York gas utilities to prepare a "study that examines both the structure of accelerated depreciation and its potential impact on ratepayers."[53] The issue of accelerated depreciation has also been considered by utilities, stakeholders, and the PSC in recent gas rate cases and LTP proceedings.

Changes to rate design. If patterns of residential gas use change substantially, it may be necessary to modify gas rate design to ensure that cost recovery continues to reflect cost causation. For instance, if a high proportion of remaining customers connected to the gas system partially electrify (i.e., by partially electrifying their heating or by fully electrifying their heating but retaining gas for other end uses like cooking), then gas system throughput will decline faster than gas system costs. Under the current ratemaking paradigm, gas distribution rates would need to increase to cover utilities' annual revenue requirements and support safe and reliable operation. Increasing distribution rates would result in substantially larger bill increases for high-usage customers (i.e., customers that have not electrified at all)

[52] The cost causation rate design principle states that costs should be allocated to those who directly cause them to be incurred.
[53] Gas Planning Order, p. 61.

than for low-usage customers (i.e., customers that have partially electrified). In this scenario, cost recovery would not reflect cost causation because utilities incur similar costs in some categories costs to serve low-usage customers and high-usage customers (e.g., pipe costs associated with customer connections, system reinforcement costs associated with meeting peak demand), but would charge high-usage customers much more. In such a scenario, recovering a greater share of utility revenue requirements from low-usage customers, for example via higher fixed charges (and commensurately less from volumetric charges) or via special volumetric rates for partially electrified customers, could realign cost recovery with cost causation. This approach could also protect customers that have not been able to adopt partial electrification measures from undue energy cost burdens, a group that may disproportionately be lower income.

Securitization. If a utility asset is no longer used and useful, it may no longer be appropriate to recover its undepreciated book value or associated utility shareholder equity returns from customers. In such cases, the remaining undepreciated book value of the asset could be securitized. Securitization enables utilities to recover the cost of capital by issuing bonds backed by future dedicated, non-bypassable utility charges. Because these charges are highly stable, the resulting bonds typically receive high credit ratings enabling lower financing costs than equity or traditional debt. This functionally replaces utility shareholders' regulated rate of return on equity with a lower bond coupon rate. Securitization could benefit both utilities and customers by moderating rates while enabling utilities to recover prudently incurred investments. However, to date, New York State has only authorized utility securitization for storm recovery costs. The use of securitization for traditional utility costs would need to be closely evaluated separately.

Electric benefit payments. In a future in which electric system demand peaks during the winter, customers who retain gas service to meet their peak heating needs provide a benefit to electric ratepayers. Retention of gas service can reduce the electric system's peak demand during the coldest hours of the year. In this way, remaining gas customers help to avoid the need for incremental investment in electricity generation and distribution capacity that would have been needed to meet a higher peak demand had those customers fully electrified. For example, under the Pathways Analysis scenarios, the difference between Net Zero Scenario A and Net Zero Scenario B's electric peak demand is 3 GW in 2040. A higher electric peak demand would require substantial additional investments in electric generation, transmission, and distribution infrastructure. This electric sector benefit enabled by greater reliance on the gas system during the coldest hours of the year would not be compensated under the current cost recovery paradigm. Providing compensation to gas ratepayers for a share of this net benefits would reduce cost burdens on remaining gas ratepayers and improving the financial viability of a low-throughput gas system.

Affordability constraint. If the cost management strategies noted above are insufficient to provide long-term price and financial stability to a declining gas system, it may be necessary to impose limits on customer energy bills. While this approach would grant customers some protection from rising rates, it would also necessitate the establishment of an alternative mechanism to ensure utilities can recover prudently incurred costs. How such an affordability constraint and alternative cost recovery mechanism could be structured is highly uncertain.

In scenarios with steeply declining gas system usage, the practices described above could, if designed and implemented with great care, help allocate energy system costs in a manner that better reflects cost causation, support customer affordability, and protects the financial health of the gas industry. While these cost recovery practices could be beneficial, they may have complicated or even unintended effects. As such, additional research is needed to understand their potential implications.

Recommendations

- DPS staff and NYSERDA should research innovative cost recovery practices to evaluate their risks as well as how they could support the operational viability of gas utilities, ensure energy affordability, and improve alignment between cost causation and cost allocation across various scenarios.

4.6. Alternative Fuels

As described in the Low-Carbon Alternative Fuels chapter of this Plan, low-carbon alternative fuels are an important component of New York's clean energy transition, providing opportunities for emissions reductions in difficult-to-electrify settings while supporting emission reductions in non-energy sectors such as waste and agriculture.

