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 then reviews several current market issues.

This paper has been prepared in November 2020 in the midst of the Coronavirus pandemic impacting the United States and the global community. This paper then, to a great extent, represents a snapshot in time. How and when will the economy and markets fully recover, and how changed might energy markets be in the end? We will see. Meanwhile, we extend our sincere hopes for good health and safety to all.

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 56.1 million (17% of the U.S.). Total state domestic product for the region is $4.3 trillion (20% of the U.S. total).

Regional Natural Gas Market

The nine-state region has 13.8 million natural gas customers (18% of the U.S. total of 76 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 29% of the primary energy consumption of the six New England states, 36% of New Jersey, 36% of New York, and 34% of Pennsylvania, compared to the national average of 31% (based on 2018 U.S. EIA data).

Gas Customers

New England has 2.8 million natural gas customers. Residential customers total 2.5 million; commercial and industrial customers number over 280,000.
New Jersey has 3 million natural gas customers. Residential customers total 2.8 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 million natural gas customers. Residential customers number 2.8 million; commercial and industrial customers number 250,000.

Natural gas remains the leading home heating fuel: in New England it is 40%, followed by fuel oil (34%); in New Jersey, 75%, followed by electricity (14%); in New York, 61%, followed by fuel oil (19%); and in Pennsylvania, 51%, followed by electricity (24%), and fuel oil (15%).

**Consumption/Sendout by Sector**

Total annual sendout in New England is about 910 billion cubic feet (Bcf), in New Jersey about 760 Bcf, in New York about 1,290 Bcf, and in Pennsylvania about 1,300 Bcf (2019 EIA annual data).

In New England, gas consumption by end-use sector is 24% residential, 24% commercial, 13% industrial, and 39% power generation. In New Jersey, it is 31% residential, 21% commercial, 9% industrial, and 39% power generation. In New York, it is 37% residential, 25% commercial, 7% industrial, and 31% power generation. In Pennsylvania, it is 18% residential, 12% commercial, 19% industrial, and 51% power generation.

In New England, the local gas distribution company, or LDC, design day demand is 4.8 Bcf per day, in New Jersey over 4 Bcf/d, and in Pennsylvania 5.4 Bcf/d. In New York, gas system peak demand is 7.8 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.

**Electric 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 it remains in the mix for proposed plants as well. In New England, natural gas represents 49% of current regional electric capacity, in New Jersey, 67% (in-state generation), in New York, over 50%, and in Pennsylvania, 42%.

*The U.S. interstate natural gas pipeline system includes 300,000 miles of transmission pipeline, according to the U.S. PHMSA. The EIA map on the left illustrates the extensive system.*
The 9 Northeast states have close to 14 million gas customers, about 18% 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). Net imports as a percentage of total natural gas consumption in the U.S. totaled 8% in 2011, but dropped to about 2.5% in 2016. “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 two 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 and Ohio. Marcellus/Utica production is resulting in new delivery points and new pipeline infrastructure. Appalachian production reached 32 Bcf/d in early 2020.

Exports from Canada to the Eastern U.S. have fallen from 2.8 Bcf/d in 2007 to 0.8 Bcf/d in 2019, in light of Marcellus and Utica shale gas availability.

LNG imports into the U.S. were 53 Bcf in 2019, substantially lower than the high point of 771 Bcf a decade earlier. The Everett LNG facility outside Boston imported 35 Bcf in 2019, which represented about 67% of total 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. Canaport in New Brunswick, Canada delivered 18 Bcf to the regional market in 2019. The offshore Northeast Gateway terminal imported about 5 Bcf in early 2019.

Pipeline and LNG Deliverability

New England

New England has 2,698 miles of gas transmission pipeline, according to the U.S. Department of Transportation / Pipeline and Hazardous Materials Safety Administration (PHMSA).


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 Ex-
elon (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 connections with a major gas utility and a major power plant. LNG is also transported to multiple LDCs’ satellite storage tanks from trucks that fuel at the Everett facility. The terminal’s vaporization capability is 715 MMcf/d; it also has daily sendout by truck 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 or 2018, and about 5 Bcf to meet cold weather demand in early 2019.

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.

