Everett Marine Terminal Focus Area Working Group

Report to the
Energy Transformation Advisory Board

Research Compendium

An Overview of the Everett Marine Terminal and Its Role in Serving Regional Energy Needs

July 10, 2026

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Table of Acronyms

Acronym	Definition
AFL-CIO	American Federation of Labor and Congress of Industrial Organizations
AG	Attorney General (Massachusetts)
AGT	Algonquin Gas Transmission
ANPRM	Advance Notice of Proposed Rulemaking
BESS	Battery Energy Storage System
BOG	Boil-off Gas
CAR	Capacity Auction Reforms (ISO-NE)
CCS	Carbon Capture and Storage
CFR	Code of Federal Regulations
CLF	Conservation Law Foundation
CMR	Code of Massachusetts Regulations
COSA	Cost of Service Agreement
COTP	Captain of the Port
CZM	Massachusetts Office of Coastal Zone Management
DEP	Massachusetts Department of Environmental Protection (MassDEP)
DER	Distributed Energy Resources
DOE	U.S. Department of Energy
DOMAC	Distrigas of Massachusetts (Corporation / LLC)
DPA	Designated Port Area
DPU	Massachusetts Department of Public Utilities
E3	Energy and Environmental Economics
EEA	Massachusetts Executive Office of Energy and Environmental Affairs
EER	Evolved Energy Research
EFI	Energy Futures Initiative
EFSB	Energy Facility Siting Board
EGMA	Eversource Gas of Massachusetts
EIA	U.S. Energy Information Administration
EJ	Environmental Justice
EMT	Everett Marine Terminal
ENGIE	ENGIE (formerly GDF Suez)
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute

FAWG	Focus Area Working Group
FERC	Federal Energy Regulatory Commission
FLIGHT	EPA Facility Level Information on Greenhouse Gases Tool
FPC	Federal Power Commission
FSRU	Floating Storage Regasification Unit
FTE	Full-Time Equivalent
GDF	GDF Suez (later ENGIE)
GHG	Greenhouse Gas
GWP	Global Warming Potential
HVAC	Heating, Ventilation, and Air Conditioning
IPCC	Intergovernmental Panel on Climate Change
ISO-NE	ISO New England
LDC	Local Distribution Company
LIUNA	Laborers' International Union of North America
LMOP	EPA Landfill Methane Outreach Program
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
M&NP	Maritimes & Northeast Pipeline
MBTA	Massachusetts Bay Transportation Authority
MEPA	Massachusetts Environmental Policy Act
MHP	Municipal Harbor Plan
MTSA	Maritime Transportation Security Act
NEC	Northeast Energy Center
NECEC	New England Clean Energy Connect
NEGC	New England Gas and Coke Company
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NOAA	National Oceanic and Atmospheric Administration
NPCC	Northeast Power Coordinating Council
NPDES	National Pollutant Discharge Elimination System

NPMS	National Pipeline Mapping System
NSTAR	NSTAR Gas (Eversource)
NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
PEAT	Probabilistic Energy Adequacy Tool
PHMSA	Pipeline and Hazardous Materials Safety Administration
RACT	Reasonably Available Control Technology
RARE	Reliable Affordable Resilient Enhancement
RICE	Reciprocating Internal Combustion Engine
ROFR	Right of First Refusal
SCR	Selective Catalytic Reduction
SCV	Submerged Combustion Vaporizer
SEIU	Service Employees International Union
STEM	Science, Technology, Engineering, and Mathematics
TGP	Tennessee Gas Pipeline
USCG	United States Coast Guard
USPS	United States Postal Service
VOC	Volatile Organic Compounds
WSA	Waterway Suitability Assessment
YMCA	Young Men's Christian Association

Introduction

This compendium assembles the research, data, and analysis that informed the deliberations of the Everett Marine Terminal Focus Area Working Group. It is intended as a reference resource — a comprehensive record of the operational, regulatory, financial, environmental, and energy system dimensions of the Everett Marine Terminal (EMT) and the gas supply infrastructure on which Massachusetts local distribution companies (LDCs) depend. The material gathered here draws on Federal Energy Regulatory Commission (FERC) filings, Massachusetts Department of Public Utilities (DPU) docket records, utility forecast and supply plans, U.S. Energy Information Administration (EIA) import data, Environmental Protection Agency (EPA) and Pipeline and Hazardous Materials Safety Administration (PHMSA) facility reports, ISO New England (ISO-NE) analyses, academic research, and stakeholder submissions.

The FAWG's findings, recommendations, and the contract and regulatory context necessary to understand them are presented in *Part I: Assessment of Alternatives, Findings & Recommendations*. Readers seeking the FAWG's conclusions should begin there. This compendium provides a deeper analytical record.

The compendium is organized as follows. **Chapter 1** traces the history of the Everett site and the gas system in Massachusetts. **Chapter 2** describes the current regional gas supply system. **Chapter 3** provides a detailed operational, financial, and regulatory profile of EMT. **Chapter 4** examines EMT's situational context, including its relationship with the host community and environmental justice considerations. **Chapter 5** analyzes the greenhouse gas emissions associated with EMT supply. **Chapter 6** reviews prior research on gas capacity in the energy transition. The chapters can be read in sequence or independently.

1. The History of the Everett Site

1.1. The Town Gas Era & The New England Gas and Coke Company

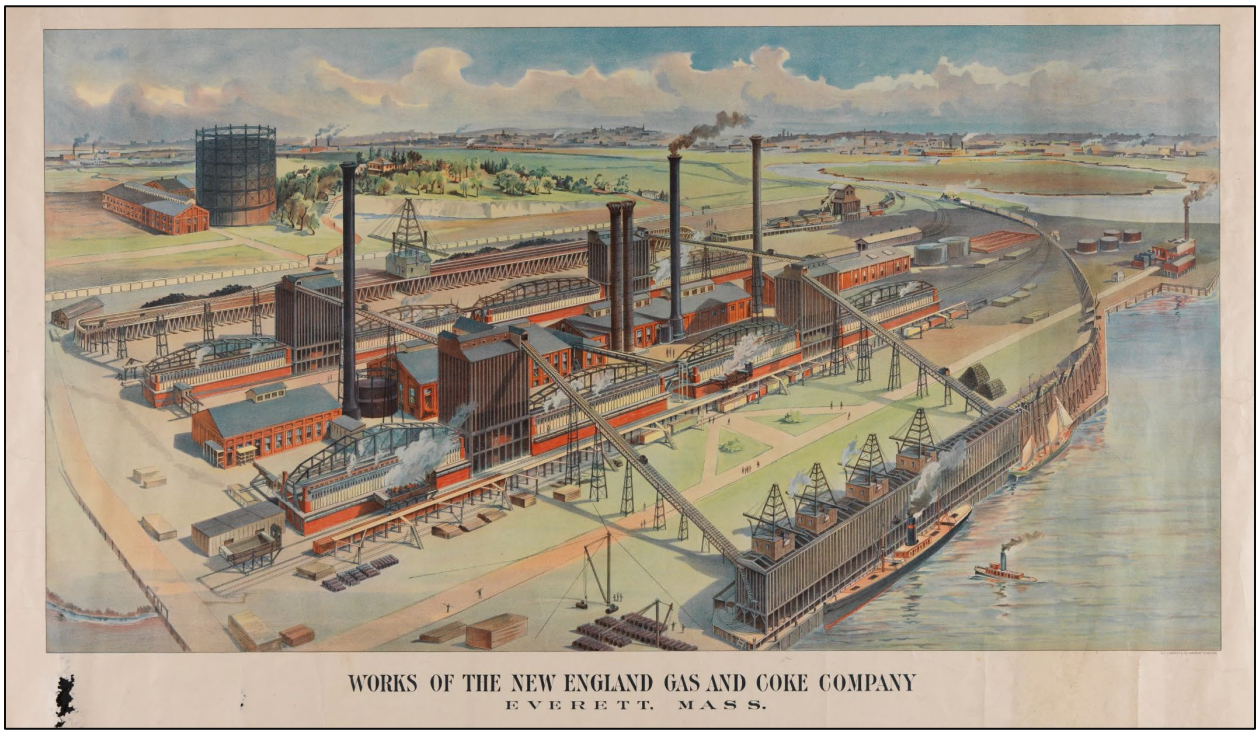

Figure 1. Chromolithograph of the New England Gas and Coke Company. Pre-1920.[1]

New England was among the earliest regions in the United States to develop gas distribution infrastructure.[2] The Boston Gas Light Company was chartered in 1823—only the second gas company in the nation—and began commercial service on January 1, 1829 with gas streetlights in Dock Square near Faneuil Hall. By 1855, the Massachusetts Legislature had enacted a general incorporation statute for gas companies, and by the early 1900s, the Commonwealth hosted roughly one hundred manufactured gas plants producing "town gas" by heating coal in sealed ovens called retorts. This gas production process had to be run continuously, and the resulting flat supply rate did not align with the fluctuations in demand over the course of the day; each gasworks, tied to a particular service territory, constructed its own storage capacity to manage variable consumption rates. The gas holders developed for this purpose—large telescoping metal cylinders that rose and fell with the volume of gas inside them—became defining features of the urban landscape as they rose from evening lows due to household demand to morning highs via overnight production.

