Everett Marine Terminal's Role in New England

prepared for

Constellation Energy Generation, LLC

May 18, 2026

LEVITAN & ASSOCIATES, INC.
101 Federal Street, Suite 1900
Boston, Massachusetts 02110
Tel (617) 531-2818
Fax (617) 531-2826

Table of Contents

Table of Figures

Table of Tables

Glossary

AIM	Algonquin Incremental Market
Algonquin	Algonquin Gas Transmission
Bcf	Billion Cubic Feet
Brunswick	Emera Brunswick Pipeline
CAR	Capacity Auction Reforms
CAR-PD	Capacity Auction Reforms Prompt / Deactivation
CAR-SA	Capacity Auction Reforms Seasonal / Accreditation
CEMS	EPA Continuous Emissions Monitoring Systems
CLNG	Constellation LNG
CNG	Compressed Natural Gas
Dth	Dekatherm
DOER	Massachusetts Department of Energy Resources
EDD	Effective Degree Days
EEA	Massachusetts Executive Office of Energy and Environmental Affairs
EGMA	Eversource Gas Company of Massachusetts
EMT	Everett Marine Terminal
EO654	Executive Order No. 654
EU	European Union
ExC	Enhancement by Compression
FAWG	Focus Area Working Group
FCA	Forward capacity auction
FERC	Federal Energy Regulatory Commission
GJ	Gigajoule
GW	Gigawatt
HOS	Hours of service
HDD	Heating Degree Days
HP	Horsepower
Iroquois	Iroquois Gas Transmission System
LAI	Levitan & Associates Inc
LDC	Local Distribution Company
LNG	Liquified Natural Gas
MA DPU	Massachusetts Department of Public Utilities
MDQ	Maximum Daily Quantity
MFN	Most Favored Nations
MMBtu	Million British thermal units
MMcf	Million cubic feet
M&N	Maritimes &Northeast Pipeline
NCDC	Non-Commodity Demand Charge
NEC	Northeast Energy Center
NEPOOL	New England Power Pool
NGrid	National Grid
OET	Office of Energy Transformation
OFO	Operational Flow Order
O&M	Operations and Maintenance
PEAT	Probabilistic Energy Adequacy Tool
PNGTS	Portland Natural Gas Transmission System
psig	pounds per square inch gauge
RARE	Reliable Affordable Resilient Enhancement
RFO	Residual Fuel Oil
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
ROW	Right of way
scf	standard cubic feet
Tennessee	Tennessee Gas Pipeline
Transco	Transcontinental Gas Pipe Line
WS	Winter Storm

Note on Conversion Factors

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One MMBtu equals one Dth.

The standard measure of gas volume in the English system of units is standard cubic feet or "scf." The "s" for standard is typically omitted in expressing gas volume in cubic feet. Therefore "scf" is typically short formed to "cf." Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

1 Mcf ≈ 1 MMBtu = 1 Dth

1 MDth = 1,000 Dth

1 Bcf = 1,000 MMcf ≈ 10^6 MMBtu = 10^6 Dth = 1,000 MDth

Executive Summary

Levitan & Associates, Inc. (LAI) has conducted an independent engineering economic study commissioned by Constellation Energy Generation, LLC to address the operational significance of its Everett Marine Terminal (EMT) for purposes of gas-grid and electric-grid reliability and resilience. While EMT is presently covered under contracts with gas utilities in Massachusetts through 2030, its future upon the expiration of these contracts is uncertain. When the contracts end in 2030, key uncertainty factors include pathways toward electrification, the New England states' ability to revitalize offshore wind in the decade ahead, transmission exports from Quebec during cold snaps, and the states' appetite for significant pipeline expansions designed to lessen congestion. New England's recent experience during Winter Storm (WS) Fern helps to inform what might happen in the future if a like meteorological event were to repeat and EMT was not available to support the gas system.

Highlights of this analysis are these:

- EMT is a unique and critical reliability resource which can provide three distinct services to region's gas system. These services include peak day vapor for local distribution companies (LDCs) and generators, back-end pressure support for constrained segments of the Algonquin Gas Transmission (Algonquin) and Tennessee Gas Pipeline (Tennessee) interstate pipelines and the National Grid (NGrid) Boston Gas local distribution system, and the provision of liquified natural gas (LNG) via trucks to LDC-owned satellite LNG facilities. EMT's location in the heart of New England's demand center is advantageous for both its dispatch of vapor and liquid. The retirement of EMT imperils the reliability of LDCs on peak days, makes the generation fleet more reliant on oil, and limits the ability of the pipelines to offer more flexible deliveries than allowed under the tariff in order to protect system integrity without taking draconian action. No other postulated addition or improvement to the region's gas system offers the multifaceted benefits provided by EMT. While regional goals associated with decarbonization indicate the need to move away from gas, the term of the need for EMT's services cannot easily be predicted.
- WS Fern and the ensuing cold snap were significant tests for the gas system, which performed admirably thanks in large part to key contributions from EMT and Repsol's St. John LNG import terminal. Production from the Marcellus and Utica shale formations were reduced by 2 Bcf/d due to freeze-offs, increasing the importance of supply injections into the east and north ends of New England's gas system. The period between January 16th and February 9th was the coldest 21-day stretch since January 2018. During this period, Algonquin and Tennessee reported scheduled

receipts from EMT of 3.3 Bcf of vapor, not including deliveries directly into NGrid's Greater Boston distribution system. The facility loaded 100 trucks during this period for refill of the LDCs' satellite LNG facilities, a quantity much greater than average truck deliveries under normal temperature conditions. EMT supply to generators mitigated oil usage at a time when the region's oil inventories were ultimately drawn down to critical levels, requiring ISO-NE to rely on residual fuel oil to enable generation from the old-style steamers.

- St. John LNG and EMT have complementary, but not interchangeable roles in the New England gas market. While Repsol's St. John LNG facility offers much needed regional supply, the facility is an imperfect substitute for EMT's array of benefits. EMT's key connections to Algonquin's J System, Tennessee's east end, and NGrid's distribution system enable it to provide instantaneous injections when most needed, which Repsol cannot offer. EMT's role as a liquid trucking hub also cannot be emulated due to EMT's relative proximity to key satellite LNG facilities. Additionally, St. John LNG runs at near full capacity on the coldest days of the year, meaning that it would not have additional sendout capability to replace EMT vapor in a world without EMT.

- The hypothetical subtraction of EMT during WS Fern would have resulted in reduced regional deliverability of natural gas and reduced flexibility for variable intraday volumes. For generators, this would have necessitated additional fuel switching off of natural gas to oil and potentially further management actions by ISO-NE. LDCs would have faced reliability challenges, given that it was not possible to have alternative solutions in place, on either the supply side or the demand side, prior to the winter of 2025-26.

- LAI finds that the charges borne by the LDCs in order to cover the costs of operating EMT are within the realm of reasonableness in light of historic cost of service, prevailing market conditions, and challenges associated with securing and scheduling LNG supply. EMT's Operations & Maintenance (O&M) costs are compensated via the Non-Commodity Demand Charges (NCDC) in the LDC contracts. O&M-related data points from FERC and Mystic Reliability Must Run (RMR) filings reveal that EMT's fixed operating costs, as paid by the LDCs through the NCDC, have remained level or slightly reduced on a nominal basis over the last twenty years, despite inflationary factors. The supply costs of securing cargoes, vaporization costs, and Constellation LNG's (CLNG) return-on-equity are built into the commodity demand charge and commodity rate portions of the LDC contracts. These charges are predicated on industry-standard pricing indices with a premium to capture the costs associated with EMT's inventory management and the limited pool of cargoes able to transit up the Mystic River to EMT.

- LAI estimates that incremental pipeline capacity sufficient to replicate EMT's system benefits during WS Fern would cost approximately $2.1 billion to build. Total electric and gas ratepayer costs for pipeline reservation charges over a ten-year term would reach $4.6 billion for in-region improvements, with a potential additional $1.5 billion for upstream improvements needed to enable gas flows into New England. Because these costs are calculated over only ten years, they likely understate the true long-term ratepayer burden and should be understood as a conservative lower bound on the relative economics of an energy future in New England with and without EMT, all other things being the same. Incremental pipeline infrastructure of this magnitude may struggle to secure necessary local and state permits, given the region's history with proposed gas infrastructure and climate targets. These pipeline costs greatly exceed the ratepayer costs associated with maintaining the current EMT contracts. This comparison should not be read as a conclusion that new pipeline infrastructure is unwarranted. It should instead be interpreted in the narrow context that incremental pipeline capacity should not be considered as a strategy to avoid the costs associated with maintaining the continued availability of EMT. The ratepayer cost comparison does not capture the potential benefits associated with incremental pipeline expansion, such as avoiding the incremental emissions associated with burning more oil, and, most importantly, the sustained reduction in leading regional gas price indices.

- LAI notes that the marginal cost of retaining a fully depreciated asset versus the incremental costs associated with investing in new resources to supplant EMT indicate that retention of EMT is likely a sensible choice. Additionally, multi-year contract terms will enable pricing optimization, because the further in advance cargoes can be reserved, the lower the pricing volatility. This consideration also applies to the time lag between when a contract is executed and the initial delivery term: from a ratepayer standpoint, the further in advance the better and *vice versa*.

- Bolstering New England's existing satellite facilities, or siting of new portable facilities, can only serve as a mitigation measure for LDC reliance on gas supply from EMT, but cannot replace the array of benefits EMT offers. Increased vaporization of on-system LDC facilities would not make gas available to the region's generation fleet on peak days, nor could it provide balancing and pressure support services to the interstate pipelines that EMT currently provides. Further, these satellite facilities do not liquefy during peak winter months and cannot emulate EMT as a source of incremental liquid on the coldest days of the year. New England satellite facilities currently rely on EMT for liquid replenishment. Substituting EMT's trucking capabilities with supply from outside New England would introduce new logistical challenges for the LDCs. During peak winter months, every incremental mile traversed for trucks carrying hazardous materials poses increased risks of delays or accidents. EMT's location allows its liquid customers a level of flexibility that LNG sources from Pennsylvania or Quebec cannot replicate without major investment in staging trucks during the peak heating season to ensure timely delivery.

- The LDCs' costs for EMT service can be reduced if additional customers contract for seasonal (or longer term) service. ISO-NE recognizes the essential role that both EMT and St. John LNG play in maintaining electric reliability. ISO-NE has committed to capacity market reforms that recognize the value of firm fuel for winter reliability by paying a higher capacity price to generators with firm fuel. ISO-NE's Capacity Auction Reforms (CAR) may incentivize regional generators to sign seasonal contracts with EMT, which could lower the cost burden for LDCs while improving both electric reliability and resilience by adding firm fueling to enable the performance of all or a portion of the gas-only generation fleet in New England.
- LAI notes a number of primary uncertainty factors affecting the merit of continued reliance on EMT in lieu of rival pipeline or trucking solutions. First, the cost of lining up requisite LNG volumes in global markets is subject to global price indexation, which exposes New England to inherent volatility in response to global geopolitical events and temperature conditions in markets that procure LNG to meet their gas supply needs, the European Union (EU), in particular. An effort to line up LNG long in advance of commencement of delivery and to do so for longer tenor commitments would redound favorably from a ratepayer standpoint. Second, the cost of pipeline new build in New England is high and hard to predict even for relatively small projects, but nevertheless a potential pathway toward worthwhile energy price benefits. Third, LNG trucking options from Quebec and Pennsylvania are inherently less reliable than nearby supply but nevertheless may constitute an acceptable alternative if the cost is deemed manageable by the LDCs and risk tolerance issues surrounding long hauls and hazardous driving conditions can be resolved. Fourth, the performance efficacy of non-pipeline alternatives, including demand response and targeted energy efficiency, appears to be a high-risk, high-cost alternative to EMT. And, finally, ISO-NE's current efforts to retool the capacity market through auction reforms offer great promise but require stakeholder approval and the blessing of FERC, which may not be realized for quite some time.

1 Introduction and Background

1.1 Purpose and Scope of Study

This study was designed to meet three primary objectives:

- To facilitate an understanding of EMT's critical role supporting gas and electric reliability both in Massachusetts and across New England;
- To present a justification of EMT's cost and the terms applicable to the LDC contracts in light of terminal operational requirements and global LNG procurement; and
- To assess the feasibility and costs associated with replacing EMT's array of reliability benefits in the regional gas and electric markets.

1.2 Overview of the Everett Marine Terminal and Its History

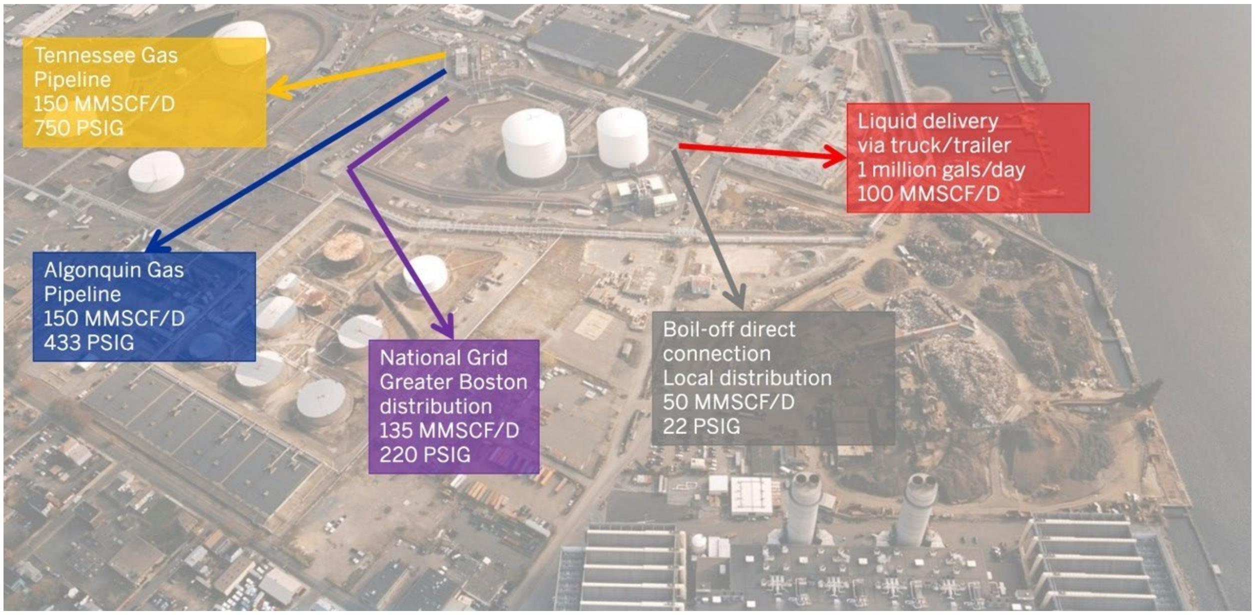
EMT has a long history of reliable performance serving customers in New England.

EMT began operations in 1971 as an integrated LNG marine import, storage, and vaporization facility on a 35-acre industrial site in Everett, Massachusetts with a dedicated marine berth on the Mystic River. It is the nation's oldest such facility and has provided gas supply to New England for over half a century. Because New England does not have any conventional underground storage capacity, it is by far the largest and most strategically-placed gas supply source capable of providing New England with supplemental pressure and flow on short notice.

EMT provides gas supply to the region through three vectors: first, vapor sendout via the Algonquin and Tennessee pipelines; second, vapor sendout directly into the NGrid distribution system, and third, liquid sendout via truck to satellite LNG storage tanks located throughout New England.[1] Figure 1 summarizes EMT's sendout connections.

[1] The facility also includes a vehicle fueling station, added in May 2012, but this is a low volume service.

Figure 1. EMT Sendout Connections[2]



EMT's initial vaporization capacity at startup was 135 MDth/d, connecting the terminal to the local low-pressure (220 psig) Boston Gas distribution system. An additional 150 MDth/d of vaporization capacity was added in 1989 to supply Algonquin through a medium-pressure (433 psig) connection as annual import volumes increased. Sendout to Algonquin is injected into the end of its highly constrained J System. A high-pressure (750 psig) connection to Tennessee was activated in January 1999 with the addition of another 150 MDth/d of vaporization capacity. Construction of the final 600 MDth/d of vaporization capacity to support high-pressure deliverability to Mystic 8&9 power generation stations was completed in 2002.[3] This final block of vaporization capacity included four 150-MDth/d vaporizers. Three of these vaporizers were designed to be used at part-load to meet Mystic 8&9 requirements, while the fourth served as supplemental vaporization that can be used as backup capacity during maintenance to other units or on high demand days. The sendout from vaporizers added in 2002 are tied into the sendout from the facility's other vaporization systems to enhance reliability and serve other connections, particularly now that Mystic 8&9 has retired. The sustainable vaporization capacity of the facility is 715 MDth/d.[4]

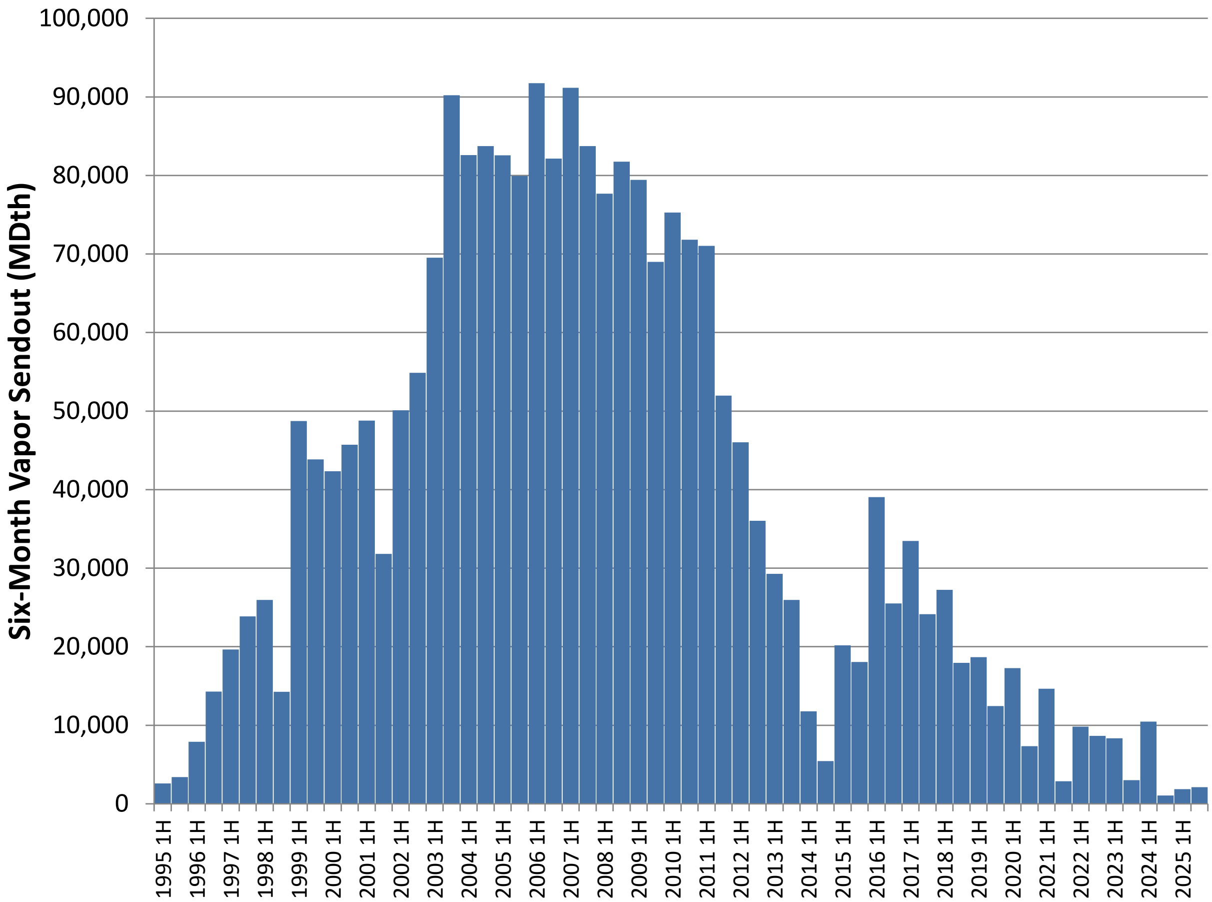
Figure 2 shows the vapor sendout quantities reported by EMT to the Federal Energy Regulatory Commission (FERC) in its Semi-Annual Operational Reports from 1995 through 2025. As shown in Figure 7 below, EMT vapor sendout for first half of 2026 is likely to be much

---

[2] Constellation LNG - Everett Marine Terminal (EMT) Northeast Gas Association Winter 2025 Report, November 13, 2025. https://northeastgas.org/files/galleries/2025_Everett_Marine_Terminal_NGA_WinterReport.pdf
[3] References to Mystic 8&9 and Mystic are synonymous.
[4] *Id.*

higher than the levels observed in 2025, as Algonquin and Tennessee reported total scheduled receipts of 3,300 MDth from EMT over the three-week period between January 20th and February 9th.[5] This is greater than the vapor sendout reported by EMT for each of the three prior six-month periods.

Figure 2. Vapor Sendout from EMT, 1995-2025



The addition of vaporization capacity to supply Tennessee corresponds to the increase in vapor sendout in the first half of 1999. The phased increase in total vapor sendout from the second half of 2002 to the second half of 2003 corresponds to the flow of test gas prior to Mystic 8 beginning commercial operation on April 14, 2003, and Mystic 9 beginning commercial operation on June 10, 2003.

High gas demand for generation in Japan following the March 2011 Fukushima disaster sustained upward pressure in global LNG prices, thereby motivating suppliers to move LNG into the premium market in Asia. Falling domestic gas prices resulting from the shale gas boom and, tightened supplies across the Atlantic Basin and higher oil-indexed pricing

---

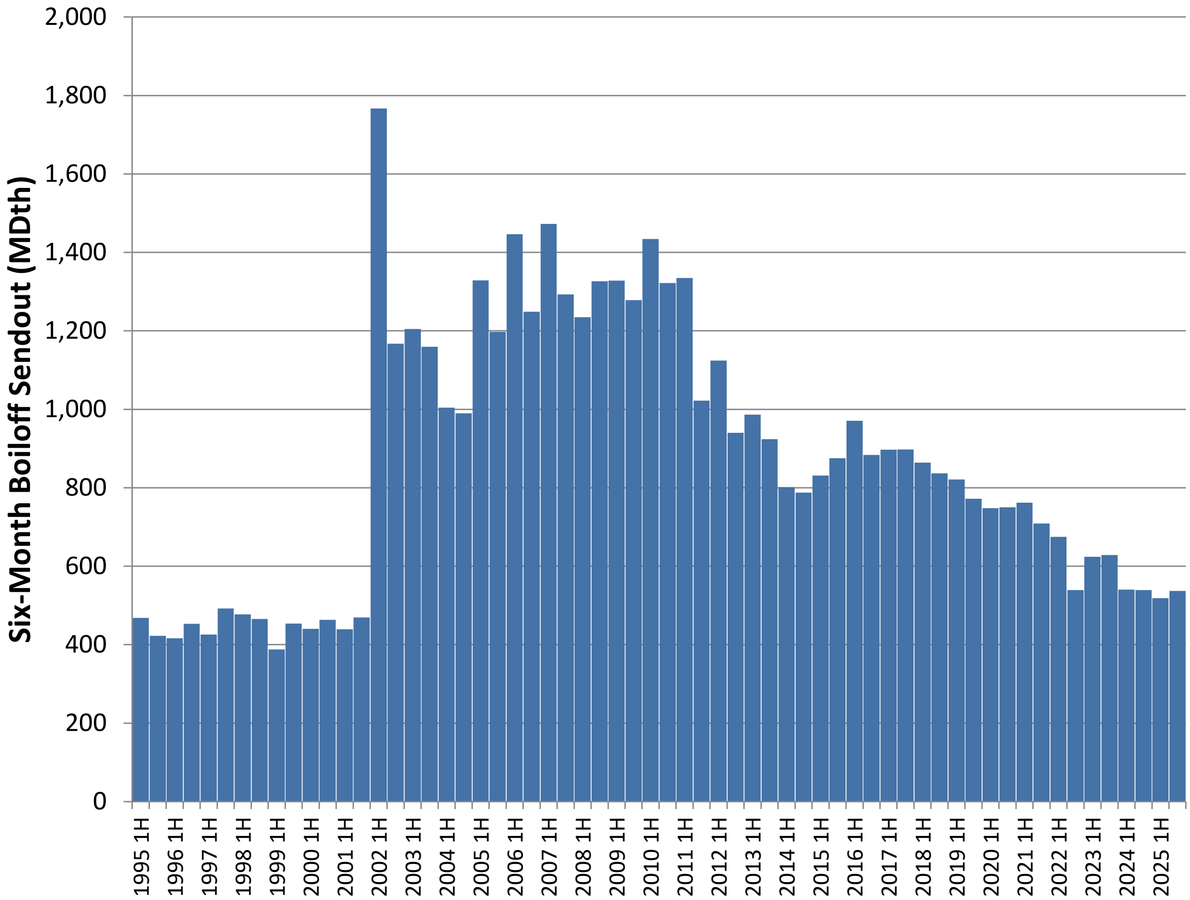
[5] Source: Algonquin and Tennessee Informational Postings for Intraday 3 cycle.

induced ENGIE (operator of EMT at the time) to limit the volume of gas available to the New England market.[6] EMT held a reverse auction with New England's LDCs and marketers for seasonal services in spring 2013 that failed to price rationalize the level of seasonal service into Algonquin and Tennessee observed for many years in the pre-2012 interval. Vapor sendout was further reduced during the term of Mystic RMR Agreement with ISO-NE, from June 2022 through May 2024. Following the retirement of Mystic after the RMR Agreement ended, vapor sendout has decreased to its current volumes.

EMT additionally delivers up to 50 MDth/d of boiloff gas to NGrid when a ship is offloading, and at a lower rate during normal operations. During normal operations, boiloff occurs as ambient heat surrounding the LNG storage tanks causes LNG to vaporize. Despite the use of insulation in LNG storage, some level of boiloff is unavoidable and boiloff gas must be managed to ensure safe LNG storage. EMT typically manages boiloff via vapor sendout routed through the NGrid system. Figure 3 shows the boiloff deliveries reported in EMT's Semi-Annual Operational Reports to FERC. The boiloff volumes are a function of the amount of LNG stored in the tank and deliveries.