Canaport LNG (located across the Maine border in Saint John, New Brunswick) is owned and operated by Repsol and Irving Oil. It can deliver up to 1 Bcf/d into the Brunswick Pipeline, which connects with the Maritimes & Northeast Pipeline, that transports the volumes into New England. Since its inception, it has delivered over 430 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 1,570 miles of gas transmission pipeline. The interstate pipeline companies serving New Jersey are: Algonquin Gas Transmission, Columbia Gas Transmission, Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp.

The LDCs utilize local LNG storage for peak day support.

New York

New York has 4,592 miles of gas transmission pipeline. The pipeline compa-
Companies serving New York State are: Algonquin Gas Transmission, Columbia Gas Transmission, Eastern Gas Transmission & Storage (formerly Dominion), Empire State Pipeline Co., Iroquois Gas Transmission System, Millennium Pipeline Company, National Fuel Gas Supply Co., North Country Pipeline, Stagecoach Gas Services, Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp. 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 liquified. New York has no LNG import facility.

**Pennsylvania**

Pennsylvania has 10,345 miles of gas transmission pipeline. The pipeline companies serving Pennsylvania are: Columbia Gas Transmission, Eastern Gas Transmission & Storage, National Fuel Gas Supply Co., Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp. 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.

For years 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 is now a significant production region.

Appalachian production, centered in Pennsylvania, Ohio, and West Virginia, reached close to 33 Bcf/d in early 2020. Pennsylvania’s annual production grew to 6.8 Tcf in 2019 (compared to 0.6 Tcf in 2010); it is the second-largest state producer of natural gas in the U.S.

Interstate pipeline companies serving the Appalachian region continue to work to add interconnects from area producers. Several projects have been completed, others are in development, while still others face siting challenges, an issue discussed below.

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 11 Bcf in 2019. 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. Gas from offshore Nova Scotia was produced for two decades from the Sable Offshore Energy Project, but its production ceased at the end of 2018. In February 2019, Canada’s NEB noted: “The Maritimes will transform from being an exporter of natural gas to being an importer of natural gas from the U.S.”

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.

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 Canaport LNG facility has 9.9 Bcf of storage. LNG is also produced and supplied by companies in Québec and Pennsylvania.

**Recent System Upgrades… and Setbacks**

Looking back, 2020 seems most notable for infrastructure projects that did not advance – but nonetheless, some infrastructure additions did occur over the last year, including:

- Empire: “Empire North Expansion”
- Enbridge: “Atlantic Bridge” [construction completed, awaiting final permitting]
- PNGTS: “Portland XPress” [phase 3]
- Tennessee Gas: “Station 261” [phase 1]
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. LNG remains especially important to the Northeast region for winter peak days. This photo is of an LNG storage tank in Boston owned by National Grid.

Photo: National Grid

- Transco: “Gateway Expansion Project.”

Several other projects however experienced permitting delays, and some others were withdrawn in the first half of 2020. The Constitution Pipeline, in development for eight years, was withdrawn in the spring, as was the proposed “Northeast Supply Enhancement Project (NESE).” In its press statement on NESE, Williams/Transco said that “the decision to pause this important infrastructure project is unfortunate for the region” but that it could not proceed without the required state environmental permits from New York and New Jersey. The Atlantic Coast Pipeline, while not in this region, was also withdrawn in the summer, reflecting the difficulty of adding new large-scale projects in the midst of state permitting delays and opposition.

This chart from the FERC displays pipeline capacity additions by year for the period of 2015-19. The Northeast, shown in orange, did add fairly substantial increments in 2015-17, but the last few years indicate a slowing of new capacity additions. Some of this reflects the natural cycle of project development and individual project timing, but it also reflects perhaps that the region has entered a new era of extremely difficult siting for natural gas… and likely for other energy sources as well.

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 southern 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
As mentioned, challenges faced by new projects include siting, environmental concerns, and securing market position. Contract commitments in New England remain 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 Corp. in Pennsylvania, through its subsidiary, UGI LNG, has LNG storage, associated peak shaving services, and an LNG tanker truck-loading terminal. Enegir (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, which is expected to be completed in 2021. 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.

Portable or mobile compressed natural gas (CNG), another supply/delivery option, is designed to bring natural gas to communities and businesses that are not located near a pipeline or distribution system. Some large commercial and industrial facilities, such as medical centers and colleges, have opted for “portable” or “mobile” natural gas delivered by truck. In this approach, large tube trailers are filled at large compression facilities and the CNG is delivered to the customer’s facility, where it is de-pressurized, off-loaded, and flowed into the customer’s gas (or dual-fuel) equipment. CNG is also being looked at by several gas utilities as another supply input into the distribution network at particularly constrained points, such as the greater New York City area.