[1] Plant illustration: "Works of the New England Gas and Coke Company, Everett, Mass.," George H. Walker & Co. chromolithograph, c. 1899, Historic New England, accession GC002.02.128. https://www.historicnewengland.org/explore/collections-access/gusn/198895

[2] Much of the section below is largely sourced from Hatheway, A.W., & Speight, T.B. (2017). Manufactured Gas Plant Remediation: A Case Study (1st ed.). CRC Press. https://doi.org/10.1201/b22447.

Everett's Mystic River Shoreline began to play a central role in the Massachusetts energy system through the machinations of Gilded Age streetcar magnate Henry Melville Whitney, who came to fame in 1888 by pioneering the trolley system that would one day become the MBTA's Green Line. Whitney's trains required a reliable source of coal for power, so in 1889, he formed a vertically integrated coal syndicate to purchase, lease, and option mines in Nova Scotia. Looking for a location in Greater Boston to offload the enormous collier cargo ships and process the mineral into energy-dense coke, Whitney identified recently reclaimed land from a salt marsh near the confluence of the Mystic and Island End Rivers in Everett to build what would become the plant for the New England Gas and Coke Company (NEGC). When it opened in 1899, the 288-acre NEGC plant was the largest such facility in the United States[3], with capacity to process 2,000 to 2,400 tons of coal daily, a 900-foot wharf along a dredged channel, and rail access to transport coke and other refined products directly out of the facility. Incidentally, manufactured gas was produced as a byproduct of the coking process,[4] and could be stored in a 5-million-cubic-foot gasholder installed onsite (roughly one seven-hundredth of the volumetric capacity of Everett today).

Seeking a profitable use for the byproduct gas, Whitney also established the Massachusetts Pipeline Gas Company to distribute wholesale to Greater Boston's various town gas companies.[5] NEGC came onto the scene shortly following a "rate war" that nearly bankrupted competing gas distribution companies around Boston. By achieving economies of scale on gas production and wholesale sales, NEGC sought to become indispensable to the gas system and avoid a similar fate. In order to cement this position, Whitney leveraged his political connections to push for a broad regulatory exemption for his gas companies from the Massachusetts legislature. The so-called "Whitney Gas Bill" was originally written to grant him the power of eminent domain to lay gas pipelines, the right to build distribution in any community he chose, and a 10-year property tax exemption. The bill was watered down in rewrites, but Whitney successfully argued out of full Board of Gas and Electric Light Commissioners[6] jurisdiction since NEGC sold byproduct gas to other companies and was therefore not a "gas company". Republican Governor Wolcott was alarmed by what was widely perceived as an industrial power grab through outright legislative fraud, but the legislature overrode his veto to pass the bill in June 1896.[7] In a final intervention, Wolcott's allies included a poison pill provision in the bill to cap the price of NEGC's gas at 60 cents, dooming Whitney's enterprise to unprofitability and eventual restructuring.

Despite this, in the decades that followed, the coking facility at Everett evolved into an industrial powerhouse and the cornerstone of Massachusetts's gas supply system. 1902, the Massachusetts Gas

[3] Alton D. Adams, "New England Gas and Coke," Journal of Political Economy 11, no. 2 (March 1903): 257–272, https://www.journals.uchicago.edu/doi/pdf/10.1086/250936.
[4] Other byproducts included ammonia, tar, and benzol.
[5] During this period, NEGC was also one of the first to adopt the usage of British thermal units or "Btu" as a technical specification of gas quantity.
[6] The precursor agency to today's Department of Public Utilities.
[7] Acts of 1896, c. 537 (passed over Governor Wolcott's veto, June 9, 1896); see Attorney General v. Massachusetts Pipe Line Gas Co., 179 Mass. 15 (1901), and Mass. DPU, Corporate History of Gas and Electric Utilities in Massachusetts (2023 update), entry for Massachusetts Pipe Line Gas Company.

Companies was formed to take over the financially troubled NEGC,[8] and in 1905 it was consolidated with the city's eight distributors into the Boston Consolidated Gas Company (BCGC or Boston Gas). BCGC constructed a new combined-process gasworks on land adjacent to the coke plant to form Everett Station in 1907. By 1917, the combined facility was supplying roughly 40% of Boston's base-load gas, approximately 2.9 billion cubic feet, against 4.15 billion produced by BCGC's gasworks elsewhere in the city. Under a contract in force that year, NEGC committed to delivering 5 million cubic feet of unpurified gas per day to Boston Consolidated for 29½ cents per thousand cubic feet.[9] The complex continued to grow, adding a steelmaking blast furnace, coal tar processing facility and 34 miles of internal railroad track; during World War II, its workforce peaked at over 1,000, supporting many of the working-class families that formed Everett's backbone.[10]

[8] Adams, "New England Gas and Coke," J. Pol. Econ. (1903), 264–268, detailing the 60-cent rate cap and ensuing financial distress; Mass. DPU, Corporate History (2023), entries for Massachusetts Pipe Line Gas Company and New England Gas and Coke Company.
[9] At this energy content of this gas (at a minimum of 575 Btu/cubic feet), this cost would be equivalent to over $16 per MMBtu in today's dollars, twice the Massachusetts 2025 EIA Citygate Price.
[10] Eastern Enterprises corporate-history entry in International Directory of Company Histories, vol. 6 (St. James Press, 1992); contemporary company ephemera held by Historic New England (New England Gas and Coke Company collection, GC002.02.128).

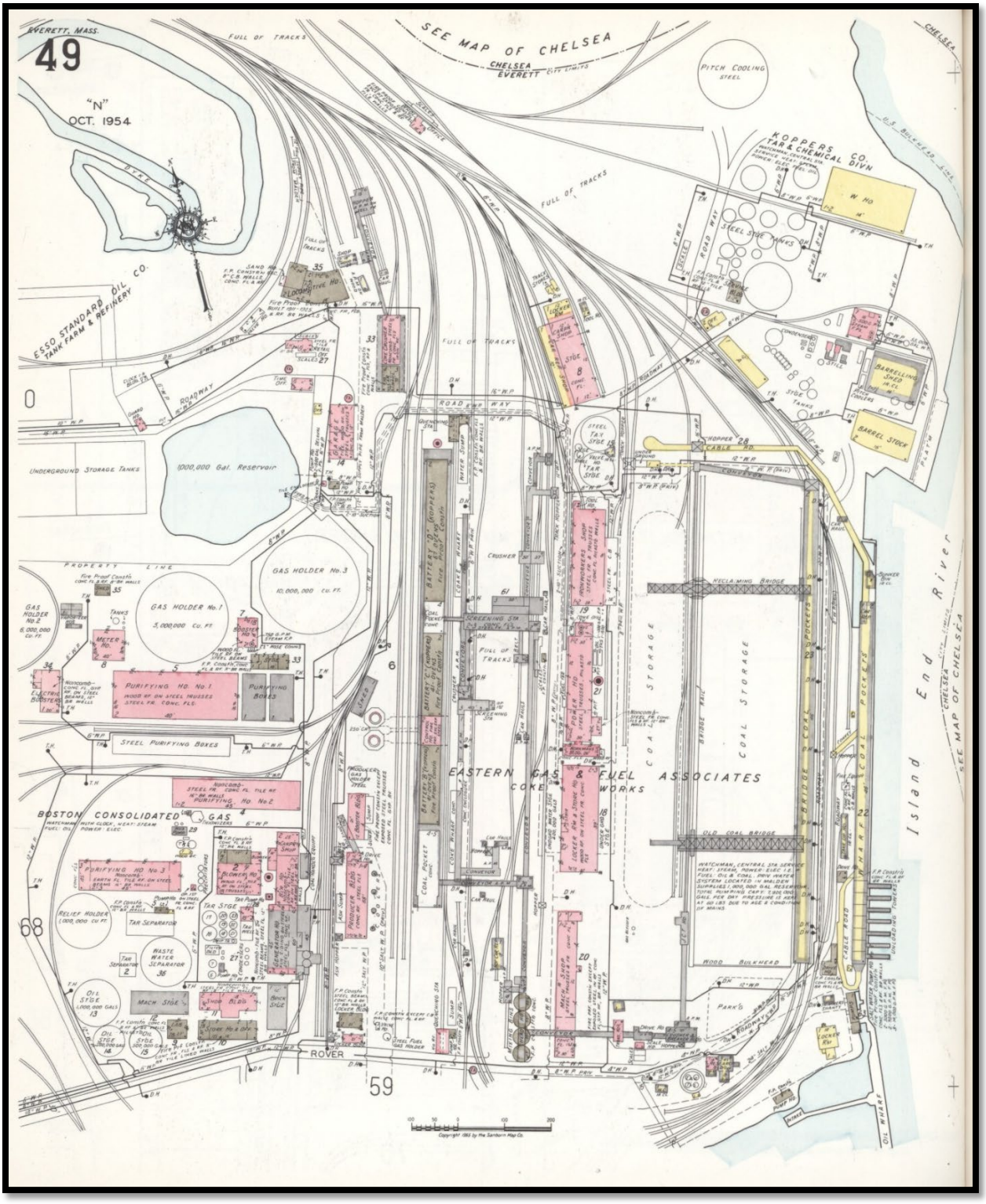

Figure 2: Sanborn Fire Insurance map of Eastern Gas and Fuel Associates facility, 1955.[11]

[11] Sanborn Fire Insurance Map from Everett, Middlesex County, Massachusetts. Sanborn Map Company, 1955. Map. https://www.loc.gov/item/sanborn03725_006/.