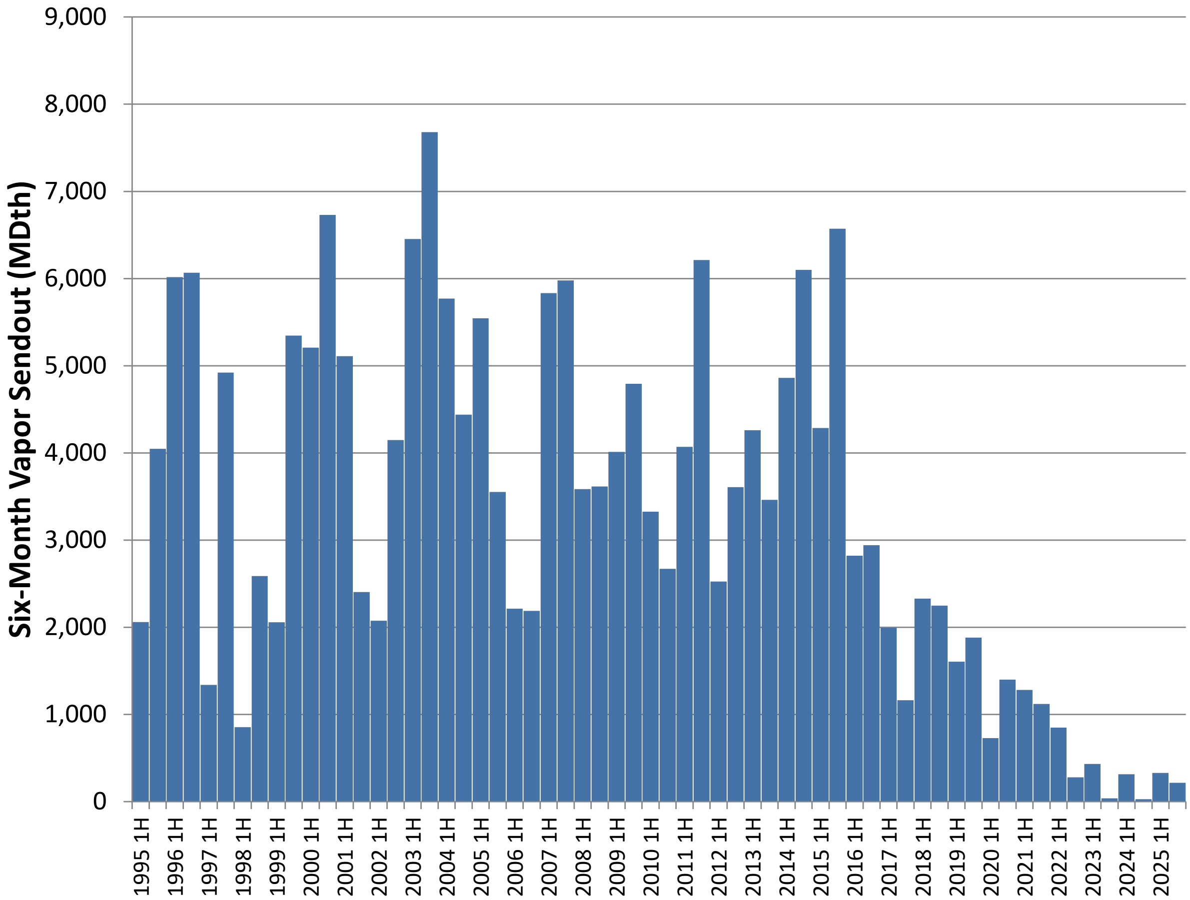
[6] Power Magazine, July 2, 2013, "Everett LNG Terminal at the Crossroads," https://www.powermag.com/everett-lng-terminal-at-the-crossroads/.

Figure 3. Boiloff Sendout from EMT, 1995-2025



In addition to its vaporization capability, EMT has four loading bays and can send out up to one million gallons per day of LNG by truck, equivalent to 100 MDth/d of vapor. Figure 4 shows the liquid sendout quantities reported by EMT to FERC in its Semi-Annual Operational Reports from 1995 through 2025.

Figure 4. Liquid Sendout from EMT, 1995-2025

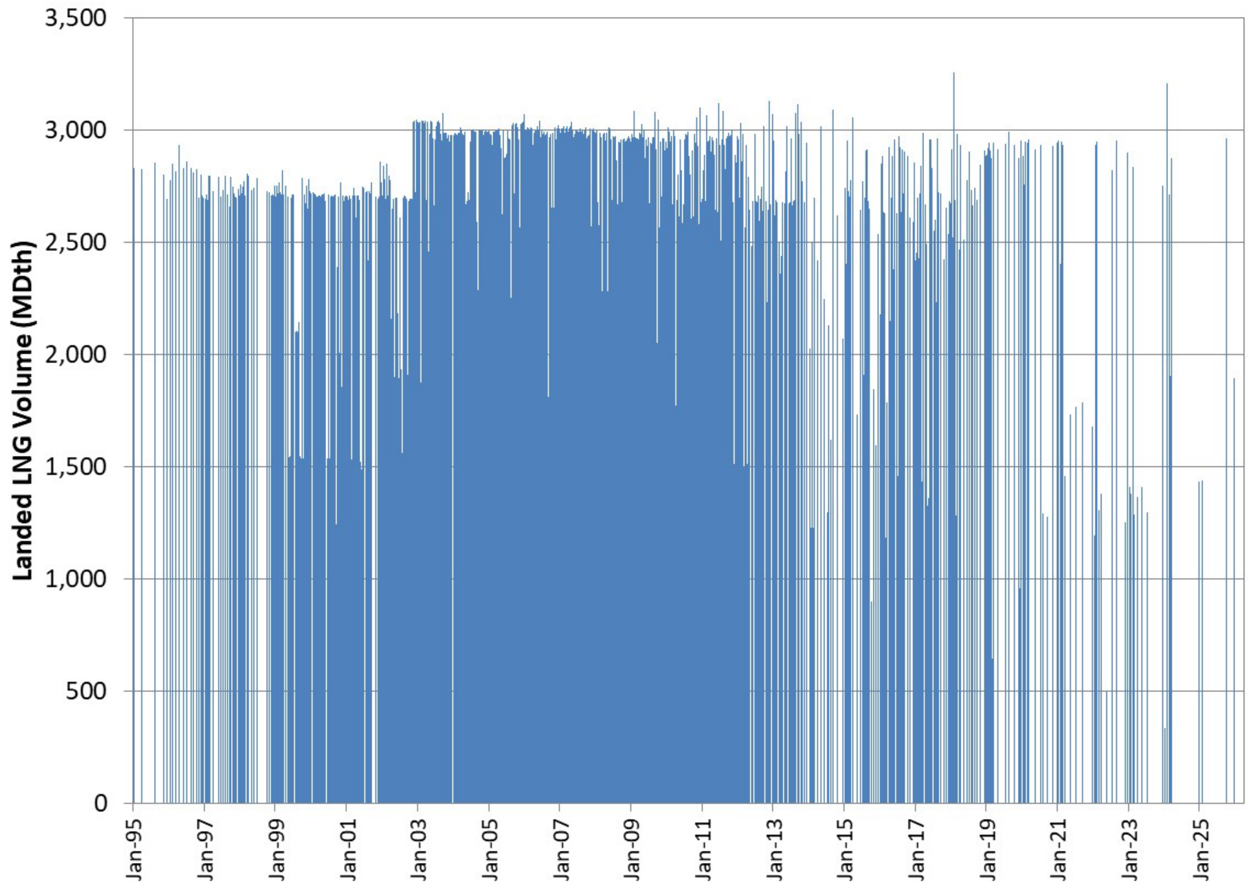


Variation in liquid sendout levels is the result of variation in severity of winter weather and resultant LDC demand and LNG storage drawdown. The variation in liquid sendout levels reflects certain large LDCs in New England diversifying their respective portfolios by sourcing truck-transported LNG from outside New England.

The change in sendout patterns is reflected in the frequency of cargoes, shown in Figure 5 for the period from 1995 through 2025 by volume and origin. EMT's storage tank has a capacity of 3.4 Bcf, which is roughly equal to one cargo. EMT must retain "heel" gas inventory to ensure safe and continuous operation.[7] This means that operators must carefully manage inventory relative to the timing of ship arrivals to ensure that cargoes can be fully unloaded. Trinidad has been the primary source of LNG for EMT for much of the last thirty years, although the frequency of cargoes has declined over the last fifteen years as sendout patterns from the facility have changed.

[7] Heel gas is the minimum volume of LNG necessary to keep the natural gas at cryogenic temperatures. Typically, 5-10% of storage capacity must be kept as heel gas, though the specific inventory needs can vary based on the quality of gas delivered from LNG cargoes.

Figure 5. Cargos Received at EMT, 1995-2025



EMT's supply arrangements have evolved over its fifty-year history. Since Mystic's retirement, EMT receives gas supplies under a long-term authorization for CLNG to import a total volume equivalent to 50 Bcf from Trinidad and other international sources by vessel over a 66-month term from December 1, 2024, through June 1, 2030.[8] CLNG also has a current blanket authorization to import up to 100 Bcf from various international sources over the two-year term from May 15, 2026, through May 14, 2028.[9]

1.3 New England's Natural Gas Infrastructure

Despite its proximity to gas production in Appalachia, New England faces unique gas supply challenges associated with serving heating customers and power plants during peak winter

[8] U.S. Department of Energy, Office of Fossil Energy and Carbon Management, Order No. 5210, Docket No. 24-102-LNG, November 22, 2024, https://www.energy.gov/sites/default/files/2024-11/ord5210.pdf.

[9] U.S. Department of Energy, Office of Fossil Energy and Carbon Management, Order No. 5413, Docket No. 26-17-LNG, April16, 2026, https://www.energy.gov/sites/default/files/2026-04/26-17-LNG.pdf.

months. New England's pipeline deliverability constraints have been studied extensively and are well-documented in a series of technical reports by LAI and others.[10]

New England imports gas into the region via five interstate pipelines: Algonquin, Tennessee, Iroquois Gas Transmission System (Iroquois), Portland Natural Gas Transmission System (PNGTS), and Maritimes & Northeast Pipeline (M&N).[11] The two largest pipelines, Algonquin and Tennessee, are primarily supplied by Marcellus and Utica shale production and, on cold days, underground storage in the Appalachian region. Iroquois and PNGTS deliver gas sourced from withdrawals at the Dawn storage hub in southern Ontario and other Canadian sources. Imports into New England via M&N are sourced exclusively from Repsol's St. John LNG import facility in New Brunswick. Based on total design day capacity, the five interstate pipelines can import roughly 5 Bcf/d into New England, or 4.1 Bcf/d if M&N is excluded.[12]

LAI has previously estimated total LDC design day demand in New England of approximately 5 Bcf/d.[13] On the electric side, total dual fuel and gas-only generation in New England amount to 18 GW: dual fuel capability is approximately 9.5 GW and gas-only installed capability is about 8 GW.[14] Dual-fuel and gas-only generators make up over 60% of ISO-NE installed capacity.[15]

Unlike PJM and western New York, New England does not have geology suitable for traditional, underground natural gas storage that can help meet peak day demand. In lieu of

---

[10] Northeast Gas/Electric System Study, prepared for Northeast Power Coordinating Council by Levitan & Associates, January 21, 2025 (NPCC Gas/Electric Study).
https://cdn.prod.website-files.com/67229043316834b1a60feba3/678fee912264907c381a0f68_NPCC%20Northeast%20Gas%20Electric%20System%20Study.pdf.
Gas-Electric System Interface Study: Target 2 Report. Levitan & Associates, Inc conducted on behalf of the Eastern Interconnection Planning Collaborative, March 9, 2015.
https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cdecca552ef1200018509d9/1558105276098/Final+Draft+Target+2.pdf.
Natural Gas Demand Forecast through 2032 and Natural Gas Topology Tool prepared by ICF for ISO-NE in 2023, https://www.iso-ne.com/static-assets/documents/2023/03/a13_b_rca_daily_gas_pipeline_forecast.pdf.
Analysis of Winter Supplies from Gas-Fired Generators, prepared for ISO-NE by Analysis Group, November 13, 2025, https://www.iso-ne.com/static-assets/documents/100029/a03.2.b_mc_rc_2025_11_12_13_car-sa_gas_availability_study_ag.pdf.
[11] A sixth pipeline, Granite State Gas Transmission operates entirely within New England.
[12] These values are net of downstream flow to downstate New York on Iroquois.
[13] NPCC Gas/Electric Study, page 33. This value does not include downstream demand in Atlantic Canada. This is generally consistent with ICF's findings in the Natural Gas Demand Forecast through 2032 and Natural Gas Topology Tool prepared for ISO-NE in 2023: "Under design day conditions, LDC winter peak day demand was projected to reach 4,983 BBtu in 2021/22 and 5,464 BBtu by 2031/32" (https://www.iso-ne.com/static-assets/documents/2023/03/a13_b_rca_daily_gas_pipeline_forecast.pdf, page 11).
[14] NPCC Gas/Electric Study, page 28, see Figure 10. See, also, Analysis of Winter Supplies from Gas-Fired Generators, Analysis Group, November 13, 2025, page 38.
[15] ISO-NE lists "About 28,900 MW of generating capability" on its Resource Mix web page. Accessed April 28, 2026. https://www.iso-ne.com/about/key-stats/resource-mix

sufficient pipeline capacity or traditional underground storage, the region depends on LNG to meet incremental demand at high heating degree days (HDDs). In addition to EMT and St. John LNG, the region's LNG facilities include satellite tanks, a third-party liquefaction and storage facility, and, less significantly, portable LNG facilities and an offshore import facility.[16]

The regional array of satellite facilities includes 43 tanks spread across 29 sites, shown in Figure 6. Total storage capacity is about 16.8 Bcf. Daily vaporization capability is approximately 1.5 Bcf/d. Seven facilities have liquefaction capabilities: Eversource's Hopkinton and Ludlow plants, Connecticut Natural Gas's Rocky Hill plant, Yankee Gas's Waterbury plant, NGrid's Providence LNG plant, Southern Connecticut Gas's Milford plant, and the Northeast Energy Center in Charlton, Massachusetts. Unlike the LDC satellite tanks throughout New England, the Charlton plant is a merchant facility which sells truck-delivered LNG to the LDCs. Collectively, the seven liquefaction facilities can produce 0.09 Bcf/d during the refill season. The sites lacking liquefaction are entirely dependent on trucks for refill, which can be sourced from local liquefaction facilities, EMT, or from outside New England.

[16] Excelerate's Northeast Gateway is a buoy submersible system in the Massachusetts Bay designed to receive specialized LNG cargoes. This facility has not sent out gas since February 2022. The only storage at Northeast Gateway is when a tanker is on site.

Figure 6. Pipeline and LNG Infrastructure in New England

Portable LNG and compressed natural gas (CNG) facilities contribute relatively small, but necessary volumes during peak hours in particularly constrained portions of the LDCs' distribution systems. Limited on-site storage at these peak-shaving facilities necessitates near-constant trucks to supply the facility while operating.

New England's constrained gas infrastructure is evidenced in pricing run-ups during recent cold weather events. The "polar vortex" of January 2014 and the "bomb cyclone" blizzard event in January 2018 led to prolonged elevated prices. Peak Algonquin Citygates prices exceeded $75/Dth while production area prices were $4-6/Dth. Boston's coldest day in the past 15 years occurred in February 2023 and caused New England-delivered gas to top $65/Dth while Eastern Gas South, formerly Dominion South Point, the leading pricing index in the Marcellus Shale region, was less than $3/Dth. Most recently, Algonquin Citygates hit an all-time high during WS Fern, exceeding $125/Dth. Without EMT's deliveries during WS Fern, supplies into New England would have been further constrained and price spikes would likely have increased in frequency, duration and magnitude.

The 2019 outage in Aquidneck Island, Rhode Island, demonstrated the consequence and extreme risk of gas system failures. When system pressure collapsed during a perfect storm of lost satellite LNG vaporization in Providence, pipeline failure and upstream supply limitations "into-the-pipe" resulted in roughly 7,000 customers losing gas service for up to a week. The estimated cost of the outage was $25 million.[17] If a comparable event were to occur in and around Boston, the costs would likely be at least an order of magnitude greater. Absent EMT, the possibility of a pressure-driven system shutdown or critical decay in line segment pressure minimums could be significantly higher and surely so if there were a simultaneous failure of other pipeline or LNG infrastructure. The overall experience in Texas during WS Uri in 2021 is another harsh reminder of the consequences of gas outages.[18,19]

Large-scale efforts to commercialize new pipeline capacity into New England have not been successful. Kinder Morgan cancelled its Northeast Energy Direct project in 2016. Spectra Energy (now Enbridge) also cancelled its proposed Access Northeast expansion project in 2017. Either pipeline project would have contributed materially to reducing pipeline congestion and thereby lowered delivered gas costs to both LDCs and gas-fired generators throughout the region. Instead, a series of smaller projects has added incremental pipeline capacity into the region. These smaller projects include the Algonquin Incremental Market (AIM) project; the Algonquin & M&N Atlantic Bridge project; the PNGTS Continent to Coast, Portland Xpress, and Westbrook Xpress projects; and the Tennessee Connecticut Expansion and 261 Upgrade projects. Two proposed projects, Iroquois' Enhancement by Compression (ExC) project, and Algonquin's Reliable Affordable Resilient Enhancement (RARE) project are currently under review by FERC and state permitting authorities.

---

[17] "Summary Investigation into the Aquidneck Island Gas Service Interruption of January 21, 2019," State of Rhode Island Division of Public Utilities & Carriers, October 30, 2019. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/AI_Report.pdf

[18] Texas officials attributed 246 deaths to the storm and resulting gas and electricity outage.

[19] "February 2021 Winter Storm-Related Deaths – Texas," Texas Department of State Health Services, December 31, 2021. https://www.dshs.texas.gov/sites/default/files/commprep/disasterepi/surveillance/SMOC_FebWinterStorm_MortalitySurvReport_12-30-21.pdf

1.4 Regulatory and Policy Context

After Mystic was scheduled to retire at the conclusion of the RMR period on May 31, 2024, the future of EMT was uncertain. On September 8, 2022, FERC held a forum to discuss the electricity and natural gas challenges facing the New England region (2022 FERC Forum).[20] Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. In comments submitted after the forum, ISO-NE explained that "the region does not have enough gas supply to meet demand in extreme weather conditions. Given this situation, the region cannot afford to lose any of its existing gas infrastructure, and must take action in response to threats to the viability of the Everett LNG facility."[21]

On June 20, 2023, FERC held a second forum to discuss solutions to the electric and gas challenges facing the New England region (2023 FERC Forum).[22] The forum's panels and presentations discussed the role of EMT and potential infrastructure and market solutions. On November 6, 2023, FERC Chairman Willie Phillips and NERC CEO James Robb issued a joint statement regarding their concern about the potential loss of EMT and the potential resultant consequences on the reliability and affordability of the region's energy supplies.[23] They encouraged all parties to keep reliability and affordability at the center of negotiations regarding the future of Everett.

In February 2024, NGrid, Eversource, and Unitil filed petitions with the Massachusetts Department of Public Utilities (MA DPU) requesting approval of contracts with CLNG for gas supply service from EMT over the period from June 1, 2024, through May 31, 2030.[24] The volumes associated with these contracts are shown in Table 1.

[20] FERC, New England Winter Gas-Electric Forum, September 8, 2022. https://www.ferc.gov/news-events/events/new-england-winter-gas-electric-forum-09082022

[21] ISO-NE Post-Forum Comments re New England Winter Gas-Electric Forum, November 7, 2022, Docket AD22-9-000, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221107-5135.

[22] FERC, 2023 New England Winter Gas-Electric Forum, June 20, 2023. https://www.ferc.gov/news-events/events/2023-new-england-winter-gas-electric-forum-06202023

[23] FECR, Joint Statement of FERC, NERC on Reliability, November 06, 2023. https://www.ferc.gov/news-events/news/joint-statement-ferc-nerc-reliability

[24] MA DPU Docket Nos. 24-25, 24-26, 24-27, and 24-28, May 17, 2024

Table 1. Contract Volumes in LDC Agreements with EMT

LDC	Maximum Daily Quantity (MDth/d)	Maximum Seasonal Quantity (MDth)
NGrid – Boston Gas	27.0-78.0	500-2,100
Eversource – NSTAR	15.0	450
Eversource – EGMA	19.6	882
Unitil – Fitchburg G&E[25]	3.4	83

The structure of the LDCs' contracts with EMT is built around a call option framework, through which LDCs pay a NCDC reflecting EMT's fixed facility costs, and a Commodity Demand Charge reflecting the reservation of LNG supply. The call option price framework also includes a variable withdrawal charge for volumes actually taken as well as a reimbursement charge for reservation of a portion of CLNG's firm transportation entitlements on Algonquin and Tennessee that enable citygate deliveries, which does not apply to NGrid. The contracts each include a "Most Favored Nations" (MFN) provision that requires similar contracts for incremental EMT volumes to pay a volume-weighted share of EMT's fixed costs as covered by the NCDC.[26] This means that additional EMT volumes and/or customers could result in a downward adjustment, on a unitized basis, of this component, as the associated costs are spread across a larger total contracted volume.

The Massachusetts Attorney General filed testimony from The Brattle Group in response to the LDCs' petitions estimating that the total cost of the contracts over the six-year terms would be $946 million, or potentially as high as $1,099 million, depending on global index prices, but acknowledged that "the alternatives to the Agreements are currently insufficient to fully replace supplies from EMT and the reliability benefits provided by the facility."[27]

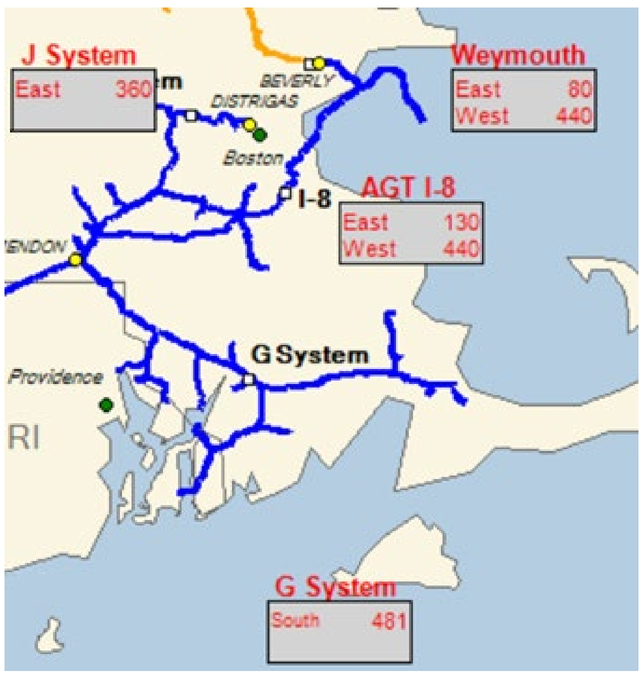
In the Order approving the contracts, the MA DPU found that the contracts were in the public interest, and further noted its expectation that the LDCs "fully investigate all possible alternatives to EMT over the six-year term of the Agreements, including energy efficiency, strategic electrification, and networked geothermal projects, and, to the extent feasible, to coordinate their planning efforts."[28] The MA DPU further directed that the LDCs file annual reports that address:

[25] Unitil also filed for approval of a trucking contract with Transgas for the transportation of LNG from EMT to Unitil's LNG facility in Westminster, Massachusetts.
[26] Testimony of Jay V. Fletcher (Fletcher Testimony), MA DPU Docket No. 26-28, February 20, 2026, page 7:9-15.
[27] MA DPU Docket Nos. 24-25, 24-26, 24-27, and 24-28. Direct Joint Testimony of Brattle Group on behalf of the Attorney General.
[28] MA DPU Docket Nos. 24-25-B, 24-26-B, 24-27-B, and 24-28-B; May 17, 2024; page 55.

- Whether, and to what extent, the EMT contracts have facilitated plans to meet GHG reduction goals;
- A description of efforts to reduce customer demand for natural gas; and
- A description of efforts to reduce or eliminate reliance on EMT.

In September 2025, Eversource petitioned MA DPU to approve ten-year contracts for capacity created by Algonquin's RARE project, including 25 MDth/d for Eversource Gas Company of Massachusetts (EGMA) and 5 MDth/d for NSTAR.[29] In both cases, Eversource notes that the contracts, if approved, will allow for an equivalent reduction in contract volumes with EMT after the current terms end in 2030. The contracts with Algonquin will replace the EMT contract volumes deliverable on Algonquin's G System but not the volumes deliverable on Algonquin's J System, which supplies Boston and Cambridge. Figure 7 shows the relative locations of the G and J Systems.

Figure 7. Algonquin Facilities in Eastern Massachusetts[30]



Eversource notes further that there will be estimated savings associated with the Algonquin RARE contracts relative to the EMT contracts across both utilities over ten years.[31] In the

[29] MA DPU Docket Nos. 25-133 and 25-134, January 30, 2026.
[30] Algonquin Informational Postings, values reflect Peak Day Design capacity. https://rtba.enbridge.com/InformationalPosting/Default.aspx?bu=AG&Type=PD
[31] LAI has not assessed how Eversource derived these savings regarding the RARE entitlement. Such savings may represent a cost shift to other EMT customers, not a cost reduction, because the fixed costs associated with operating the terminal and arranging full cargoes would not be reduced as a result of Eversource partially decontracting from EMT.

Order approving the contracts, the MA DPU noted that reducing the need to contract with EMT is consistent with previous directives to "make significant strides to reduce or eliminate their reliance on EMT in the near-term," and further noting its expectation for Eversource "to fully investigate all possible alternatives to the EMT facility to address its needs on the Algonquin J-System."[32]

In February 2026, Berkshire Gas petitioned MA DPU to extend an existing supply contract with CLNG for an additional two years, which corresponds to the end date of the other LDC contracts.[33] The contract extension maintains the 5.4 MDth/d maximum daily quantity (MDQ) of the Berkshire contract, and reduces the number of days per year from 45 to 30, resulting in a Maximum Seasonal Quantity of 162 MDth. In its petition, Berkshire provided testimony indicating that interstate pipelines in the region remain fully subscribed and that no feasible alternatives were available. As of the issuance of this report, the MA DPU review of the contract extension is still underway. In its comments in support of the Berkshire contract with EMT, CLNG states that, "Due to the contract structure and economies of scale, the addition of Berkshire to the pool of EMT customers reduces the NCDC for existing customers."[34]

In 2024, the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) Office of Energy Transformation (OET) established a Focus Area Working Group (FAWG) to examine options for transitioning away from EMT. The draft findings of the EMT FAWG were shared with the Energy Transformation Advisory Board on February 4, 2026.[35] The EMT FAWG found that the LDCs that executed contracts with CLNG "will remain reliant on EMT beyond 2030, to varying degrees, though the nature of the reliance will evolve by LDC." The recommendations resulting from the draft findings include:[36]

- Incorporate EMT dependency considerations into Integrated Energy Planning efforts, prioritizing demand reduction strategies;
- Develop policy recommendations that lead to cost mitigation to gas ratepayers; and
- Develop additional clarity on the long-term role that gas storage will play in the energy transition.