Industry Realignments & Mergers

Some industry realignments of note occurred over the past year. Perhaps the most significant was the decision by Dominion to sell its natural gas transmission and storage assets to Berkshire Hathaway. As of November 1, 2020, Berkshire
Hathaway Energy completed its acquisition of the Dominion Energy's Gas Transmission and Storage business in the eastern region. The new company, BHE GT&S, is now a standalone subsidiary of Berkshire Hathaway Energy's Pipeline Group. Dominion Transmission is known as Eastern Gas Transmission and Storage. Berkshire also now has partial ownership of Dominion’s prior shares in Iroquois Gas Transmission and Millennium Pipeline, among other entities.

Eversource completed its acquisition of Columbia Gas of Massachusetts in October 2020, accruing over 300,000 natural gas customers. By the end of 2020, Blackstone Gas Company, a small utility in MA, is expected to become part of Liberty Utilities.

Also this year National Fuel Gas Company acquired Shell’s upstream and midstream gathering assets in Pennsylvania.

**MARKET ISSUES**

**Supply Outlook**

U.S. production reached new heights in 2019, a 10% increase over 2018 levels. 2020 was on track to set another record… until the coronavirus outbreak. As of March, EIA was forecasting that U.S. dry natural gas production would set another annual record in 2020. By April it had readjusted the annual outlook in light of COVID-19. EIA as of November is now forecasting that dry natural gas production will average 91 Bcf/d for 2020, lower than the 2019 average. In July, EIA observed that “The April 2020 decline in natural gas production was the largest monthly decrease since Hurricane Isaac-related shut-ins in August 2012… The declining market led oil and natural gas operators to shut-in wells and limit the number of wells brought online, lowering the output for the major oil- and natural gas-producing regions.”

U.S. consumption also set a new record in 2019, but it too is on track to fall below last year’s levels – down by about 2% overall.

While production has been cut back in the near-term, the U.S. resource base for natural gas nevertheless remains extensive.

In September 2019, the Potential Gas Committee (PGC) at the Colorado School of Mines released its 2018 biennial report, *Potential Supply of Natural Gas in the United States.* The report stated that the U.S. possesses a technically recoverable natural gas resource potential of 3,374 Tcf, which is the highest resource evaluation in the PGC’s 54-year history. The future supply of domestic natural gas continues to increase due to the emergence and advancement of key technologies that unlock gas production from reservoirs such as the nation’s shale formations.
Canada, which has considerable natural gas reserves, remains an important energy partner, although its share of the U.S. natural gas market is expected to decline. In its December 2019 report, *Canada’s Energy Future 2019*, the Canada Energy Regulator (CER) projected that natural gas production will increase over the next decades, driven by the power generation market and LNG exports.

The higher U.S. 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 2019, the U.S. exported far more LNG (1.8 Tcf) than it imported (53 Bcf), a trend that will continue. Even so, the global LNG industry faces its own challenges in light of low global energy prices and a recent concern expressed by some in Europe about sourcing LNG from U.S. shale fields.

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.

### Efficiency Initiatives

The Northeast region is a recognized national leader in per capita energy efficiency. A 2019 report by the American Council for an Energy Efficient Economy (ACEEE) noted that $1.4 billion was invested in natural gas efficiency programs nationwide in 2018 (latest data). Over 40% ($572 million) of the national total was invested in the nine Northeast states alone.

ACEEE notes 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, 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.” It concludes though that “natural gas efficiency programs are sustainable and worth pursuing for both economic and environmental reasons.”

Efficiency is seen as a core part of utilities’ decarbonization efforts.
“NGA Regional Market Trends Update—November 2020”

Price Trends

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

The natural gas price trend in this new era of domestic production continues to be 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 2019 the average natural gas commodity price was around $2.50/MMBtu.

