NGA Regional Market Trends Update
April 2022

The Northeast Gas Association (NGA) is pleased to present this periodic overview of market characteristics and recent developments in the Northeast region of the United States. This paper summarizes key features of the natural gas system in New England, New Jersey, New York, and Pennsylvania, and highlights several current market issues.

MARKET BACKGROUND

Population and Economy

The Northeast region consists of the nine states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. The composite population is 56 million (17% of the U.S.). Total state domestic product for the region is $4.6 trillion (20% of the U.S. total).

Regional Natural Gas Market

The nine-state region has 14 million natural gas customers (19% of the U.S. total of 74 million). Total annual gas sendout on the regional gas system is 4.2 trillion cubic feet (Tcf), or 15% of U.S. total consumption (measured in volumes delivered to consumers).

Primary Energy Consumption

Natural gas represents 30% of the primary energy consumption of the six New England states, 38% of New Jersey, 35% of New York, and 37% of Pennsylvania, compared to the national average of 31% (based on 2019 U.S. EIA data).

Gas Customers

New England has 2.85 million natural gas customers. Residential customers total 2.57 million; commercial and industrial customers are about 285,000.

New Jersey has 3.1 million natural gas customers. Residential customers total 2.87 million; commercial and industrial customers number about 250,000.

New York has 5 million natural gas customers. Residential customers total 4.5 million; commercial and industrial customers number about 420,000.

Pennsylvania has 3.1 million natural gas customers. Residential customers number 2.8 million; commercial and industrial customers number about 255,000.

Natural gas remains the leading home heating fuel: in New England it is 40%, followed by fuel oil (35%); in New Jersey, 74%, followed by electricity (14%); in New York, 59%, followed by fuel oil (20%); and in Pennsylvania, 51%, followed by electricity (23%), and fuel oil (16%).

Consumption/Sendout by Sector

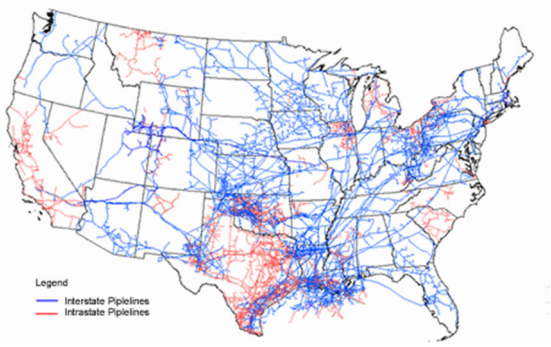
Total annual sendout in New England is about 865 billion cubic feet (Bcf), in New Jersey about 650 Bcf, in New York about 1,235 Bcf, and in Pennsylvania 1,400 Bcf (2020 EIA annual data).

In New England, gas consumption by end-use sector is 23% residential, 23% commercial, 13% industrial, and 41% power generation. In New Jersey, it is 34% residential, 21% commercial, 9% industrial, and 35% power generation. In New York, it is 35% residential, 23% commercial, 7% industrial, and 34% power generation. In Pennsylvania, it is 16% residential, 10% commercial, 18% industrial, and 58% power generation.

In New England, the local gas distribution company (LDC) design day demand is 4.8 Bcf per day, in New Jersey over 4 Bcf/d, and in Pennsylvania 5.6 Bcf/d. In New York, gas system peak demand is close to 8 Bcf/d. While winter is still the peak season for demand, the increasing use of gas for power generation has led to higher demand in summer months.

Electricity Generation Sector

Based on annual fuel mix and generator applications in the queues at ISO-NE, NYISO, and PJM, natural gas is the leading current fuel source for electricity generation, and some proposed plants remain in the mix as well. In New England, natural gas represents 46% of current regional electric generating capacity, in New Jersey, 67% (in-state generation), in New York, over 50%, and in Pennsylvania, 45%.



The U.S. interstate natural gas pipeline system includes 302,000 miles of transmission pipeline, according to the U.S. DOT's PHMSA.

The EIA map on the left illustrates the extensive system.

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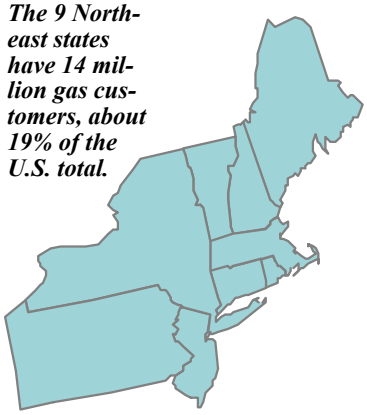


The 9 Northeast states have 14 million gas customers, about 19% of the U.S. total.

Regional Market: Gas Supply Sources

Domestic resources account for 90% of the natural gas consumed in the U.S. The balance is imported from Canada, and a small share is imported in the form of liquefied natural gas (LNG).

"The U.S. became a net natural gas exporter on an annual basis in 2017 for the first time in almost 60 years," according to the EIA.

Historically, the Northeast relied on three supply areas: Gulf Coast U.S., Canada, and imported LNG. Throughout the last few decades, supply areas expanded to include Rockies/Midcontinent gas and eastern Canada. For the Northeast, the most significant supply change has been the relatively recent development of the Marcellus and Utica Shale gas basins in Appalachia. Appalachian production has reached over 34 Bcf/d in 2022.

Exports from Canada to the Eastern U.S. have declined from 2.8 Bcf/d in 2007 to 0.9 Bcf/d in 2021, due to Marcellus and Utica shale gas availability.

LNG imports into the U.S. were 21.4 Bcf in 2021, substantially lower than the high point of 771 Bcf in the previous decade. The Everett LNG facility outside Boston imported 21.4 Bcf in 2021, which represented 100% of U.S. imports.

LNG imports play a critical role in helping gas utilities in the Northeast region meet winter peak day requirements; LNG provides about 27% of New England utilities' peak day requirements. Saint John LNG in New Brunswick, Canada delivered 24.6 Bcf to the regional market in 2021. The offshore Northeast Gateway terminal imported no volumes in 2020 or 2021, but did import 3 Bcf in early 2022.

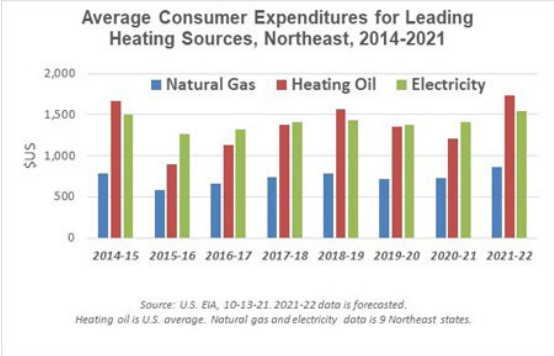
Pipeline and LNG Deliverability

New England

New England has 2,695 miles of gas transmission pipeline, according to the U.S. Department of Transportation / Pipeline and Hazardous Materials Safety Administration (PHMSA).

The interstate and intrastate pipeline companies serving New England are: Algonquin Gas Transmission, Granite State Gas Transmission, Iroquois Gas Transmission System, Maritimes & Northeast Pipeline, Portland Natural Gas Transmission System, and Tennessee Gas Pipeline Company.