On March 16, 2026, the Healey-Driscoll Administration in Massachusetts issued Executive Order No. 654: *To Secure Massachusetts' Energy Future by Establishing an Energy Supply*

[32] MA DPU Docket Nos. 25-133 and 25-134, January 30, 2026, pages 22.
[33] MA DPU Docket No. 26-28, February 20, 2026.
[34] Comments of Constellation LNG, LLC, MA DPU Docket No. 26-28, March 30, 2026, page 3.
[35] EMT FAWG, Findings of Relevance, January 28, 2026.
https://www.mass.gov/doc/everett-marine-terminal-fawg-draft-findings/download
[36] EMT FAWG, Recommended Pathway, January 28, 2026.
https://www.mass.gov/doc/everett-marine-terminal-fawg-draft-recommendation-pathway/download

Plan that Drives Affordability and Reliability (EO654).[37] EO654 describes EMT as "a strategic energy asset for Massachusetts and the New England region, capable of meeting up to ten percent of the region's natural gas supply needs on the coldest days, and gas storage and delivery capabilities, in general, are critical to meeting peak winter energy demand." As part of a portfolio of actions, EO654 directs OET, in coordination with the Department of Energy Resources (DOER) and the EMT FAWG to:

- Identify opportunities to accelerate demand reduction in strategic locations served by EMT, including, but not limited to, geotargeting of energy efficiency and demand reduction incentives, and targeted supply-side or gas distribution system related interventions to enable elimination of future reliance on the terminal for Massachusetts gas utilities and meet winter energy needs affordably and reliably; and

- Identify options to fund ongoing operation of EMT in a manner that does not overly burden gas utility ratepayers and maximizes the use of the asset while it is operational and relied on by the gas utilities for supply and system reliability.

The LDCs filed their second annual EMT reports on April 1, 2026.[38] Collectively, they determined that "eliminating reliance on EMT for all LDCs by the end of the current contract term is not feasible based on current information given operational requirements, infrastructure limitations, regulatory considerations, and implementation timelines,"[39] though reductions in their reliance may be achievable.

2 EMT's Contribution to Gas and Electric Reliability in New England

2.1 EMT's Role in System Balancing

EMT is a vital supply and storage resource for the New England gas and, by proxy, electric systems during peak winter conditions. EMT contributes to reliability in three ways: first, providing incremental gas supply in addition to conventional pipeline forward hauls from Marcellus and Canada; second, providing locational pressure support and intraday flexibility at the respective termini of Algonquin and Tennessee as well as the NGrid system; and third, provision of liquid volumes to satellite storage tanks, particularly during periods of extreme cold when local inventory has been drawn down. In addition to supplying contracted volumes to LDCs, EMT makes vapor sales to gas generators and marketers that support electric grid reliability. The portfolio of services provided by EMT cannot be

[37] Executive Order No. 654, March 16, 2026. https://www.mass.gov/executive-orders/no-654-to-secure-massachusetts-energy-future-by-establishing-an-energy-supply-plan-that-drives-affordability-and-reliability
[38] MA DPU Docket Nos. 25-41, 25-42 and 25-44, April 1, 2026
[39] NGrid 2nd EMT Annual Report, April 1, 2026, page 4.

replicated by any other single facility in the region. The reliability value of EMT is therefore understood not only as the value of performance during tight operating conditions, but also as the value of a locationally advantaged, globally supplied energy reserve located in the greater Boston gas and electric load pocket.

EMT's integrated operational capabilities produce diverse systemwide benefits that may be viewed as an integrated whole. EMT's strategic location is paramount. EMT's locational advantage sustains displacement benefits on Algonquin and Tennessee, helps to preserve satellite LNG inventory and to dampen spot gas and power price run-ups when CLNG can make vapor sales to marketers and/or generators. Reduced gas and power prices benefit ratepayers.

2.1.1 Provision of Gas Supply

EMT's location downstream of pipeline constraints represents counterflow on the pipelines serving southern New England, thereby alleviating pipeline congestion. EMT is limited by the capacity of its interconnections with Algonquin and Tennessee of 275 MDth/d and 200 MDth/d, respectively.[40] EMT's observed maximum total sendout to Algonquin and Tennessee of approximately 350 MDth/d, a level which was reached most recently in January 2022, is equivalent to approximately 7% of Massachusetts LDCs' peak day needs. It also equates to supplying approximately 2.1 GW of gas-fired generation for 24 hours.[41] As discussed above, EMT is able to shape its intraday pipeline injections to provide pressure support while also injecting directly into NGrid's local distribution system. Replacing this contribution to regional gas supply with an alternative source of incremental capacity would require material investment in new pipeline infrastructure.

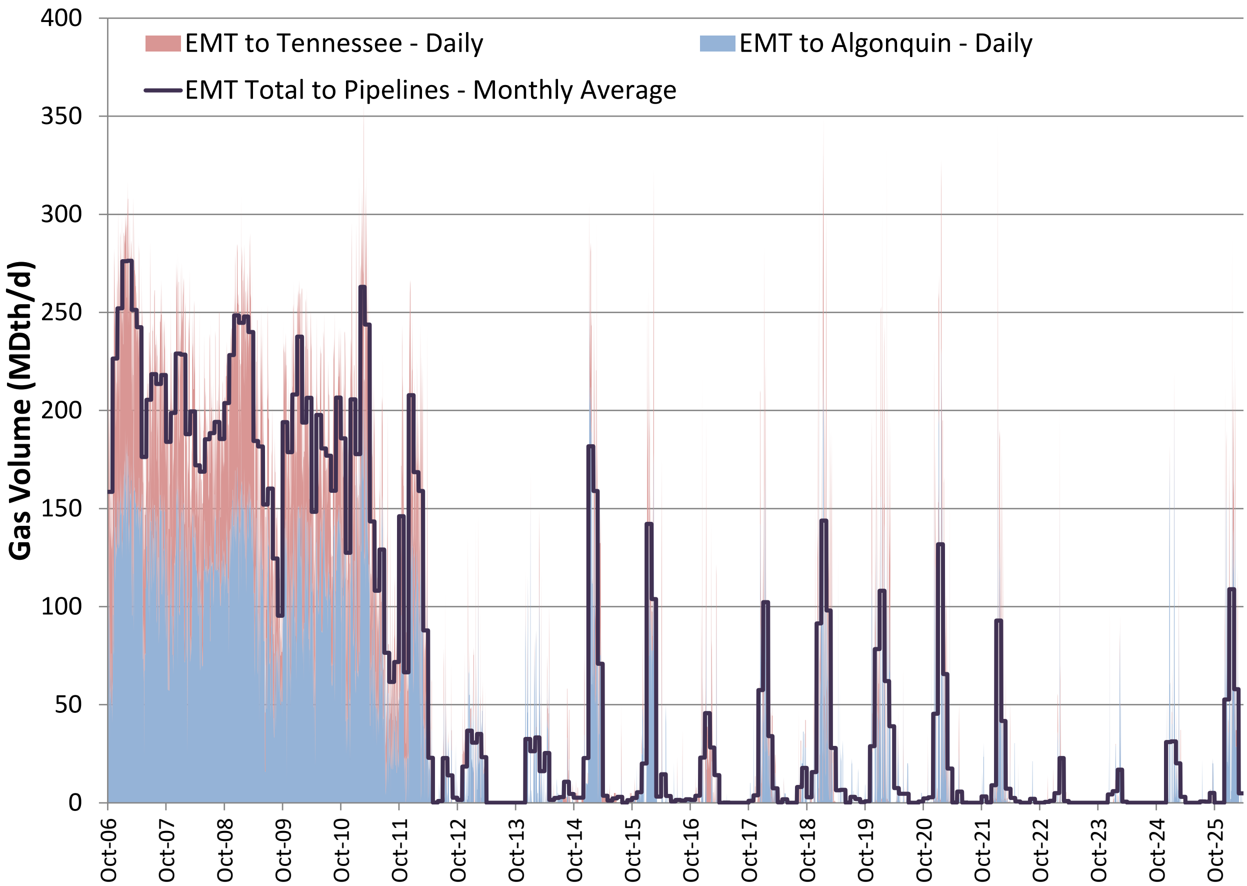
EMT's contribution to the flow balance in New England is shown in Figure 8, based on historical vapor sendout into Algonquin and Tennessee.[42] Consistent with the trend in total vapor sendout discussed in Section 1.2, sendout to the pipelines has transitioned from baseload to winter peaking in the early 2010s. While volumes from EMT are not needed to serve demand year-round, during periods of seasonal peak demand, the resource continues to be critical.

[40] The segments to which EMT is connected, Algonquin's J System and Tennessee east of Station 267, have throughout capacities of 360 MDth/d and 202 MDth/d, respectively. Source: Algonquin and Tennessee Informational Postings.

[41] Estimate assumes a heat rate of 7,000 Btu/kWh.

[42] Historical daily sendout volumes to NGrid are not publicly available.

Figure 8. EMT Sendout to Algonquin and Tennessee, October 2006-March 2026



The LDCs justified the need for the contracts with the following statements in supporting testimony explaining that EMT was the best available option for closing supply deficits:

- Berkshire: "[D]emand for natural gas continues to grow in the Company's service territory, albeit at a modest rate. This modest demand growth is heat sensitive, so acquiring supplies with fewer days of service helps shape the Company's supplies to its demands. Based on this forecasted demand growth, the Company will continue to need all of its existing supplies... no incremental projects currently exist on [Tennessee] that would provide the Company with incremental gas supplies to be used as a replacement for the Proposed Agreement."[43]
- Eversource: "Without gas supplies from [EMT], inadequate gas supplies to serve customers on the G-system [and J-System] could occur during a design winter. If there are inadequate gas supplies to serve customers on the G-system [or the J-

[43] Fletcher Testimony, page 9:12-18.

System] during a design winter, the costs associated with a gas outage would far outweigh the costs of the Proposed Agreement."[44]

- NGrid: "[T]he Agreement is needed to help to meet the Company's design season and design day requirements. In addition, the Agreement decreases current peak hour deficits at certain of the Company's take stations which feed the system also served by EMT."[45]
- Unitil: "Imported LNG serves as a critical source of gas supply that supplements domestic gas supplies during peak periods or when curtailments occur on the heavily constrained pipeline systems that deliver gas into New England. Natural gas demand growth continues to exceed the growth in new pipeline capacity."[46]

2.1.2 Pressure Support and Intraday Flexibility

EMT's interconnections at the eastern ends of the Algonquin and Tennessee systems, as well as with NGrid's distribution system, allow for large injections into highly constrained segments. EMT therefore serves as critical source of pipeline balancing services that provide both pipelines with the intraday scheduling flexibility to accommodate both LDCs' and gas generators' twice daily ramps.

In filed comments to FERC following the 2022 FERC Forum, CLNG noted that, "In the past two years [prior to November 2022], EMT has been called upon intraday 21 times to provide pressure support for Algonquin and Tennessee to enable the reliable operations of their systems."[47] CLNG additionally stated that the "Shaping and balancing services [provided by EMT] allows for injections onto the pipeline when needed and in a manner that allows the overall volumes on the pipe to vary from ratable requirements and better match demand profiles ... Over the previous two-year period, EMT provided this service over 69 times, that we have documented."[48] Notably, neither the winter of 2020-21 nor the winter of 2021-22 was as cold as the winter of 2025-26, which according to ISO-NE was the coldest winter in 20 years, although not as cold as the conditions associated with LDC design day planning.[49]

---

[44] Petition of Eversource Gas Company of Massachusetts d/b/a Eversource Energy for Approval of a Gas Supply Agreement with Constellation LNG, LLC, pursuant to G.L. c. 164, § 94A, MA DPU Docket No. 24-26, February 12, 2024, page 3. Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of a Gas Supply Agreement with Constellation LNG, LLC, pursuant to G.L. c. 164, § 94A, MA DPU Docket No. 24-27, page 3.

[45] Joint Testimony of Elizabeth D. Arangio, Faye Brown, Samara Jaffe, Michael J. Pini, and Deborah Whitney (Arangio Testimony), MA DPU Docket No. 24-25, February 9, 2024, page 29:12-25.

[46] Testimony of Francis X. Wells, MA DPU Docket No. 24-28, February 16, 2024, page 11:7-11.

[47] Comments of Constellation Energy Generation LLC, filed November 7, 2022, in FERC Docket No. AD22-9-000, see page 11.

[48] Comments of Constellation Energy Generation LLC, filed November 7, 2022, in FERC Docket No. AD22-9-000, see page 12.

[49] NEPOOL Participants Committee System & Market Operations Report March 2026, presented by Stephen George at the March 5, 2026, meeting. See slide 15.

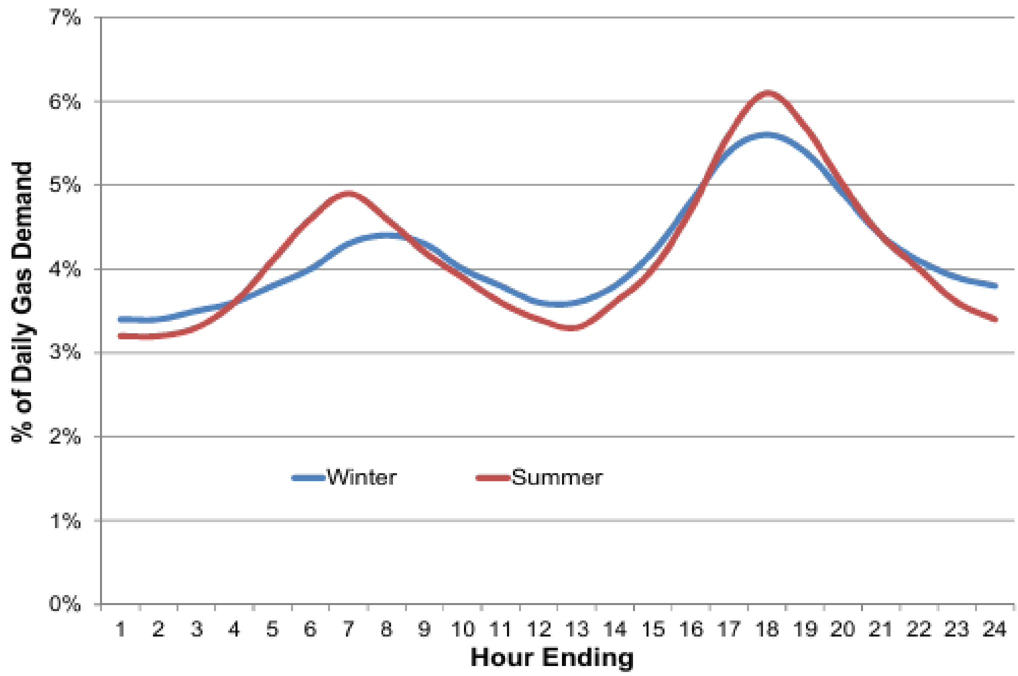
Pipelines are designed and certificated to deliver gas ratably, i.e., about 1/24th of the daily quantity per hour. Customer demands, both LDC and generator, however, vary throughout the day, resulting in the need for non-ratable deliveries. Hourly LDC variances are much lower than those of generators, however. The pipelines will accommodate non-ratable deliveries through use of linepack when possible, but the pipelines' first priority is to protect system operations and delivery pressures in order to meet firm customers' contracted needs. Therefore, there are limits to the flexibility provided through linepack, particularly on high demand days. Injections from EMT support the pipelines' ability to allow non-ratable takes. As gas demand continues to increase without the addition of incremental transportation capacity, the ability of the pipelines to be flexible on high demand days continues to be reduced. Since the pipelines have been able to rely on EMT's balancing function for decades, exactly how formidable the scheduling challenge would be in the absence of EMT cannot be known for sure, but stricter adherence to the tariffs would be required.

On the LDC side, Figure 9 shows the seasonal intraday gas demand profile that LAI has developed using typical meteorological year data sets prepared by the National Renewable Energy Laboratory for the Department of Energy's Office of Energy Efficiency and Renewable Energy, LAI's professional judgment and limited reporting of peak hour factors in LDC forecasts and other public sources.

---

https://www.iso-ne.com/static-assets/documents/100033/system-and-market-ops-report-mar-2026.pdf

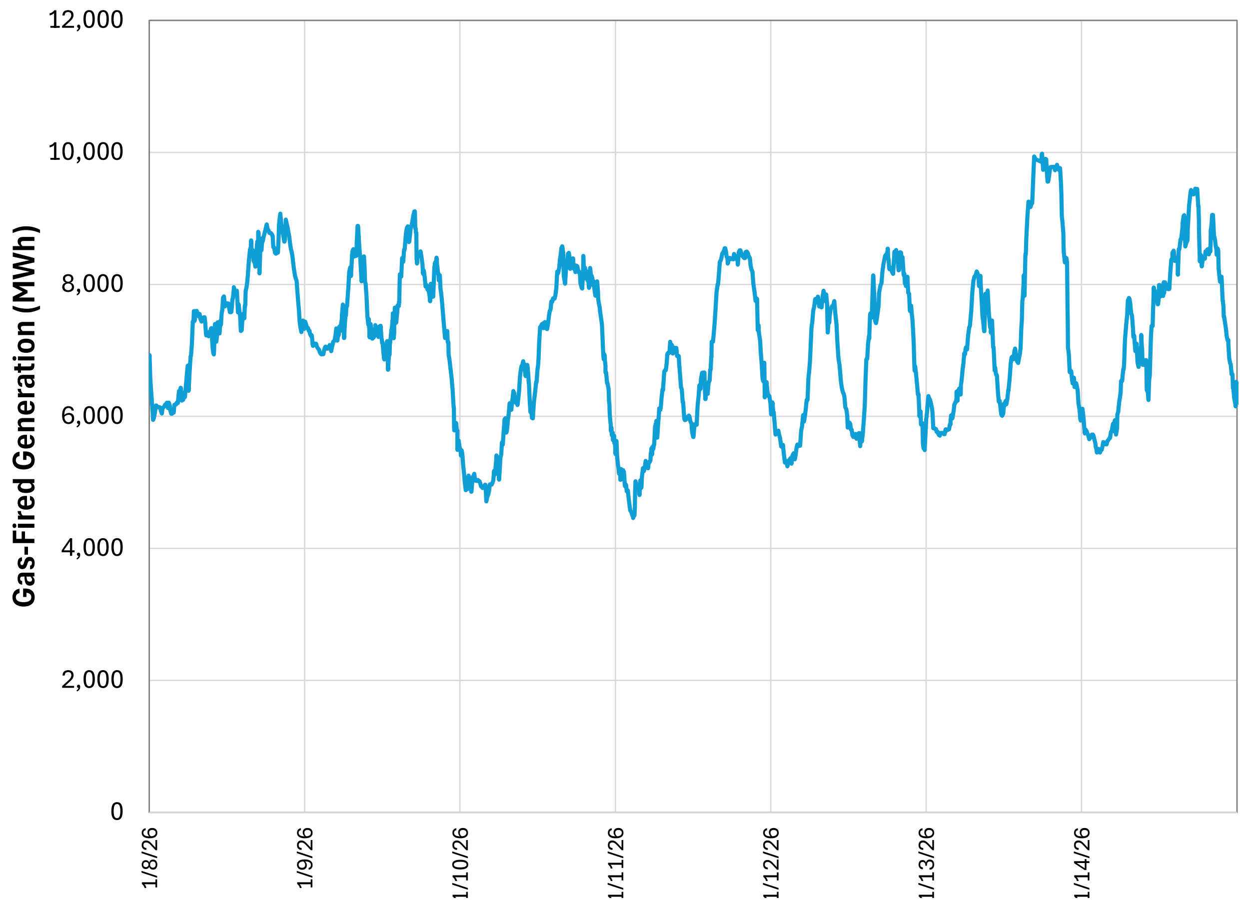
Figure 9. Intraday Seasonal Gas Demand Profiles for LDCs[50]



On the generation side, Figure 10 shows the hourly profile of gas-fired generation during the second week of January 2026, illustrating the non-ratable nature of the associated gas demand.

[50] Gas-Electric System Interface Study: Target 2 Report. Levitan & Associates, Inc conducted on behalf of the Eastern Interconnection Planning Collaborative, March 9, 2015. See page 82. https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5cdecca552ef1200018509d9/1558105276098/Final+Draft+Target+2.pdf

Figure 10. ISO-NE Gas-Fired Generation Intraday Profile, Second Week of January 2026[51]



LAI reviewed hourly generators performance data from the EPA Continuous Emissions Monitoring Systems (CEMS) database.[52] Fuel type allocation, distinguishing whether various generating units were running on gas or oil, was determined by each unit's hourly CO_2 emissions rate. The analysis covered the 20 coldest days from the 2014 to 2025 period, plus some additional intervening days within cold weather events for a total of 25 days.[53]

Figure 11 shows the maximum combined gas and oil ramping over an eight-hour period during the top 25 coldest days. Gas-fired generation provided ramping and was dispatched up to meet load peaks even on the most oil-heavy days. In the large majority of events, 19 of

---

[51] ISO-NE, Dispatch Fuel Mix, https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/gen-fuel-mix. For purposes of this dataset, generation is reported by primary fuel type. It is therefore possible that some of the MWh were generated using oil at a dual-fuel plant.

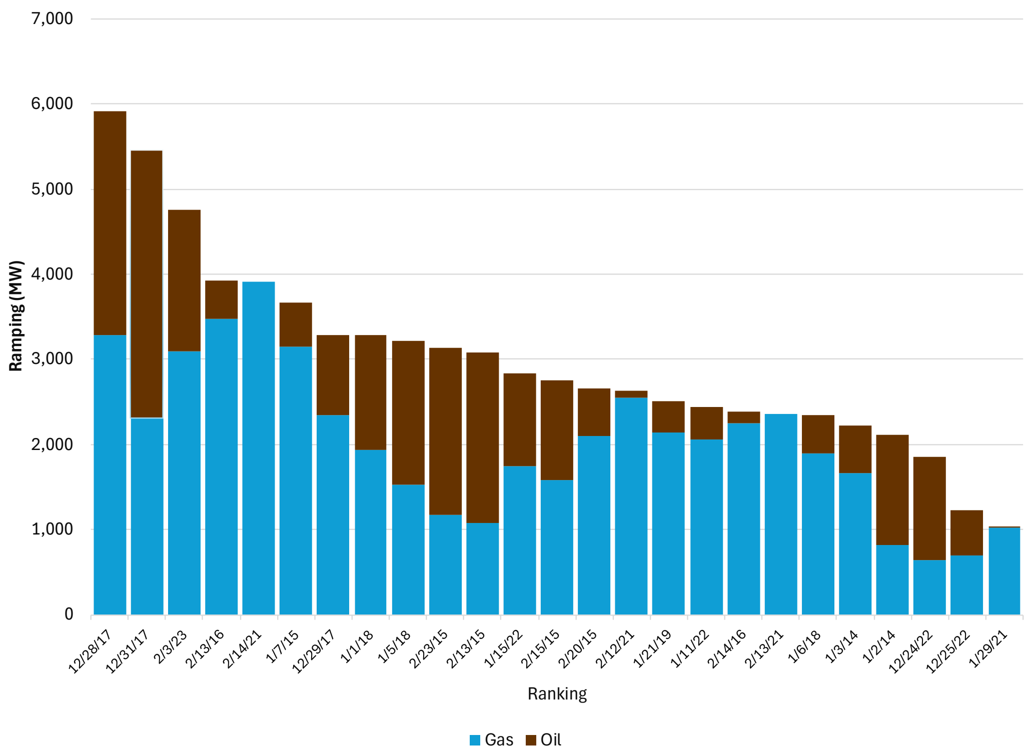
[52] Data available at https://campd.epa.gov/.

[53] Based on temperatures at Logan International Airport. Dry bulb temperature data is sourced from ISO-NE Zonal Information reports.
https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

25, gas was the dominant ramping fuel, often by a wide margin. During the sampled days, despite stressed winter conditions, gas nevertheless met about two-thirds of the ramping burden.

EMT provides a non-ratable supply source with intraday availability that can absorb generator takes when pipeline nominations are largely dedicated to high priority LDC residential and commercial loads. Even on the coldest days over the past decade, gas remained an integral part of the electric load ramp in part due to key balancing services from EMT previously discussed.

Figure 11. Load Ramping Served by Gas and Oil during Cold Spell Events



The LDCs justified the need for the EMT contracts with the following statements in supporting testimony related to gas system reliability:[54]

- EGMA: "EMT's unique ability to quickly make non-ratable hourly deliveries of large volumes of gas directly into the interstate pipeline network allows EMT to provide vital pressure support at the end of the system when needed, and its ability to shape deliveries to align with demand requirements of natural gas customers and interstate

[54] Berkshire is located far enough upstream from EMT on Tennessee that it does not ascribe specific locational benefits to service from EMT.

pipelines serving Massachusetts, has become more important as the regional infrastructure has become increasingly stressed in the last several years."[55]

- NSTAR: "When EMT injects gas into the Algonquin pipeline on the coldest days of the year, regardless of where it is destined and who has contracted for it, the J-system which is at the end of the pipeline grid sees increased pressures."[56]
- NGrid: "Constellation has the capability to inject into the end of the Algonquin and Tennessee systems in Everett and bolster pressures on these constrained portions of the pipelines systems that in turn supply approximately half of the Company's take stations in Massachusetts. These injections are critical to ensure adequate pressures are maintained to these [NGrid] take stations and to provide for uninterrupted deliveries to the Company's customers. The Company's contractual pipeline deliveries alone may not be adequate to maintain system pressures to these stations. As the upstream pipelines serving the Company's distribution system continue to become more constrained, the operational flexibilities which they have historically provided will continue to diminish."[57]
- Unitil: "It is important to note that this supply provides critical pressure support for [Algonquin and Tennessee] which benefits the entire region. The location of the Everett terminal, in the heart of the regional energy market area, allows incremental supply to access market areas that reside in the most constrained parts of the pipeline systems."[58]

2.1.3 Liquid Refill

EMT's liquid sales and truck loading operations serve as a critical source of LNG refill for the New England's array of satellite LNG plants. From its four trucking bays, EMT can fill up to 100 cryogenic tanker trucks daily, each carrying approximately 10,000 to 12,500 gallons of LNG, equivalent to about 1,000 Dth per truck for a maximum total of 100,000 Dth/d. Most of the satellite facilities in New England have no liquefaction capabilities, and barely enough storage capacity to support two or three days of nameplate vaporization. These facilities frequently "turn" their LNG inventory multiple times per winter when high demand conditions occur. The satellite tanks that turn are entirely dependent on timely refills via truck during cold snaps. The few LDC-owned satellite tanks that do have on-site liquefaction capability do not liquefy in the winter. Therefore, when inventory at the satellite facilities is drawn down or running low during the peak heating season, EMT's incremental LNG supply for refill is critical for LDC reliability.

[55] MA DPU Docket Nos. 24-26, February 12, 2024.
[56] MA DPU Docket Nos. 24-27, February 12, 2024.
[57] MA DPU Docket Nos. 24-25, February 9, 2024.
[58] MA DPU Docket Nos. 24-28, February 16, 2024.