In the first half of 2020, natural gas prices at the U.S. Henry Hub benchmark reached record lows, according to EIA, which noted in July: “Monthly prices reached a low of $1.63/MMBtu in June, the lowest monthly inflation-adjusted (real) price since at least 1989. Prices started the year low because of mild winter weather, which resulted in less natural gas demand for space heating. Beginning in March, spring weather and the economic slowdown induced by mitigation efforts for the coronavirus disease 2019 (COVID-19) contributed to lower demand, further lowering prices.”

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

EIA has projected an average commodity spot price of around $2.14 per MMBtu in 2020, but that the average price will rise to over $3/MMBtu in 2021 in the wake of lowered production trends.

Winter Challenges & Market Constraints

In its outlook for the winter of 2020/21, the FERC observed that “Electric and natural gas markets are expected to be constrained in the Northeast.” 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

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

Photo: Joseph Murphy
New England. It is evidenced in the winter months when the demand is highest and system capacity 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.

Natural gas winter futures prices for the 2021/21 winter are once again expected to be at their highest in the Northeast region, where Transco Zone 6 and Algonquin continue to exceed the national benchmark at Henry Hub and other regional hubs. Natural gas utility customers in the 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 and Electric Power Generation

The regional power generation fleet, highly reliant on natural gas, is positioned to remain so for several more years, even as the regional power grids transition to an increasingly clean energy profile. Combined-cycle technology (CCT) made the natural gas power plant the energy system of choice for 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.

Natural gas power plants have continued to be added in the region in recent years, as retirements of oil, coal and some nuclear plants have continued.

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 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), became operational in New York. It entered service in the same timeframe that one of the last units of Indian Point nuclear plant closed; Indian Point’s last nuclear unit will close in spring 2021.

Natural gas units continue to provide important baseload and fast-start capability, and remain pivotal to grid reliability. PJM’s “2019 Regional Transmission Expansion Plan,” released in February 2020, noted that “Both natural gas and solar fuels comprise 43 percent of the generation in PJM’s interconnection queue... Favorable fuel economics have emerged with the development of the Marcellus and Utica shale formations natural gas reserves, located in the middle of PJM's footprint.”


Public policy and legislative initiatives in the region are increasingly prioritizing non-fossil fuel units for new generation and encouraging electric utilities to contract for substantial amounts of offshore wind and imports of Canadian hydro. (The Northeast states alone are looking to add over 23 GW of offshore wind capacity in the next decade-and-a-half.) Solar continues to make inroads behind-the-meter as its technology costs decline.
The highest power demand in the summer of 2020 on the ISO-NE system occurred on July 27. As seen in the snapshot here, natural gas at the peak hour represented close to 70% of generation.

The continued value of natural gas to the region nevertheless was underscored in the biennial “Regional System Plan” from ISO-NE, released in October 2019: “Natural-gas-fired generation’s proportion of the system capacity mix is expected to grow from 49.5% in 2019 to approximately 54.4% by 2023 but decrease to 48.6% by 2028. Further retirements of coal and oil generators are expected over the next 10 years due to generally low natural gas prices, renewable energy additions, and pending environmental regulations. The Pilgrim nuclear plant in Massachusetts retired in 2019. Although renewable resources are anticipated to grow over the long term, the ISO expects natural gas resources to continue to set the marginal price for wholesale electricity in most hours over the planning horizon.”

Fuel choices and power system reliability remain highly topical at national and regional/state energy forums. Fuel security and grid resilience remain key topics for the RTOs. At the same time, some state government leaders are expressing concern that the power markets are not facilitating the clean energy transition on a fast-enough timetable. In October 2020, for example, five of the six New England governors called for a “modernized grid.”

The issues are complex: the future of nuclear, the uncertainty over increasing pipeline infrastructure in areas like the Northeast, the balancing of intermittent renewable resources on the system, the valuing of capacity in power markets, addressing emissions through carbon pricing or a cap-and-trade framework, onshore connectivity, solar acreage, and affordability, among others. Debate will continue into 2021 and beyond as the Northeast region’s power markets evolve to reflect the changing policy and regulatory environment.

Utility System Expansions, Limitations and Reassessments
Natural gas demand has been rising due to its advantageous price, reliability, and efficiency. Since 2012, the number of homes heating with natural gas in the Northeast region has increased by over one million, to over twelve million heating customers. U.S. Census data for 2019 indicated that the natural gas furnace remains the predominant heating choice for new home construction in the Northeast. It now heats 55% of the homes in the region.