1.2. Delivered Fuels, Natural Gas and the Economics of Energy Storage

During the early 20th century, delivered oil as household fuel also emerged as a key driver of Massachusetts's heating-fuel market, thanks in part to facilities developed in Everett. Imported oil was historically cheaper and more widely available than town gas in New England[12], and the network of small oil companies supplying kerosene for basement tanks in many households was particularly well suited to the region's dispersed towns, harsh winters, and limited pipeline infrastructure. Even today, Massachusetts and New England as a whole have one of the highest rates of home heating oil use in the nation.[13] The owners of Everett Station seized upon the strategic location by founding the Beacon Oil Company in 1919, which built New England's first oil refinery and storage tank complex alongside the gasworks in the following year.[14,15] The refinery had a capacity of 15,000 barrels per day and storage for 950,000 barrels, producing gasoline, kerosene, fuel oil, asphalt, and lubricating products.[16]

At the same time, natural gas began to reshape the national energy system, but New England was the last major region in the country to receive service, largely due to its distance from producing regions. The region sits at the terminus of the national pipeline network, farther from the major gas-producing basins than any other population center in the lower 48 states. The Tennessee Gas Pipeline was originally built to serve wartime defense industries in Appalachia.[17] The Algonquin Gas Transmission system followed, with pipelines extending into Massachusetts in 1952[18] and starting operations in 1953, ending at a terminal meter at Everett, augmenting and ultimately displacing the town gas production that had occurred there since the 1890s. These two pipelines enabled the gradual conversion of New England's distribution systems from manufactured gas to natural gas over the 1950s and into the 1960s. But even with access secured, geography continued to constrain regional gas supplies upstream during peak demand periods, especially on the coldest days of winter.[19]

For this reason, gas supply planning in New England has long focused on securing adequate alternative resources for peak-demand days when pipeline supplies are most constrained.[20] While other regions of

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[12] Christopher J. Castaneda, Invisible Fuel: Manufactured and Natural Gas in America, 1800–2000 (New York: Twayne Publishers, 1999), 87–112.
[13] U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS) 2020," Table HC6.10 (Space Heating in U.S. Homes by Region), released March 2023, https://www.eia.gov/consumption/residential/data/2020/.
[14] "Eastern Enterprises History," International Directory of Company Histories, vol. 6 (St. James Press, 1992), reproduced at FundingUniverse, https://www.fundinguniverse.com/company-histories/eastern-enterprises-history/.
[15] "What Happened to Beacon Oil?," Industrial Artifacts (business-history feature, 2024); see also Mass. DPU, Corporate History of Gas and Electric Utilities in Massachusetts (2023 update). Beacon Oil was established by the Massachusetts Gas Companies trust in 1919; the Everett refinery began operations in July 1920 with capacity of 15,000 barrels per day and 950,000 barrels of storage.
[16] "Eastern Enterprises History," International Directory of Company Histories, vol. 6 (St. James Press, 1992), reproduced at FundingUniverse, https://www.fundinguniverse.com/company-histories/eastern-enterprises-history/; see also Beacon Oil Company, Annual Report (1920), on file with the Massachusetts Department of Corporations and Taxation.
[17] David Raley, "Tennessee Gas and Transmission's Wartime Pipeline," Business History Conference working paper (2008), drawing on Tenneco/El Paso corporate archives https://thebhc.org/sites/default/files/raley.pdf;
[18] International Directory of Company Histories, vol. 6 (1992), Eastern Enterprises entry, describing EGFA's participation in Algonquin and 1953 commencement of southwestern natural-gas deliveries to the Northeast; Mass. EEA, "Natural Gas Distribution," mass.gov.
[19] Natural Gas Supply Association, "New England Natural Gas — Regions," naturalgassolution.org (accessed March 2026).
[20] Hatheway and Speight, Manufactured Gas Plant Remediation: A Case Study.

the U.S. utilize depleted gas fields, aquifers, or salt caverns to store gas in summer and retrieve it during winter, New England's granite and metamorphic rock formations lack such geological storage capacity.[21] As a result, Everett Station's gasworks and similar facilities continued to play an essential role as the transition from manufactured gas to natural gas played out 1950s, by ensuring resource adequacy to the regional gas network. High-Btu substitute gas processes, relying on existing manufactured gas infrastructure, emerged in the late 1930s and 1940s as transitional peak-shaving tools to fill supply gaps that the initial pipeline buildout could not reliably meet. Everett's coking and gasworks operations remained active until 1961, more than a decade after natural gas first reached the region.[22,23]

1.3. New England's Gas Supply Crisis and the LNG Solution

As gas constraints persisted through the mid-20th century, New England's gas system operators turned to above-ground liquefied natural gas (LNG) facilities for storage. Many LNG storage facilities were built on former manufactured gas sites, with new tanks and vaporization facilities replacing the 19th century gasholders and coking plants while taking advantage of established linkages to the local gas distribution network.[24]

In the same way, EMT was founded on the former Everett Station site to take advantage of the waterfront wharf, interconnections to Boston Gas's distribution system and the interstate pipeline network, and permissible industrial zoning due to its ongoing status as a petroleum facility. At the time of its 1971 commissioning as the first LNG import terminal in the continental U.S., EMT comprised two large LNG storage tanks (approximately 180 feet tall with combined capacity of approximately 3.4 billion cubic feet of gas equivalent, or 42 million gallons), a marine berth, vaporization equipment with peak send-out capacity of approximately 135 million standard cubic feet per day (MMSCF/D), a fraction of its current rated send out of 715 MMSCF/D). The terminal was developed by the Cabot Corporation, via two purpose-built subsidiary entities: Distrigas Corporation held the FPC import license and contracted supply but owned no physical facilities, while Distrigas of Massachusetts Corporation (DOMAC) owned and operated the Everett terminal and held contracts with end purchasers such as Boston Gas Company. This structure was designed in part to limit the FPC's jurisdictional reach over different links in the supply chain, in response to perceived overreach in the 1960s. Cabot retained ownership for nearly three decades before selling the LNG business to Belgium's Tractebel for

[21] ISO New England, "Natural Gas" fact sheet (April 2021), at 1. Available at iso-ne.com.
[22] "Eastern Enterprises History," International Directory of Company Histories, vol. 6 (St. James Press, 1992), reproduced at FundingUniverse, https://www.fundinguniverse.com/company-histories/eastern-enterprises-history/ (describing 1950s closure of Everett blast furnace and New Haven/Everett coke plants in response to declining domestic steel demand and rail-industry shift to diesel).
[23] Massachusetts Department of Environmental Protection, Waste Site / Reportable Releases Database ("WSC Sites"), records for Everett, MA, https://www.mass.gov/info-details/waste-site-reportable-releases-lookup; see also Allen W. Hatheway, Remediation of Former Manufactured Gas Plants and Other Coal-Tar Sites (Boca Raton, FL: CRC Press, 2012), tables 4.7–4.9 (Massachusetts MGP plant histories).
[24] On Salem, see Comment of New England Power Company and Boston Gas Company, each d/b/a National Grid, FERC Docket No. PF14-5-000 (Salem Lateral Project), Feb. 21, 2014, at 1–2 ("The Salem LNG facility was formerly the site of a manufactured gas plant which operated from the 1890s to the 1960s"). On Lynn and the broader Massachusetts manufactured-gas-plant inventory, see Hatheway and Speight

approximately $680 million in 2000.[25] Ownership subsequently passed to GDF Suez, which was renamed ENGIE in 2015 before Exelon acquired the facility in 2018, which eventually spun out Constellation, EMT's current owner operator.[26]

Distrigas's request for large-scale, long-term LNG imports into the U.S. represented a new regulatory front for the FPC, reshaping the national gas market's regulatory structure.[27] The National Gas Act contains two sections that have been relevant to the regulation of EMT over the years. Section 7 treats certificated facilities as regulated interstate infrastructure — cost-of-service rates, tariffed access, and FERC approval required before service can be abandoned — while Section 3 authorizes import/export facilities under a public-interest standard without rate regulation, access mandates, or abandonment obligations. Section 7 was intended to cover entities that exhibit interstate utility characteristics, while Section 3 provides more leeway to covered entities that typically behave more like market supply resources. EMT has been regulated under both sections and, to this day, faces questions about whether its service is more akin to utility-like regulation or to market-supplied resources.