EMT's proximity to the network of LNG satellite and peak-shaving facilities in New England provides reliability benefits relative to sourcing LNG from outside the region. During the peak heating season, when road conditions are icy and high winds are typical, every mile matters for LNG trucking. A truck loaded at EMT can reach virtually any satellite facility in Massachusetts, Rhode Island, or Connecticut within a single driver's hours of service (HOS) window, even in extreme cold weather conditions because the one-way distances are within 10 to 120 miles. This proximity advantage, combined with EMT's ability to receive mid-winter cargo replenishment from the global LNG market, allows EMT to offer significant reliability and timing benefits relative to alternative sources. Facilities that are dependent on liquefaction for LNG supply cannot quickly refill during extended demand events.

Unitil justified the need for its EMT contract with the following statement in supporting testimony related to trucking: "[EMT] has always been the preferred LNG source for Unitil because of its proximity to Westminster and its ability to schedule deliveries quickly in tandem with the transportation services provided by Transgas. [EMT] is located approximately 75 miles from the Westminster LNG facility and deliveries are available upon 48 hours of notice with willingness to accommodate for shorter notice in certain circumstances, as well as contingency planning around weather events that impact driving conditions. Reliable alternatives that have been identified are approximately 300 miles away from Westminster and require 72 hours of notice to be given on business days only due to distances and the need for additional qualified drivers for the longer haul."[59]

2.2 Performance During WS Fern and the Subsequent Cold Snap

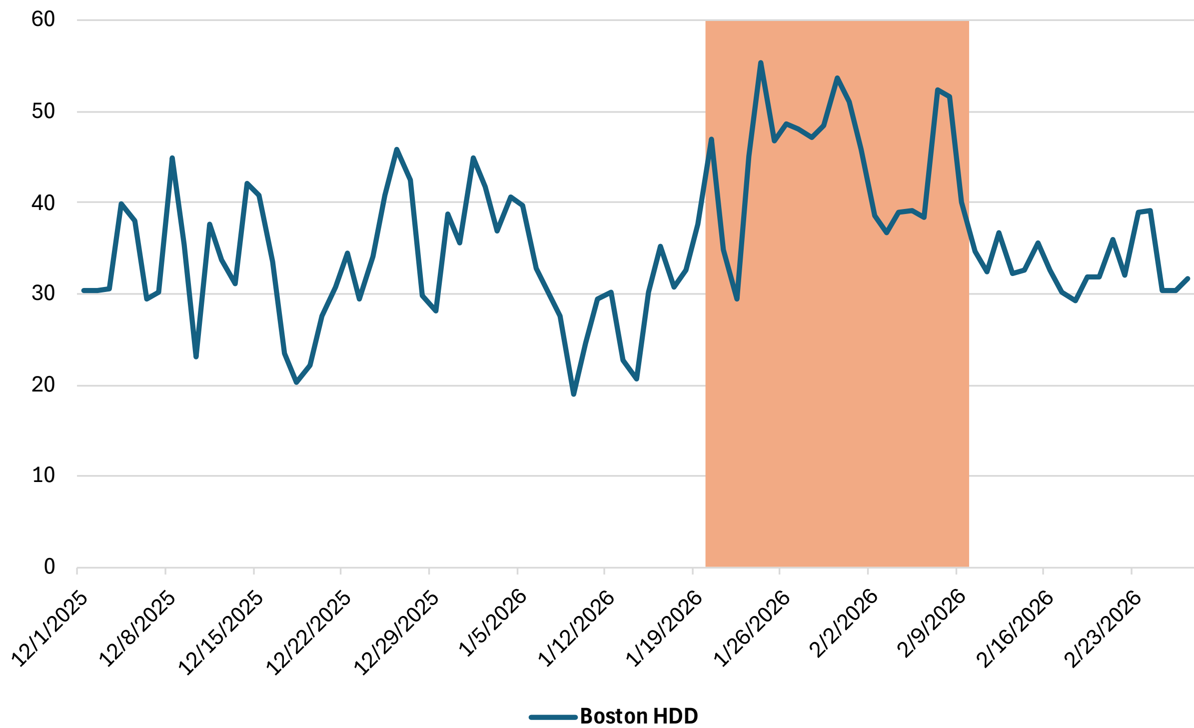
WS Fern hit the northeast in late January 2026. Subsequently, a smaller cold front hit the northeast in early February. Per data from ISO-NE, Boston experienced five days exceeding 50 HDDs, with the coldest day occurring on January 24th (55 HDDs), as shown in Figure 12.[60] Individually, these peak days were not exceptionally cold by LDC planning standards.[61] However, the period from January 20th to February 9th was the coldest 21-day period in regard to total HDDs since January 2018.

[59] MA DPU Docket Nos. 24-28, Testimony of Francis X. Wells, 12:16 to 13:3, February 12, 2024.

[60] Weather data is adjusted to reflect the "gas day," starting at 10AM eastern of the listed date and ending at 10AM of the following calendar date.

[61] NGrid uses a Boston-area design day of 78 Effective Degree Days (EDDs) for gas supply planning purposes. EDDs are HDDs, adjusted for daily average wind speed.

Figure 12. HDDs in Boston During Winter 2025-26



WS Fern provided a significant test to gas infrastructure across the greater Northeast. The cold snap was particularly disruptive in PJM.[62] Freeze-offs in the Marcellus and Utica shale production regions reduced northeast production by around 2 Bcf/d.[63] PJM declared Conservative Operations from January 24th through February 1st and scheduled generation in advance to ensure reliability. This had the effect of increasing generator scheduling of gas deliveries with out of market commitments that pre-scheduled demand irrespective of price.[64] In New England, the cold weather prompted Algonquin to issue its first-ever hourly Operational Flow Order (OFO) due to excess non-ratable takes.[65] Regional gas prices spiked, indicating supply limitations and prompting significant gas-to-oil switching among generators. Figure 13 shows the ISO-NE fuel mix during the winter of 2025-26, highlighting

[62] PJM reported total uplift between January 24 and February 1, 2026, equal to $797.6 million. "January Cold Weather Operations," page 75. https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update.pdf.

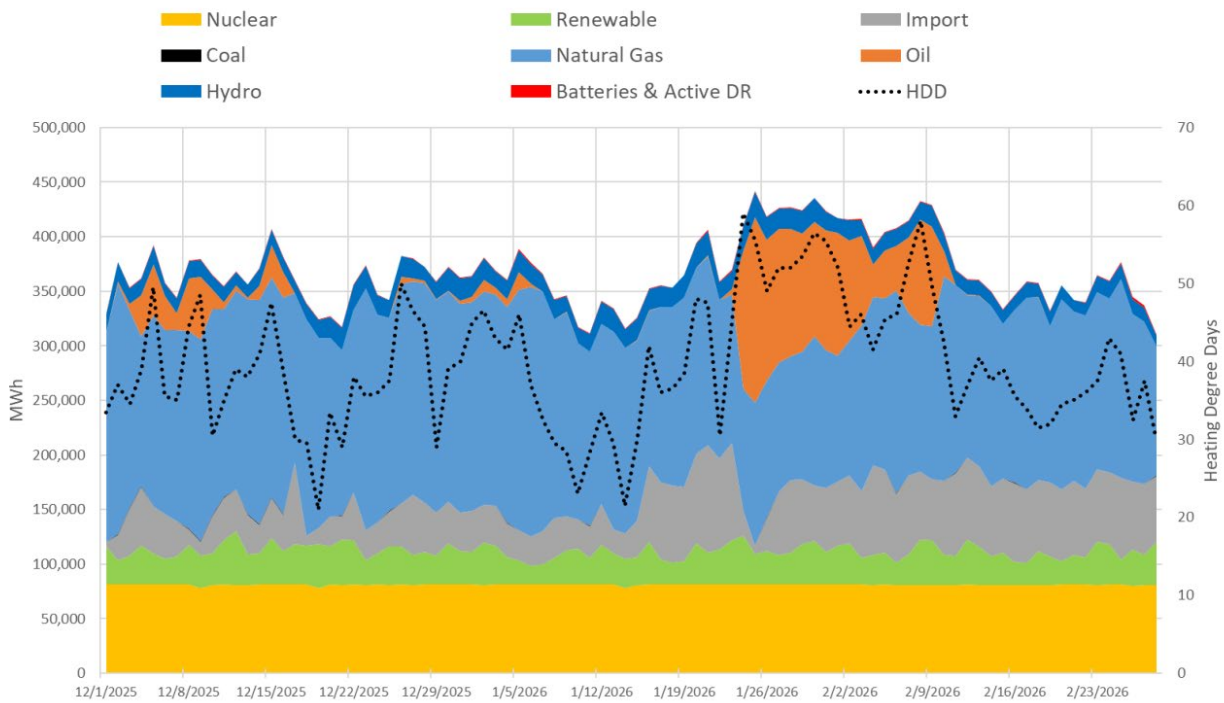
[63] https://naturalgasintel.com/news/natural-gas-production-issues-linger-in-appalachia-after-17-consecutive-days-of-subfreezing-temps/

[64] Electric Power Supply Association, Winter Storm Fern: How Power Markets Withstood an Extended Winter Stress Test, February 13, 2026. https://epsa.org/winter-storm-fern-how-power-markets-withstood-an-extended-winter-stress-test/

[65] Algonquin Critical Notice posted 1/26/2026 8:15AM.

the increased reliance on oil during WS Fern and its aftermath relative to the more normal winter periods that preceded and followed.

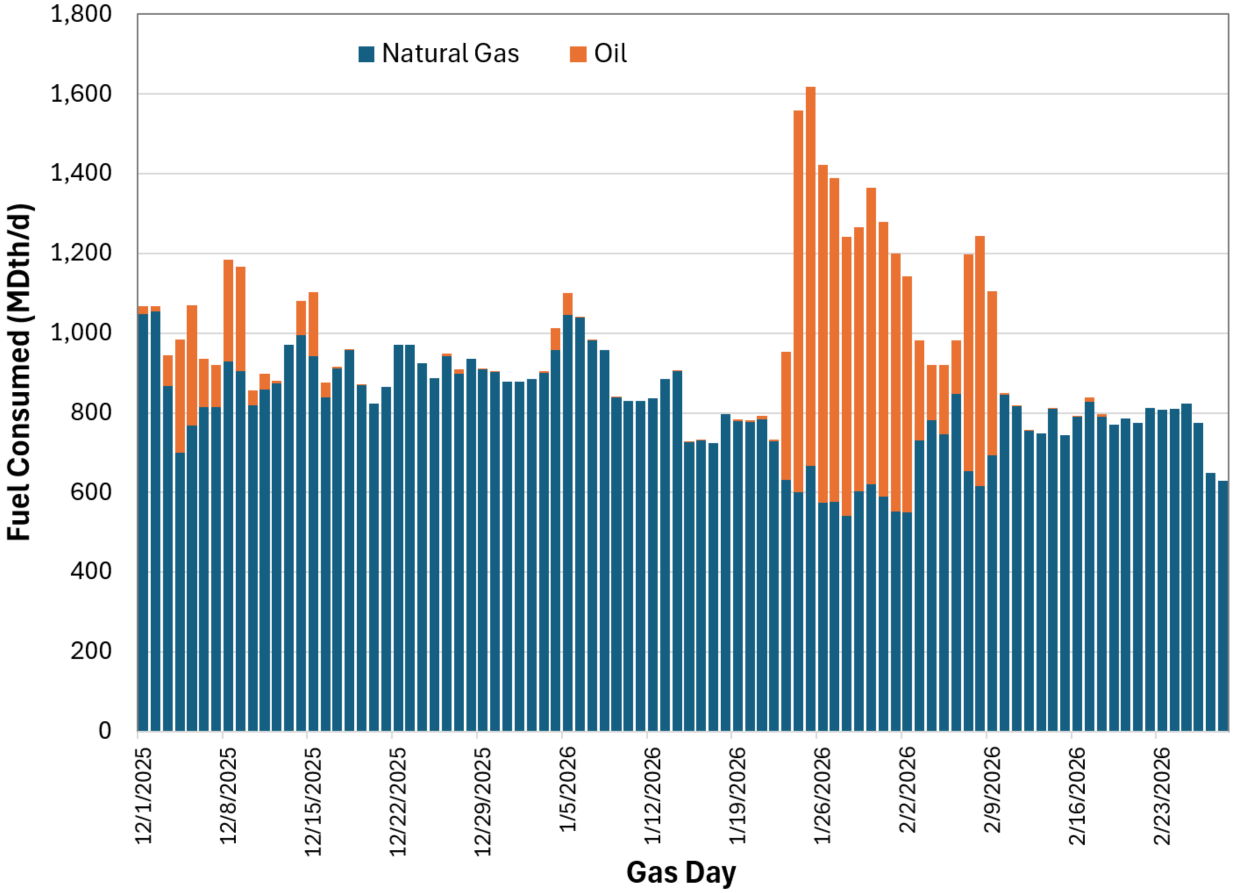
Figure 13. Winter Energy Sources by Day During Winter 2025-26[66]



Looking specifically at fuel usage by gas-capable generators connected to Algonquin and Tennessee during winter 2025-26, Figure 14 shows the increased use of oil at these plants during WS Fern and the subsequent cold snap. Absent sendout from EMT, even less natural gas would have been available to these generators during this period.

[66] NEPOOL Participants Committee System & Market Operations Report March 2026, presented by Stephen George at the March 5, 2026, meeting. See slide 21.

Figure 14. Fuel Use by Algonquin and Tennessee Generators During Winter 2025-26[67]

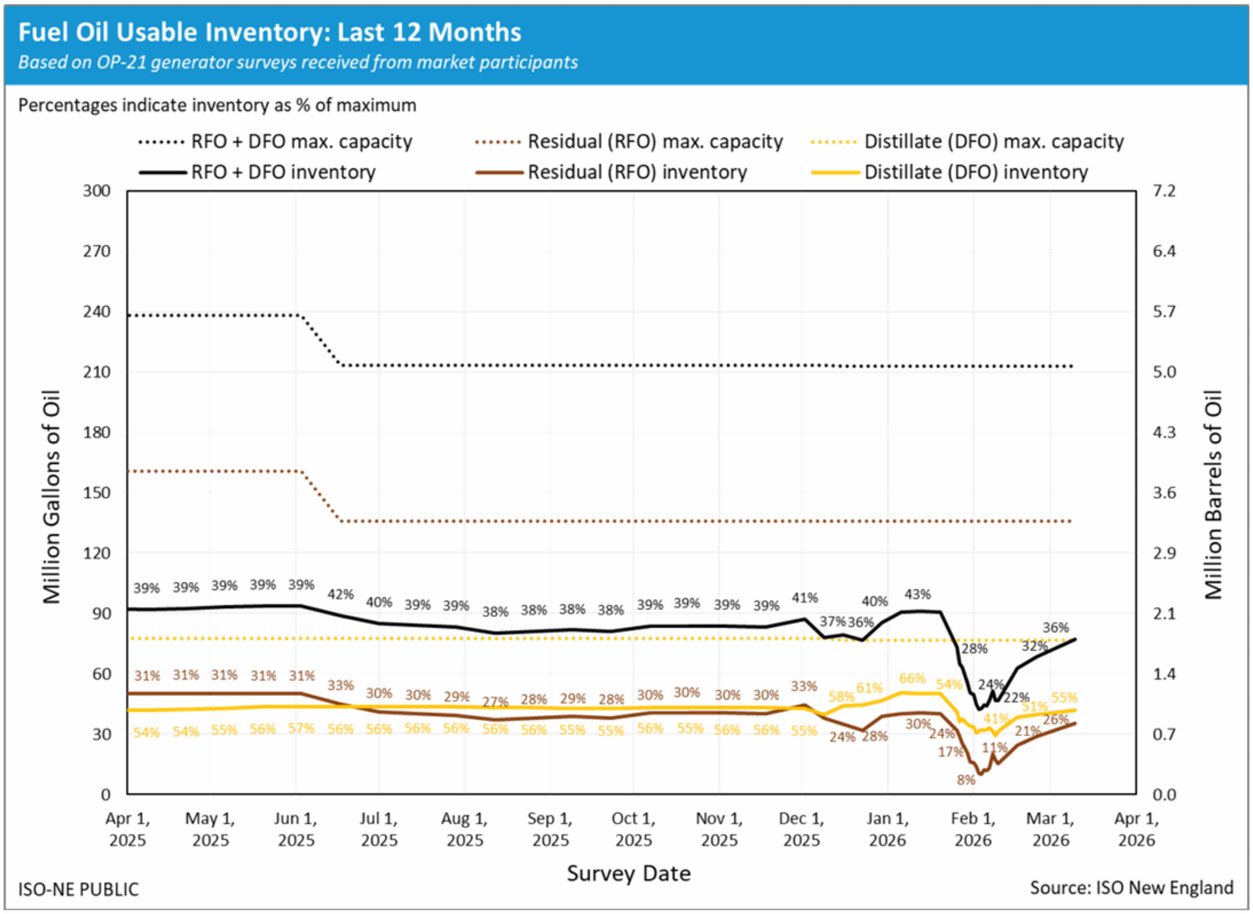


The heavy use of oil during the cold period led to a predictable depletion of generators' oil inventory. Per ISO-NE, total regional usable fuel oil inventory dipped to near 20% in early February as WS Fern delayed truck-based refueling and the limited availability of barges delayed Residual Fuel Oil (RFO) replenishment. RFO, in particular, dipped to 8% of regional maximum capacity prior to timely refills. At the March 5, 2026 New England Power Pool (NEPOOL) Participants Committee meeting, an ISO-NE representative observed that the region was fortunate that harbor freezing did not become an issue and that suppliers had available product and barge access once logistics resumed.[68] Figure 15 details the depletion of usable oil inventory during WS Fern and the subsequent cold snap. EMT's output throughout the cold snap helped avoid further depletion of the region's strained oil inventory. Additional reliance on oil-fired generation would have caused still more adverse environmental effects in light of the difference in criteria pollutants and, to a lesser extent, carbon, between oil and natural gas. Fuel switching also incurs additional Regional

[67] U.S. EPA, Clean Air Markets Program Data, https://campd.epa.gov/data.
[68] NEPOOL, Supplemental Notice of April 9, 2026, Participants Committee Meeting, page 5246. https://www.iso-ne.com/static-assets/documents/100034/npc-2026-04-09-supplemental.pdf.

Greenhouse Gas Initiative (RGGI) allowance costs. With Virginia electing to re-enter the RGGI program, allowance prices have been trading at over $40/ton.[69]

Figure 15. ISO-NE Fuel Usable Inventory during WS Fern[70]

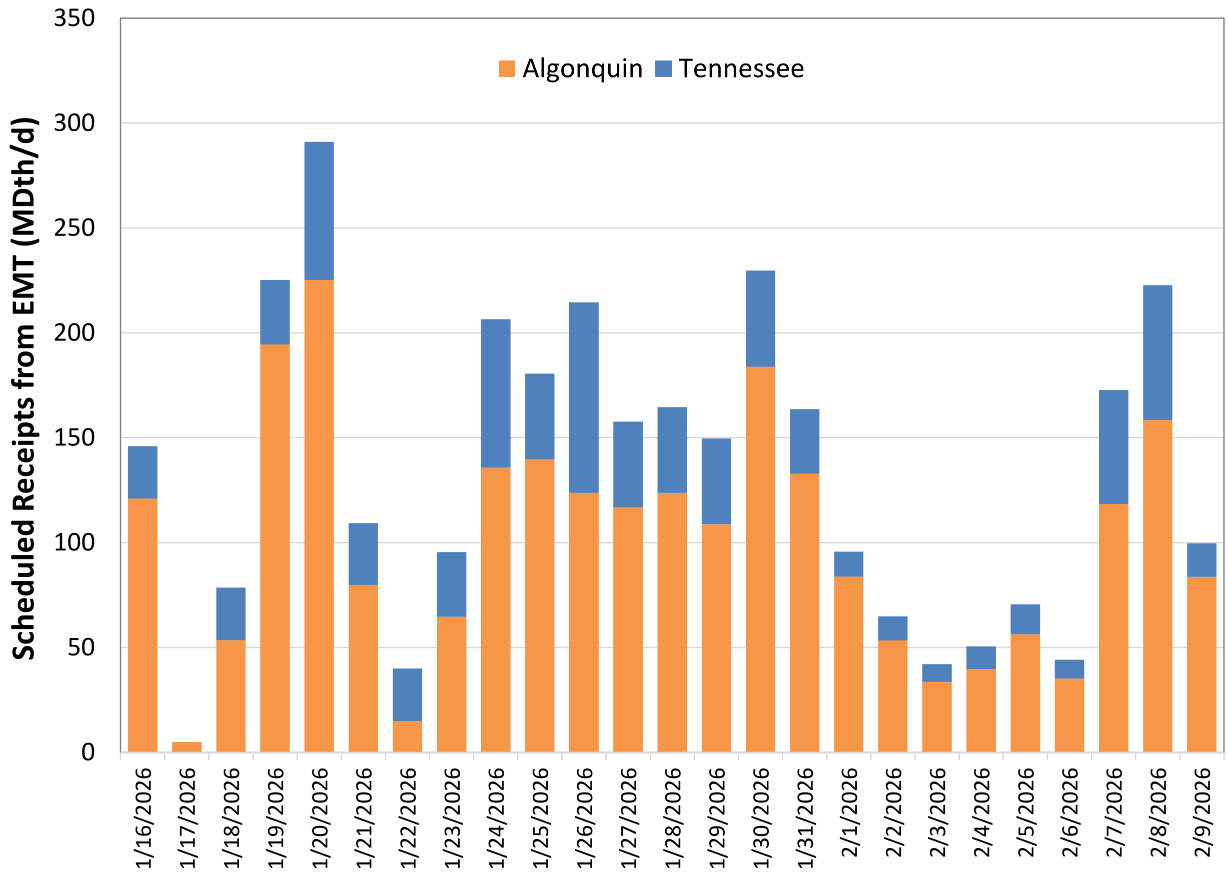


EMT injected significant volumes into Algonquin, Tennessee, and NGrid during WS Fern and the ensuing cold snap, supporting the supply needs of LDCs and other large gas consumers such as generators. Without EMT's supplies, at minimum more oil-fired generation would have been needed to meet the demands of the electric grid. Figure 16 shows the magnitude of EMT's scheduled sendout into Algonquin and Tennessee during WS Fern and the ensuing cold snap. This figure does not include volumes scheduled directly into NGrid, which are not reported publicly.

[69] cCarbon, "Why are Allowance Prices in RGGI Beyond $45?" Accessed March 3, 2026. https://www.ccarbon.info/article/why-are-allowance-prices-in-rggi-beyond-45/

[70] Oil-Depletion and Usable-Oil Inventory Graphs, ISO-NE. https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/oil-depletion-graphs

Figure 16. Algonquin and Tennessee Scheduled Receipts from EMT During WS Fern[71]

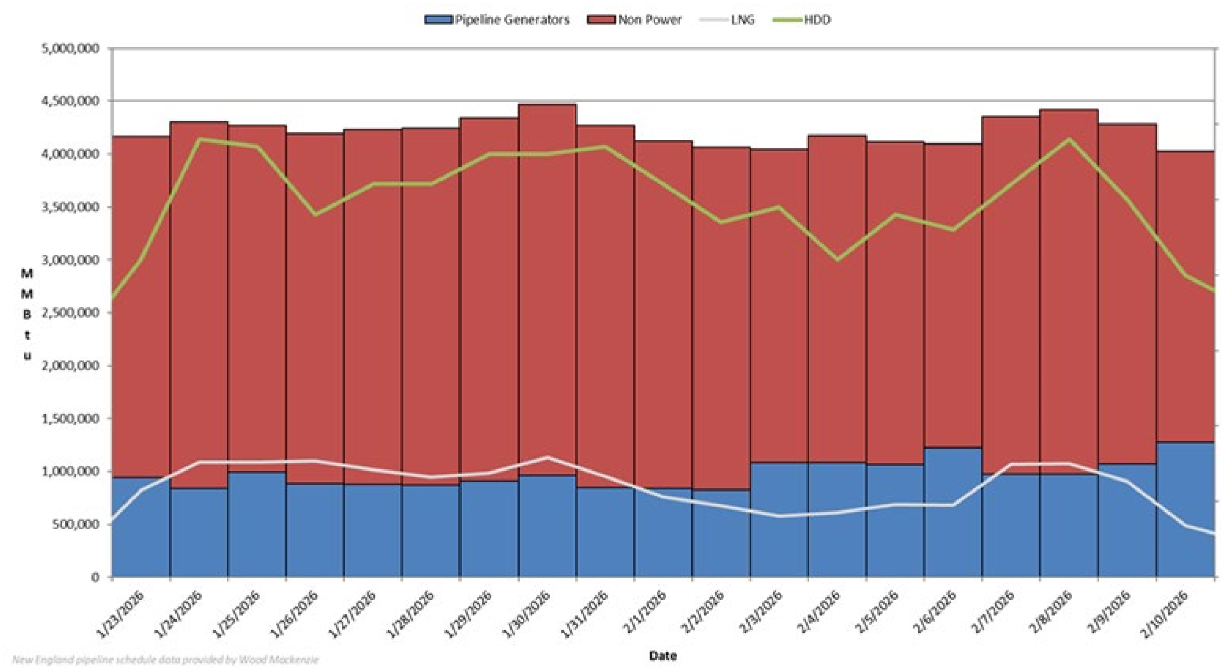


Over the period between January 16 and February 9, 2026, Algonquin and Tennessee had scheduled receipts from EMT of over 3.3 Bcf, which contributed to meeting the near-peak day demands of New England LDCs and the demands of other large gas consumers, such as gas-fired generators. With winter Northeast gas markets priced above Atlantic Basin LNG prices during the month of December 2025, CLNG was engaged by numerous counterparties for short duration, spot sales. Over the course of December 2025, CLNG procured enough incremental LNG supply to support concurrent short-duration winter Northeast gas sales. This additional supply ensured that EMT would have inventory to support these spot sales while still honoring commitments to the LDCs during and after the extended cold weather. During this period, the day with the highest scheduled Algonquin and Tennessee receipts from EMT was January 20th, 2026 with a total of 291 MDth. This included volumes that supported critical deliveries to the region's other large gas consumers, such as gas-fired generators. Assuming that the gas in excess of the LDCs' combined MDQ supported gas generation, scheduled receipts from EMT during the 21-day

[71] Algonquin and Tennessee Informational Postings via S&P Capital IQ's Operational Capacity Summary. Reported volumes are for the Intraday 3 cycle.

period enabled at least 323 GWh of regional gas-fired generation, which is the equivalent of roughly 25,200,000 gallons of oil.[72] The assumed use of sendout from EMT to supply generation is borne out by ISO-NE reporting that during the recent "Cold Weather Outbreak," LNG terminal vaporization was about 0.88 Bcf/d and gas demand for power generation was about 0.98 Bcf/d.[73] Figure 17,prepared by ISO-NE, illustrates the split between pipeline deliveries to generators and other customers, primarily LDCs.