However, rising demand and new customer additions are beginning to run up against system delivery constraints in some areas. Five utilities in Massachusetts have put moratoria in place on new customer connections because of supply and delivery constraints. In 2019, Con Edison and National Grid announced moratoria on new customer connections in the New York City area because of system constraints. Both are working to implement a broad portfolio of supply and demand management options, from greater efficiency, to incorporating CNG, LNG and renewable natural gas, to incentives for customers who upgrade their heating equipment or install heat pumps to reduce natural gas usage. They also are looking to possible compression expansions by two pipelines to increase natural gas supply in the next two or three years, if possible.

Even as natural gas remains the most popular heating fuel, there are efforts now to try to reverse or slow its growth.

In 2019 a few communities in California and Massachusetts proposed local building ordinances to prohibit gas (and other fossil fuel) connections for new customers, citing environmental concerns and the desire for an all-electric system. (In November 2020, the San Francisco Board of Supervisors did vote to ban natural gas in new construction, effective in June 2021.) A community in the Boston area, Brookline, voted in late 2019 to ban oil and natural gas connections in new buildings, and other communities such as Cambridge, MA announced they were also exploring that option. In July 2020, the Attorney General of MA ruled that the Brookline ban was not legal – it was a violation of state law and was preempted by the state building code.

Nevertheless, the “gas ban” efforts reflects a challenge to the growth trends of natural gas. In comments provided to the Cambridge, MA City Council public hearing in December 2019 as it discussed a proposed restriction on natural gas in new buildings, NGA noted that such an action would directly impact consumer choice and energy affordability for city residents and businesses. “The industry shares the City’s goal of reducing carbon emissions,” said NGA, but the pathway needs to be carefully considered for its impacts, feasibility
and timing.

Two state initiatives are now addressing the role of natural gas in the midst of this changing environment. The New York State Public Service Commission in March 2020 initiated a proceeding to consider issues related to the planning procedures used by New York’s natural gas local distribution companies (LDCs). The proceeding, said the Commission, “responds to recent actions by certain LDCs to invoke moratoria on new service connections based on their assessment that supply constraints would prevent them from maintaining reliable service to all customers during every hour of the year in parts of their service territories. The Gas Planning Proceeding will address four interrelated issues: (1) the identification of “vulnerable locations” where there is an expected/forecasted future imbalance in the supply of and demand for natural gas; (2) reliance on peaking services to meet demand; (3) management of moratoria conditions when such events are contemplated; and (4) the design of a “modernized” gas system planning process.”

In October 2020, the MA Department of Public Utilities (DPU) announced its own investigation into the future role of natural gas. The DPU “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.”

Assessing the Future Role of Natural Gas
As Interest in Decarbonization and Electrification Grows

The benefits of natural gas – lower price, lower emissions, domestic supply – contribute to continued levels of customer conversions and new customer development.

The natural gas industry recognizes the interest of policymakers, regulators, customers, and the public in decarbonizing the energy system as much and as swiftly as possible. Natural gas utilities have proposed various pathways to decarbonization, including greater efficiency, incorporation of renewable natural gas, and the accelerated replacement of older, more “leak-prone” system components.

Concurrently, several national and regional advocacy groups and consultants are promoting “strategic electrification” or “beneficial electrification” as the new overarching energy system paradigm, under
which all systems – heating, power generation, and transportation – would operate via electricity, and that fossil fuels would be substantially reduced and eventually eliminated.

The costs and practicality of electrification are a concern. The approach to the energy future needs to be thoughtful and mindful always of such critical criteria as energy affordability and system reliability.

Several studies released by ACEEE identify value in converting homes heated with heating oil and propane to electricity, but find less benefit in converting natural gas homes, especially in colder climates. In a September 2018 blog post, ACEEE observed: “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.”

In a June 2020 report on electrification efforts at the state level, ACEEE observed again: “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 January 2019, NYSERDA published “New Efficiency: New York—Analysis of Residential Heat Pump Potential and Economics.” It noted that “generally, installations replacing natural gas have negative IRRs [internal rates of return].”