New England is the site of three import terminals for LNG, two of which are operational. The onshore terminal in Everett, outside of Boston, is owned by Exelon (Constellation). LNG is delivered by tanker to the terminal which has storage capacity of 3.4 Bcf. The terminal has pipeline interconnections as well as connec-



As illustrated in the chart, natural gas in the Northeast (shown in blue) maintains a price advantage over heating oil and electricity for heating fuel costs. Natural gas remains the heating fuel of choice: 85% of new single-family homes built in the Northeast in 2020 were constructed to run on natural gas, according to the U.S. Census.

Chart source: U.S. Energy Information Administration, Oct. 2021

tions with a large gas utility and a major power plant. LNG is also transported to multiple LDCs' satellite storage tanks by trucks that fuel at the Everett facility. The terminal's vaporization capability is 715 MMcf/d; it also has daily sendout by trucks of another 100 MMcf/d.

The offshore Northeast Gateway facility (near Cape Ann, MA) is owned by Excelerate Energy. It can receive LNG cargoes and inject the revaporized gas into Enbridge's HubLine pipeline system. After several years of inactivity it brought in 2.6 Bcf in 2015 and 2.3 Bcf in 2016, none in 2017 and 2018, and about 5 Bcf to meet cold weather demand in early 2019. As noted above it had no imports in 2020/2021 but brought in a cargo of 3 Bcf in January/February 2022.

The offshore Neptune LNG facility owned by ENGIE (also near Cape Ann, MA) was completed in 2010. It has been inactive since its start-up, and is presently offline.

Saint John LNG—formerly called Canaport - is located across the Maine border in Saint John, New Brunswick and is operated by Repsol. It can deliver up to 1 Bcf/d into the Brunswick Pipeline, which connects with the Maritimes & Northeast Pipeline, which then transports the volumes into New England. Since its inception, it has delivered over 450 Bcf into the regional market. Canada's National Energy Board noted in March 2017 that "Canaport is a peak demand serving facility with deliveries increasing during the winter months in response to cold temperatures."

New Jersey

New Jersey has 1,568 miles of gas transmission pipeline.

The interstate pipeline companies serving New Jersey are: Algonquin Gas Transmission, Columbia Gas Transmission, Tennessee Gas Pipeline Company, Texas Eastern Gas Transmission, and Transcontinental Gas Pipe Line Corporation.

The LDCs utilize local LNG storage for peak day support.

New York

New York has 4,593 miles of gas transmission pipeline. The pipeline companies serving New York State are: Algonquin Gas Transmission, Columbia Gas Transmission, Eastern Gas Transmission & Storage (formerly Dominion), Empire State Pipeline Company, Iroquois Gas Transmission System, Millennium Pipeline Company, National Fuel Gas Supply Corporation, North Country Pipeline, Stagecoach Gas Services, Tennessee Gas Pipeline Company, Texas Eastern Gas Transmission, and Transcontinental Gas Pipe Line Corporation. New York also has gathering systems such as Laser Pipeline.

LNG is utilized by two local utilities in the New York City and Long Island areas. The LNG is received from the pipeline in vapor form and then liquefied. New York has no LNG import facility.

Pennsylvania

Pennsylvania has 10,488 miles of gas transmission pipeline. The pipeline companies serving Pennsylvania are: Columbia Gas Transmission, Eastern Gas Transmission & Storage, National Fuel Gas Supply Corporation, Tennessee Gas Pipeline Company, Texas Eastern Gas Transmission, and Transcontinental Gas Pipe Line Corporation. LNG is utilized by two LDCs and produced by the affiliate of another utility for sale into the regional energy market.

Regional Production

The Northeast region, a major consumer of natural gas and a high-priced energy market, is a center of U.S. natural gas production.

Historically the region had only limited natural gas production in New York and Pennsylvania. (There is no gas resource production base in New Jersey or New England.) With the advancement of hydraulic fracturing and the development of the Marcellus resource base, the Northeast has become a significant production region.

As noted, Appalachian production, centered in Pennsylvania, Ohio, and West Virginia, is currently over 34 Bcf/d. Pennsylvania's annual production grew to 7.6 Tcf in 2021 (compared to 0.6 Tcf in 2010); it is the second-largest state producer of natural gas in the U.S. In recent years the Appalachian region, noted EIA in February 2022, "has provided the largest share of U.S. domestic natural gas output, accounting for one-third of Lower-48 production since 2016."

Interstate pipeline companies serving the Appalachian region continue to seek to add interconnects from area producers to the market.

There is a shale gas resource in New York but use of the hydraulic fracturing process is prohibited per state regulation announced in late 2014. New York does allow conventional drilling production. Total annual state output was about 10 Bcf in 2020. The state's conventional production has steadily declined since 2007, when annual production totaled 55 Bcf.

There is some limited conventional production in eastern Canada.

However, as summarized by Canada's CER in June 2021: "The Maritimes was once supplied by natural gas produced in offshore Nova Scotia, with some

volumes of gas imported during peak times from the U.S. and globally from the Canaport LNG terminal in New Brunswick. Nova Scotia's offshore natural gas production declined since 2014 and was finally shut down in mid-2018. Since 2015, natural gas has been increasingly imported through St. Stephen, New Brunswick, from the U.S. on the bi-directional M&NE Pipeline. Today, St. Stephen primarily imports natural gas, after mostly exporting until 2015."

In New Brunswick, the McCully field of Corridor Resources, which began production in 2007, provides small amounts of gas for delivery into the Maritimes & Northeast Pipeline.

Regional Storage

Storage is a crucial part of the natural gas supply and delivery chain. The Northeast region has considerable underground storage, notably in Pennsylvania (8.2% of the U.S. total); underground storage in New York is about 2.6% of the U.S. total. (The geology of New Jersey and New England is not suitable for underground gas storage.) The Dawn storage field in Ontario, Canada is also quite extensive and located very close to this Northeast market.

LNG is an important part of the storage portfolio. Total LNG storage capacity in New York is 3.2 Bcf, in New Jersey about 4 Bcf, in Pennsylvania 6.7 Bcf, and in New England 16 Bcf on the LDC system and another 3.4 Bcf at the Everett import terminal. The Saint John LNG facility has 9.9 Bcf of storage. LNG is also produced and supplied by companies in Québec and Pennsylvania.

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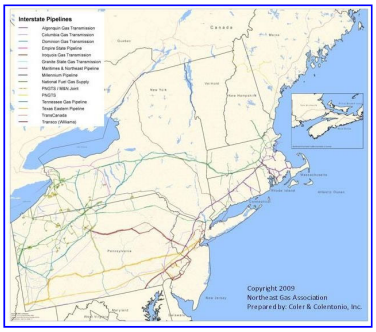
The interstate pipeline system in the Northeast accesses supplies from multiple sources. The pipelines also can access storage at different points along their systems, including underground storage in Pennsylvania, New York and Ontario.