Figure 17. Natural Gas Schedules to Generators vs. Non-Power Use per ISO-NE[74]



During WS Fern and the following cold snap, EMT's injections into Algonquin and Tennessee tempered basis spikes that, absent EMT deliveries, would have been more pronounced and frequent. This moderating effect is evidenced by gas prices during this period showing that New England indices had a smaller price spike relative to upstream locations in New York and New Jersey, which do not have direct access to imported LNG. Traditionally, New York and New Jersey indices are priced lower than New England indices due to their relative proximity to liquid supply points. On the peak pricing day during WS Fern, January 27th, 2026 northeast delivered gas prices exceeded $100/Dth. The leading index for delivered gas sales in the New York City area, Transcontinental Gas Pipeline (Transco) Zone 6-NY, was priced

---

[72] Using a simple heat rate of 7,000 Btu/kWh (higher heating value). 5.99 barrels oil per Dth calculated using January 2026 EIA 923 data for New England RFO/DFO generation. 11.2 Dth per MWh from EIA Electric Power Annual table 8.1.

[73] NEPOOL Participants Committee System & Market Operations Report March 2026, presented by Stephen George at the March 5, 2026, meeting. See slide 42. https://www.iso-ne.com/static-assets/documents/100033/system-and-market-ops-report-mar-2026.pdf

[74] *Id.*

16% higher than New England's leading index (Algonquin Citygates). Though it is difficult to pin pricing differences on one single factor, New England's access to imported LNG via EMT and St. John LNG dampened local price spikes on the coldest days. This dampening effect yields valuable consumer savings for both LDC customers and in the wholesale energy market administered by ISO-NE.

Figure 18. Northeast Natural Gas Prices, November 2025-March 2026

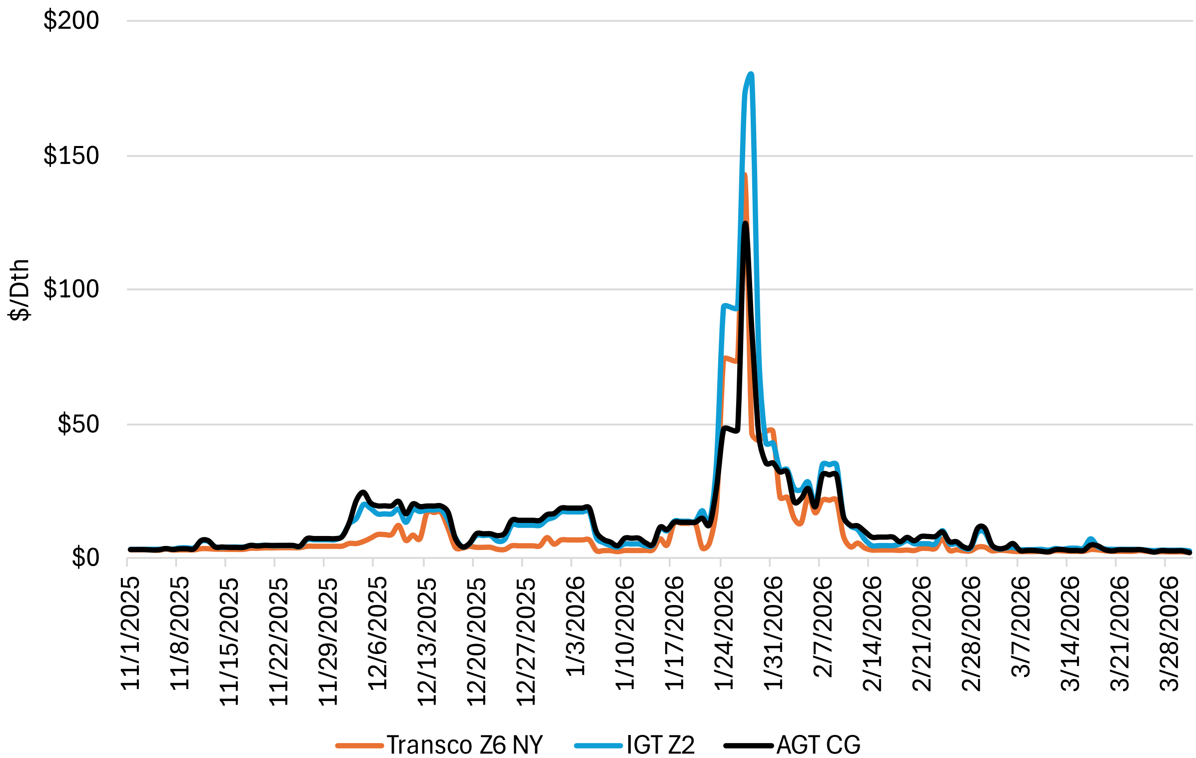
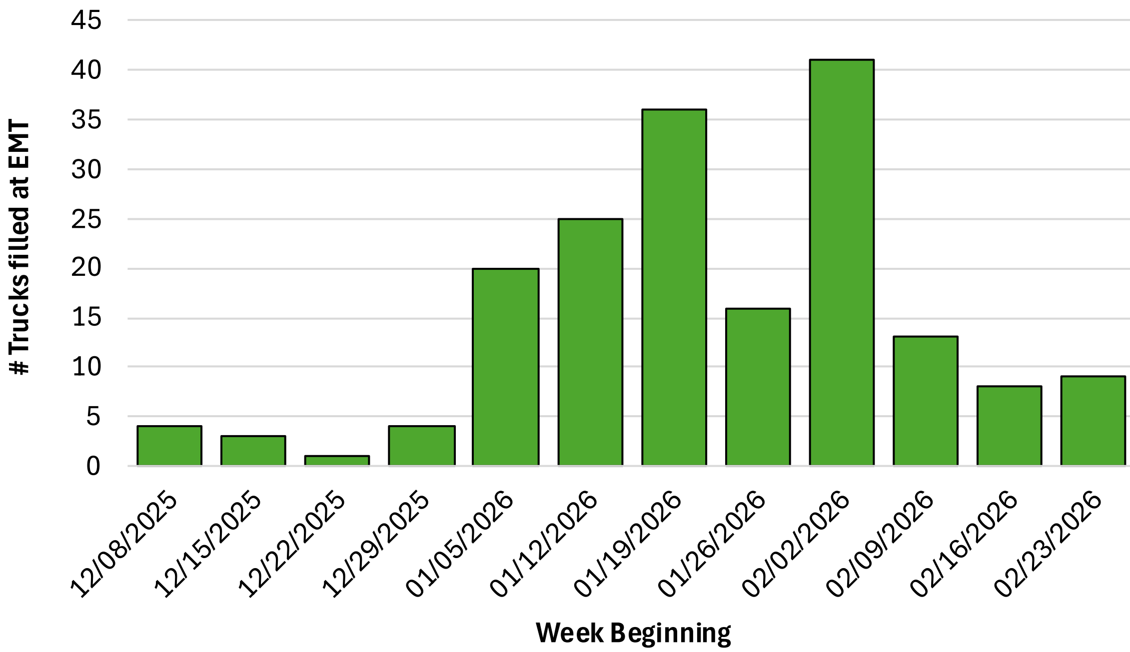


Figure 19 displays the number of trucks loaded at EMT over the winter period (December through February). Of the total 183 trucks, 100 were loaded during the 21-day period during WS Fern and the ensuing cold snap (January 21st to February 10th). EMT's trucking and scheduling flexibility under duress is noteworthy. These just-in-time supplies enabled LDCs to continue the operation of small but locationally critical satellite facilities with limited on-site storage. EMT's proximity to these LNG plants enabled the LDCs to organize refill while minimizing road miles on days with extreme snowfall, high winds and icy roads. On those days, every additional mile the trucks need to travel introduces incremental risks.

Figure 19. Weekly Totals of Trucks filled at EMT, Winter 2025-26



2.3 Comparative Assessment of St. John LNG

St. John LNG, located in Saint John, New Brunswick, is a large-scale LNG import and storage facility operated in connection with Repsol's Atlantic Basin LNG trading operations. The facility is able to receive the larger Q-Flex and Q-Max vessels, which provides Repsol with efficiency on shipping costs.[75] St. John LNG may also enjoy flexibility in sourcing as a result of being able to accommodate larger vessels.[76] Repsol has a diverse LNG supply portfolio and recent cargos have been sourced from locations including Australia, Peru and Trinidad.[77]

St. John LNG and EMT have complementary, but not interchangeable, roles in the New England gas market. The contemplated loss of either facility would create an operational reliability gap that the other cannot fill, all other things being the same.

St. John LNG has 10 Bcf of storage capacity, sustainable vaporization of 1 Bcf/d, and maximum vaporization of 1.2 Bcf/d. Vapor sendout is transported via the Emera Brunswick (Brunswick) pipeline, which has a design capacity of 850 MDth/d and connects with M&N in

---

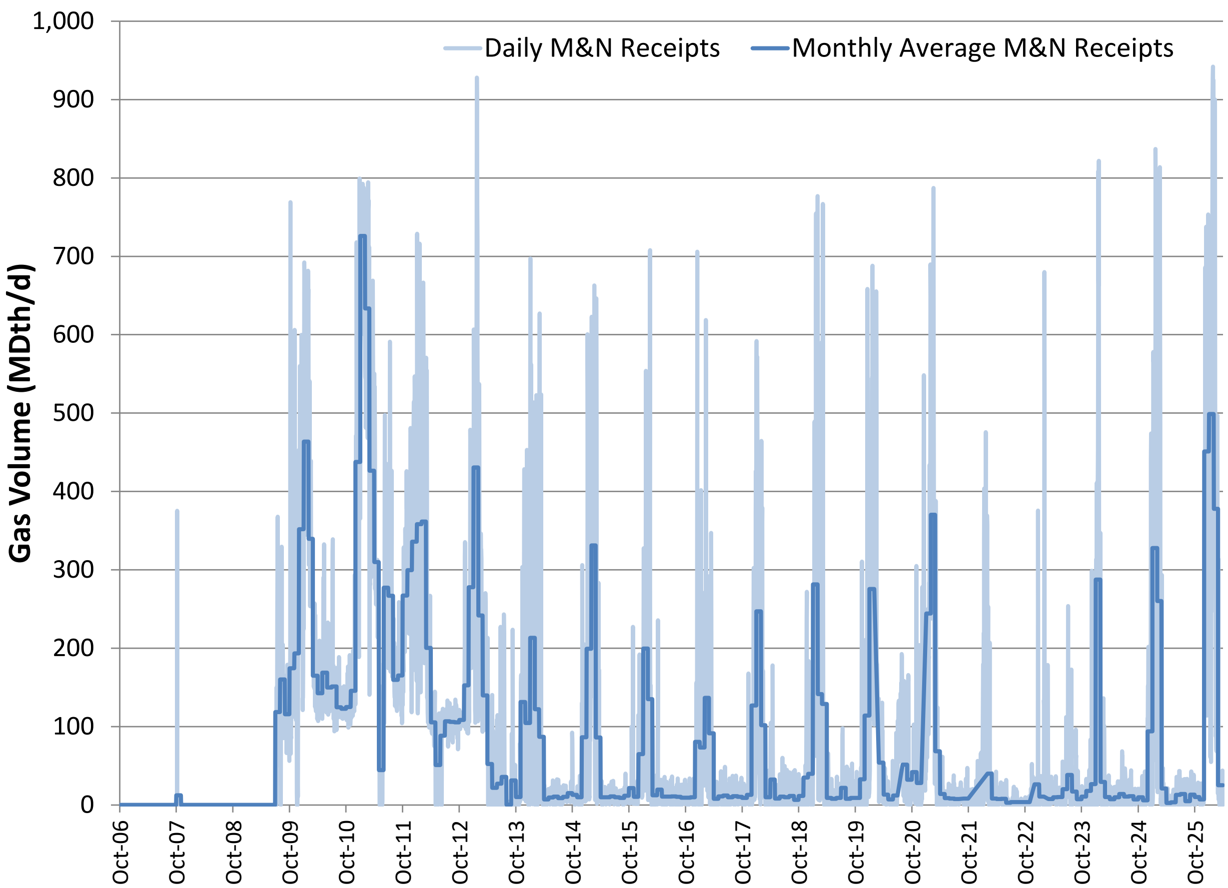
[75] "Repsol Signs a Multi-year LNG supply agreement with Qatargas," October 7, 2010. Accessed May 13, 2026. https://www.saintjohnlng.com/post/repsol-signs-a-multiyear-lng-supply-agreement-with-qatargas.

[76] The largest LNG vessels hold 5.5 Bcf, nearly twice the storage capability of the smaller and older vessels Constellation relies upon for EMT.

[77] Data available at https://www150.statcan.gc.ca/n1/pub/71-607-x/2021004/imp-eng.htm

Maine near the U.S.-Canada border.[78] Figure 20 and Figure 21 show St. John LNG's historical sendout over the last twenty years and during the winter of 2025-26, respectively. M&N has reported receipts in excess of Brunswick's reported design capacity during two separate cold weather events, first in January 2013 and most recently during WS Fern, with maximum receipts of 942 MDth/d on January 26, 2026.

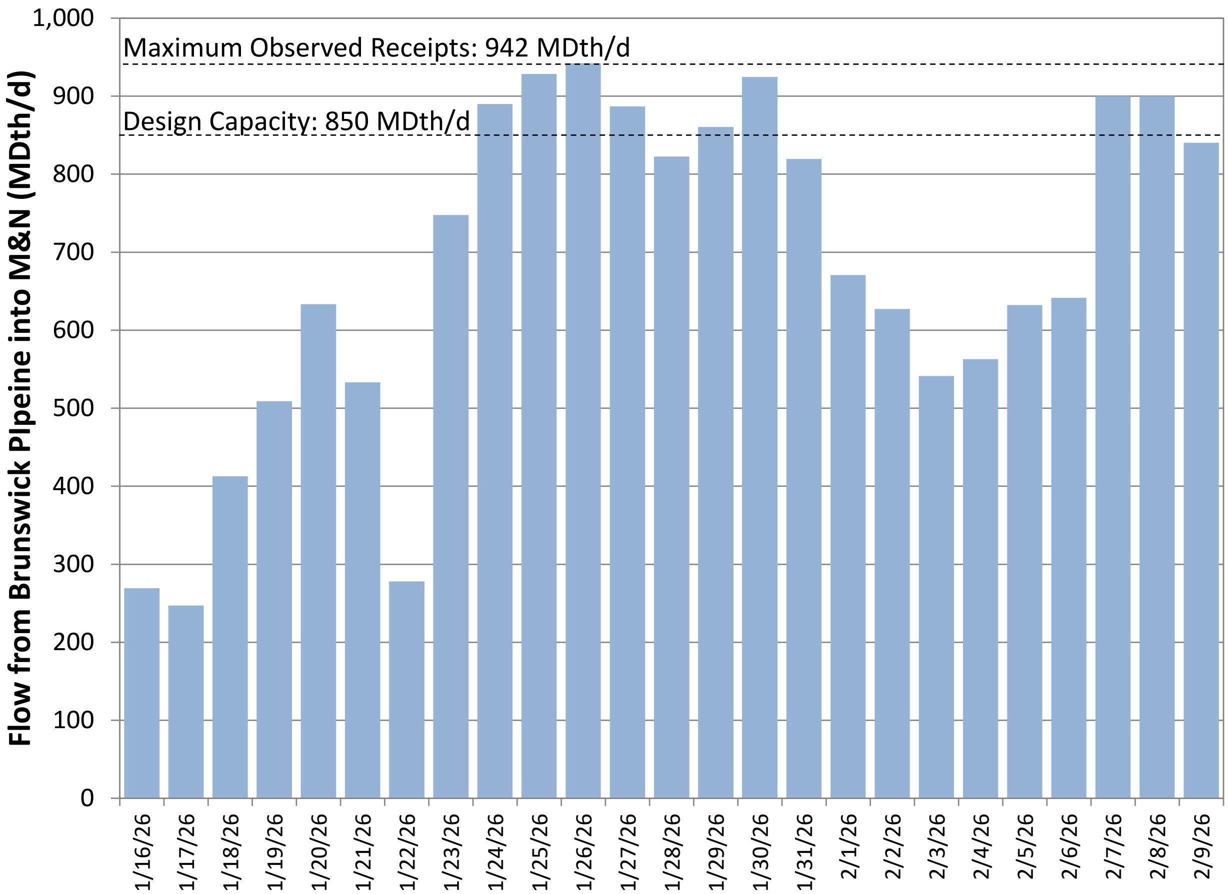
Figure 20. M&N Receipts from Brunswick Pipeline, October 2006-March 2026[79]



[78] Brunswick Pipeline Quick Facts, https://www.emeranewbrunswick.com/pipeline-operations/about-the-brunswick-pipeline

[79] M&N Informational Postings via S&P Capital IQ's Operational Capacity Summary. Reported volumes are for the Intraday 3 cycle.

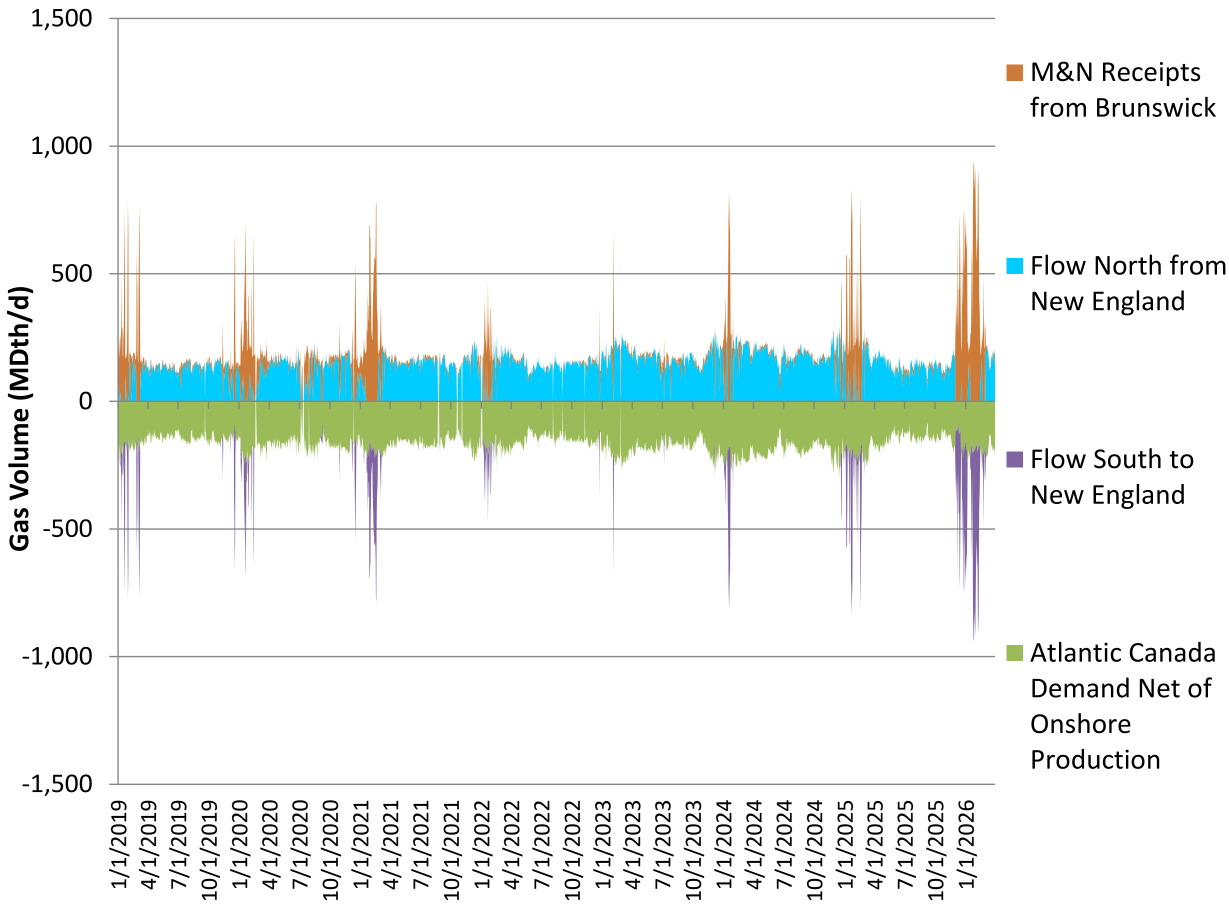
Figure 21. M&N Receipts from Brunswick Pipeline During WS Fern



While all sendout from St. John LNG via the Brunswick pipeline is initially delivered into New England because the interconnection between the Brunswick pipeline and M&N is located in Maine, a portion of the gas that is delivered into M&N subsequently flows north into Canada, as shown in Figure 22 and Figure 23. Repsol holds 730 MDth/d of firm transportation capacity on M&N, deliverable to Dracut and Beverly.[80]

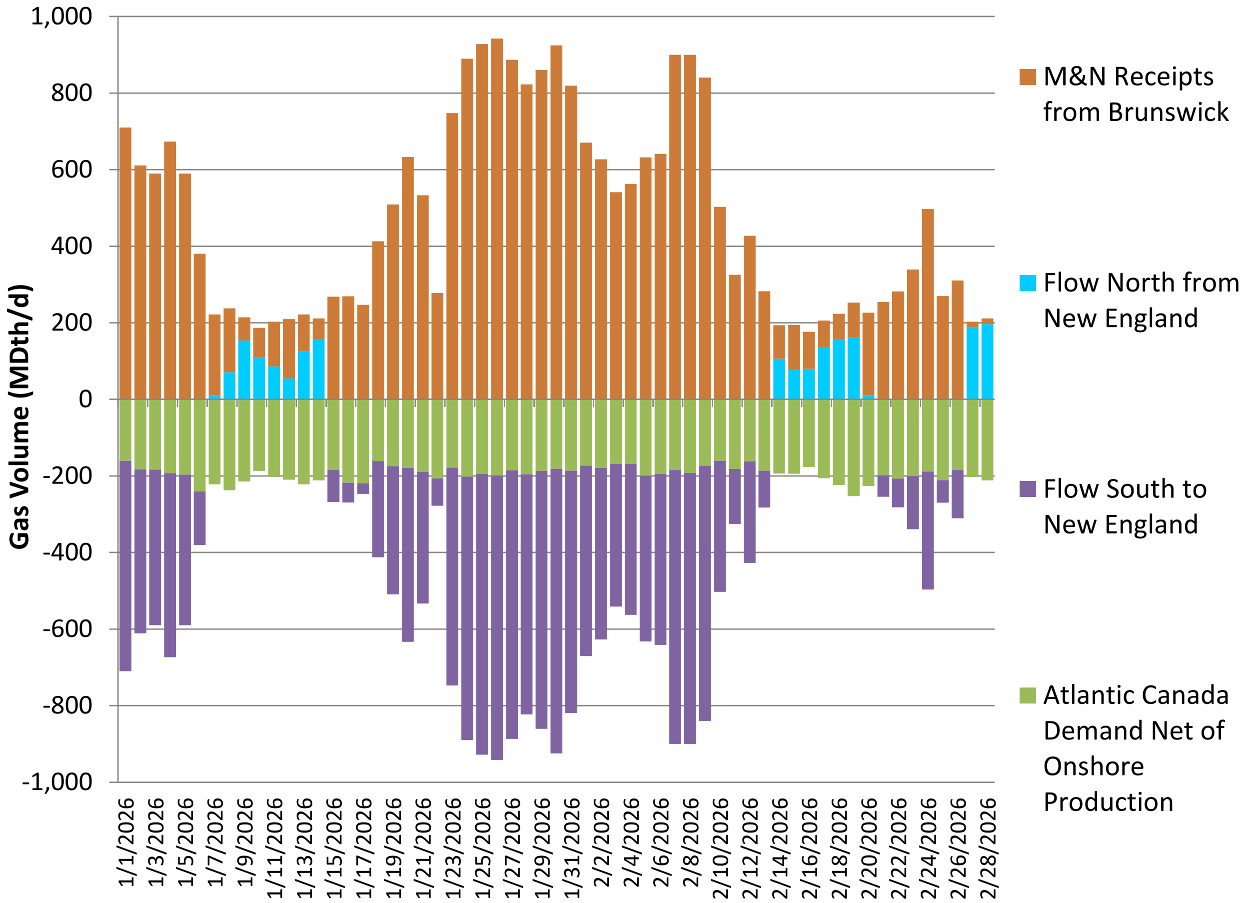
[80] Repsol has eight years remaining on its contract for firm transportation on M&N. The annual cost of this agreement is approximately $100 million. M&N has indicated, in its 2024 FERC rate filing (Docket No. RP24-780), that it does not expect Repsol to continue to hold firm service beyond the agreement's expiration date.

Figure 22. M&N Flow Balance at U.S.-Canada Border, January 2019-March 2026[81]



[81] M&N Informational Postings and Capital IQ. Data is shown only since January 2019 to represent flows following the cessation of production from offshore Atlantic Canada.