The importance of natural gas as a reliable balancing fuel for intermittent renewables (until such time as battery storage becomes fully feasible) remains generally acknowledged. In its April 2018 “National Electrification Assessment,” the Electric Power Research Institute (EPRI) noted the central role for gas in power generation over the next several decades. “Natural gas use continues to grow in all four EPRI scenarios based on its operational flexibility and an assumed cost of around $4/MMBtu...Direct gas use in industry and gas-fired electric generation grows while gas use in building heat remains relatively flat over time.”

The growing interest in electrification and a relative ambivalence about the future role of natural gas in some policy circles was addressed in a May 2017 paper from the Natural Regulatory Research Institute (NRRI), “Questioning the Future of Natural Gas”: “A reasonable argument is that U.S. and state energy policy should encourage the use of natural gas for different uses rather than its suppres-
sion. A proper balancing of economic and environmental considerations would likely reach that conclusion. Those who advocate less natural-gas usage generally skew their finding by giving little if any weight to the economic effects….Climate change concerns should certainly be a factor in developing energy policy, but not the sole or even overriding factor.”

Ken Costello, the author of the NRRI report, is now an independent consultant, and is still articulating well the comparative benefits of natural gas at this time of growing policy interest in electrification. In November 2020 he wrote an op-ed in the San Francisco Chronicle after that city’s Board voted to ban natural gas in new buildings. It’s worth quoting at some length: “A ban represents a command-and-control policy at its worst. It is a highly blunt instrument, draconian and highly costly relative to other alternatives to mitigate greenhouse gas emissions. The good that comes to energy consumers and society from natural gas far exceeds the bad. 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.”

**Infrastructure Siting Challenges and Regulatory Delays**

Energy infrastructure has always encountered siting issues. Examples include siting wind turbines on mountain ridges or offshore, nuclear power, and electric and gas transmission.

Siting challenges for fossil fuel projects appear to have reached a new level in the U.S. and Canada in a time of growing awareness of climate change. Today’s increasing “dependence” on natural gas is viewed by some as an obstacle to the deployment of “clean energy.”

In the U.S., delays at the state level, particularly regarding the issuance of state water quality certificates, add to project costs and prolong uncertainty. To secure federal approval, natural gas pipeline projects must demonstrate market need and financial viability, and their routes must comply with environ-
mental requirements. Contract commitments by proposed customers or shippers are essential to the process.

In 2020, the siting trends continued, as several pipeline proposals were withdrawn after multiple years of navigating the permitting process, including the Constitution Pipeline, the NESE Project, and the Atlantic Coast Pipeline. The developers noted the costs of delay and the uncertainty of the regulatory process.

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 and seek balanced and reasonable solutions.

**Environmental Considerations**

Environmental issues are central to debates about energy system usage and infrastructure expansion. The natural gas industry can contribute by noting past progress and offering future solutions.

**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. MIT’s June 2011 study on gas concluded that using very efficient natural gas-powered plants to replace coal-fired plants was “the most cost-effective way of reducing CO₂ emissions in the power sector” in the coming years. Natural gas will also play “a central role in integrating more intermittent renewable sources – wind and solar – into the electricity system because they can easily be brought in and out of service as needed.”

The rise in natural gas use in power generation is leading to lower air emissions, from sulfur dioxide to carbon dioxide. In November 2020, U.S. EIA noted: “U.S. electric power sector emissions have fallen 33% from their peak in 2007 because less electricity has been generated from coal and more electricity has been generated from natural gas (which emits less CO₂ when combusted) and non-carbon sources.”

At the regional level, air emission trends remain favorable. NY ISO reported in 2020 that emissions rates from its power sector dropped by 55% for CO₂, 92% for NOₓ, and 99% for SO₂ over the last two decades. ISO-NE reported that from 2001 to 2018, total emissions from power plants in New England declined by 98% for SO₂, 74% for NOₓ, and 36% for CO₂. The ISO 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.”

PJM reported substantial declines in NO\textsubscript{X}, SO\textsubscript{2}, and CO\textsubscript{2} from 2005 to 2018 (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 2018, Natural Gas STAR partners reported methane emissions reduction of 130.6 Bcf in the U.S., which provided “cross-cutting benefits” according to EPA. Reducing pipeline leaks is of paramount interest (see section on infrastructure replacement below).