Recent System Upgrades

Siting remains a challenge for the regional energy market, but even with some notable project cancellations over the last few years, some valuable incremental new capacity has continued to be added to the natural gas system. In 2021, some of the infrastructure additions included:

- Enbridge/Texas Eastern: "Appalachia to Market" in PA
- Enbridge/Texas Eastern: "Middlesex Extension" in NJ
- TC Energy/PNGTS: "Westbrook XPress" [phases 2 & 3], in ME
- Kinder Morgan/Tennessee Gas: "Station 261 Upgrade" [phase 2], in MA
- National Fuel Gas Supply: "FM100" in PA
- Williams/Transco: "Leidy South Project" in PA.

Planned Infrastructure Enhancements

The Northeast region's natural gas industry plans several infrastructure projects in the near-term to meet market demand. Its natural gas system remains constrained at several points, especially into New England and downstate New York/ Long Island. Citing supply and delivery limitations, several gas utilities in the region have implemented moratoria on new customer connections.

NGA posts updates on proposed expansion projects at:

http://www.northeastgas.org/pipeline_expansion.php

Challenges faced by new project developments include siting, environmental concerns, and securing market position. Contract commitments in New England have been a vexing market issue, as the largest consuming sector, power generation, is constrained by the complex economic structure of its wholesale electricity market. Local natural gas utilities have tried to invest in incremental pipeline projects to meet system expansion and reliability needs, but this too has proven to be challenging.

LNG is another supply option for the market in general and for gas LDCs. UGI Corporation in Pennsylvania, through its subsidiary, UGI LNG, has LNG storage, associated peak shaving services, and an LNG tanker truck-loading terminal. Energir (Gaz Métro LNG) in Québec increased its liquefaction capability in 2016. National Grid received federal regulatory approval to add liquefaction at its Providence, RI facility; the upgrade is expected to be completed this year. Philadelphia Gas Works (PGW) received city approval in 2019 to advance its proposed LNG project with Passyunk Energy Center, LLC (PEC) to facilitate the marketing and sale of LNG to regional customers. In October 2021, the Energy Facilities Siting Board in Massachusetts approved a proposal by Northeast Energy Center LLC to construct a new LNG storage and trucking facility in central MA, with storage of 2 million gallons; the LNG would be sourced off the nearby Tennessee Gas Pipeline system. The anchor customer is the utility National Grid, but supplies could be available to other utilities in the region as well.

Another supply/delivery option is portable or mobile compressed natural gas (CNG) or LNG. These "virtual pipeline" options are designed to bring natural gas to communities and businesses that are not located near a pipeline or distribution system. In this approach, large tube trailers are filled at compression facilities and the CNG is delivered by truck to the customer's facility, where the gas is depressurized, off-loaded, and flowed into the customer's gas (or dual-fuel) equipment. CNG is also being employed by several gas utilities as another supply input into the distribution network at particularly constrained points, such as the greater New York City area and Long Island. LNG can be utilized in the same manner, to supplement existing system supply and meet local demand.

MARKET ISSUES

Supply Outlook

The recovery from the COVID-19 pandemic has continued to shape the nation's economy and the natural gas production market since March 2020. U.S.

Another key supply point for the region is liquefied natural gas (LNG). The region has three operating import facilities, two in MA and one in New Brunswick, Canada. Nationally and regionally, LNG imports are down, as U.S. domestic production is on the increase. LNG remains especially important to New England for peak days. This photo is of an LNG storage tank in Boston owned and operated by National Grid.

Photo: National Grid

natural gas production set new records in 2019, as did gas consumption levels; but production and consumption both declined in 2020 along with the economic contraction. Dry natural gas production fell but only by about 1% in 2020 (whereas U.S. oil production declined by 8%).

While the national trend showed decline, natural gas production growth actually continued in Appalachia. In an issues brief in March 2021, EIA observed: "Natural gas production from the Marcellus and Utica/Point Pleasant shales of Ohio, West Virginia, and Pennsylvania continued to grow despite low regional natural gas spot prices. Natural gas production from these three states increased from 32.1 Bcf/d in 2019 to 33.6 Bcf/d in 2020."

Appalachian growth continued as well in 2021. Looking at production trends there for the first part of 2021, EIA stated: "The Appalachian Basin… accounted for 34% of all U.S. dry natural gas production in the first half of 2021. On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world the first half of 2021, behind Russia and the rest of the United States."

Meanwhile, the U.S. resource base for natural gas remains extensive. In October 2021, the Potential Gas Committee (PGC) at the Colorado School of Mines released its 2020 biennial report, *Potential Supply of Natural Gas in the United States.* The new assessment finds that the United States possesses a technically recoverable natural gas resource potential of 3,368 trillion cubic feet (Tcf).

When the PGC's assessments of technically recoverable resources are combined with EIA's latest determination of proved reserves (495 Tcf of natural gas as of year-end 2019), the U.S. future supply of natural gas stands at a record 3,863 Tcf, a modest increase of 25 Tcf (<1%) over the previous PGC evaluation. The PGC also noted that shale gas accounts for 63% of the country's total potential resources, at 2,130 Tcf.

Canada, which has considerable natural gas reserves, remains an important energy partner, even though its share of the U.S. natural gas market is expected to decline. In its November 2020 report, *Canada's Energy Future 2020*, the Canada Energy Regulator (CER) projected that natural gas production will likely remain steady over the next decades, driven by the power generation market and LNG exports. The CER observed: "Natural gas use differs greatly between the two scenarios. The large increase in the Reference Scenario is driven by strong growth in production of oil and natural gas (natural gas is often used in the production process for these commodities). In addition, natural gas plays a greater role in electricity generation in the Reference Scenario. Natural gas use declines in the Evolving Scenario, driven by lower oil and natural gas production, a greater share of renewables in electricity generation, and higher blending of renewable natural gas."

Higher domestic production in the U.S. also affects LNG imports. LNG imports into the U.S. are substantially lower than a decade ago, and the focus for the U.S. gas market has shifted from imports to exports. In 2021, the U.S. *exported* far more LNG (3.6 Tcf) than it *imported* (21 Bcf), a trend that will continue.

With the Northeast delivery system remaining constrained at certain points, regionally based LNG facilities will continue to help ease bottlenecks and increase supply and delivery options.

A new factor to note as of spring 2022 is the impact of Russia's invasion of Ukraine. As will be noted below, this has dramatically impacted commodity energy prices globally. It has also spurred countries in Europe and elsewhere to seek to reduce their reliance on Russian energy supplies as much and as soon as possible. The U.S. has held discussions with the European Commission to facilitate greater energy trade with a major role planned for U.S. exports of LNG to Europe in the coming years.

"On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world the first half of 2021, behind Russia and the rest of the United States."

- U.S. EIA, June 2021

Efficiency Initiatives

The Northeast region is nationally recognized as a leader in per capita energy efficiency. A February 2022 report by the American Council for an Energy Efficient Economy (ACEEE) noted that $1.5 billion was invested in natural gas efficiency programs nationwide in 2020 (latest data). About 40% ($593 million) of the national total was invested in the nine Northeast states alone.