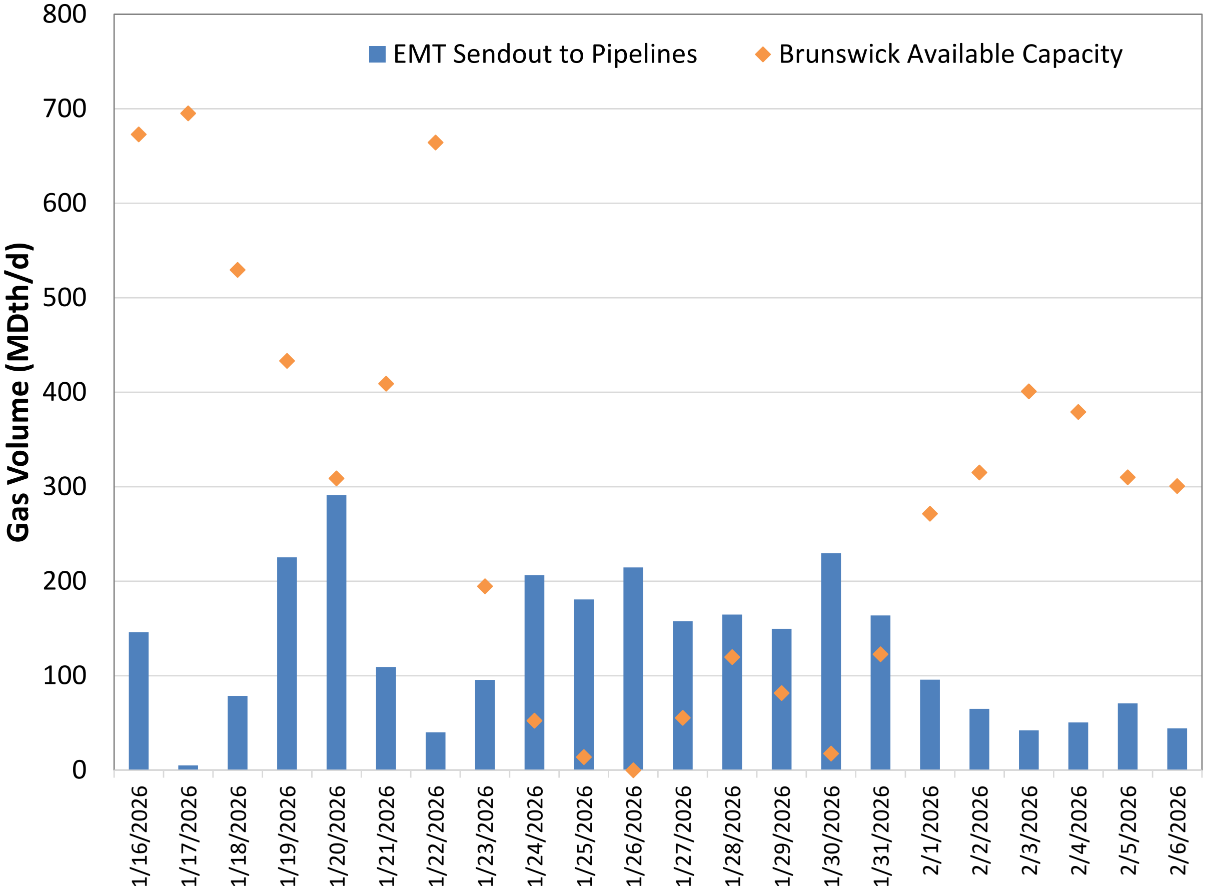
Figure 23. M&N Flow Balance at U.S. Canada Border, January and February 2026[82]



While St. John LNG provides significant gas supply to New England when market conditions warrant, it can only offset supply from EMT to the extent that it would otherwise be operating at less than its full sendout capacity. Figure 24 shows the unutilized sendout capacity from St. John LNG during January and February 2026, represented as the orange diamonds that show the daily difference between receipts and maximum observed receipts of 942 MDth/d, as shown above in Figure 21, compared to vapor sendout from EMT to Algonquin and Tennessee. If, hypothetically, EMT had not been operating during this period, St. John LNG would not have been able to make up the difference during the eight-day stretch from January 24th to January 31st.

82 M&N Informational Postings and Capital IQ.

Figure 24. Ability of St. John LNG to Offset Scheduled EMT Receipts During WS Fern



This calculation of relative available supply is stated in a flow balance context, without regard to locational considerations. St. John LNG injects gas further upstream than EMT, approximately 460 pipeline miles from the southern end of Algonquin's Hubline, 480 pipeline miles from the J System offtake point from the Algonquin mainline, and 510 pipeline miles from EMT. Gas flows from St. John LNG are subject to multiple capacity constraints along the path into southern New England. The southbound flow on M&N is limited by the pipeline's capacity of 849 MDth/d. Deliveries from M&N into Algonquin and Tennessee are further limited by the capacities of the downstream pipeline segments. On Algonquin, the east-to-west peak day design capacity of the I-8 Loop is 440 MDth/d. On Tennessee, gas delivered to Dracut can flow along the Concord, Tewksbury, or Wyeth laterals, which have a combined total capacity of 370 MDth/d. Up to 411 MDth/d can also backhaul toward Station 267.

Aside from capacity limitations, St. John's relative distance does not allow it to provide the same pressure support and balancing services on Algonquin's J System and Tennessee's east end as EMT. Even at gas velocities of ten to twenty miles per hour, supplies from St. John LNG would take one to two days to reach the Algonquin and Tennessee systems.

St. John LNG does not have liquid sendout capability. St. John LNG cannot, therefore, substitute for EMT in this regard.

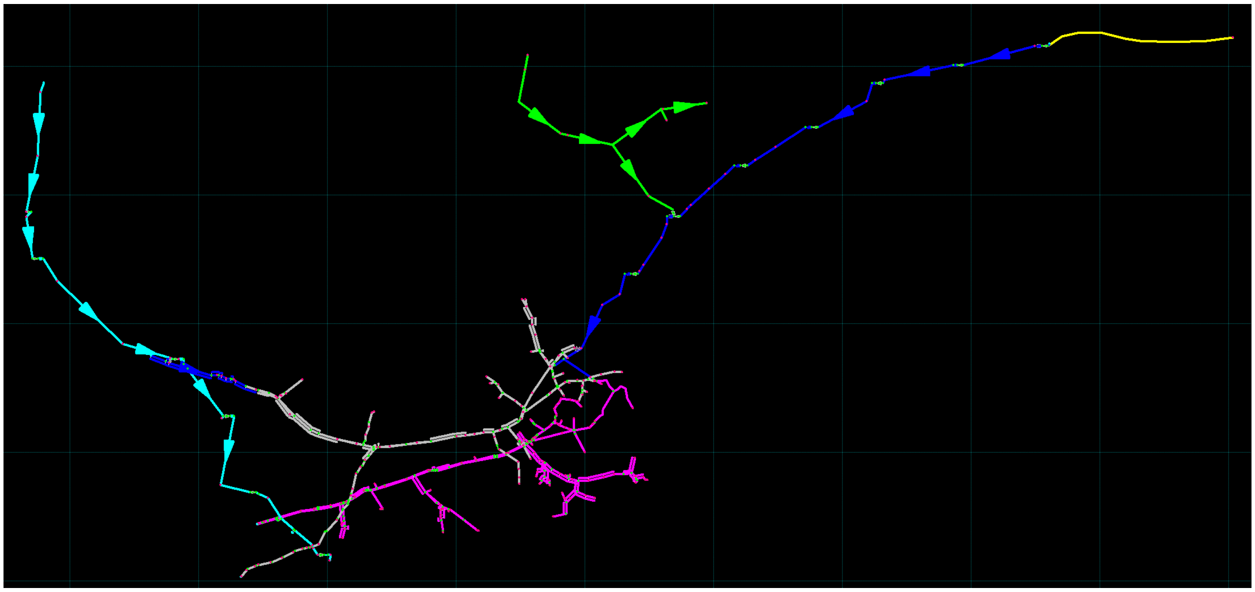
From the pipeline perspective, both Kinder Morgan and Enbridge challenged the substitutability of St. John LNG for EMT in their written comments in advance of the 2023 FERC Forum. Kinder Morgan found the assumption that St. John and the Northeast Gateway could offset EMT's retirement was unsupported, noting that even if those terminals could secure additional cargo volumes, no detailed study had been conducted to establish whether adequate pipeline capacity existed to transport materially higher LNG supplies from those facilities to New England load centers.[83] Enbridge reinforced this concern from its position as the operator of Algonquin and M&N, observing that capacity limitations on the most constrained laterals of the Algonquin system mean that additional LNG supply from upstream sources cannot reach the power plants and distribution customers that need it most. Enbridge concluded that "all the LNG in the world isn't going to help if it can't get to the plants that need it."[84] While inconclusive because it had not then been studied, Kinder Morgan's expert, Mr. Ernesto Ochoa, indicated a small project on Tennessee would be needed to bolster deliverability across its system to move gas from St. John LNG into the Tennessee mainline.[85]

2.4 But-For Assessment of EMT's Reliability Contribution During WS Fern

Using our steady-state and transient hydraulic models of New England's consolidated interstate pipeline infrastructure, LAI examined the level of impact on gas and electric system operations if EMT had hypothetically not been available during WS Fern to provide supply and balancing support.[86] Figure 25 illustrates the scope of the consolidated hydraulic model, which corresponds to the current configuration of pipeline infrastructure across the region.

[83] Kinder Morgan, Inc., Pre-Forum Comments, FERC Docket No. AD22-9-000, June 16, 2023, at page 6–7.
[84] Enbridge Gas Pipelines, Pre-Forum Comments, FERC Docket No. AD22-9-000, June 16, 2023, at page 8.
[85] Ernesto Ochoa, Vice President of Commercial, Kinder Morgan, Inc., Transcript of 2023 New England Winter Gas-Electric Forum, FERC Docket No. AD22-9-000, June 20, 2023, page 57–58.
[86] LAI is a licensee of Gregg Engineering's WinFlow, WinTran, and NextGen software.

Figure 25. Consolidated Hydraulic Model Footprint



The model parameters were validated in the steady-state by testing the final scheduled delivery volumes as posted publicly by the pipelines in their respective Informational Postings and confirming that segment flows in the model were aligned with the posted final scheduled segment flows. This validation was conducted for multiple days during the period of interest, specifically during WS Fern and its aftermath.

Following validation of the steady-state model for each day, intraday shaping was applied for purposes of the transient model based on the winter LDC demand profile shown in Figure 9 and the hourly gas demands for individual generators as reported in the CEMS database.[87] The variance in these profiles over the course of each day relies on the use of linepack, which causes corresponding intraday variance in pipeline operating pressures.

The but-for case, without EMT, was tested using these same levels of gas demand, with incremental gas demand added at Algonquin's Everett delivery meter to account for EMT's direct sendout to NGrid. This allowed a more complete quantification of EMT's benefits to overall system operations.

In the absence of EMT, both the amount of gas deliverable in New England and the intraday flexibility in delivered volumes would be reduced. Both generators and LDCs would be affected by this, because both sectors relied on EMT during WS Fern. In order to maintain system operations, including minimum delivery pressure requirements, absent vapor sendout from EMT, the pipelines would have reduced the amount of nominations that could be scheduled, and may have needed to issue additional hourly OFOs like the one issued by

[87] Emissions data for Q1 was reported to the EPA during April 2026.

Algonquin during WS Fern as described in Section 2.2. The reductions in scheduled volumes would have led to additional fuel switching by generators, to the extent that sufficient oil was available. ISO-NE noted in its March 2026 System & Market Operations Report to the NEPOOL Participants Committee that the 21-Day Energy Assessment and Forecast Report highlighted periods of reduced energy surplus. Though the forecast never indicated conditions severe enough to trigger an Energy Alert or Energy Emergency, it is unclear whether this would still have been the case in the absence of EMT.[88] LDCs would have experienced both reduced volumes and reduced pressures, leading to reliability challenges. The contracting LDCs are dependent on EMT to ensure reliability, and would not have been able to have supply-side or demand-side alternatives in place prior to winter 2025-26 had EMT retired with Mystic.

3 EMT Cost of Service Review

The costs associated with EMT's service include the fixed costs needed to operate and maintain the facility and the variable costs associated with acquiring gas supply. These costs are recouped via the LDC contracts through May 2030. These contracts are necessary. CLNG has previously stated, "[EMT] will be forced to cease operations if it does not have sufficient anchor customer commitment(s) in place after Mystic retires."[89] The contracts allow CLNG to recover the fixed costs associated with operating and maintaining the facility, rather than bearing the risk of securing and delivering adequate supply without the assurance of fixed cost recovery. Payment of the associated costs by the LDCs retains EMT as a resource for the region, which also benefits regional LDCs and generators who do not hold EMT contracts.

3.1 Costs Associated with Facility Operation

EMT's O&M cost base, which is recovered through the NCDC included in the LDC contracts, encompasses the expected range of expenses associated with running and maintaining a large-scale LNG import terminal in continuous operational readiness. These costs include cryogenic storage tank maintenance and inspection, vaporization and send-out equipment maintenance, marine berth maintenance and dredging, safety and environmental compliance systems, terminal staffing, insurance, and the administrative overhead associated with operating a complex regulated facility in an urban waterfront environment.

EMT's most recent FERC Form 2 Annual Reports from 2006-08, although dated, anchor the trendline for fixed costs over the last twenty years. These reports constitute a reliable

[88] NEPOOL Participants Committee System & Market Operations Report March 2026, presented by Stephen George at the March 5, 2026, meeting. See slide 44.
[89] Post-Forum Comments of Constellation Energy Generation, LLC, Post-Forum Comments, FERC Docket No. AD22-9-000, August 24, 2023, page 6

starting point pertaining to EMT's cost of service prior to transitioning from regulation under Natural Gas Act Section 7 to Section 3.[90]

Table 2 shows the calculated going-forward costs, which represent total cash-out-of-pocket expenses as well as additional CapEx necessarily committed to keep EMT safe to operate and available throughout the year.

Table 2. EMT's Going-Forward Costs, 2006-08 ($ millions, nominal)

	2006	2007	2008	Average
Operations[91]	$ 26.6	$ 24.5	$ 27.0	$ 26.0
Maintenance	$ 3.8	$ 3.5	$ 4.1	$ 3.8
Administration	$ 20.6	$ 27.0	$ 26.4	$ 24.7
Real Estate Taxes	$ 5.0	$ 3.6	$ 3.9	$ 4.2
Capital Expenditures[92]	$ 14.0	$ 3.8	$ 2.3	$ 6.7
Total Going-Forward	$ 70.0	$ 62.5	$ 63.6	$ 65.4

EMT's gross revenue requirements during the Mystic RMR report were reported in the Global Settlement Compliance Filing, as summarized in Table 3. To some extent, the reduction in fixed costs between 2006-08 and 2022-24 is related to the decrease in annual average sendout, due to the reduced fuel needed to run the vaporizers.

Table 3. EMT's Gross Revenue Requirements, 2022-24 ($ millions, nominal)[93]

	2022	2023	2024	Average
Production O&M	$ 38.6	$ 36.4	$ 34.6	$ 36.5
Corporate Admin & General	$ 10.3	$ 10.3	$ 10.7	$ 10.4
Depreciation Expense	$ 0.6	$ 0.7	$ 0.8	$ 0.7
Taxes Other Than Income	$ 3.5	$ 3.0	$ 3.0	$ 3.2
Pre-tax Cost of Capital	$ 6.1	$ 6.0	$ 5.1	$ 5.7
Gross Revenue Requirement	$ 59.1	$ 56.4	$ 54.2	$ 56.6

[90] Natural Gas Act Section 3 and Section 7 have different scopes. Section 3 governs the import/export of natural gas, including LNG terminals and imposes information filing requirements on public interest and compliance with safety and environmental standards. Section 7 governs the construction and operation of interstate pipelines and imposes more rigorous, case-specific reporting requirements regarding "public convenience and necessity."

[91] The largest operating expense component was fuel to vaporize the LNG for sendout as natural gas and therefore does have a variable component related to sendout volume.

[92] EMT provided beginning-of-year and end-of-year values for the LNG plant in service. The change in those values before any adjustments for depreciation or amortization is the CapEx for that year.

[93] FERC Docket No. ER18-1639, Compliance Filing of Tariff Records to Implement Global Settlement Agreement, February 12, 2025, Appendix A, p. 2. The Gross Revenue Requirements stated in Table 3 are the full facility costs, prior to the 91% adjustment factor associated with only vapor costs being included in the Cost of Service Agreement.

RTO Insider has reported that, “Brattle estimated $375 million would go to covering Everett’s operating costs.”[94] Divided across six years, this represents an annual cost of approximately $62.5 million. While these costs are lower than the going-forward costs in 2006-08, they are slightly higher than the Gross Revenue Requirements during the 2022-24 Mystic RMR period. This increase relative to the RMR period is due to material escalation in several of the underlying costs. The rate associated with EMT’s firm entitlements on Algonquin has increased as CLNG’s firm transportation charges payable to Algonquin have transitioned from a negotiated rate to the max rate. Supply chain cost inflation affecting cryogenic equipment components, specialized materials, and skilled labor has driven up both routine O&M and capital expenditure for plant availability. Additionally, core inflation in New England has run above national averages since 2021, driven by persistently elevated labor costs in the construction and skilled trades sectors, rising property values in the greater Boston metropolitan area, and supply chain disruptions that have increased the cost of specialized industrial equipment and materials.[95] EMT requires continuous maintenance of cryogenic storage tanks, vaporization equipment, marine infrastructure, and safety systems by a specialized workforce. This inflationary environment translates directly into upward pressure on O&M costs. Despite these general trends, it is noteworthy that the annual cost of service has slightly decreased on a nominal basis, and significantly decreased on a real basis, over the last twenty years. This is indicative of notable efforts by CLNG and EMT to control costs.

Increased O&M costs and decreased contracted volumes result in substantially higher unitized costs as these fixed costs are distributed across a waning number of firm customers. Because spot sendout is uncertain and generally correlated with variances in HDDs, EMT cannot count on recouping fixed O&M costs across non-contracted volumes. To the extent that future contracts are for lower volumes, such as following Eversource’s transition of some of its EMT contract volumes to Algonquin’s RARE project, the fixed O&M costs would be spread across a smaller volume, resulting in a higher unitized rate. On the other hand, if additional firm customers are secured, the unitized rate would decrease as the fixed costs are spread across higher contract volumes.

3.2 Costs Associated with Supply Arrangements

The Commodity Demand Charge that is included in the LDC contracts reflects the fact that forward supply reservations are most efficiently achieved in full cargo increments of

[94] RTO Insider, “Everett LNG Contracts Face Skepticism in DPU Proceedings,” April 3, 2024. https://www.rtoinsider.com/75338-everett-lng-contracts-skepticism-dpu-proceedings/

[95] U.S. Bureau of Labor Statistics, Consumer Price Index — Northeast Urban, 2021–2024; Associated Builders and Contractors, Construction Backlog Indicator and Labor Cost Reports, 2022–2024; Federal Reserve Bank of Boston, New England Economic Indicators, 2023

approximately 3 Bcf. Forward purchases can only be made in full. Lost margin from partial cargoes or cargoes that return to their port of origin laden with inventory not taken by CLNG is a risk factor borne by the importer. This means that it is economic for total seasonal volume across all contracts to be rounded up to the next 3 Bcf increment, with a minimum of two cargoes due to considerations such as boiloff and other losses during unloading and summer tank hibernation, as well as the need to maintain a minimum storage inventory level. Similar to how the fixed costs of facility operation are spread across the firm customers, this minimum supply reservation cost is borne proportionately among the firm customers for whom the cargoes are reserved. As the contracted volumes increase to represent a greater percentage of the tranches, the unitized cost decreases, until an incremental volume requires an additional cargo. For this reason, it is worthwhile for CLNG to engage in discussions among potential firm customers to optimize the total seasonal quantity for a given year. Potential economies can be realized as the seasonal volumes of firm customers increase.

In addition to the seasonal volume to be reserved, supply costs are impacted by the time between signing a contract and the delivery season. The longer this interval, the more flexibility CLNG has in arranging supply. There is more volatility priced into spot market LNG for more immediate delivery dates. For example, there is more volatility contracting for LNG in the summer before a given winter, than contracting years ahead. CLNG described the considerations related to supply reservation in its filed comments following the 2022 FERC Forum:[96]

- "[N]egotiating and coordinating LNG purchase and delivery arrangements is a complicated and time-consuming task ... [O]ur experience since purchasing the facility is that the nature of the global LNG market is that LNG offtake agreements for base supply are optimally negotiated with at least a 20-24 month lead time" (page 22)
- "[P]urchasing LNG on the world market imposes additional pricing risks that Constellation must consider. And this risk can be significant especially as a result of geo-political factors that can be difficult to predict or hedge" (pages 22-23)
- "In addition, there is considerable volatility in LNG prices especially given the sensitivity of LNG prices to recent geopolitical developments, and this volatility creates the need to transact quickly. Specifically, Constellation does not buy LNG speculatively. Rather, we buy LNG to meet our LNG commitments. So as to minimize our exposure to sudden and potentially drastic LNG price swings, we seek to

[96] Comments of Constellation Energy Generation, LLC, filed November 7, 2022, in FERC Docket No. AD22-9-000.

> purchase the LNG we need to serve our customers quickly, typically contemporaneous with our agreement to sell the LNG. In this way we can hedge the LNG price volatility risk.” (page 23)

An additional consideration in contracting for LNG supplies delivered to EMT is vessel suitability. EMT can only accommodate a relatively small portion of the global LNG carrier fleet. CLNG reported in 2022 that “Fewer than 20 ships worldwide can make LNG deliveries into Everett … So the fuel supply depends on a handful of ships sailing the North Atlantic in the winter.”[97]

In the case of the current LDC contracts, they were finalized and approved very close to the delivery start date, which impacted the risk premium incorporated in the pricing. The MA DPU approved the LDC contracts on May 17, 2024, giving CLNG only five months to line up supply from the limited supply of serviceable cargos to EMT.[98] This short time frame for procurement further increased the commodity risk premium. Ideally, future contracts would be negotiated and finalized well in advance of 2030. The longer the tenor of the future contracts, and the further in advance they are finalized, the lower the all-in price, all other things being the same.

The ultimate costs associated with the EMT LDC call options are driven by global LNG pricing, sourcing logistics, inventory management, and a return on investment for CLNG. The LDC contracts are indexed to global LNG prices. Global LNG prices can be affected by tight European supply conditions, LNG cargo competition from Asian markets, and geopolitical disruptions affecting global markets. The divergence between LNG pricing and regional delivered gas price indices in New England is in large measure the price of reliability. Efforts to lessen reliance going forward on global LNG price indexation in favor of NYMEX/Henry Hub has the potential to reduce both cost and the underlying volatility.

4 Assessment of Alternatives to EMT

4.1 Incremental Pipeline Infrastructure Alternatives

In the LDCs’ filings requesting approval of the EMT contracts, incremental pipeline capacity was discussed as a potential alternative to EMT. NGrid acknowledged that a large-scale expansion of an interstate pipeline “could potentially obviate the need for the [EMT] Agreement,” but casted doubt on such a project’s ability to receive necessary local, state,

[97] Answer of Constellation Mystic Power, LLC to Motion for Summary Disposition, and Answer and Motion for Leave to Answer Protests, FERC Docket ER22-1192-000, April 8, 2022, page 12.
[98] Order Approving Gas Supply Agreements, in MA DPU Dockets 24-25-B, 24-26-B, 24-27-B, and 24-28-B, May 17, 2024.

and federal permits for a project with the same geographic footprint as EMT.[99] Further, NGrid stated that the construction timeline for such a large, interstate solution poses timing risks.

Enbridge has subsequently proposed the RARE project to add 73.5 MDth/d of capacity on Algonquin, specifically, from the Ramapo interconnection with Millennium in New York to the G System serving southeastern Massachusetts and Rhode Island. Eversource has signed up for 30 MDth/d,[100] which may (if RARE is constructed) replace the portion of Eversource's EMT contracts that are delivered on the G System. RARE would not, however, replace any of the EMT quantities held by the other LDCs, as no other LDC which currently contracts for EMT services has signed up for RARE capacity, nor could RARE substitute for Eversource's contracted quantities on Algonquin's J System or into Tennessee. RARE is a limited project focused on alleviating constraints to a specific part of Algonquin's system, the G System. RARE does not offer the full array of reliability benefits associated with EMT. Enbridge pre-filed the RARE project with FERC on February 24, 2026 and identified a target in-service date of November 1, 2028, but it is currently uncertain whether or when the project will receive all necessary permits and ultimately be constructed.[101] With respect to upstream supply, Eversource notes that Ramapo is a liquid point, and does not describe arrangements to contract for gas supply into the incremental capacity associated with RARE.[102]

In order to estimate the cost of the incremental pipeline infrastructure that would be needed to operationally replace EMT, LAI first developed cost benchmarks for regional expansion projects. FERC Applications for Certificates of Public Convenience and Necessity, specifically, Exhibit K project cost data, were used to develop unitized costs for pipeline miles and incremental compression. This analysis included data points from prior proposed and constructed projects in New England. Since there has been limited recent regional construction of significant pipeline infrastructure, cost data from projects in other regions has also been incorporated in order to account for broader cost escalation trends.[103]

The hydraulic models described in Section 2.4 were used to identify postulated in-region improvements sufficient to replicate the vapor sendout benefits of EMT in the absence of EMT. This analysis assumes that sufficient upstream supply is available at the New England border to support the utilization of the incremental in-region infrastructure. The postulated in-region improvements have been scaled to replace the volume supplied by EMT as well as

---

[99] Arangio Testimony, page 35:14-16.
[100] EGMA and NSTAR Petions for Approval. MA DPU dockets No. 25-133 and 25-134.
[101] FERC Docket No. PF26-7.
[102] MA DPU 25-134, Testimony of Eric Soderman, p. 31.
[103] The RARE project represents a recent regional project, it but has not yet submitted a certificate application with detailed cost information and is therefore not included in the analysis.

to provide the pressure support and flexibility enabling non-ratable takes that would be foregone if EMT were to retire.

The estimated unitized rates for pipeline miles and incremental compression were then applied to the postulated in-region improvements in order to estimate project costs and the associated annual cost of service. The annual cost of service was multiplied by the assumed term of the transportation service agreement in order to estimate a ratepayer cost relative to costs to support EMT over a similar time horizon. As an additional consideration the cost of service associated with Williams' proposed Constitution Pipeline was used as a proxy for the cost of enabling incremental upstream supply into the postulated in-region improvements, in the event that there is not sufficient liquid supply already available.

4.1.1 Estimation of Unitized Costs for Incremental Pipeline Capacity

Assessing the cost of substituting new pipeline build for EMT requires derivation of the unitized costs of pipeline improvements. This cost analysis is grounded in the actual construction economics of comparable projects. This analysis is used to establish an estimated range of unitized capital costs for postulated pipeline buildouts based on extrapolating costs from FERC-approved projects and adjusting for escalation relative to earlier project costs and regional considerations.

Cost benchmarking for New England pipeline projects is challenging, especially since there have been limited recent regional projects and there is much uncertainty about permitting and construction. Algonquin's AIM project placed 342 MDth/d of incremental capacity into service in January 2017 at a total cost of over $1 billion. AIM's incremental capacity is on par with the maximum sendout from EMT to Algonquin and Tennessee during WS Fern plus the MDQ of NGrid's EMT contract.[104] The total cost to the project's customers over the 15-year contract terms, based on the reservation charges, is nearly $2 billion.[105] This project is now nearly a decade old and was built during a cost environment materially different from today's.

As a more recent point of comparison, Algonquin has reported estimated costs for the RARE project, which is designed to add 73.5 MDth/d of capacity starting in 2029, of approximately $300 million.[106] This is about 40% higher than the construction cost of AIM on a capacity-unitized basis. Prior to announcing the RARE project, Algonquin held an open season for Project Maple in 2023 with a target in-service date as early as November 2029. The open season described a scope with up to 500 MDth/d from Ramapo at an illustrative rate of

[104] Final Statement of Costs, FERC Docket No. CP14-96, July 11, 2017.

[105] Reservation charge of $31.0339/Dth-month x 342,000 Dth/d x 12 months x 15 years.

[106] "Enbridge Announces Two Gas Transmission Projects as it Continues to Capitalize on Growing Natural Gas Demand," Enbridge, September 2, 2025, accessed April 23, 2026. https://www.enbridge.com/media-center/news/details?id=123862&lang=en

$2.75/Dth-day and up to 250 MDth/d from Salem at an illustrative rate of $1.05/Dth-day.[107] The illustrative rates indicate an annual cost of service for the full project scope of approximately $600 million (2023 dollars). Extrapolating over ten years results in total ratepayer costs of $6 billion (2023 dollars). With detailed cost and rate estimates not yet available for the RARE project, and only preliminary values available for Project Maple, this analysis is instead focused on projects for which full Exhibit K estimates are available. This forms the basis for the appropriate adjustments to historical project costs.