4.6.1. Renewable Natural Gas

The Pathways Analysis conducted for the State Energy Plan envisions a role for RNG in a variety of settings, including replacing the uses of fossil natural gas in all end uses where gas is still used in 2050. However, supplies of low-carbon alternative fuels, including RNG, are limited and should be strategically deployed to difficult-to-electrify end uses such as industrial applications where high heat is needed, supplemental heat in uniquely cold geographies and certain building typologies, and other targeted uses. Where new infrastructure is built to enable the interconnection of RNG supplies, the State should work to ensure that the associated cost impacts to ratepayers are minimized. In addition, RNG should be sourced from sustainable feedstocks consistent with policy recommendations in the Low-Carbon Alternative Fuels chapter of this Plan.

Recommendations

- The PSC, NYSERDA, the Department of Agriculture and Markets, and utilities should explore strategic use of RNG, prioritizing opportunities that maximize emission reductions and economic development in New York's waste and agricultural sectors.
- With the understanding that RNG use is not a replacement for electrification or energy efficiency, RNG sourced from sustainable feedstocks should be strategically deployed in difficult-to-electrify end uses.

4.6.2. Hydrogen

Hydrogen is likely to play a strategic role in New York's clean energy transition as a potential emission reduction pathway in select applications. However, wide-scale use of hydrogen to replace natural gas faces significant safety, health, affordability, and operational challenges. New York's natural gas distribution system is highly complex and many of the physical assets that comprise it are several decades old. As such, retrofitting gas infrastructure to ensure hydrogen could be transported safely within the existing gas distribution system would be expensive. In addition, blending gas into the natural gas distribution system poses risks to customer health and safety and to customer-sited piping, appliances, and equipment that may not be hydrogen-compatible. Accordingly, blending hydrogen into the natural gas distribution system is infeasible and is not a pathway New York will pursue.

Utilities are encouraged to evaluate opportunities to strategically deploy hydrogen in clusters of difficult-to-electrify customers like high-heat industrial facilities or facilities on constrained portions of the electricity system. This type of deployment, which can be served by limited and dedicated hydrogen distribution infrastructure (separate from the general natural gas distribution system) may be worthwhile. Utilities, regulators, and other stakeholders should continue to conduct research on the most strategic and cost-effective uses of hydrogen, pilot projects, and similar efforts.

Recommendations

- Given the potential for negative impacts and high costs, New York should continue to not blend hydrogen into the natural gas distribution system. If warranted by future research and pilot projects, hydrogen may be strategically deployed in targeted settings, such as clusters of dedicated users with unique energy needs.

4.6.3. "Certified" or "Differentiated" Gas

"Certified" gas or "differentiated" gas are gas products that claim to have lower upstream methane emissions based on their supply source. It is not clear that these emission reduction claims are fully verifiable or consistent with New York GHG inventory methods. For example, the absence of a clear registry system for associated environmental attributes means that, at this time, additional development and engagement from researchers and industry is needed before these products can be used to claim emission reductions for the purposes of the State GHG Inventory, inventories required of regulated entities, compliance with emissions reductions targets, or other official uses.

The Department of Energy Office of Fossil Energy and Carbon Management's International Measuring, Monitoring, Reporting, and Verification Working Group is working with key domestic and international gas sector stakeholders to promote reliable, consistent information on GHG emissions and intensity associated with natural gas.[54] Work in this arena may yield a promising path for quantifying upstream emission reductions and supporting procurement of lower emissions gas supply.

Recommendations

- Certified gas and other types of differentiated gas products should not be differentiated in the State's annual GHG inventory nor should the State currently accept claims that these types of gas reduce upstream methane emissions in other GHG reporting contexts. Agencies should continue monitoring developments in this field over time.

[54] See, e.g., https://www.energy.gov/fecm/greenhouse-gas-supply-chain-emissions-measurement-monitoring-reporting-verification-framework

4.7. Strategically Managing the Gas Transition for Gas Sector Workers and Businesses

New York's gas sector is estimated to currently employ over 12,000 people across the electric power generation, fuels, and distribution sub-sectors and includes jobs in construction, manufacturing, utilities, extraction, wholesale trade, professional services, and other industries.[55] The gas system will continue to play a large role in meeting New York's energy needs through at least 2040 in all scenarios, indicating an ongoing need for a robust gas sector workforce. In the near- and medium-term, the gas system's operational and maintenance requirements are expected to remain relatively steady. Over the long-term, as New York's progress towards deep decarbonization advances, there will be a need to strategically downsize the gas system which is expected to impact the gas sector workforce. This transition is expected to take place on a multi-decade time scale.

The precise impacts of the clean energy transition on the gas sector workforce are uncertain and warrant further study. For instance, the need to strategically manage the gas transition may create additional economic and job opportunities in some sub-sectors while decreasing opportunity in other sub-sectors. Also, to the extent that the need for certain functions currently provided by the gas sector workforce is expected to decline, it will be critical to identify economic opportunities for workers engaged in those functions, including potentially as part of the broader clean energy workforce. More detailed analysis of the clean energy transition's potential impacts to the gas sector's workforce as well as interventions to promote economic opportunity is needed. The Department of Labor's (DOL) Office of Just Energy Transition is engaged in supporting gas sector workers during the long-term transition. The Clean Energy Jobs and a Just Transition chapter of this Plan discusses proposed future research in this area in greater detail.