The ACEEE also noted that efficiency opportunities exist in multiple sectors: "While the roots of natural gas efficiency programs lie within residential markets, there are now programs serving multiple types of natural gas customers – from homeowners to large industries….Programs may target specific technologies that use natural gas, such as furnaces, water heaters, boilers, and cooking equipment, or they may target the systems and facilities that are served by natural gas technologies. Improving the thermal envelope of buildings is one example of programs that address whole buildings."

In an October 2020 paper, the ACEEE noted that "low natural gas market prices over the last few years have made it more difficult for some utility programs to demonstrate cost effectiveness using traditional tests," but concludes that "natural gas efficiency programs are sustainable and worth pursuing for both economic and environmental reasons."

The Northeast states continue to be leaders in per capita energy efficiency.

Efficiency is a core part of utilities' decarbonization efforts.

Infrastructure Siting Challenges and Changing Regulatory Processes

Energy infrastructure of all types has long encountered siting issues, and natural gas is no exception.

In the U.S., project delays at the state level, particularly regarding the issuance of state water quality certificates, have added to project costs and market uncertainty. In 2020-21 the siting challenge continued, as several pipeline proposals were withdrawn after multiple years of navigating the permitting process, including the Constitution Pipeline, the NESE Project, the Atlantic Coast Pipeline, and PennEast. The developers noted the costs of delay and the uncertainty of the regulatory process. (As well, several projects proposed in eastern Canada were withdrawn in 2021, including planned LNG export terminals in Quebec and Nova Scotia, and a proposed underground storage facility in Nova Scotia.)

FERC's policy direction for project development is also under review, with implications for the energy industry. In February 2021 the agency announced it is revisiting its past policy statement on interstate natural gas pipeline proposals; and in March it noted that it has "for the first time assessed the significance of a proposed natural gas pipeline project's greenhouse gas emissions and their contribution to climate change."

The public policy framework is also being shaped by government, industry, community and broader stakeholder participants to address such issues as equity, inclusion and environmental justice in energy project considerations.

The Northeast region, as a highly congested area, poses challenges for any energy development. Public policy requires all sides to weigh the costs and benefits of energy development and seek balanced and reasonable solutions.

Price Trends

The key variables in natural gas price formation are: demand growth, the condition of the national economy, production levels, storage levels, weather, and alternative fuel prices.

The natural gas price trend in recent years has been positive for both consumers and the entire U.S. economy. In July 2008 natural gas commodity prices reached $13.50/MMBtu (and oil hovered close to $150 a barrel), whereas in 2020 the average natural gas commodity price was around $2.00/MMBtu.

The pandemic year of 2020 led to production cutbacks and very low commodity prices amid lower market demand. 2021 saw higher commodity prices for

all fuels, including natural gas, as economic demand increased, while supply chain and transport issues challenged the global delivery market. The trajectory for energy commodity prices in 2022 is even higher, as a result of continued supply chain issues, inflation, and the impact of Russia's war on Ukraine.

Natural gas prices in the U.S. market are not as high as in Europe and Asia but remain higher than in many years. In its April 2022 "Short-Term Energy Outlook," the U.S. EIA projects that "the Henry Hub price will average $5.68/MMBtu in 2Q22 and $5.23/MMBtu for all of 2022. We expect the Henry Hub spot price will average $4.01/MMBtu in 2023. The forecast drop in prices for 2023 reflects our expectation that storage levels will be higher during 2023 than in 2022."

Given the size of the domestic supply resource base, it is expected that the natural gas price bandwidth in the longer-term will remain relatively stable and moderate. However, short-term volatility reflecting delivery constraints and weather and global market disruptions will continue to affect U.S. and regional markets.

Winter Challenges & Market Constraints

In its energy market review for 2021, the FERC noted the high-price fundamentals of the Northeast gas market due to capacity limitations. In an April 2022 report, the agency stated that: "Algonquin Citygates, a Boston area hub, averaged $4.51/MMBtu in 2021 and saw its prices increase significantly late in 2021 during cold weather events. Due to constrained pipeline capacity into New England, segments of the region's pipelines often reach their maximum capacity in winter. Prices at Algonquin Citygates frequently reflect winter scarcity as well as the region's reliance on LNG imports to supplement pipeline supplies. As global demand for LNG increased, natural gas prices in New England also rose, reflecting the effects of the tight international market on the region."

It's a long-standing regional market characteristic: a high demand region with infrastructure constraints in particular market areas such as New York City/Long Island and New England. It is evidenced in the winter months when demand is highest and system capacity is at peak.

The combination of high demand, record cold and system constraints has resulted in considerable short-term price volatility in recent years regionally. In January 2018, spot prices hit extremely high levels, including a record on the Transco system in New York. While the Midwest price rose as high as $6.50/MMBtu on January 5, 2018, the spot price on that same date was $83 in Boston and $140 in the New York City area, a sharp illustration of regional price disparities.

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Natural gas day-ahead prices for the 2020/21 winter were once again at their highest in the Northeast region, especially the Algonquin citygates.

In the winter months, natural gas utility customers in the Northeast region are largely shielded from spot market price volatility thanks to gas utilities' firm contract arrangements for pipeline capacity and storage arrangements. Market participants such as some power generators which rely on non-firm capacity however are subject to spot market prices and interruptions in capacity delivery according to their contract terms.

EIA noted in 2017 that "both the Boston and New York natural gas markets have experienced winter price spikes because of pipeline constraints during periods of peak demand. Natural gas pipeline expansion projects that were completed in recent years may have reduced, but did not eliminate, sharp price increases with anticipated cold weather."

The situation in the summer months is far less challenging, although pipeline maintenance work can affect the regional market.

Gas & Electric Power Generation

The regional power generation fleet, highly reliant on natural gas, is positioned to remain so for several more years, as the regional power grids transition to a cleaner energy profile.

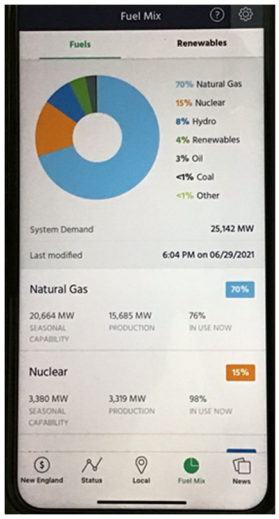
Combined-cycle technology (CCT) made the natural gas power plant the energy system of choice over the last two decades. CCT's advantages over other conventional fuel types include higher efficiency, lower heat rates, shorter construction lead times, and reduced air emissions. In recent year, natural gas power plants have continued to be added in the region, as numerous oil, coal and nuclear plants retired.

In 2018, new gas combined-cycle plants opened in Connecticut (805 MW, CPV Towantic plant), Massachusetts (674 MW, Salem Harbor unit), and New York (680 MW, CPV Valley Energy Center). In 2019, a new combined cycle plant opened in Bridgeport, CT (485 MW), and two gas peakers totaling just over 500 MW opened in MA. In April 2020 a major gas unit, Cricket Valley Energy Center (1,100 MW), came online in New York. It entered service in the same timeframe that one of the last units of the Indian Point nuclear plant closed; Indian Point's last nuclear unit closed in April 2021.