LAI identified eight projects as the most relevant benchmarks for a postulated New England pipeline buildout, each contributing different cost information depending on its region, project type, scale, vintage, and granularity of available cost data. These projects are summarized in Table 4, and include projects from the operators of Algonquin and Tennessee, the pipelines on which the postulated in-region improvements are tested, and Transco, which represents an additional pricing perspective.[108] Table 5 presents more detailed component cost information for the selected projects. These data are focused on pipeline upgrades, either lift-and-lay or looping, and incremental compression. This focus is based on the anticipated types of upgrades contemplated for postulated in-region improvements to replace EMT.

[107] Project Maple Open Season Notice for Firm Service, https://www.coventry-ct.gov/AgendaCenter/ViewFile/Item/16188?fileID=23622, accessed May 14, 2026. Illustrative rates are expressed in 2023 dollars.

[108] The Access Northeast project (FERC Docket No. PF16-1) is not included in the cost benchmarks. Access Northeast did not proceed past the pre-filing stage at FERC. No detailed cost information was filed. The Northeast Energy Direct project (FERC Docket No. CP16-21) is not included because the Market Path Component through New England was a new pipeline route and not an expansion of an existing segment. The expected cost of the greenfield pipeline was approximately $3.4 billion for incremental capacity of 1.3 Bcf/d, as estimated in 2015 for a November 2018 in-service date.

Table 4. Selected Projects for Benchmarking New Pipeline Build

	Docket No.	Capacity (MDth/d)	Total Exhibit K Cost ($ Millions)	Full In-Service Date	Region
Enbridge Projects					
AIM	CP14-96	342	$1,160	January 2017	Northeast
Atlantic Bridge	CP16-9	132.7	$627	January 2021	Northeast
Kinder Morgan Projects					
Connecticut Expansion	CP14-529	72	$100	November 2017	Northeast
Station 261 Upgrades	CP19-7	72.4	$58	October 2021	Northeast
Williams Projects					
Hillabee Expansion Phase 1	CP15-16	818.4	$276.7	July 2017	Southeast
Hillabee Expansion Phase 2	CP15-16	206.6	$101.0	May 2020	Southeast
Northeast Supply Enhancement	CP17-101	400	$926.5	December 2019[109]	Northeast
Southeast Supply Enhancement	CP25-10	1,596	$1,527	November 2027	Southeast

[109] The project was cancelled and the subsequently re-authorized, but updated Exhibit K costs have not been filed, pending completion of the project. Therefore, the expected in-service date as of when the project was originally filed is used to provide timing context for these costs.

Table 5. Infrastructure Cost Benchmarks for Selected Projects

Project	Pipe in Existing ROW (miles)	Cost of Pipe in Existing ROW ($ millions)	Cost per mile of Pipe in Existing ROW ($ millions/mile)	Incremental Compression at Existing Stations (HP)	Cost of Incremental Compression at Existing Station ($ millions)	Cost per 1,000 HP of Incremental Compression at Existing Station ($ millions/1,000 HP)
Enbridge Projects						
AIM	32.5	$653.8	$20.1[110]	81,620	$306.0	$3.7
Atlantic Bridge	6.4	$297.3	$46.5	15,500	$109.4	$7.1
Kinder Morgan Projects						
Connecticut Expansion	13.26	$100.2	$7.6			
Station 261 Upgrades	2.1	$20.4	$9.7	4,418	$14.9	$3.4
Williams Projects						
Hillabee Expansion Phase 1	20.06	$147.9	$7.4	36,500	$65.8	$1.8
Hillabee Expansion Phase 2	10.63	$115.7	$10.9	16,000	$38.2	$2.4
Southeast Supply Enhancement	54.9	$734.7	$13.4	200,607	$580.2	$2.9
Northeast Supply Enhancement	13.76	$241.6	$17.6	53,902	$167.7	$3.1

[110] There is a significant cost-per-mile differential between mainline improvements ($26.6 million per mile) and lateral improvements ($6.4 million per mile).

The changes in unitized costs for projects in similar locations are reasonably indicative of overall trends, even though the projects are not directly comparable. The escalation between the AIM and Atlantic Bridge projects indicates the relative cost of subsequent expansions of Algonquin. Separating the mainline and lateral costs for AIM and comparing the mainline pipeline improvements for AIM and Atlantic Bridge yields an increase of 75%. Applying this same escalation to the AIM lateral improvements and calculating a 2021-vintage estimate of the number of mainline and lateral looping contemplated for RARE yields a cost of $256 million.[111] The estimated cost of $300 million represents additional escalation of 16%. On the compression side, the escalation associated with upgrades of 88% between AIM and Atlantic Bridge is even higher than the change in pipeline costs.

Tennessee has had limited expansions in New England over the last ten years. Between the two identified regional projects, the Connecticut Expansion project and the Station 261 Upgrades project, unitized pipeline improvement costs increased 28% over four years.

A comparison of the pipeline components of the Transco projects in the southeast shows a 48% increase between Hillabee Expansion Phase 1 and Phase 2, and a 23% increase between Hillabee Expansion Phase 2 and the estimated costs of the Southeast Supply Expansion. The compression upgrades exhibit less escalation between Hillabee Expansion Phase 1 and Phase 2 of 32%, but similar escalation between Hillabee Expansion Phase 2 and Southeast Supply Expansion of 21%.

While pipeline construction associated with significant incremental capacity has not been completed in New England since 2021, the cost drivers have escalated sharply over this time period, reinforcing the conclusion that pipeline alternatives to EMT have become more rather than less expensive relative to EMT's cost of service.

The ENR Construction Cost Index has compounded at approximately 4.5% annually since 2015.[112] This baseline escalation rate reflects both materials cost volatility, driven primarily by steel price cycles and specialty alloy availability, and labor cost growth in the unionized pipeline construction trades. Post-pandemic supply chain disruption pushed ENR escalation above 7-8% annually during 2021 to 2023, with particular upward pressure on the cost of insulated pipe, compressor components, and the specialized cathodic protection coating systems required to ensure the integrity of high-pressure gas service. While escalation has moderated from the 2021 to 2023 peak, the cumulative effect on a 2015-

---

[111] The compressor station upgrades that are part of the RARE project are very limited in scope. The estimated cost of the project is therefore assumed to be near-fully allocable to the pipeline upgrades.

[112] Engineering News-Record, Construction Cost Index historical data, 2015–2024, available at https://www.enr.com/. Post-pandemic peak escalation of 7–8 percent annually in 2021-22 confirmed by U.S. Bureau of Labor Statistics Producer Price Indices for construction materials and components.

vintage project cost estimate compounded to 2030 results in approximately a doubling of the original cost, which is consistent with the comparison of costs for AIM and RARE, when adjusted for scale.

A project comparable to AIM, which cost $1.1 billion to construct in 2016, would cost approximately $2 billion to construct in 2030. This escalation applies equally to any postulated EMT replacement pipeline, making the cost gap between maintaining EMT and building new infrastructure wider today than at any point in the prior regulatory record. Cost of service, which is a function primarily of the cost of the new facilities, would experience a proportional increase.

Comparing the costs shown in Table 5 of the Northeast Supply Expansion and the Southeast Supply Expansion shows the regional difference. The unitized costs of the Northeast Supply Expansion as filed in March 2017 for a December 2019 in-service date are higher than those for the Southeast Supply Expansion as filed in October 2024 for a commercial operation date in November 2027. The cost of pipeline improvements is 31% higher. The cost of compression upgrades is 8% higher. Escalating the Northeast Supply Expansion costs at 4.5% per year to its updated target in-service date of 2027 would yield costs 87% and 53% higher, for pipeline improvements and compression upgrades, respectively, than the corresponding costs for the Southeast Supply Expansion. The factors driving relatively higher costs in New England compared to the southeast have not materially diminished over time as the region grapples with questions about the future of natural gas, and the general economic factors resulting in higher regional costs, such as for labor, persist.

Based on the foregoing, LAI has assumed unitized costs of $55 million per mile for mainline improvements, $30 million per mile for lateral improvements, and $8 million per 1,000 HP of incremental compression added at an existing station.[113] These costs are used for postulated in-region improvements on Algonquin and on Tennessee east of Station 264. Improvements on Tennessee west of Station 264 are assumed to have costs that are 50% lower, due to the difference between the prior contemporaneous Algonquin and Tennessee projects.

4.1.2 Identification of Postulated In-Region Improvements

The hydraulic models described in Section 2.4 were used to identify the scope and scale of postulated in-region improvements that would be needed to allow for the same delivery

[113] The unitized rate for lateral improvements is doubled relative to the level indicated by inflation because the postulated in-region lateral improvements are on the J System, which is located in a highly-congested area in and around Boston. The E System upgrades as part of the AIM project had relatively lower costs compared to mainline improvements in southeastern Connecticut.

volumes, intraday profiles, and pressures as those seen during WS Fern in the absence of EMT.

On Algonquin, the postulated improvements were designed to continue the pattern of upgrades seen in AIM, Atlantic Bridge, and RARE. These projects consist of mainline takeup-and-relay and looping and compressor station upgrades. Because RARE includes incremental capacity beyond that associated with Eversource's EMT decontracting decision, the postulated in-region improvements were developed relative to the existing infrastructure without RARE. They therefore include some of the same improvements. Expansion of the J System is also incorporated in order to enable additional upstream gas onto the J System to provide pressure support. On Tennessee, the postulated improvements serve the same purpose, to enable increased west-to-east flow and flexible deliveries downstream of Station 267. The most recent expansion projects on Tennessee supported deliveries further upstream. They are therefore not indicative of the locational improvements that would be needed to replace EMT.

For both pipelines, LAI has exercised our judgment as informed by hydraulic modeling results in determining the locations of additional looping, takeup-and-relay to replace existing pipe with larger diameter pipe, and the addition of compression at existing stations.[114] LAI's solution set is not meant to represent a definitive set of improvements, only one option that LAI's modeling efforts indicate could offset the loss of EMT without imperiling gas and electric-grid reliability goals.

The identified postulated in-region improvements include 18 miles of improvements at various locations on the Algonquin mainline, three additional compressor units at existing Algonquin stations for a total addition of 47,700 HP, five miles of improvements to Algonquin's J System, 10 miles of improvements on Tennessee's mainline west of Station 264, five miles of improvements on Tennessee's mainline east of Station 264, and two additional compressor units at existing Tennessee stations for a total addition of 15,400 HP. While these improvements are capable of rendering more than the needed volume of gas on a steady-state, or ratable, basis, the scale is necessary in order to maintain the intraday delivery flexibility that EMT can offer through variable sendout.

The total cost of these improvements is estimated as \$1.5 billion on Algonquin and \$620 million on Tennessee. The postulated improvements on Tennessee are smaller in scope because of the smaller volumes injected by EMT that need to be offset. These values are

[114] Compression has been added in increments of full units, absent insight into opportunities for uprates and software modifications at existing units.

calculated based on the unitized rates described in Section 0 and the total miles of mainline and lateral improvements and compressor station upgrades on each pipeline.

4.1.3 Ratepayer Cost Approximation

Project rates are set by dividing the cost of service for a project by the associated billing determinants using FERC ratemaking principles. This results in a monthly reservation rate in $/Dth that applies across the contract term for a project. A project's cost of service includes O&M expenses, depreciation expense at a fixed percentage of plant in service, taxes, and a return at a fixed authorized rate.

The cost of service and rate calculation for the postulated improvements on Algonquin and Tennessee are shown in Table 6 and Table 7, respectively. The capacity and associated billing determinants for each pipeline are based on the volumes injected into each pipeline on EMT's peak sendout day during WS Fern, with an adjustment to account for estimated sendout to NGrid.

Table 6. Algonquin Improvements Cost of Service and Reservation Rate

Line No.	Description	Value	Notes
1	Gas Plant in Service	$1.5 billion	Derived in Section 4.1.2
2	Return	$202.5 million	13.5% of Line 1[115]
3	O&M Expense	$6 million	0.4% of Line 1[116]
4	Depreciation Expense	$32.9 million	2.19% of Line 1[117]
5	Taxes Other than Income	$45 million	3% of Line 1[118]
6	Federal Income Taxes	$42.5 million	21% of Line 2[119]
7	State Income Taxes	$15.2 million	7.5% of Line 2[120]
8	Annual Cost of Service	$344.1 million	Sum of Lines 2 through 7
9	Cost of Service over ten years	$3.4 billion	Line 8 multiplied by 10

[115] Established in FERC Docket No. RP24-781.
[116] Estimated based on prior projects.
[117] Established in FERC Docket No. RP24-781.
[118] Estimated based on prior projects.
[119] Established by the Tax Cuts and Jobs Act of 2017
[120] Estimated based on prior projects.

Table 7. Tennessee Improvements Cost of Service and Reservation Rate

Line No.	Description	Value	Notes
1	Gas Plant in Service	$620 million	Derived in Section 4.1.2
2	Return	$71.9 million	11.6% of Line 1[121]
3	O&M Expense	$2.5 million	0.4% of Line 1
4	Depreciation Expense	$12.7 million	2.05% of Line 1[122]
5	Taxes Other than Income	$12.4 million	2% of Line 1[123]
6	Federal and State Income Taxes	$17.9 million	24.95% of Line 2[124]
8	Annual Cost of Service	$123.7 million	Sum of Lines 2 through 6
9	Cost of Service over ten years	$1.2 billion	Line 7 multiplied by 10

The FERC-authorized rates of return and depreciation incorporated in the tables above are likely insufficient for the pipelines to fully recover their costs over ten-year agreement terms. Therefore entitlement holders would likely continue to pay for these projects through system tariff rates authorized by FERC even after the agreement terms for incremental services on Algonquin and Tennessee have ended. Entitlement holders' responsibility for additional cost recovery after year ten has not been estimated in this analysis. The intentional omission of residual cost responsibility after ten years means that the actual cost of service comparison between pipeline additions in New England versus retention of EMT is conservatively stated.

As noted above, Eversource's RARE petitions indicate that the LDCs expect to be able to purchase gas at the liquid Ramapo point. LAI is uncertain whether this assumption would extend to the full upstream capacity required to supplant EMT, or whether expansion of Millennium will be required in order to supply gas into Ramapo. If a project such as Constitution or an expansion on Millennium is required to bring gas into New England to provide incremental supply, additional demand charges would apply. Constitution's cost of service as originally filed was $153.1 million. Recovery of ten years of the cost of service is estimated at $1.5 billion. The actual construction cost of Constitution is expected to increase significantly relative to the estimated costs at the time of the original filing, but Constitution represents more capacity than would be needed to supply the postulated in-region improvements to supplant EMT. This value is generally used to approximate the cost to ratepayers of bringing incremental upstream supply into the region, however that is achieved.

[121] Estimated based relative return stated in CP25-514 Application Exhibit N.
[122] Based on depreciation rate stated in CP25-514 Application Exhibit N.
[123] Estimated based on other taxes stated in CP25-514 Application Exhibit N.
[124] Based on composite income tax rate stated in CP25-514 Application Exhibit N.

The total estimated cost of service over ten years for both the Algonquin and Tennessee in-region improvements to supplant EMT is $4.6 billion. This is the amount that would need to be recovered from ratepayers. Comparing this to the estimated approximately $1 billion ratepayer cost of the current EMT contracts over six years illustrates the benefits of retaining EMT. Scaling the average annual ratepayer cost of the EMT contracts to the same ten year term assumed for incremental pipeline capacity agreements yields total demand charges of $1.7 billion for EMT, although this could be reduced through both timing and volume considerations described previously, compared to estimated total demand charges of $4.6 billion for in-region pipeline upgrades, or $6.1 billion if upstream upgrades are also required. For the sake of clarity, it may still be sensible for the region to embrace incremental pipeline capacity while EMT continues to operate once the benefits of the new pipeline build are counted.

Table 8 summarizes the comparative cost considerations of continued reliance on EMT relative to gas infrastructure upgrades.

Table 8. Comparative Cost Framework: EMT vs. Gas Infrastructure Upgrades

Cost / Attribute	**Operate EMT**	**Install Pipeline Upgrades to Increase West-to-East Capacity**
Primary scope	Continue LNG import, storage, vaporization, truck operations; preserve balancing/pressure-support services in the load pocket	Add/replace targeted assets, e.g., lift-and-lay, looping, compressor additions
CapEx	Low (EMT does not currently require any major replacements or refurbishment)	Moderate to High, depending on the scope of upgrades, which are significant to replicate EMT's diverse benefits (potentially expanded ROW, permitting, labor, materials, environmental mitigation)
Fixed annual costs (O&M / fixed revenue requirement)	Moderate (EMT is largely depreciated, fixed O&M consists of terminal staffing, safety/compliance, insurance, property taxes, marine and equipment maintenance)	High (Newly constructed assets are undepreciated - cost of service covering depreciation, taxes, and allowed return on invested capital is high and could be higher based on amortization period)
Variable operating costs	High (Primarily LNG shipping + inventory management + vaporization fuel --depends on global LNG prices and available vessels)	Low (Losses and compressor fuel, no exposure to global LNG price volatility)

Cost / Attribute	Operate EMT	Install Pipeline Upgrades to Increase West-to-East Capacity
Implementation timeline	Near-term (months to a few years) depending on counterparty willingness to commit	Longer-term (multi-year) due to permitting, siting/ROW acquisition, construction, and legal challenges; multiple pipelines have separate efforts and timelines
Key uncertainties / risk drivers	Global LNG pricing volatility; vessel/river constraints; future contract structure (e.g., cost allocation and MFN provisions); potential significant CapEx	Permitting and siting risk; construction cost escalation; schedule risk; potential mismatch with decarbonization timelines and goals; long-term cost recovery commitments; potential need for out-of-region LNG trucking

The high cost of building significant new pipeline capacity into and within New England should not be interpreted as an indication that new pipeline infrastructure into and within New England is not needed or not valued. Even if EMT should be retained beyond 2030, new pipeline infrastructure may nevertheless be necessary due to demand growth trends and other factors. There is a balancing point at which the utilization of incremental pipeline capacity would be high enough to justify its construction relative to the costs associated with meeting that same volume through increased reliance on EMT or other peaking solutions. LAI's analysis also does not account for potential reduction in the leading regional gas price indices during the peak heating season and the consequent decline in wholesale energy costs during the peak heating season, December through February that would result from either incremental pipeline build or, to a lesser extent, continued utilization of EMT. There may be good reasons to add pipeline infrastructure into New England independent of avoiding the costs associated with continued availability of EMT. Gas grid resilience, adding supply from Marcellus to portfolio, and providing liquidity for electric generators could provide commensurate benefits.

4.2 Non-Pipeline Vapor Supply Alternatives

In their contract filings and in annual FAWG reports, the LDCs described efforts to identify alternatives to EMT supply, including non-pipeline supply alternatives. These solutions were either found to be non-viable or not available at the scale needed to offset supplies from EMT.

Postulated satellite facility upgrades could serve as a partial replacement for EMT. Such upgrades would likely be costly, to an unknown degree.[125] In NGrid's 2026 Annual EMT report,

[125] LAI has not derived the expected CapEx and OpEx for expanded satellite LNG storage.

NGrid outlined plans to add vaporization at the Tewksbury, Lynn, and Salem LNG facilities. While these upgrades may be able to mitigate NGrid's need for EMT's vapor on a design day, they do not replace the many other benefits EMT provides for NGrid and, more broadly, the region. First, upgrading satellite LNG vaporization capability would not mitigate the LDCs' need for local supply of liquid during the heating season during both usual and hazardous driving conditions. Adding liquefaction and incremental storage to the satellite facilities could help mitigate this need, but the utilities have not publicly outlined such improvements. Second, NGrid's proposed projects could not replace the balancing flexibility that EMT provides the interstate pipelines. LDC-owned plants do not inject gas into the interstate pipelines and cannot be used to directly bolster pressures when pipelines experience duress. Third, incremental LDC satellite vaporization is not intended to supply gas to New England's generators, as all sized improvements would be likely rationalized on the basis of local reliability considerations, nothing else. These improvements to the satellite LNG facilities cannot replace the portfolio of regionalized local system benefits provided by EMT. Additionally, the cost of improvements to LDC-owned satellite LNG facilities, including a rate of return, would be borne solely by the applicable LDCs' customers, whereas the potential exists for EMT's costs to be borne at least in part by non-LDC customers if other parties contract for capacity.

LDCs currently have a portfolio of small portable LNG, CNG, and propane-air facilities to provide limited, but strategic injections to constrained areas of the LDCs' distribution systems that could experience catastrophic pressure decay absent local mitigation. No LDC in New England depends on these technologies entirely at the local level. In the LDCs' second annual EMT update as part of the FAWG, CNG and propane air are not discussed as viable mitigation measures when considering the retirement of EMT. Additional Portable LNG projects are described as a plausible part of a "coordinated portfolio of actions" that can "incrementally reduce EMT reliance".[126] Scaling these portable LNG resources across New England as a substitute for EMT's vaporization would require an implausible number of additional facilities and sharply increase trucking risks for the region.

There are currently five portable LNG sites in New England, three of which are owned by NGrid and two owned by Rhode Island Energy. NGrid details that these facilities are capable of up to 750 Dth/hour for up to 10 hours per day. Using this assumption, the existing facilities can currently provide roughly 37,500 Dth/d. In order to simply replace EMT's winter 2029-2030 contracted daily quantity with the LDCs, another twelve portable LNG facilities of similar magnitude would need to be sited and built. Each portable LNG facility, only having 10 hours of on-site storage, requires near-constant trucking in order to keep the portable

[126] Fitchburg Gas 2026 Annual Everett Marine Terminal Update. MA DPU Docket 25-42.

facilities running during cold conditions lasting more than a few hours. Absent EMT the trucking needed to support a large portable fleet would need to be sourced from Quebec and/ or Pennsylvania, which would require several days' notice before each truck is filled. This coordination effort may constitute unreasonable logistical challenges for the LDCs. Further, the interstate balancing, local liquid supply, and supply-for-generation benefits provided by EMT would not be replaced by a larger portable fleet. The use of portable LNG is likely limited to a select few residential, commercial or industrial pockets, and cannot offer the broad array benefits resembling those of EMT.

4.3 Satellite Facility Replenishment Alternatives

The trucking corridors between New England's satellite LNG facilities and alternative supply sources in Pennsylvania or Quebec can experience significant delays and constraints during multi-day cold events.[127] The 350 to 400 mile haul from Pennsylvania liquefaction centers to Massachusetts sits at the outer edge of a single driver's federal HOS window, meaning any delay due to weather, traffic, or loading dock congestion triggers a mandatory 10-hour rest cycle that reduces effective corridor throughput by up to 33 percent from theoretical capacity.[128] The Quebec corridor via Énergir's Montréal liquefaction complex at Pointe-aux-Trembles offers shorter hauls to northern New England but introduces international border crossing requirements at Champlain, New York, that may extend delivery times, particularly during cold snaps. While the mandatory 10-hour rest cycle could conceivably be waived under emergency conditions, reliance on waiver authority strikes LAI as too tenuous to constitute "bankable" mitigation.

For these reasons, LNG supply from Pennsylvania and Quebec requires more advance notice from New England LDCs when coordinating refill of satellite facilities. These longer lead times complicate refill logistics, as weather conditions necessitating dispatch cannot always be anticipated many days in advance. If a force majeure event cuts pipeline supply into the region and small satellite facilities with one or two days of storage are needed to vaporize for multiple days, it is implausible that trucks from Quebec and/or Pennsylvania can reach eastern Massachusetts or Rhode Island in a timely fashion, especially when such a contingency is most likely to occur when driving conditions are difficult. In LAI's view, reliance on winter LNG supply from outside New England lessens the reliability of the region's large network of satellite LNG facilities and introduces a new array of logistical challenges for the LDCs.

---

[127] Though trucks could be staged to help mitigate drive time in anticipation of cold weather, the strategy becomes untenable during more widespread cold weather such as during WS Fern.
[128] Federal Motor Carrier Safety Administration, HOS, https://www.fmcsa.dot.gov/regulations/hours-of-service

The Northeast Energy Center (NEC) in Charlton, MA, is the closest non-LDC owned LNG supply source, other than EMT, for satellite facilities in eastern Massachusetts. This facility can liquefy up to 21 MDth/d from Tennessee and has a 165 MDth storage tank.[129] Since NEC is fed by the same Tennessee mainline where capacity constraints can occur throughout the winter, the facility does not liquefy gas during cold snaps when the demand for LNG is most acute. While the facility is able to fill its tank before winter to serve as a source of trucked LNG during the heating season, the lack of pipeline capacity dedicated to the plant and its small tank size limits what can be offered to LDCs during winter months.

5 Capacity Auction Reforms and EMT's Role in Resource Adequacy

In EO654, Governor Healey directed the OET, in coordination with DOER and the EMT FAWG to "identify options to fund ongoing operation of [EMT] in a manner that does not overly burden gas utility ratepayers and maximizes the use of the asset while it is operational and relied on by the gas utilities for supply and system reliability."[130] This requires an assessment of EMT's value to other gas consumers and a plan for monetizing that value so as to reduce the burden on LDC ratepayers. As discussed above, EMT plays a key role in ensuring electric reliability in ISO-NE. Mystic was the anchor customer for EMT until its retirement in May 2024. Therefore, gas-only generators located in southern New England represent the best available option for increasing EMT's utilization and reducing LDC ratepayers' burden.

EMT's ability to profitably serve the gas-only generator market segment depends on EMT's ability to offer LNG supply at a price in accord with generators' willingness to pay. This willingness to pay is hard to pin down as capacity markets are presently being retooled and the resultant price signals affecting the eligibility of firm capacity resources will not be known until much later this year, or, perhaps, 2027. As explained below, ISO-NE has committed to implementing capacity market design changes for the Capacity Commitment Period covering 2028-29, which will incentivize gas-only generators to enter into seasonal LNG peaking contracts to provide reliably incremental gas supply to New England.[131]

The MFN provisions in the existing LDC contracts may limit EMT's ability to profitably enter into seasonal LNG contracts with gas-only generators. Compared to LDCs, gas-only

---

[129] Historically, the facility has not scheduled more than 18 MDth in a single day according to ID3 data.
[130] Executive Order No. 654, March 16, 2026.
https://www.mass.gov/executive-orders/no-654-to-secure-massachusetts-energy-future-by-establishing-an-energy-supply-plan-that-drives-affordability-and-reliability
[131] Analysis Group, Specifications and Requirements for Gas-Only Resources Designating as Firm Capacity, April 15, 2026
https://www.iso-ne.com/static-assets/documents/100034/a07.c_mc_rc_2026_04_14-16_gas_only_resource_contract_requirements_memo.pdf

generators have a lower willingness to pay for gas on days when pipeline supply is constrained and there are potentially complex ISO-NE clearing dynamics that may hinder generation commitments to EMT and/or Repsol. Gas-only generators' lower willingness to pay is due to size of the incentives generated by ISO-NE's market design. The electric system ties reliability to a one event in ten years ("one-in-ten") criterion, and shortages in power supply relative to demand can often be mitigated by rotating or localized blackouts in order to limit adverse consequences to end users. Gas distribution outages are certainly more severe, disruptive and dangerous than electric outages because they cannot be restored remotely and typically require coordinated efforts by multiple LDCs under regional mutual aid provisions to relight appliances house to house, and for each commercial customer. Manual door-to-door relight of appliances is a process that takes days to weeks. Because of these adverse consequences, LDC planning for a design day is usually for a stricter condition such as a once in 40 years weather event. While there are greater costs and human consequences of gas outages vis-à-vis electric outages, the relative cost of a gas versus electric outage has little to do with a generator's willingness-to-pay.