On February 17, 1970, Distrigas Corporation filed with the FPC under Section 3 of the Natural Gas Act (Docket No. CP 70-196), seeking authority to import up to six shiploads of LNG annually (later increased to fourteen) from Algeria for a twenty-year term, with delivery to terminals at Everett and Staten Island.[28] On March 9, 1972, the FPC issued Opinion No. 613, granting Section 3 authorization while disclaiming Section 7 jurisdiction over the import terminal facilities. FPC reasoned that foreign commerce ceased at the "ship's flange at the point of entry" and that Distrigas should be treated as if it were a domestic producer or gatherer, requiring only import authorization for its operations.[29] Barely a year later, on May 25, 1973 the FPC reversed its decision, and ordered the company to file Section 7 applications due to a "commingling" theory — the facilities received gas destined for both interstate and intrastate sales.[30] The 1974 D.C. Circuit decision on the company's appeal (*Distrigas Corp v. FPC*, later upheld by the Supreme Court) held that Section 3's authority is "at once plenary and elastic" and the Commission could impose Section 7-equivalent certification requirements as conditions of import authorization.[31] This new precedent remained controlling law for decades, and was explicitly referenced in FERC's pivotal 2002 *Hackberry LNG Terminal* order, which restructured the modern regulatory framework for LNG terminals.[32] The FPC also imposed specific safety conditions on the terminal,

[25] Oil & Gas Journal, "Tractebel to Buy Cabot LNG for $680 Million," July 13, 2000, https://www.ogj.com/pipelines-transportation/lng/article/17254116/tractebel-to-buy-cabot-lng-for-680-million (reporting Tractebel's $680-million purchase of Cabot Corp. subsidiary Cabot LNG, including the Everett terminal, a 10 percent interest in Trinidad's Atlantic LNG liquefaction facility, and the LNG tanker Matthew; closing expected late August 2000). See also "Cabot LNG Sold to Tractebel for $680M," Natural Gas Intelligence (July 2000); Orders Granting, Amending and Vacating Authority to Import and Export Natural Gas, 66 Fed. Reg. (Sept. 20, 2001).
[26] POWER Magazine, "Everett LNG Terminal at the Crossroads" (2023).
[27] Energy Law Journal, Vol. 24, No. 2, "Liquefied Natural Gas: Regulation in a Competitive Natural Gas Market" (2003), at 293–94.
[28] Distrigas Corp. v. FPC, 495 F.2d 1057, 1059 (D.C. Cir. 1974).
[29] FPC Opinion No. 613, supra note 10. See also Energy Law Journal, supra note 27, at 294–95.
[30] Distrigas Corp. v. FPC, 495 F.2d at 1060–61.
[31] Id. at 1063–64.
[32] Hackberry LNG Terminal, LLC, 101 FERC ¶ 61,294 (2002). See also FERC Joint Concurrence, Chairman Glick & Commissioner Clements, EcoEléctrica, L.P. (discussing Hackberry's relationship to the Distrigas precedent).

including requirements to curtail LNG transfer operations whenever junkyard activity occurred adjacent to the transfer line, to provide adequate dike height and ditching to contain any maximum credible spill, and to file semi-annual safety reports.[33]

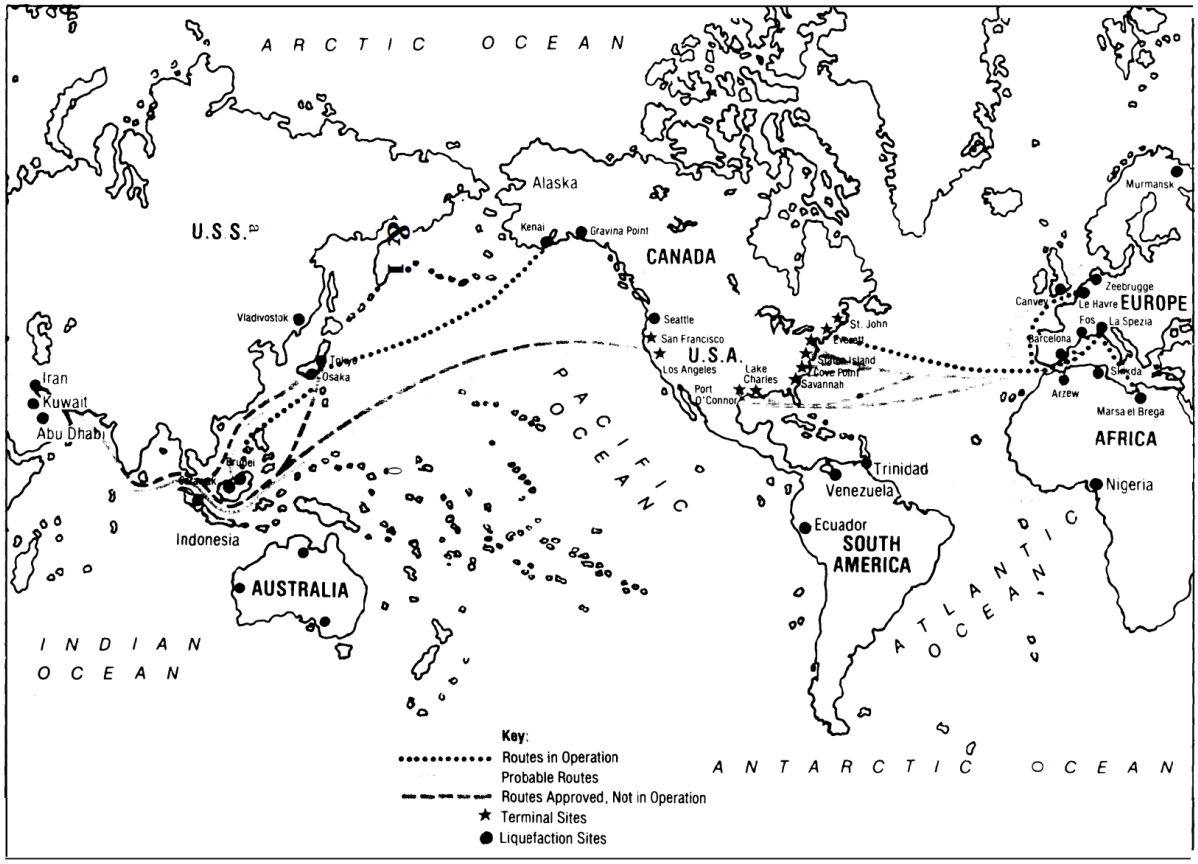

Figure 3. 1977 Map of LNG trade routes.[34]

EMT's suppliers shifted over time, through partnership with gas companies first in Algeria and later Trinidad and Tobago. Algeria, the world's first LNG-exporting nation, partnered with EMT for the first LNG imports into the continental U.S.; its first shipment arrived at Everett in November 1971, carried by 50,000 cubic-meter tanker *Descartes.*[35,36] The initial contract authorized DOMAC to sell approximately 4.75 million MMBtu of LNG per year to Boston Gas, with storage capacity of 1.1 to 1.7 million MMBtu per month.[37] *Descartes* would make 15 trips per year on 20-day cycles. However, as domestic gas prices fell and Algerian prices rose in the 1980s, Distrigas was forced into bankruptcy after a last shipment in August 1985. While EMT remained in operation, deliveries to the terminal were suspended for

[33] FPC Opinion No. 613, supra note 10 (safety conditions).
[34] United States, Congress, Office of Technology Assessment. *Transportation of Liquefied Natural Gas*. Government Printing Office, 1977. *Princeton University*, www.princeton.edu/~ota/disk3/1977/7712/771203.PDF.
[35] Oil & Gas Journal, "US LNG Imports Poised to Play Long-Term Supply Role" (2003).
[36] The *Descartes* was so closely associated with Everett that the FERC-approved rate schedule for the terminal was informally known as the "Descartes tariff." Distrigas of Massachusetts Corp. v. Boston Gas Co., 693 F.2d 1113, 1118 n.7 (1st Cir. 1982).
[37] Id. at 1117.

approximately a year through 1987. Sales to Boston Gas dropped from 14 Bcf in 1984 to zero in 1986 and 1987[38] but resumed in 1988 at 6 Bcf, rising to 17 Bcf in 1989 after EMT restructured long-term commercial agreements with Algeria. EMT eventually diversified its suppliers. With the turn of the century, EMT transitioned from Algeria as its dominant supply to Atlantic LNG (Trinidad and Tobago), which constructed a new modern facility in part to serve EMT.

EMT's integration into the regional natural gas transmission network was significantly enhanced through two discrete, permitted expansions. In 1989, EMT placed a medium-pressure LNG sendout system into service, consisting of LNG pumps and shell-and-tube vaporizers with an aggregate authorized capacity of approximately 150 MMscf/d. This expansion established a direct interconnection with the Algonquin Gas Transmission system, materially improving EMT's ability to deliver regasified LNG into the regional pipeline network. In 1998, EMT further expanded its sendout capability by adding an additional 150,000 MMscf/d of vaporization capacity, again utilizing LNG pumps and shell and tube vaporizers. In conjunction with this expansion, a 7.5-mile, 20 inch diameter pipeline lateral was constructed to provide a direct interconnection between EMT and the Tennessee Gas Pipeline system, further strengthening the terminal's role in regional gas supply reliability and system flexibility.

1.4. The Shale Revolution and LNG

In its first three decades of operations, EMT benefited from global LNG prices that were regularly cheaper than US natural gas, especially during peak-day pipeline constraints. Pricing data from Boston Gas' 1989 DPU Annual Return shows a rate of $2.67 per MCF from Distrigas, while average prices from Tennessee and Algonquin contracts were $5.10 and $3.99, respectively. With growing demand in the 2000's, this favorable pricing environment encouraged further investment in LNG receiving infrastructure, including two offshore deepwater ports in Massachusetts Bay: Excelerate Energy's Northeast Gateway (commissioned in 2008, approximately 13 miles off Gloucester) and GDF Suez's Neptune LNG (commissioned in 2010, approximately 22 miles offshore). The Saint John LNG terminal in Saint John, New Brunswick (originally known as Canaport LNG before acquisition by Spanish energy company Repsol) also emerged to offer an additional LNG import pathway into the New England market. Construction began in September 2005, and the facility received its first cargo in June 2009, making it the first LNG terminal in Canada. The facility connects to New England markets via the 145-kilometer Emera New Brunswick Pipeline, which runs to an interconnection with the Maritimes & Northeast Pipeline (M&NP) near St. Stephen, New Brunswick. The M&NP, in turn, extends through Maine and New Hampshire into Massachusetts, where it connects to the broader pipeline grid at Dracut.