Natural gas units continue to provide important baseload and fast-start capability, and remain pivotal to grid reliability.

In its "2020 Regional Transmission Expansion Plan," released in early 2021, PJM noted that its "interconnection process is showing trends of increasing re-

newable generation." At the same time, one of the other key trends in its "changing capacity mix" is "new generating plants powered by Marcellus and Utica shale natural gas." The New York Independent System Operator (NYISO) noted in its May 2021 report "*Power Trends 2021*" that the portion of New York's installed capacity from natural gas and dual-fuel facilities rose from 47% in 2000 to 64% in 2021. As the ISO noted in its 2019 report: "Reflecting economic and public policy investment signals, recent generation additions have primarily been natural gas-fueled in downstate New York and wind-powered in upstate."

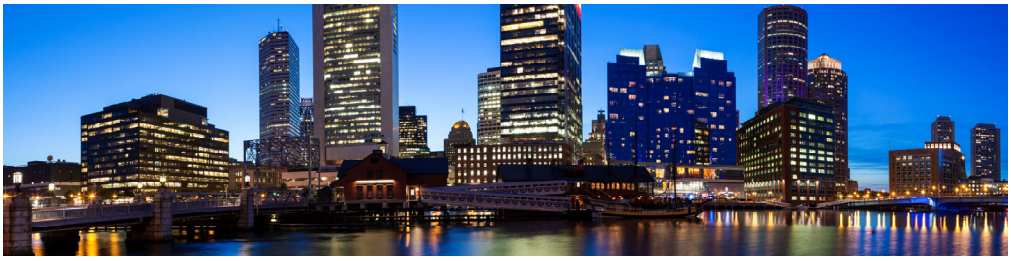


Natural gas continues to be key to meeting power demand in the region. The photo above shows the peak hour on the ISO-NE system on June 29, 2021; natural gas at that time represented 70% of the regional power generation mix.

Public policy and legislative initiatives in the Northeast region are prioritizing non-fossil fuel units for new generation and encouraging electric utilities to contract for offshore wind and imports of Canadian hydro. Solar continues to make inroads behind-the-meter as its technology costs decline.

The central role of natural gas in the region nevertheless was underscored in the FERC's summer energy market assessment released in May 2021: "Natural gas fired generation is expected to continue to play a pivotal role in the summer of 2021 at an average market share of 48% across organized wholesale electric markets, making it the largest source of electric capacity…NYISO and ISO-NE are the most natural gas dependent regions with over 55% of their electricity being generated by natural gas-fired power plants this summer."

Natural gas offers baseload service with a generally lower air emissions profile and relatively stable prices. As the power grid shifts to greater reliance on new clean energy sources, natural gas can support system reliability, given the intermittent characteristics of the anticipated new resources.



Air emissions from power generation in the region have declined substantially in the past two decades thanks in great part to the use of cleaner-burning fuels such as natural gas.
Photo: Joseph Murphy

Photo: Cricket Valley Energy Center

The states in the Northeast continue to assess the role of natural gas going forward, as they seek to implement aggressive carbon reduction goals. In October 2021, the NYS Department of Environmental Conservation rejected two proposed natural gas power facilities, one in Queens, one upstate, declaring that the projects "would be inconsistent with the statewide greenhouse gas emissions limits established in the Climate Leadership and Community Protection Act (CLCPA)."

In June 2021 the NY ISO highlighted some of the market challenges: "As the state reviews a potential moratorium on any new or repowered gas generation, we have to ask the question of how to maintain reliability during the iterative, multi-step process to a carbon-free grid as contemplated by the CAC [Climate Action Council]. At the NYISO, we've performed studies to examine how a zero-emissions grid will perform, modeling a number of scenarios in which renewable resources (such as solar and wind) and non-emitting resources (such as energy storage) exclusively supply the grid. We've presented some of these studies to the CAC in order to help plan for the 2040 grid of the future. These studies show that fossil fuel-powered resources will continue to be needed on the road to 2040 to offset this intermittency until new, cleaner technologies can provide the responsiveness now fulfilled primarily by natural gas generation. Limiting options at the start of the transition could actually stifle progress toward our climate goals and produce higher emissions along the way."

In an op-ed in February 2022 in "Commonwealth Magazine," the CEO of ISO-NE expressed some of the same operational and reliability concerns as those expressed by NY ISO in the summer of 2021. Gordon van Welie wrote in February: "In the interim, we cannot escape the reality that until more clean energy resources are built, and until we have a robust, long duration source of clean balancing energy, the region will remain reliant on natural gas and, to a lesser extent, oil-fired generation to both produce the power it needs and to balance supply and demand during periods when renewables cannot produce electricity."

States' Regulatory Review of "The Future" of Natural Gas

Natural gas demand in the region continues to increase due to its advantageous price, reliability, and efficiency. About 12.5 million customers heat their homes with natural gas in the Northeast region. U.S. Census data for 2020 indicated that the natural gas furnace remains the predominant heating choice for new

home construction in the Northeast. Natural gas now heats 55% of the homes in the region.

However, greater demand and new customer additions are beginning to run up against system delivery constraints in some areas, as new infrastructure development is itself constrained. As the states define their greenhouse gas (GHG) emissions reduction plans, they are also reassessing the role of natural gas in power generation, as noted above, and in the building sector.

Last year, both Massachusetts and Rhode Island enacted new GHG legislation with more aggressive timeframes for achieving reductions economy-wide. Other states in the region have likewise embraced comprehensive legislation and regulatory reviews.

This section briefly reviews the processes underway in two Northeastern states - New York and Massachusetts - both of which explicitly focus on reducing and/or transforming the role of natural gas.

New York's climate legislation, the CLCPA, which was enacted in 2019, mandates that GHG emissions be reduced to 40% of 1990 levels by 2030 and to 85% by 2050. The power grid is planning to run on 70% renewables by 2030 and be net-zero by 2040. New York's Climate Action Council (CAC) is holding panel and committee meetings to develop recommendations on how to transform the power, building and transportation sectors. Public hearings are underway in 2022 while the final scoping plan on how to achieve the required reductions is expected in 2023.

Concurrently, the New York State Public Service Commission (PSC) is proceeding with its own review of the planning procedures used by New York's natural gas local distribution companies (LDCs) and how they align with the CLCPA. In March 2021 the PSC issued its "first-ever gas planning process proposal to combat climate change" (20-G-0131). It envisions a different planning model for gas utilities going forward, as illustrated by these quotes from the PSC's press release:

> "Importantly, this improved planning process should help guide utilities into New York State's low carbon future by maximizing the use of energy efficiency, new technologies (such as electric heat pumps) and demand response programs, and limiting unnecessary infrastructure investment and the potential for stranded costs that might result."
>
> "As part of this planning process,

A natural gas distribution line being upgraded and about to be installed, outside Boston, in spring 2021.

each utility must propose a 'no-infrastructure option', in addition to any other options that address identified needs in the filing. This option should include a mix of utility-sponsored demand reduction measures that will close any gap between the projected load and available supply. This option should also include one or more contingency solutions, such as compressed natural gas or peaking services, which can be called upon if necessary."