A contract under which generators paid less than their volume-weighted share of EMT's fixed costs could be economic for generators while also reducing the LDCs' share of fixed costs, which is presently set at 100%. Resolving how the MFN provision is to be treated may constitute a barrier for reform, however. Winter 28/29 and 29/30 are covered by the existing LDC contracts and amendments to the MFN provision would have to be separately negotiated. A material change to the current LDC contracts would likely require approval by the DPU. If DPU is supportive, LAI expects that LDC contracts that begin in Winter 2030/31 may include significantly revised MFN provisions that enable EMT to serve gas-only generators and reduce the cost burden for LDC ratepayers. LDC demand for EMT capacity is price inelastic because LDCs must have reliable winter gas supply. The electric system has alternatives to gas-fired generation to meet power demand including oil switching and demand response, making its demand for EMT capacity less price inelastic. Allocating EMT capacity without recognizing this distinction would misallocate a critical reliability resource.

5.1 EMT's Contribution to Winter Resource Adequacy

The January 2004 cold snap underscored the importance of fuel-security for winter electric reliability. During the January 2004 cold snap, constrained natural gas supplies created a risk of outages. ISO-NE managed these risks by implementing steps of its emergency operating procedures including public appeals for energy conservation.[132]

[132]ISO-NE, Operational Fuel-Security Analysis, January 17, 2018, page 10 https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf

Over the next decade, winter reliability was maintained as increases in pipeline and dual-fuel generating capacity offset load growth and ISO-NE used its Forward Capacity Auction (FCA) Framework to ensure reliability. ISO-NE's FCA is the mechanism through which it procures the generating capacity needed to ensure resource adequacy over a three-year forward horizon. Resources that clear the FCA receive capacity payments denominated in dollars per kilowatt-month ($/kW-mo) that reflect the market's determination of the value of firm, dispatchable generation capacity in New England. These capacity payments are the ISO-NE-sanctioned benchmark for the cost of maintaining reliable, available electricity supply each year.

In 2016 ISO-NE initiated a study to better understand the region's winter fuel security risks. The resulting January 2018 Operational Fuel-Security Analysis determined that:

> "regional dependency on several key facilities is a particular concern highlighted by this study. An extended outage at any one of these key facilities—a natural gas pipeline compressor station, the Distrigas LNG import facility in Massachusetts and the Mystic 8 and 9 generators it fuels, the Canaport LNG import facility in Canada, or the Millstone nuclear power plant—would result in frequent energy shortages that would require frequent and long periods of rolling blackouts. .... The reliability impact of any one of these outages cannot be eliminated, even on a system with more LNG, oil inventory, and imports, the study shows. Each outage scenario would require load shedding that could affect hundreds of thousands of average New England homes at a time."[133]

Constellation's predecessor, Exelon, submitted Retirement De-List Bids for the Mystic Generation Station to ISO-NE in March 2018, proposing to retire all four of the Mystic units as of June 1, 2022. Soon thereafter, in April 2018, Engie SA, which was unloading its global upstream LNG business to Total SA at the time, agreed to sell EMT to Exelon, enabling Constellation to secure gas supply for the remainder of its existing capacity commitments, i.e., through May 31, 2022.[134] In response to Exelon's retirement filing, ISO-NE made filings at FERC where it sought waiver of several provisions of its Tariff and FERC approval of a cost-of-service Agreement with Mystic for the purpose of ensuring fuel security. In its filing, ISO-NE recognized that its Tariff provided for cost-of-service agreements only for the purpose of

---

ISO-NE, Final Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 "Cold Snap", October 12, 2004, page 14-15
https://www.iso-ne.com/static-assets/documents/2017/09/iso-ne_final_report_jan2004_cold_snap.pdf

[133] ISO-NE, Operational Fuel-Security Analysis, January 17, 2018, page 50-51.

[134] "Exelon Generation Files to Retire Mystic Generating Station in 2022, Absent Any Regulatory Solution," March 29, 2018. Accessed May 13, 2026.
https://www.sec.gov/Archives/edgar/data/1168165/000162828018003780/exc20180329991.htm.

addressing local reliability concerns and did not allow for cost-of-service agreements to ensure fuel security.[135] ISO-NE nevertheless argued that these provisions should be waived as the loss of Mystic presented unacceptable fuel security risks for winters of 2022-23 and 2023-24. ISO-NE also explained that EMT's reliance on Mystic, its largest customer, could set in motion a series of adverse events that would endanger regional fuel security in the event of EMT's retirement.[136] In its subsequent order, FERC directed ISO-NE to "to submit within 60 days of the date of this order interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[137] As discussed above, ISO-NE ultimately entered into a cost-of-service agreement for Mystic 8 & 9 and the associated EMT fuel costs for FCA 13 and FCA 14.

While ISO-NE has made various improvements to its market design since 2019, ISO-NE continues to develop the seasonal capacity auction framework (CAR-SA) with implementation for future prompt capacity auctions covering the 2028-29 Capacity Commitment Period. As explained in a 2026 ISO-NE FERC filing, the market design improvements planned for CAR-SA will address fuel and energy constraints arising from limited supplies of oil and gas during winter to ensure that capacity compensation accurately reflects the value of resource performance during the times of highest seasonal demand, including, for example, long, severe cold spells.[138] ISO-NE also explained that under CAR-SA the winter capacity price will send a price signal that reflects the value of resources toward meeting winter demand, providing capacity suppliers with the incentive to ensure resources are capable of performing to meet that demand by shoring up fuel supplies and/or installing dual fuel capability.[139]

ISO-NE has also been exploring the need for a regional energy adequacy target in its ongoing Operational Impacts of Extreme Weather Events Key Project[140] ISO-NE developed the Probabilistic Energy Adequacy Tool (PEAT) to measure energy adequacy given dispatch of its resource mix, outages, and fuel constraints on gas and oil. PEAT is being used to develop the Regional Energy Shortfall Threshold metrics, which has proven to be an invaluable tool to help quantify the frequency and magnitude of energy shortfalls as well as to help all stakeholders understand complex tradeoffs. Like all models, timely updates are often needed to keep pace with changing events. Previously, ISO-NE made modifications to the

---

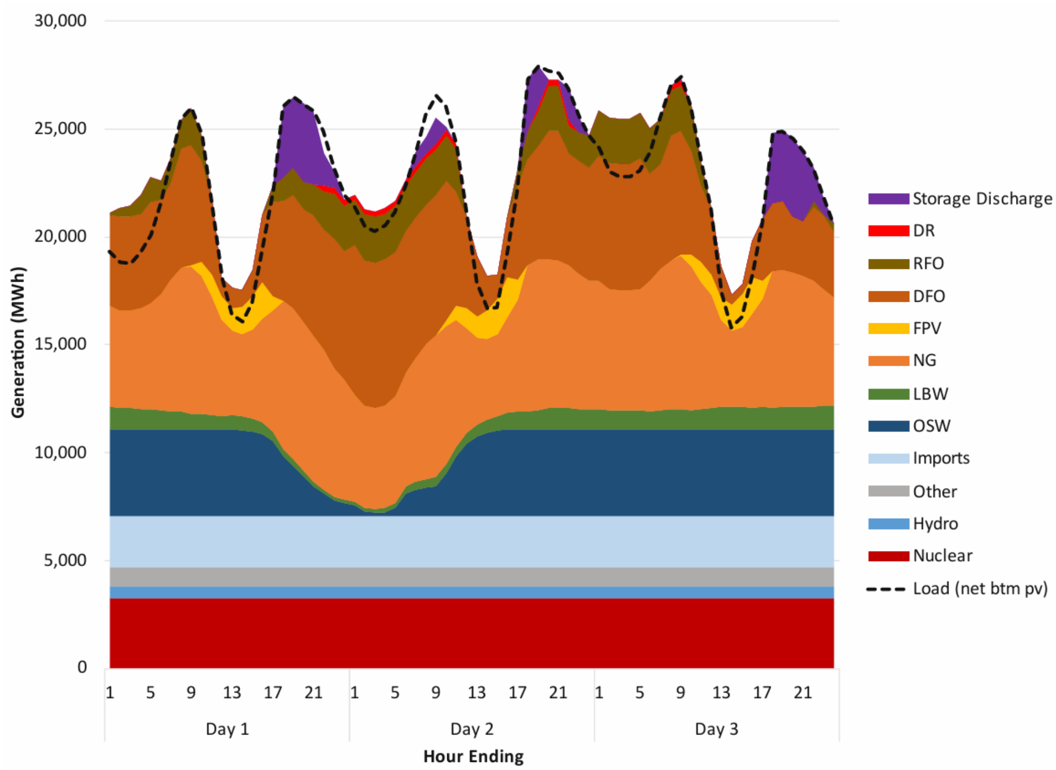
[135] FERC, Docket No. ER18-1639-000, July 13, 2018, ¶4.
[136] FERC, Docket Nos. ER18-1509-000, July 2, 2018, ¶11.
[137] *Id.,* ¶2.
[138] CAR-PD filing, page 6.
[139] *Id.*
[140] https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events

PEAT model and ran deterministic cases of stressed weather conditions. One long-term scenario examined the combined loss of EMT and a delay in offshore wind buildout through 2032. That analysis was conducted before the full consequences of federal opposition to offshore wind were understood. The offshore wind delay assumptions used in the scenario may now understate the actual reduction in offshore wind capacity available during cold snaps, when offshore wind historically performs well. Uncertainty about how much wind will be available and perform during the peak heating season in the first half of the 2030s or beyond is outside the scope of this inquiry. Nevertheless, LAI flags this factor in the narrow context of potential retirement of EMT.[141]

In the PEAT case, ISO-NE requires operator actions such as net import relief, voltage reduction, and appeals to conservation to balance load. In Figure 26, periods where energy shortfalls occurred can be seen where the dashed line representing load is above the stacked areas representing supply.

[141] ISO-NE's "Cap Offshore Wind and 1.6 GW Nameplate Capacity" 2032 PEAT sensitivity showed a near-doubling of energy shortfall, and noted that "In terms of magnitude of energy shortfall, this sensitivity is similar to the all nuclear retirement/no replacement and the all RFO retirement/no replacement sensitivities." Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results, ISO-NE, Posted December 11, 2023. See slide 223.
https://www.iso-ne.com/static-assets/documents/100006/operational_impact_of_exteme_weather_events_final_report.pdf
ISO-NE assumed 4 GW of incremental offshore wind development beyond Vineyard Wind and Revolution Wind in the 2032 baseline case.

Figure 26. Hourly Generation and Load, PEAT Model Selection



Notably, this case still included 2,800 MW of additional generic offshore wind, none of which is likely to materialize in the early 2030s.[142] Net imports from Canada have also fallen substantially since the study was conducted, likely due to sustained drought conditions, demand growth in Canada, and strained geo-political relations. In LAI's opinion, the retention of EMT may constitute a low-cost hedge against uncertainty about offshore wind in general, and transmission exports during extreme cold from Quebec.

5.2 Overview of ISO-NE's Capacity Auction Reforms (CAR) Project

In 2021, ISO-NE began working with the New England stakeholders to evaluate potential changes to how ISO-NE recognizes and accredits capacity. The resulting planned capacity market reforms, or "CAR," include three major changes:

- Moving to a prompt capacity market that will allow the capacity auction to utilize more up-to-date information regarding available supply and demand for the delivery period;
- Replacing the single, Annual Capacity Auction with two seasonal (summer and winter) capacity auctions; and,

[142] NPCC Gas/Electric Study, pages 42-44.

- Replace the existing summer performance-based accreditation framework with a seasonal marginal reliability-based accreditation framework that measures the contribution of resources during the periods that will be of highest risk to reliability and based on resources' availability, output variability, and fuel/energy constraints.[143]

ISO-NE divided CAR into two phases. The first phase, Capacity Auction Reforms Prompt/Deactivation (CAR-PD), covered implementation of a prompt capacity market, whereas the second phase, CAR-SA, includes the seasonal capacity market and related seasonal marginal reliability-based accreditation framework. ISO-NE filed proposed tariff reforms implementing CAR-PD on December 31, 2025. They were subsequently approved by FERC on March 30, 2026.[144]

ISO-NE's CAR-SA proposal is the subject of ongoing stakeholder proceedings. ISO-NE plans to file its proposed framework at FERC in Q4 2026.[145] The seasonal capacity markets and seasonal marginal-reliability-based accreditation framework included in the CAR-SA proposal will affect the accreditation and compensation of every resource in ISO-NE.

Under ISO-NE's CAR-SA proposal, firm gas-only resources backed by "firm gas contracts" are treated as unconstrained and are accredited based on their physical capacity and availability. Notably, ISO-NE's consultant has also recommended not requiring a firm transportation path be identified for firm LNG contracts:

> Resources electing as Firm Capacity under an LNG contract do not need to demonstrate firm transportation to the resource. In general, supplies from the region's three active LNG terminals, Saint John LNG, Everett Marine Terminal, and the Northeast Gateway, can be delivered to the New England gas system under tight market conditions because supply from these facilities are backhauls, moving against the general flow of supplies, and thus are not constrained by transportation infrastructure constraints.[146]

---

[143] For example, forced/maintenance outages, Intermittent Power Resources variable output profiles, and gas/oil energy constraints.
[144] FERC, Docket No. ER26-925-000, March 30, 2026
https://www.iso-ne.com/static-assets/documents/100033/er26-925-000.pdf
[145] Capacity Auction Reforms Key Project, https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project
[146] Analysis Group, Memorandum re: Specifications and Requirements for Gas-Only Resources Designating as Firm Capacity, April 15, 2026, page 9.
https://www.iso-ne.com/static-assets/documents/100034/a07.c_mc_rc_2026_04_14-16_gas_only_resource_contract_requirements_memo.pdf

In contrast, non-firm gas-only resources are subject to a "market constraint" based on the expected supply of gas available to generators in the ISO-NE market and the marginal reliability benefit of clearing additional non-firm gas-only capacity.[147] Under the market constraint, the marginal value of non-firm gas-only capacity relative to non-gas capacity is calculated, and leads to diminishing value assigned to higher clearing quantities of gas-only generators that must share the same available gas. Therefore, the accredited value ISO-NE assigns to non-firm capacity will depend on ISO-NE's expectation of gas available to generators on cold days, which in turn depends on injections by EMT and Repsol's scheduled throughput on M&N. As discussed above, ISO-NE has recognized the need for LNG to support winter reliability and incentivizing incremental LNG supplies is one of the explicit goals of the gas constraint and fuel firming design effort. LAI believes that ISO-NE's final proposal will set firm-fueling requirements at a level that could make them economic for some gas-only generators, but might not support the price levels that would be required under EMT's existing LDC MFN provisions.

5.3 Outstanding Issues and Evolving Framework

ISO-NE's preliminary results indicate that the winter season marginal reliability value of non-firm gas-only resources is "decreasing but still potentially substantial" when between 2 GW and 4 GW of non-firm gas-generation clears in the capacity market and rapidly decreasing when more than 4 GW of non-firm gas-generation clears.[148] As discussed above, ISO-NE has about 8 GW of gas-only generation. ISO-NE generators do control a small amount of firm pipeline capacity. Some non-firm gas-only generation may decide not to participate in the winter season auction. LAI expects that over 6 GW of gas-only resources will submit offers for the winter season auction. So long as the quantity of offers significantly exceeds 4 GW, the marginal reliability value of non-firm gas-only resources will be low. ISO-NE's proposal is still under development and the results it has presented to date are preliminary. However, ISO-NE's preliminary results suggest that the non-firm gas-only capacity price will be at a large discount to the firm capacity price.

The incremental cost to EMT of providing a fuel-firming contract depends on ISO-NE's fuel-firming requirements for contract period, maximum daily volume, number of delivery days and any other requirements. As of May 2026, ISO-NE does not have a final proposal for these requirements and ISO-NE analysis and consultations with stakeholders are ongoing.

Gas-only generators in New England may seek peaking option contracts with EMT and/or St. John LNG in order to qualify as a firm capacity resource, thereby escaping the non-firm gas

[147] https://www.iso-ne.com/static-assets/documents/100031/a04.1.b_mc_rc_2026_01_13-14_car-sa_gas_capacity_market_constraint_detailed_design_memorandum.pdf

[148] ISO-NE, Introducing a Gas Capacity Demand Curve in the Winter Capacity Market, January 7, 2026, page 7 https://www.iso-ne.com/static-assets/documents/100034/a07.d_mc_rc_2026_04_14-16_carsa_ia_ram.pdf.

clearing constraint. The extent to which new price signals that emerge from ISO-NE's CAR affect New England generators' willingness to pay for firm callability will not be known until much later this year or 2027. To the extent that generators do contract with EMT for peaking supplies, the same considerations noted above regarding the benefits of signing contracts further in advance of delivery in order to secure better supply pricing terms would apply.

6 Conclusions and Policy Considerations

The analysis performed by LAI in regard to gas and electric resilience during harsh weather conditions resulted in these conclusions, including recognition of key uncertainty variables going forward.

- There is a razor-thin margin between New England's coincident gas and electric peak demand and peak day/peak season supplies. The region experienced this thin margin during WS Fern. Toward the end of WS Fern, oil inventory among ISO-NE's dual fuel generation fleet was nearing depletion levels. Gas grid reliability objectives are enhanced by EMT and St. John LNG. While the backbone for gas-grid reliability are the five pipelines serving New England, they typically experience congestion throughout the peak heating season which significantly constrains gas use for generation. Electric grid reliability objectives are met through ISO-NE's reliance on oil-fired generation and the incremental supplies from the LNG terminals. In LAI's view, both gas and electric grid resilience objectives cannot be met through any one alternative solution to EMT. No single resource can fully remedy the region's vulnerability to potential disruptions in energy supply. Therefore, a complementary, portfolio approach best insulates New England from disruptive events. This approach includes EMT.
- As discussed in EO654, EMT is "a strategic energy asset for Massachusetts and the New England region, capable of meeting up to ten percent of the region's natural gas supply needs on the coldest days."[149] Stated on an electric equivalency basis, EMT's observed maximum total sendout to Algonquin and Tennessee, when adjusted for NGrid's MDQ, of approximately 350 MDth/d represents approximately 2.1 GW of gas-fired generation at full power output for 24 hours. Replacing this contribution to regional gas supply with an alternative source of incremental capacity would require major investment in new pipeline infrastructure. Such an investment would be by definition "new" and therefore amortized over the relevant TSA term of not less than ten years. In comparison, EMT's investment is sunk and the asset is near fully

[149] Executive Order No. 654, March 16, 2026. https://www.mass.gov/executive-orders/no-654-to-secure-massachusetts-energy-future-by-establishing-an-energy-supply-plan-that-drives-affordability-and-reliability

depreciated, thereby providing New England with a comparatively low cost, rolling asset option that can be struck by LDCs and, potentially, gas-only generators whenever the time is right. New pipeline projects into and within New England may nevertheless be warranted *with or without* EMT in 2030. Notably, larger pipeline projects have the potential to yield significant wholesale energy price benefits by directly reducing the delivered cost of gas. EMT does this, too, by dampening the frequency, duration, and magnitude of the gas price spikes during extreme cold.

- EMT performed admirably during WS Fern, ensuring sufficient LNG inventory to meet all contractual requirements held by Massachusetts LDCs, in addition to deliveries to other customers. Local deliveries to NGrid confer reliability benefits to the greater Boston area as far west as Wellesley. Absent EMT, there is no straightforward replacement for EMT's backdoor deliveries to NGrid. Trucks from Everett also replenished drawn down inventory at a multitude of tanks that turn many times during harsh weather conditions. The regional array of satellite facilities includes 43 tanks spread across 29 sites. Total storage capacity is about 16.8 Bcf. Daily vaporization capability is approximately 1.5 Bcf/d. Historically, trucks from Everett have played an integral role both topping out and replenishing LNG facilities throughout New England. Even the largest satellite facilities with ample liquefaction capability to top out inventory in early December may need to use EMT to restock during a design winter.

- St. John LNG was also heavily utilized during WS Fern, maximizing or nearly maximizing throughput for about 20 days to delivery points in northern New England. From an operating standpoint St. John LNG is an imperfect substitute for EMT because the primary delivery points are in northern New England, while the preponderance of direct connected generation is on Algonquin and Tennessee in southern New England. Hence, St. John and EMT have a distinct spatial distribution of balancing services: EMT provides up to about 430 MDth/d in instantaneous, non-ratable supply in the Boston load pocket. Moreover, St. John LNG lacks trucks. If, say, EMT were to retire, the regional LDCs would then be dependent on trucks emanating from Quebec and/or Pennsylvania, and, to a much lesser extent, Charlton, Massachusetts, which is favorably positioned to the satellite tanks, but cannot sustain meaningful replenishment quantities. Excluding Charlton, a comparatively small storage resource, restock from Quebec and/or Pennsylvania is long haul in nature, subject to hazardous materials and driving restrictions set by the Department of Transportation's Federal Motor Carrier Safety Administration, Hazardous Materials Regulations, and can be subject to hazardous driving conditions.

- CLNG recoups EMT's cost of service through its negotiated agreements with LDCs. Since Mystic's retirement in 2024, by far EMT's largest customer, total sendout has materially declined, thereby reducing the seasonal and annual product volume of relevance in setting rates to ensure EMT's availability and reliable performance. The rates governing EMT's cost of service include the high cost of lining up LNG supplies indexed to global LNG price indices in vessels compatible with EMT's unique delivery requirements. Consistent with global LNG procurement logistics, the cost of LNG supply must be scheduled many months before delivery regardless of actual HDDs during the peak heating season.
- LAI expresses skepticism in regard to the ability of non-pipeline alternatives, such as incremental satellite LNG vaporization or new portable LNG sites, to serve as a substitute for EMT. These technologies would increase the need for timely LNG trucks, which LDCs would have difficulty coordinating in a world without EMT. Demand response and targeted energy efficiency programs on NGrid have the potential to lessen exposure to extreme dislocation during a future WS Fern-type event. LAI acknowledges incomplete understanding of the cost and sustainability of a demand side solution set in lieu of EMT.
- From 2024 through 2030, total expected payments by LDCs in Massachusetts to EMT amount to roughly $1 billion, split roughly 40% for terminal operating costs and 60% for LNG procurement and delivery. Most payment obligations are baked into the non-commodity and commodity demand charges, which are independent of how frequently the LDCs strike their respective calls. As a result, the large majority of the LDCs' costs under the contracts are fixed because they must be: CLNG's costs of maintaining the facility and lining up LNG cargoes for the 2024-30 term are unavoidable.[150] Additionally, since the contracts were negotiated in the summer prior to the start of the contracts, as opposed to further in advance, the commodity portion included the typical risk premiums found in spot market transactions. Like all LNG importers, the cost of spot cargos or near-term supply is indexed to relatively volatile global indices. Unlike other importers, EMT is restricted to a small pool of potential vessels due to limitations of the Mystic River. Contracting well ahead of delivery could help tame the price impact of these limiting factors. Should EMT continue beyond 2030, contracting well in advance of 2030 would likely significantly reduce the spot market premium.

[150] MA DPU Docket Nos. 24-25, 24-26, 24-27, and 24-28. Direct Joint Testimony of Brattle Group on behalf of the Attorney General, 63:10-13: "the Agreements will lock in customer costs in the form of Non-Commodity Demand Charges and Commodity Demand Charges. That is, a large majority of costs under these Agreements (approximately 90 percent) are fixed; meaning they are unrelated to the gas volumes ultimately delivered."

- The prices paid by Massachusetts LDCs to EMT to ensure call optionality through 2030 appear to be in the zone of reasonableness when compared to potential pipeline solutions designed to emulate EMT's benefits. The estimated cost of postulated in-region improvements sufficient to replicate EMT's gas supply and reliability benefits is $2.1 billion. Combined with the cost of upstream improvements to deliver supply into the region, the potential ratepayer impact is estimated to be $4.6 to $6.1 billion. The error bars on these notional cost estimates are likely large. While it is striking to compare the anticipated cost of new facilities fresh off the drawing boards with old, nearly fully depreciated assets, uncertainty about EMT's cost of service is primarily explained by natural gas price index volatility.

- ISO-NE's present efforts to retool the capacity market through accreditation has the potential to promote electric reliability objectives through firm-up options on the pipelines serving the region and through call options with EMT and/or St. John. Heightened use of LNG imports through bilateral arrangements with gas-only generators has the potential to serve gas generation owners' financial interests. This reduction may hinge on the interpretation and imposition of MFN provisions in future contracts. It may result in the reduction of total costs borne by LDCs in Massachusetts by sharing joint fixed costs between generators and LDCs. It has the potential to enhance electric grid resilience and reliability goals by ensuring a dependable fleet of gas-only generation that has bankable callability during extreme winter weather. The potential for a "win-win-win" solution represents a promising challenge before New England stakeholders.

- LAI notes a number of primary uncertainty factors affecting the merit of continued reliance on EMT in lieu of rival pipeline or trucking solutions, as follows:

    (i) the cost of lining up requisite LNG volumes in global markets is subject to global LNG price indexation in the current LDC contracts, which is inherently volatile in response to geopolitical events and temperature conditions in the EU, even, indirectly, Asia;

    (ii) LNG procurement efforts to extend EMT's availability past 2030 could and should include modernizing the index along a new center of gravity for LNG export trade tied to NYMEX/Henry Hub;

    (iii) the cost of pipeline new build in New England is high and difficult to estimate with precision, even for small projects, but nevertheless a potential path toward worthwhile regional benefits;

(iv) LNG trucking options from Quebec and Pennsylvania are less reliable than nearby supply but may constitute an acceptable alternative *if* the cost is deemed manageable by the LDCs and risk tolerance issues can be resolved;

(v) the performance efficacy of non-pipeline alternatives, including demand response and targeted energy efficiency appears to be a high-risk, high-cost alternative to EMT, which should be verified;

(vi) states' commitment to accelerated decarbonization goals in light of affordability considerations raises concerns about the pace of electrification, reliance on oil to power up heat pumps, coupled with the pace of offshore wind and transmission exchange; and

(vii) ISO CAR initiatives offer great promise for additional counterparties to share costs with the LDCs but are still evolving and require stakeholder approval which may not be known for quite some time.