[38] Boston Gas Annual Returns to the DPU: 1984 – 1989. Purchased Gas.

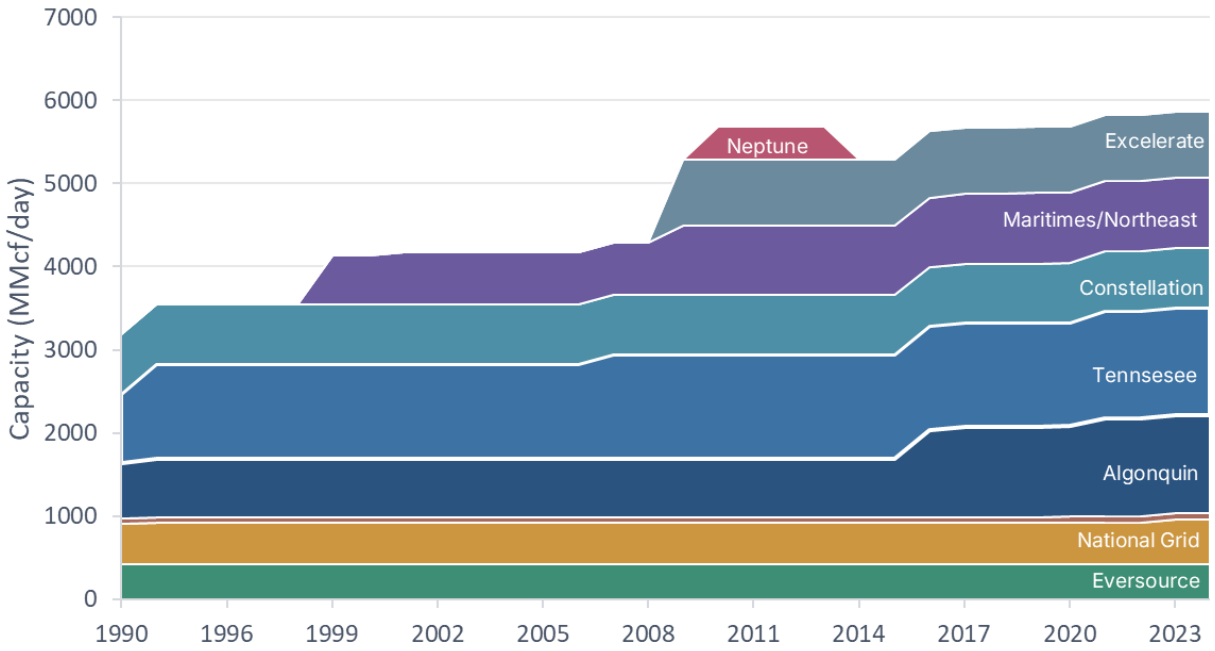

Figure 4. Timeline of additions to Massachusetts gas capacity resources. Source: PHMSA, EIA

The development of hydraulic fracturing and horizontal drilling techniques—the "shale revolution" beginning in earnest around 2008—fundamentally altered New England's LNG market. Dramatically increased domestic gas production, especially in the Marcellus and Utica shale formations, dropped U.S. natural gas prices from peaks above $12 per Mcf to below $3, a new reality that rendered global LNG uncompetitive except during extreme winter peaks. The shale revolution also lowered oil prices, reducing the incentive for New England's continued heating-oil customers to switch to natural gas and softening gas demand growth as a result. Utilization of EMT's services shifted during this period, influenced by contractual positioning, supply portfolio optimization, and regional market dynamics. Alternative suppliers, such as the two deepwater ports in Massachusetts Bay, struggled as a result: the two ports with a combined cost of approximately $750 million have sat largely idle for most of their productive lifetimes, with Neptune LNG receiving no commercial LNG cargoes from its commissioning in 2010 to its suspension in 2013.

1.5. Synthesis

The history of energy infrastructure on Everett's shoreline shaped EMT's status today, in geographic, regulatory, and economic terms. Generations of energy infrastructure built along the Mystic since the 1890s have carved out a central role in the regional gas system, taking advantage of its waterfront access, purpose-built direct connections to the Greater Boston distribution network, and later linkages to interstate pipelines. Each major shift in the energy system—from manufactured gas to natural gas, and from imported LNG to shale gas—was accompanied by new facilities built on the same Everett

peninsula to fill a different market niche. The importance of these facilities shaped state and national energy regulation, often through specialized regulatory treatment, because the facilities built in Everett filled a unique role that placed them "outside" the traditional gas utility systems of their respective eras. EMT and other LNG facilities have faced ups and downs, but their services are procured due to geographically determined constraints in regional gas supplies on peak-demand days. As New England undergoes a 21st-century energy transition and a new energy mix takes shape, the future of EMT's role in the regional system will once again be shaped by contemporary policy and commercial influences, informed by the facility's history of repeated reinvention.

2. Gas Supply in Massachusetts Today

2.1. Meeting Peak Day Demand

Natural gas consumption in Massachusetts is highly seasonal. The state's gas distribution systems move roughly 1.0 billion cubic feet of fuel to consumers per day on average (about 373 Bcf per year), but on the coldest days of the year, regional LDC peak-day demand approaches 5 Bcf per day across New England (Figure 4), with Massachusetts accounting for more than half of that total.[39] The LDCs engineer their systems to meet these moments of peak demand and must demonstrate resource adequacy to reliably provide for them. Peak demand days tend to coincide with the moments of greatest constraint on interstate pipelines. Designing the gas system and procuring adequate supply to meet the gap between average and peak consumption is the central challenge of gas supply planning in Massachusetts.

The *design day* is a regulatory and engineering construct, representing the coldest day a utility must be capable of fully serving. It is typically defined as the coldest day in a multi-decade (usually the past 20-40 years) weather record in the utility's service territory, or a statistically equivalent standard set by state regulators.[40] Design day weather is, by definition, a rare event, but it provides a common regulatory standard for LDCs to plan against. The Commonwealth's gas utilities are obligated to serve all customers on demand, and failure to do so during a prolonged cold event can result in pressure losses that require manual restoration of service, a costly, time-consuming, and potentially dangerous outcome. But, due to the design-day standard, utilities must secure and maintain supply and delivery capacity well above typical usage, resulting in underused contracts, storage, and backups whose costs are reflected as fixed charges.

Moreover, where in the gas system supply capacity is located is just as important as how much exists: resources (such as those listed in Table 1 and illustrated in Figure 5, Figure 6, and Figure 7) need to be positioned to deliver gas to impacted areas during periods of pipeline constraint, since distant sources are of limited use if the transmission network is stressed. To meet design day needs, the utilities must guarantee both **supply adequacy** (enough gas to meet peak demand) and **delivery reliability** (the capacity to deliver those supplies to all customers who want them) through the various tools at their disposal. EMT provides LDCs with both of these services. In other regions, geologic storage plays a significant role in ensuring adequacy, while larger networks provide reliability. For a variety of reasons alluded to above, the region lacks such infrastructure and has developed and maintained distinctive mechanisms to ensure these services. This section provides an overview of these mechanisms.

[39] Annual Massachusetts consumption of 373 Bcf, equivalent to roughly 1.0 Bcf per day on average, from American Gas Association, Massachusetts State Profile (accessed 2026). Regional LDC peak-day demand of approximately 4,983 BBtu (~4.9 Bcf) and Massachusetts's share of more than half of New England LDC demand from ICF, Natural Gas Demand Forecast through 2032, prepared for ISO New England (March 2023).
[40] Each New England LDC selects its own design-day temperature, generally representing the coldest day observed in the past 20 to 40 years in the utility's service territory.

Table 1. Major gas resources available in Massachusetts

Resource Types	Resources	Role
Supply Pipelines	*Algonquin (AGT)*	Combined handle ~90% of routine demand
	Tennessee (TGPL)	
	Maritimes & Northeast (M&N)	Access to Canadian peaking resources; provides domestic resources to NH & Maine (bidirectional flow)
LNG Import and Storage	*EMT*	Local supply and storage during peak periods
	Repsol / Saint John via Maritimes	Regional supply for peak demand periods accessible via Maritimes & Northeast Pipeline
Deepwater Ports	*Northeast Gateway, Neptune (Inactive)*	Northeast Gateway periodically receives shipments typically to serve generator needs under certain market conditions
Liquefaction Facilities	*Hopkinton (Eversource), Fields Point (National Grid), NEC LLC*	Allow production and storage at optimal times
LDC Storage and Vaporization	*~ 20 in Massachusetts*	LNG and LPG handle localized, short-term demand spikes