In August 2021 the PSC issued an order in a gas utility rate case that also highlights a new emphasis on reducing natural gas usage in the state (quotes from the PSC's press release):

In 2020, Harvard's new central energy facility in Allston, MA became fully operational. It runs primarily on natural gas.

"The Commission ruled that CLCPA requirements apply to this rate case and all future rate cases. Based on the CLCPA requirements, the Commission today directed the utility to discontinue natural gas marketing efforts and promotional programs, and provide educational information to customers about alternative heating options and the emission reduction requirements of the CLCPA. The goal is to have the utility sell less gas in the future, a clear-cut indication of what will happen at other gas utilities in New York State as CLCPA requirements take effect."

"Through approval of the joint proposal, the Commission is requiring the companies to prioritize energy efficiency and demand response as part of an effort to avoid construction of capital projects that may increase greenhouse gas emissions, with the overall goal of reducing demand for natural gas."

In Massachusetts, there are also regulatory and legislative/administrative reassessments underway.

In October 2020, the Department of Public Utilities (DPU) announced its own investigation into the future role of natural gas, stating it "will assess the role of gas companies in ensuring a low-carbon future and explore strategies that enable the Commonwealth to achieve net zero greenhouse gas emissions while safeguarding ratepayer interests and securing safe, reliable, and affordable natural gas service." In March 2022, each Massachusetts natural gas utility filed an "initial net zero enablement plan" with the Department of Public Utilities under the DPU 20-80 "future of gas" docket, along with an independent consultant statewide report analyzing the decarbonization pathways, considerations and alternative regulatory design for achieving net zero emissions by 2050.

The Commonwealth's 2030 Energy and Climate plan, released by the Energy & Environmental Affairs (EEA) Secretariat in late 2020, envisions adding

750,000 electric vehicles by 2030 and retrofitting one million existing homes with clean heat technology. The 2030 Plan states that "the number of buildings using natural gas, fuel oil, and propane for space and water heating must begin to steadily and permanently decline, and the deployment of heat pumps and building envelope improvements retrofits must become widespread."

The MA Department of Energy Resources (DOER) is meanwhile coordinating the development of a new "Stretch Energy Code" as called for in the state's 2021 climate legislation, to include a "definition of net-zero buildings and to set [a] performance standard." The new code is anticipated to be identified later in 2022.

Making the Case for Natural Gas in the Energy Transition

What is the role of natural gas in this era of energy transition? This section highlights some different perspectives on natural gas's future.

Several studies released by the ACEEE in recent years have identified value in converting homes heated with heating oil and propane to electricity, but found less benefit in converting those heated with natural gas, especially in colder climates. In a September 2018 blog post, ACEEE observed that: "For the residential sector, recent ACEEE research has found that some applications (oil– and propane-heated homes and homes in the South) can meet the criteria for beneficial electrification discussed above. For these applications it can make sense to electrify the next time a heating or cooling system or water heater needs to be replaced. But for many homes, electrification may not currently make sense and as a result, natural gas use will likely continue for decades, particularly in the North."

The Northeast states have added over 1.5 million new natural gas customers since 2010.

In a June 2020 report on electrification efforts at the state level, the ACEEE observed that: "In areas with high use of delivered fuels (fuel oil or propane), many programs target customers using these fuels because the economics of electrification in these situations are often better than when displacing natural gas."

In an April 2021 article in Scientific American entitled "Can Natural Gas Be Part of a Low-Carbon Future," Michael Webber reviews some of the possible technological pathways to help decarbonize the existing gas network. He concludes: "Reining in climate change requires many solutions. Declaring who cannot be part of those, such as natural gas companies, only raises resistance to progress. Because decarbonized gas can complement renewable electricity and because it might be a faster, cheaper and more effective path for parts of society that are difficult to electrify, we should not discard gas as an option. We have a massive gas infrastructure, and we have to figure out what to do with it. Scrapping it would be slow, expensive and incredibly difficult, but we could instead put it to

work to help create a low-carbon future."

Also in April 2021, The Columbia Center on Global Energy Policy released a new report entitled: "Investing in the U.S. Natural Gas Pipeline System to Support Net-Zero Targets," written by Erin M. Blanton, Melissa C. Lott, and Kirsten Nicole Smith. This paper, part of the work by Columbia University's Center on Global Energy Policy on natural gas and the energy transition, examines projections of continued natural gas use and the zero-carbon fuels that are poised to become a bigger part of the energy mix. The authors note: "…while it may seem counterintuitive, investing more in the domestic natural gas pipeline network could help the US reach net-zero emission goals more quickly and cheaply. Fortifying and upgrading the system could prepare the existing infrastructure to transport zero-carbon fuels as they become available and, in the meantime, reduce harmful methane leaks from natural gas."

An op-ed by Ken Costello (former economist with the National Regulatory Research Institute (NRRI)), which was published by the *San Francisco Chronicle* after that city's Board voted to ban natural gas in new buildings, summed up the case for natural gas as follows:

"What natural gas has going for it is plenty: (1) abundant domestic availability, (2) low price for the foreseeable future, (3) relative cleanliness when compared with other fossil fuels, (4) promising technological prospects for a more benign environmental footprint in the future, (5) flexibility in electric power production, one use being a backup to renewable energy. It seems absurd to ban or even restrict a product that has done, and is expected in the future to do, so much good for both energy consumers and the economy."

Natural Gas Utilities & Decarbonization Pathways

The natural gas industry is committed to being part of the solution to achieving a clean, reliable, affordable energy system. The Northeast region's natural gas utilities are actively working to reduce the carbon content of their systems – through increased efficiency, the incorporation of renewable natural gas (RNG) and hydrogen, and the replacement of older pipe components, such as cast-iron and bare steel. This section highlights several current areas of activity.

Energy Efficiency

Energy efficiency has been a key part of the utilities' energy and environmental planning for decades, and has been a national success story.

The Northeast states remain leaders in both electric and natural gas efficiency programs, and they believe that the continued emphasis on efficiency is critical to future progress. The most recent annual state efficiency study by ACEEE, released in February 2022, observes that the nine Northeast states collectively invested 40% of all investments nationwide in natural gas efficiency programs. The commitment to these types of deep and sustaining efficiency investments helps consumers save on their energy bills while also maximizing the use of the existing natural gas distribution system. "Efficiency first" is a sensible concept and practice.

Accelerated Pipeline Replacement

Related to safe operations and environmental performance is the accelerated replacement and repair of older pipeline system components (pipes constructed of bare steel or cast-iron) that are considered more "leak-prone." The U.S. Department of Energy observed in January 2017 that: "Safety remains the primary policy driver for LDC pipeline and infrastructure repair programs. However, the significance of methane emissions is becoming more recognized and companies, regulators, and other stakeholders are seeking ways to incorporate emission reductions into utility programs while limiting the cost to consumers."

In February 2020, the National Association of Regulatory Utility Commissioners (NARUC) published an informational handbook summarizing natural gas distribution infrastructure replacement programs in 41 states and the District of Columbia. The handbook cited substantial progress in replacing aging bare steel and cast-iron main miles and service counts across the U.S. in recent years, while noting: "However, bare steel and cast iron still account for 5.1 percent of main miles and 2.7 percent of service lines, demonstrating the need for continued action on infrastructure replacement."