Recommendations

- DOL, DPS, NYSERDA, and the State's Regional Economic Development Councils should work closely with utilities and labor organizations to leverage gas sector employees' existing skills in the clean energy transition to maximize economic opportunity for current gas sector workers.
- DOL and NYSERDA should conduct research to assess the employment impacts of the clean energy transition on fossil fuel sector workers, including in the gas sector, to support the development of just transition policies, as discussed in the Clean Energy Jobs and a Just Transition chapter of this Plan.

4.8. Strategically Managing the Gas Transition for Disadvantaged Communities

An unmanaged natural gas system transition poses significant health, affordability, and equity risks to DACs.

- <u>Health.</u> Combusting natural gas within homes can increase the concentration of carbon monoxide (CO), methane (CH_4), formaldehyde (CH_2O), benzene (C_6H_6), nitrous oxide (N_2O), and

[55] Department of Energy, 2024 U.S. Energy and Employment Report. Available at: https://www.energy.gov/policy/us-energy-employment-jobs-report-useer.

nitrogen dioxide (NO_2), which can pose hazards to human health particularly when there is insufficient ventilation.[56] If DACs do not have equitable access to electric alternatives, they may face disproportionate public health burdens from indoor air pollution.

- Affordability. As gas system usage declines and customers depart the gas system, the costs of maintaining the gas system will fall on remaining customers unless remedial action is taken. This could place a disproportionate energy cost burden on LMI customers and residents in DACs.
- Equity. There is a risk that DACs will not have equitable access to clean energy building upgrades like weatherization, energy efficiency, and heat pumps, or to economic or employment opportunities associated with the clean energy transition.

New York should pursue strategic interventions to mitigate these risks throughout the gas transition.

- Program outreach. Clean energy program administrators should engage trusted community-based organizations to help reach businesses and households within DACs. Administrators should also develop communication materials that address language barriers and conduct targeted outreach within DACs.
- Program design. Programs should also be designed to address potential barriers to DAC participation. This may include incentives which cover upfront capital costs, low- or no-interest financing mechanisms, and exploring and integrating funding that can support non-energy building improvements including health and safety upgrades that are necessary to install energy efficiency and electrification measures.
- Affordability programs. New York should continue to prioritize funding for and enrollment in programs designed to ensure customer energy affordability.
- Neighborhood-scale planning. Where appropriate, as part of their long-term planning, utilities should prioritize planning and deployment of affordable, neighborhood-scale clean solutions within DACs.

These topics are discussed in greater detail in the Environmental and Climate Justice chapter and the Buildings chapter of this Plan.

Recommendations

- NYSERDA and utilities should continue to integrate clean energy program design elements that ensure DACs and LMI customers have equitable access to clean energy upgrades.

4.9. Gas System Transition Plan

As discussed throughout this chapter, the gas sector is entering a period of substantial change. As natural gas use is projected to decline over the long-term (Section 4.1), the State will need to consider changes to utility planning practices and investment decisions (Sections 4.2 and 4.3), policy (Section 4.4), and cost

[56] Seltenrich, N. Clearing the Air: Gas Stove Emissions and Direct Health Effects. Environmental Health Perspectives, Volume 132, Issue 2. February 28, 2024. Available at: https://ehp.niehs.nih.gov/doi/10.1289/EHP14180.

recovery mechanisms (Section 4.5), as well as the use of alternative fuels (Section 4.6) and potential impacts to the gas sector workforce (Section 4.7) and DACs (Section 4.8). Adoption of further policies in pursuit of established GHG reduction targets will accentuate the need to consider aspects of the gas transition. These topics interact with one another and have cross-cutting implications for multiple gas sector stakeholders. Accordingly, it is necessary to establish a forum in which key stakeholders can collaboratively develop a strategic gas system transition plan.

This plan will provide direction for utilities—through their investments, programs, and other initiatives—to effectuate an orderly transition of the gas system needed to achieve the State's goals while addressing affordability and risks to customers and other gas sector stakeholders. Once a strategic gas system transition plan is established, utilities' future rate filings and proposals for projects, programs, and investments can and should be developed to advance the plan.

Recommendations

- DPS staff should conduct a gas system transition plan in collaboration with NYSERDA, one or more utility, and other key stakeholders to be published concurrently with the next update to the State Energy Plan. The plan should include an evaluation of the potential to strategically reduce gas system investment in context of several future scenarios, including ones that align with the planning case in this Plan and others that comply with long-term State policy targets. It will also include an assessment of innovative cost recovery practices across various scenarios as well as other pertinent elements of the gas transition.

- The State should subsequently leverage the lessons from this initial study to develop a statewide strategic gas system transition plan with all New York utilities.