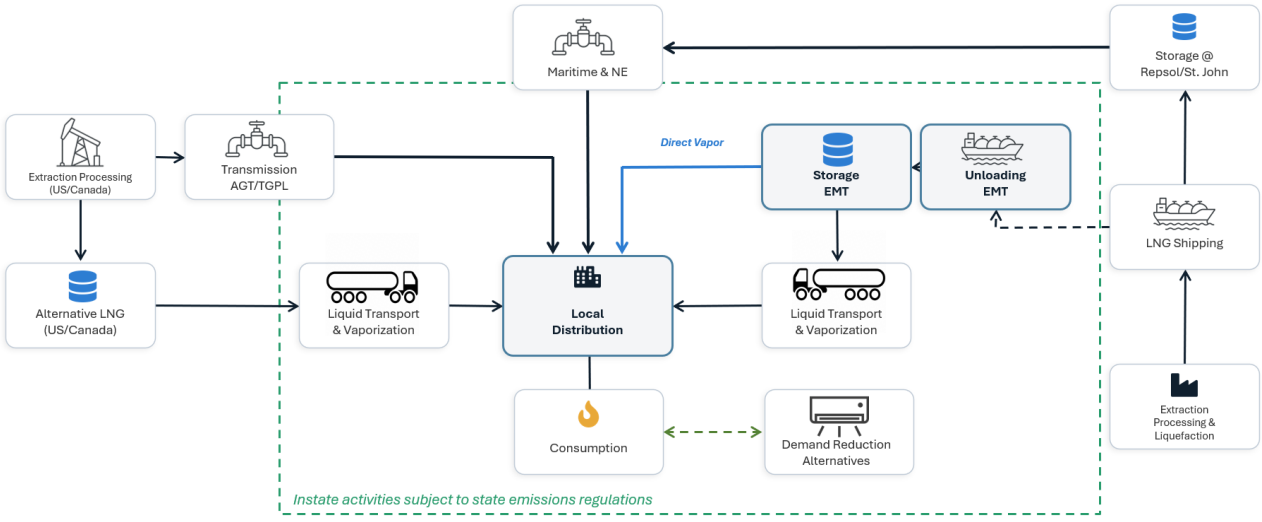

Figure 5. Overview of the Massachusetts gas system, showing the available sources of gas supply input, and the distinct routes through which those supplies reach the local distribution network for customer consumption. The graphic also highlights how demand reduction alternatives can reduce consumption needs and thereby lower the requirement for external supplies.

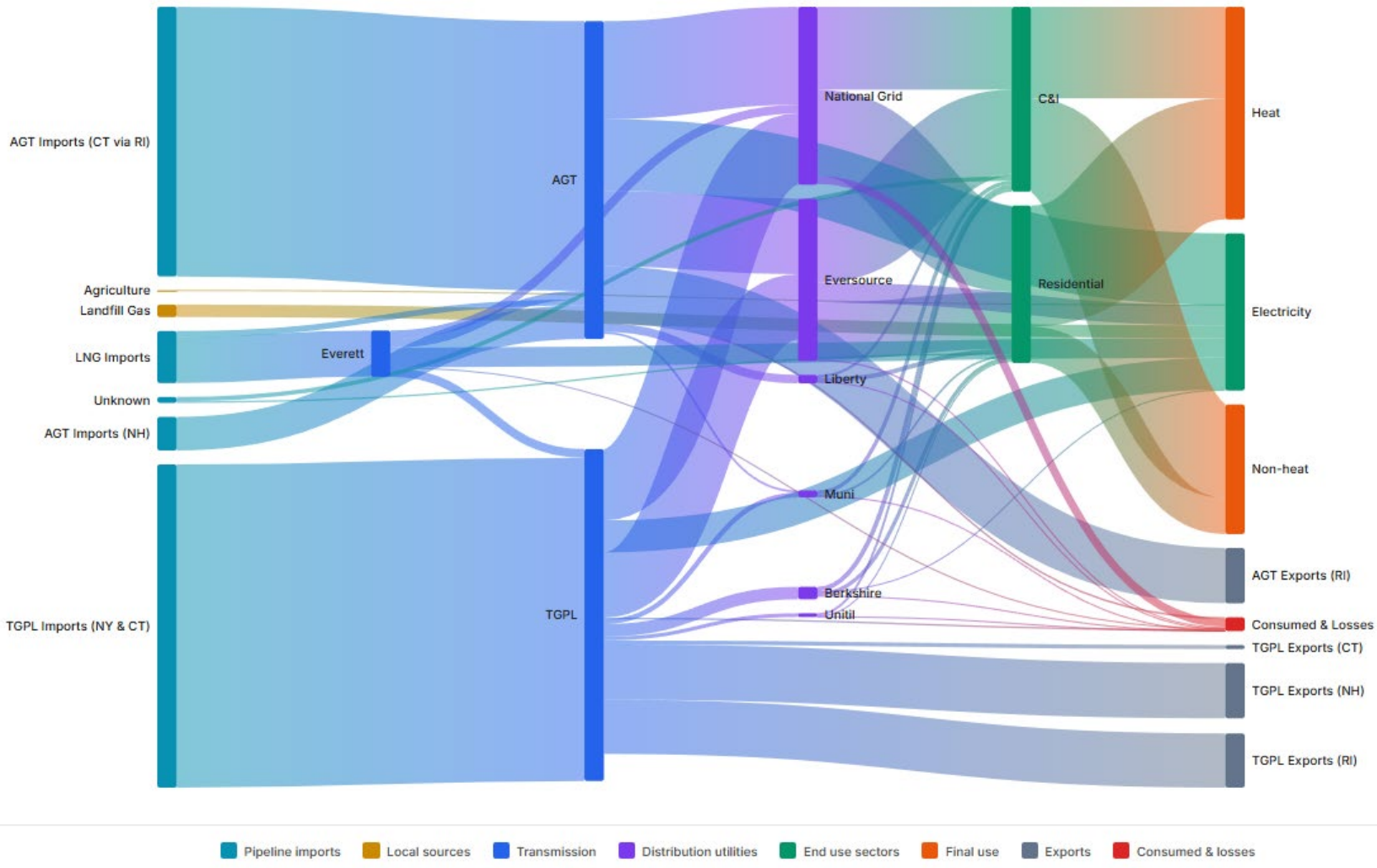

Figure 6. Sankey diagram of aggregate gas flows for 2023 (most recent year of complete data). Source EIA Form 176, EPA LMOP, EPA AgSTAR. Values are approximate due to limitations in cross-dataset consistency. Imports via the Maritimes are labeled as AGT Imports (NH).

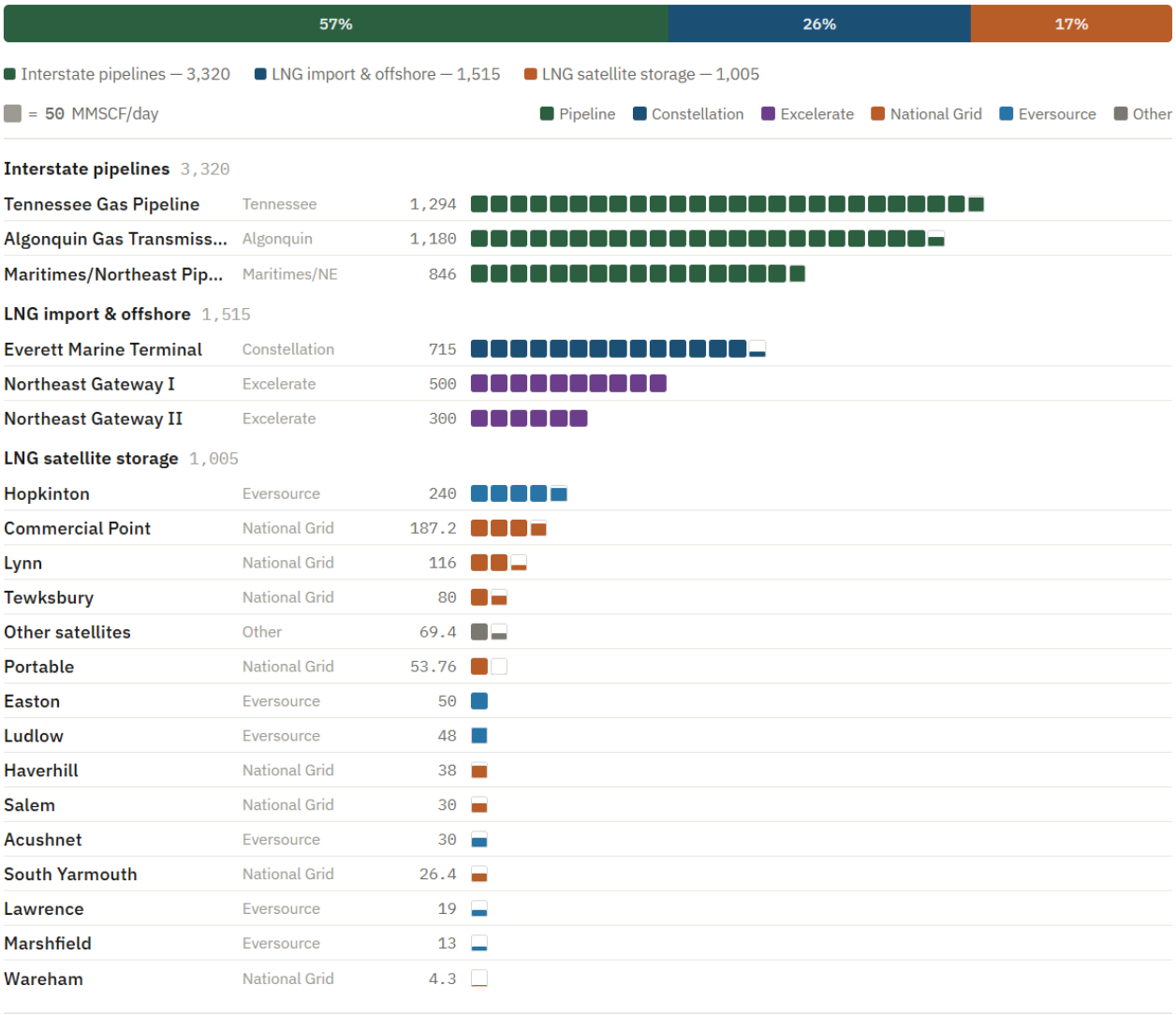

Figure 7. Design-day sendout capacity by facility (MMSCF/Day). ***Other*** *includes several smaller facilities and portables. Source: EIA, PHMSA,[41] and operator data. Note: EMT's rated capacity includes vaporization for the defunct Mystic Generating Station.*