PHMSA continues to urge action on repairing older, potentially more leak-prone systems. The gas utilities in the Northeast are committed to modernizing the region's distribution systems.

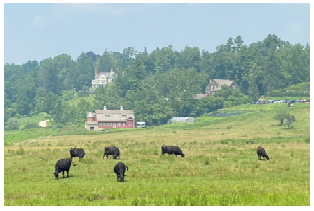
Renewable Natural Gas

Renewable Natural Gas (RNG), also known as bio-methane or biogas, is pipeline quality gas derived from biomass that is fully interchangeable with natural gas. The future natural gas network is projected to include renewable gas from dairy farms, wastewater treatment plants, landfills, wood waste, and food waste plants.

In the Northeast there is growing interest and action in implementing RNG. An interesting project that was commercialized this summer occurred in Vermont, with the start of gas production at "the largest anaerobic digester in the

Northeast," located at the Goodrich dairy farm in Salisbury, Vermont. The digester, built, owned, and operated by Vanguard Renewables (of Wellesley, MA), can recycle daily more than 180 tons of unavoidable food and beverage waste from manufacturers, retailers, and distributors, and 100 tons of dairy manure into renewable natural gas (RNG). The Goodrichs' 900 cows provide the manure and Vermont businesses - including Ben and Jerry's and Cabot/Agri-mark - supply the food waste. Middlebury College will buy the majority of the RNG generated by the digester as part of its Energy2028 project, which calls for the College's use of 100 percent renewable energy by 2028. VGS, the gas utility, installed the infrastructure to transport the RNG and make it available to Middlebury College as well as other customers who want to lower their carbon footprint.

Governor Phil Scott at the commissioning ceremony stated: "Think about it – we've got a Vermont farm, a Vermont utility, a Vermont college, and national energy innovators all coming together to build a model for our region. And it can be replicated in other parts of the state, and country, as well. This is truly transformative work that Vermonters can be proud of."



RNG is also seen as a potential source for natural gas in the transportation sector. According to the U.S. Department of Energy, "like conventional natural gas, RNG can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). RNG qualifies as an advanced biofuel under the Renewable Fuel Standard."

In April 2022, National Grid released its "clean energy vision" for the energy transition which includes a major role for RNG, and also for green hydrogen.

Hydrogen's Potential

Hydrogen is seen as a potentially significant source in a low-carbon energy future. For natural gas systems, hydrogen has the potential to reduce carbon intensity through blending into existing gas pipeline systems.

The Canada Energy Regulator notes there are three methods to produce hydrogen:

"Grey hydrogen uses an industrial process called 'steam methane reforming', which uses high temperature steam to separate hydrogen from methane– the main component of natural gas.

Blue hydrogen uses the same method as grey hydrogen, except it captures and stores the carbon dioxide (CO_2) emissions resulting from the process.

Green hydrogen utilizes renewable electricity and a process called electrolysis (passing an electric current through water) to separate and extract hydrogen molecules from water."

Hydrogen is currently used in the transportation sector as a vehicle fuel as well, notably in California, but on a very limited basis.

In a June 2021 "Market Snapshot" paper on hydrogen, the Canada Energy Regulator summarized the hydrogen opportunity this way:

> "Hydrogen has the potential to play a key role in the transition to a low-carbon economy and net-zero emissions. It may provide a way to leverage some existing energy and infrastructure, including fossil fuel resources and natural gas pipelines. Yet, work is still needed for hydrogen to be deployed at mass scale, including to increase cost-competitiveness with other fuels. Globally, efforts are focused on developing and harmonizing regulations, standards, and codes and addressing hydrogen storage and transportation challenges."

Research work continues. GTI's Hydrogen Technology Center is evaluating effects of a hydrogen-natural gas blend on non-metallic material properties and operational safety, as well as determining operational impacts of a hydrogen blend in pipelines, such as leak detection. GTI is also working with the Electric Power Research Institute (EPRI) on a joint "Low-Carbon Resources Initiative (LCRI)", a five-year R&D commitment focused on the advancement of low-carbon technologies for large-scale deployment across the energy economy. The joint initiative began in 2020.

Image: U.S. Dept. of Energy

NGA's NYSEARCH is also conducting timely research into low carbon fuels and pipeline integrity – see below.

Environmental Considerations

Environmental issues are central to regional decision-making with respect to energy system usage and infrastructure expansion. This section reviews the natural gas industry's past progress and actions to support the transition to a lower-carbon future.

Reductions in air emissions from power generation

Natural gas compares favorably to other fossil fuels regarding air emissions, and it remains a favored fuel for power generation.

The rise in natural gas use in power generation has contributed to lower air emissions, from sulfur dioxide to carbon dioxide. In June 2021, U.S. EIA noted that CO_2 emissions from the U.S. electric power sector fell by 32% from 2005 to 2019. EIA observed: "Although both the increased use of renewables and the shift from coal-fired to natural gas-fired generation contributed to reductions in electric

power sector CO_2 emissions, the shift from coal to natural gas had a larger effect." EIA estimates that almost 65% of the decline in CO_2 power sector emissions nationally over this time period is attributable to the shift from coal-fired to natural gas-fired electricity generation.

At the regional level, air emission trends remain favorable. NY ISO reported in 2021 that emissions rates from its power sector dropped by 52% for CO_2, 93% for NO_X, and 99% for SO_2 over the last two decades. ISO-NE reported that total emissions from power plants in New England declined by 99% for SO_2, 78% for NO_X, and 42% for CO_2 since 2001. The ISO has noted: "Several factors have played a role in the overall reduction of generator air emissions…The biggest contributor has been the region's shift to lower-emitting, highly efficient natural-gas-fired generation. Natural gas-fired resources account for the vast majority of new generators built in New England since 1997, and they typically outcompete oil- and coal-fired generators in the marketplace to serve the region's electricity needs."

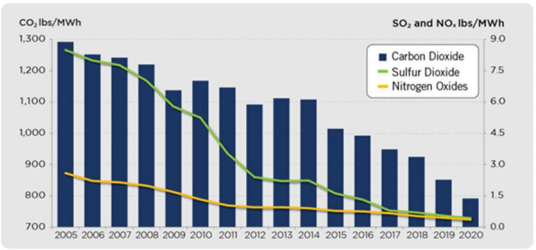


Chart: PJM, 2021

PJM reports that between 2005 and 2020, CO_2 emission rates fell 39% across its footprint, while nitrogen oxides dropped by 86% and sulfur dioxide by 95% (see chart).

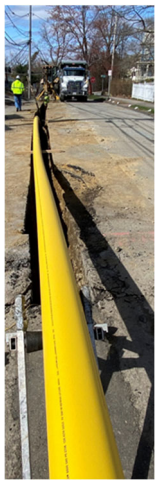
Reductions of methane emissions in natural gas system operations

The natural gas industry is cognizant of its responsibility to reduce emissions throughout its system operations. Many of NGA's distribution and transmission company members participate in the EPA's Natural Gas STAR Program and progress continues on this front. In 2019, Natural Gas STAR partners reported methane emissions reduction of 46.1 Bcf in the U.S., which provided "cross-cutting benefits" according to EPA.