Natural gas systems in total account for about a quarter of all U.S. methane emissions, or nearly 3% of all U.S. greenhouse gas (GHG) emissions. Since 1990, methane emissions related to the U.S. natural gas system have declined by 23.7%, according to the EPA’s April 2020 national GHG inventory report. The report, reflecting 2018 data, noted: “The decrease in transmission and storage emissions is largely due to reduced compressor station emissions (including emissions from compressor and equipment leaks)….Distribution system emissions, which account for 8 percent of CH\textsubscript{4} emissions from natural gas systems and less than 1 percent of non-combustion CO\textsubscript{2} emissions, result [sic] 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\textsubscript{4} and CO\textsubscript{2} emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH\textsubscript{4} emissions in 2018 were 73 percent lower than 1990 levels.”

In the distribution sector, the main emphasis is on accelerating the replacement of older, potentially more “leak-prone” pipe.

The latest GHG data from New York indicated that methane emissions related to “natural gas leakage” have declined by 20% in the last dozen years; in Massachusetts, methane emissions from natural gas systems have declined by 67% since 1990.
Shale gas development

Development of shale gas in the U.S. continues to merit analysis and technological improvements. MIT’s June 2011 study on natural gas noted that “the environmental impacts of shale development are challenging but manageable.” An October 2011 paper by the National Regulatory Research Institute (NRRI) noted that “Based on more than one million wells drilled with fracking, however, there is little evidence that fracking directly causes groundwater contamination....[R] eports show that these incidents resulted from surface spills, poor cementing jobs in wellbores, and other operational failures.”

Proper procedures and oversight are necessary at all stages of the process.

The Pennsylvania Governor’s Marcellus Shale Advisory Commission reported that “The primary concerns regarding hydraulic fracturing relate to surface spills of fluids, well control and lost containment of production and flowback water on the surface.”

The Pennsylvania DEP’s “2017 Oil and Gas Annual Report” released in August 2018 noted: “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.”

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.

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: “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.”

PHMSA continues to urge action on repairing older, potentially more leak-prone systems. In general, due to its older systems, the Northeast states have higher levels of such distribution pipe components than the national average, but those
percentages are declining as system replacement continues.

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 cites substantial progress in replacing aging bare steel and cast iron main miles and service counts across the U.S. in recent years, but notes as well: “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.”

**Pipeline Safety Management and Public Awareness**

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 leading cause of incidents); 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.

After the 2018 Merrimack Valley incident north of Boston which had widespread impact in three communities, Massachusetts Governor Charlie Baker led the state’s gas utilities to undertake implementation of 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.

NGA is presently conducting an initiative of Massachusetts and other utilities in the region to implement PSMS. The NGA membership collaborative approach is viewed as one of the largest coordinated PSMS implementation programs underway in the U.S.
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 will 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, from Vermont and Maine to New York City and beyond.

In 2019, NGA and GTI released the “Interconnect Guide for Renewable Natural Gas in New York State.” The report was sponsored by and developed in coordination with several New York natural gas utilities. The report provides a guideline for RNG pipeline interconnections that is applicable and of value throughout the U.S. and Canada. It provides a framework and technical guidance by which project developers and the local gas utility can use common core principles and a rigorous technical framework to facilitate maximizing the acceptance and introduction of RNG into the natural gas pipeline network.

RNG is also seen as a potential source for natural gas in the transportation sector. The U.S. Department of Energy notes that “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.”

RNG is a cornerstone of utilities’ efforts to decarbonize their supply sources.

Hydrogen’s Potential

Among the energy sources seen as potentially significant for establishing a low-carbon energy future is hydrogen.

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 (CO₂) 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. There are a few hydrogen fueling stations in the region through such firms as Air Liquide, and there is consideration of establishing a “Northeast hydrogen roadmap.”

There are challenges of cost and scale. In November 2020, the U.S. Department of Energy (DOE) released its "Hydrogen Program Plan." DOE noted: “The key technical challenges for hydrogen and related technologies are cost, durability, reliability, and performance, as well as the lack of hydrogen infrastructure. To achieve widespread commercialization, hydrogen utilization technologies must enter larger markets and be able to compete with incumbent technologies in terms of life-cycle cost, performance, durability, and environmental impact. Non-technical barriers also need to be addressed, such as developing and harmonizing codes and standards, fostering best practices for safety, and developing a robust supply chain and workforce.”

It is a challenge, but there remains great expectations as well that the technology can contribute successfully to a low-carbon future.

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

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

NGA and its members continue to 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.