[41] Pipeline and Hazardous Materials Safety Administration (PHMSA). "Liquefied Natural Gas (LNG) Annual Data – 2010 to Present." U.S. Department of Transportation. Last modified May 11, 2026. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

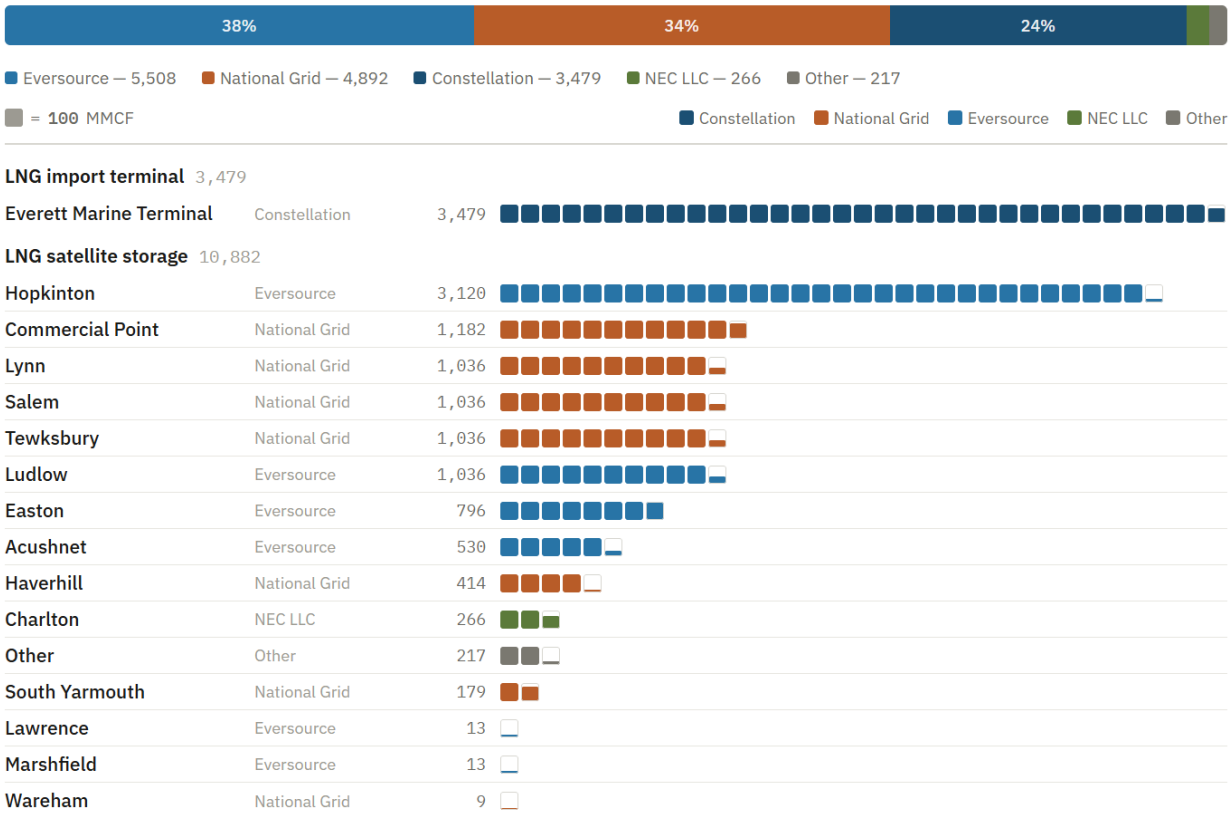

*Figure 8. LNG storage volumes in Massachusetts. **Other** includes several smaller facilities and portables. Source: EIA, PHMSA,[42] and operator data.*

[42] Pipeline and Hazardous Materials Safety Administration (PHMSA). "Liquefied Natural Gas (LNG) Annual Data – 2010 to Present." U.S. Department of Transportation. Last modified May 11, 2026. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

2.2. Interstate Pipelines

Interstate natural gas pipelines are the primary conduit for gas supply into New England, accounting for the large majority of fuel consumed in the region on a typical day. The physical, regulatory, and commercial structures of these systems shape the role that supply and storage resources like EMT play within the system, managing the constraints pipelines impose.

Physical Operation

Natural gas moves through pipelines under pressure, driven by compressor stations spaced along the route that maintain the pressure differential necessary to sustain flow. Pipeline capacity is not a fixed quantity: it varies with temperature, compression availability, the number and location of active delivery points, and the direction and magnitude of flows at any given time. On high-demand days, when multiple utilities and generators are simultaneously drawing at or near maximum contracted volumes, the system operates with little margin. But the use of the system by these different consumers varies substantially. Power generators typically rely on a combination of short-term, portfolio-based, or market-responsive fuel arrangements, while LDCs typically hold long-term, firm contracts for pipeline supplies.

Constraints in interstate pipelines can develop at specific points along the route, such as compressor stations, lateral interconnections, or delivery points where local demand exceeds the pressure the system can maintain under simultaneous load conditions. This locational dimension of pipeline constraints is particularly significant in eastern Massachusetts. The Algonquin Gas Transmission system delivers gas via a series of laterals branching from the mainline into individual utility territories. Under design-day conditions, these laterals can reach their physical delivery limits even when the mainline itself has available capacity. As a result, gas that exists in abundance at the Algonquin-Tennessee interconnection in Connecticut may be operationally unavailable to a utility in Cambridge or Somerville if the lateral serving that territory is fully subscribed.

Regulatory Framework

Interstate natural gas pipelines are regulated by FERC under Section 7 of the Natural Gas Act, which requires pipeline operators to obtain certificates of public convenience and necessity before constructing, operating, or abandoning interstate facilities. FERC's certificate process evaluates proposed projects against a public interest standard that weighs economic need, environmental impact, and landowner and community concerns. Once certificated, a pipeline operator is obligated to provide service under its approved tariff and cannot abandon that service without regulatory approval. Due to this regulatory structure, pipeline capacity additions require years of permitting, environmental review, and often litigation before construction can begin. Several proposed expansions of the Algonquin and Tennessee systems into New England over the past decade were either abandoned or significantly scaled back following opposition during the certificate process. The result is a regional pipeline system

whose capacity reflects decisions made decades ago, modified only at the margins by incremental projects that successfully navigated sustained regulatory and political resistance.

Commercial Structure

Access to interstate pipeline capacity is governed by an open-access regime established by FERC Order No. 636 in 1992, which required pipeline operators to unbundle transportation services from gas sales and offer firm capacity to shippers on a non-discriminatory basis. Under this structure, LDCs and other gas buyers and sellers (including Constellation) hold firm transportation contracts that entitle them to reserved capacity on specific pipeline segments to specific locations, up to a nominated volume, on any day they choose to exercise it. Firm capacity holders have scheduling priority over interruptible shippers, customers who pay lower rates in exchange for accepting the risk of curtailment when the pipeline is fully subscribed.

Firm transportation contracts are procured years in advance and carry fixed demand charges regardless of utilization. An LDC that holds firm capacity on Algonquin pays for that reservation whether or not it nominates gas on any given day. The cost of that reservation reflects the value of guaranteed access under peak conditions, not average-day throughput. Conversely, a potential customer that does not hold sufficient firm capacity cannot simply purchase additional pipeline gas on a cold day: the capacity to move that gas may not be available, and interruptible service offers no guarantee of delivery precisely when delivery is most needed.

The capacity release market allows firm holders to sell unused capacity to other shippers, providing some flexibility. But on design days, when every firm holder is drawing at or near maximum, released capacity is scarce and expensive. Like the physical pipeline system, the commercial system has slack on average days and almost none on the coldest ones.