Natural gas systems in total account for a quarter (25%) of all U.S. methane emissions. Since 1990, methane emissions from the U.S. natural gas system have declined by 15.7%, according to the EPA's April 2022 national GHG inventory report. The report, reflecting data through 2020, noted that: "The decrease in CH_4 emissions is largely due to decreases in emissions from distribution, transmission, and storage ...Distribution system emissions, which accounted for 8 percent of CH_4 emissions from natural gas systems and less than 1 percent of CO_2 emissions, result mainly from leak emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH_4 and CO_2 emissions from this stage, as have station upgrades at metering

and regulating (M&R) stations. Distribution system CH_4 emissions in 2020 were 70 percent lower than 1990 levels...Distribution system CO_2 emissions in 2020 were 69 percent lower than 1990 levels."

In the distribution sector, as noted above, the main emphasis is on accelerating the replacement of older, potentially more "leak-prone" pipe, and progress in that regard continues.



Addressing methane emissions more broadly has been a key focus of the U.S. government this year. In June 2021, the U.S. Congress approved legislation to restore limits on methane emissions from new oil and gas wells. Also in June, PHMSA issued an advisory bulletin reminding pipeline operators to update their inspection and maintenance plans to address the elimination of hazardous leaks, and to minimize natural gas releases from pipeline facilities. PHMSA stated: "The updated plans must also address the replacement or remediation at facilities that historically have been known to experience leaks. This action is only one piece of PHMSA's ongoing efforts to minimize methane emissions."

In November, the Biden Administration announced its "Methane Emissions Reduction Action Plan" to identify and cost-effectively reduce methane emissions from all major sources. As part of this effort, EPA is proposing new regulations that will significantly broaden and strengthen methane emissions reduction for new oil and gas facilities. In addition, for the first time ever, it will require that states develop plans that will reduce methane emissions from existing sources nationwide - including from an estimated 300,000 oil and gas well sites. The Administration stated: "Overall, the proposed requirements would reduce emissions from covered sources, equipment, and operations by approximately 75%."

Also in November the COP26 climate change summit in Glasgow highlighted efforts led by the U.S. and others to implement a coordinated multi-nation effort to reduce global methane emissions substantially over the next decade – in energy systems, agriculture, and land management. About 100 nations agreed to "the Global Methane Pledge" to reduce methane emissions 30% by 2030. Meaningful methane reduction is seen as an achievable goal given available technology.

Shale gas development

Development of shale gas in the U.S. continues to merit analysis and technological improvements.

Reducing the use of flaring of gas at the production stage (principally during the drilling process for oil, where "associated gas" is flared) is a primary focus and a commonly-agreed, long-overdue step.

The Pennsylvania DEP's "2017 Oil and Gas Annual Report" released in August 2018 noted that: "Although there is no evidence that hydraulic fracturing has resulted in a direct impact to a water supply in Pennsylvania, there are cases

where related oil and gas activities have adversely affected private water supplies. DEP investigates all stray gas-related complaints and if it is determined that a water supply is adversely affected by oil and gas activities, DEP works with the responsible operator to ensure the water supply is restored or replaced."

In its "2020 Annual Report," released in June 2021, the PA DEP noted: "Hydraulic fracturing fluid is comprised mostly of water with a small amount of chemicals to help lubricate and to prevent mold and scale from building up in the well bore. Fluids that return to the surface after the hydraulic fracturing process are generally called produced fluids. In 2020, about 86 percent of all produced fluids was recycled and/or reused in the production/hydraulic fracturing of other natural gas wells. If produced fluids are unable to be reused to hydraulically fracture other wells, they are typically disposed of in Class II Underground Injection Control disposal wells. In 2020, about 14 percent of produced fluids were disposed of in Class II UIC disposal wells."

Reducing the use of diesel fuel in the production process, enhancing "green completion" in the entire production cycle to reduce emissions, and mitigating community impacts, continue to receive industry attention in Pennsylvania and elsewhere.

Pipeline Safety Management and Public Awareness

Photo: PA PUC

Pipeline safety is always a priority for the industry. Federal and state regulatory requirements are extensive, and recent regulations have been announced to enhance operational safety, from transmission and distribution integrity management to control room operations.

Both industry and government regulators prioritize worker and contractor training, including addressing the prevalence of "third party damage"; the importance of "call before you dig" programs; increasing public awareness of natural gas; encouraging individuals to call utility or emergency personnel if they smell gas in the home or street; and maintaining and enhancing the physical components of the delivery system by implementing methods like "accelerated infrastructure replacement."

NGA and its members continue to work on important initiatives in the areas of public awareness and new technologies. NGA introduced in recent years a "First Responder utility online safety training program" based on an award-winning program developed by National Grid; and works with member utilities each year on a coordinated safety awareness advertising campaign through both traditional media (TV, cable, radio) and digital media platforms (e.g., Google).

After the 2018 Merrimack Valley incident north of Boston which had widespread impact in three communities, Governor Charlie Baker directed the state's

gas utilities to implement a pipeline safety management system (PSMS). The purpose of a Safety Management System is to help pipeline operators create a framework for developing a comprehensive, process-oriented approach to safety, emphasizing continual assessment and improvement.

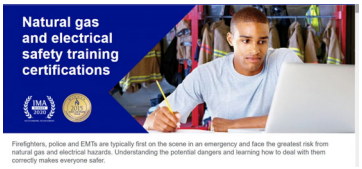


Image: National Grid

NGA is presently conducting a multi-year initiative of Massachusetts and member utilities from other states in the region and in the U.S. to implement PSMS. The collaborative approach is one of the largest coordinated PSMS implementation programs underway in the country. A central part of the work is helping members collaborate and participate in a true learning environment, through sharing leading practices gathered from and used by a broad cross section of operators, both large and small.

NGA has also created an online Resource Center for PSMS (https://www.ngapsms.com/).

New Technology R&D

NGA has a significant R&D program operated by NYSEARCH.

NYSEARCH has been involved with innovative projects such as pipeline sensing and guided wave technology, and continues to utilize its own testbed facility (in Johnson City, NY) for advanced demonstrations.

Recent success stories include the development, testing and commercialization of the Remote Methane Leak Detector (RMLD), the EXPLORER II robotics program, and tests of drones for gas company facility inspection flights. Its current portfolio is addressing such topics as leak detection, pipe location, improved installation, maintenance and repairs, and real-time sensing for distribution.

NYSEARCH is also conducting an evaluation and test program for methane emissions technology, and evaluating residential methane detector technology.

NGA has also partnered with the Gas Technology Institute (GTI) to facilitate knowledge transfers regarding new technologies that can enhance operations, safety, efficiency, and analysis.

NGA and its members support innovative advances in natural gas technology.

The Year Ahead

NGA will continue to post updates throughout the year at:

www.northeastgas.org

We wish everyone good health and safety this year and beyond.