2.3. On System LNG Resources

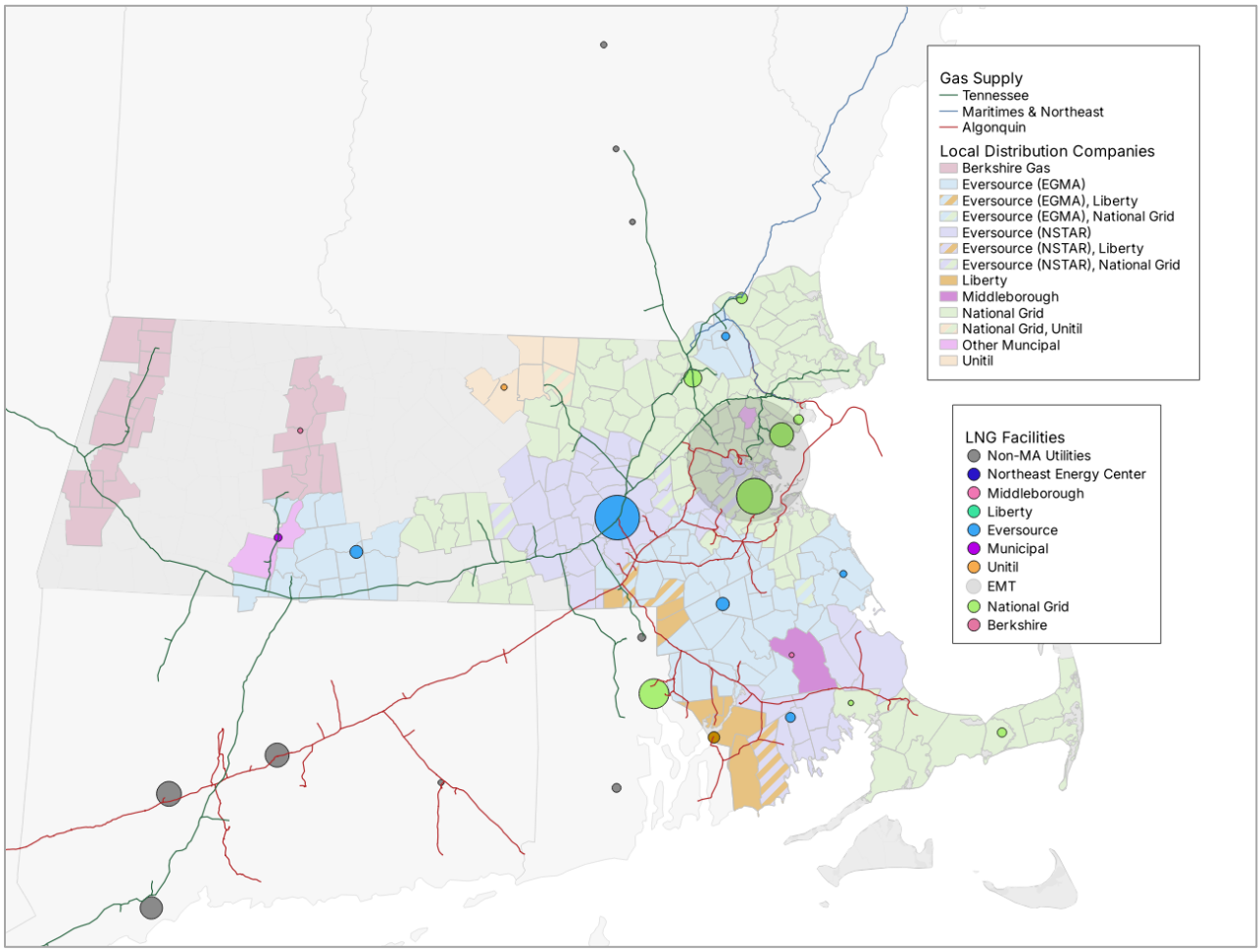

Figure 9. Map of on-system LNG resources in relation to utility territories and pipeline system. Size of each circle depicts relative capacity. Source: PHMSA LNG Annual Reports, EPA FLIGHT.

Many utility-owned *on-system* LNG facilities circumvent these pipeline constraints by having ready capacity on specific parts of the system. On-system LNG facilities are liquefied natural gas storage, vaporization, and, in some cases, liquefaction assets owned and operated by local distribution companies, sited within or adjacent to their service territories. Unlike EMT, which operates as a wholesale supply resource connected to the interstate transmission system, on-system LNG facilities are integrated directly into LDC distribution networks. They are designed to solve localized problems, such as pressure support at the end of a lateral, supply redundancy at a point distant from a pipeline interconnection, or peak shaving at a load center that cannot be reliably served by mainline deliveries alone.

Approximately 24 facilities without liquefaction capabilities are dependent on trucking LNG from a supply source (Figure 9). Trucked LNG faces different considerations than pipeline gas, since truck traffic can be disrupted by winter road conditions, which are often difficult during peak gas demand

days. The trucking operation also introduces community impacts along delivery routes, including heavy vehicle traffic, noise, and the public safety considerations associated with transporting cryogenic fuel on public roadways. Local LNG supply resources, such as EMT, utility own liquefaction facilities and the independent Northeast Energy Center, are typically considered lower-risk than long-distance resources (~300 miles away in Pennsylvania and Quebec), although Middleboro and Berkshire gas have regularly used out-of-state supply sources in recent years.[43]

Across New England as a whole, the LNG peak-shaving fleet today comprises approximately 30 facilities holding roughly 47 fixed LNG storage tanks and seasonal portable vaporizer units in total, the legacy of a sustained mid-twentieth-century build-out to fill seasonal supply gaps when interstate pipeline deliveries proved unreliable (Figure 9).[44] Massachusetts LDCs collectively operate permanent on-system LNG storage facilities, with aggregate fixed storage capacity of approximately 662 million cubic feet (Figure 8).[45] This *maximum storage volume* measures the total quantity of LNG that can be held in the facilities in its liquefied state, which offers a distinct constraint from *sendout rate* (Figure 7), the speed at which that inventory can be vaporized and injected into the distribution system (a function of vaporizer count and capacity). A facility with substantial storage volume but limited vaporization infrastructure can accumulate inventory over weeks of off-peak operation, but only slowly release it at its vaporization rate under peak conditions.

Many of these facilities entered service alongside EMT in the late 60s and early 70s, in a geographic distribution intended to provide localized support to specific laterals and service areas while relying on EMT as a regional supply resource. While still meeting peak demands, utilization of these facilities during periods of normal operations has declined substantially as domestic sources have become more economic.

In addition, few on-system LNG facilities have liquefaction capability and are entirely dependent on truck deliveries of LNG produced elsewhere (primarily from EMT, Fields Point, Hopkinton, and NEC Charlton) to maintain and replenish their inventories. This supply chain dependency means that the reliability of on-system facilities is dependent on the reliability of the regional LNG production and distribution network. As a result, a disruption in truck supply during a sustained cold event could affect multiple on-system facilities that rely solely on trucked LNG.

National Grid (Boston Gas)

National Grid's Boston Gas territory is the most extensively served by on-system LNG among the Massachusetts LDCs. The company's seven permanent facilities—anchored by Commercial Point in

[43] See recent annual returns, page 48: www.mass.gov/financial-and-operating-annual-returns-to-the-dpu.
[44] Northeast Gas Association, Statistical Guide to the Northeast Region (2021), available at https://northeastgas.org/files/galleries/stat_guide_2021_(1).pdf; PHMSA, LNG facility data, available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.
[45] Facility capacity figures derived from PHMSA, Liquefied Natural Gas (LNG) Facilities and Total Storage Capacities (2024 reporting year), supplemented by operator filings at the DPU.

Dorchester (187.2 MMcf), Lynn (116 MMcf), and Tewksbury (80 MMcf)[46]—reflect both the density of its load and the complexity of the pipeline topology serving eastern Massachusetts. National Grid also deploys six portable vaporizer units during the heating season, providing an additional ~50 MMcf of flexible, relocatable sendout capacity that can be positioned in response to localized system conditions.

Eversource

Eversource's four EGMA facilities serve geographically distinct portions of its Massachusetts territory. The Easton (50 MMcf) and Ludlow (48 MMcf) facilities are the largest, with Ludlow notable as one of the few Massachusetts LDC on-system facilities with active liquefaction capability.[47] At a rated liquefaction rate of 8 MMcf per day, Ludlow can convert pipeline gas to LNG during off-peak periods, building inventory that is available for peak-season vaporization, a meaningful operational advantage that reduces reliance on truck supply for that facility. The Lawrence and Marshfield facilities serve the northern and southeastern portions of EGMA's territory respectively, providing localized peak support where pipeline lateral capacity is constrained.

Eversource's fifth on-system facility, the Hopkinton LNG plant owned by the Eversource subsidiary Hopkinton LNG Corporation, serves NSTAR Gas and is the largest of Eversource's Massachusetts peak shaving assets, with three storage tanks rivaling EMT's total storage volume. Under a 2014 gas-services agreement with NSTAR, Eversource has been executing a multi-year refurbishment program, totaling more than $300 million across Hopkinton and a companion facility, that recently replaced the original liquefier with new nitrogen-cycle equipment, eliminating the flammable refrigerants used in the legacy process and extending the facility's reliable operating life.[48]

Other Utilities

Unitil's Westminster facility (7 MMcf) and Berkshire Gas's Whately plant (3 MMcf)[49] satellite installations provide localized peak support within their respective service areas. Both are truck-supplied, storage-only facilities that serve distinct branches of the system. Their function is to supplement pipeline supply at specific load points rather than to serve as system-wide resources. The

[46] Facility capacity figures derived from PHMSA, Liquefied Natural Gas (LNG) Facilities and Total Storage Capacities (2024 reporting year), supplemented by operator filings at the Massachusetts Department of Public Utilities and Energy Facilities Siting Board. See also Figure 8.
[47] Eversource Gas of Massachusetts, on-system facility data filed with the Massachusetts DPU and PHMSA LNG Annual Reports; Ludlow rated liquefaction capacity from operator filings.
[48] Hopkinton Independent, June 21, 2023, supra (statements of Jim Blackburn, Eversource Manager of LNG Engineering and Technical Services, describing the 2014 gas-services agreement between Hopkinton LNG Corporation and NSTAR Gas as the framework for facility refurbishment, with Eversource then "about two-thirds of the way into the more than $300 million worth of investments into its two facilities" and replacing the original liquefier with new nitrogen-cycle equipment in place of flammable refrigerants); see also Hopkinton LNG Corporation v. Board of Assessors of the Town of Hopkinton, Mass. Appellate Tax Board (June 21, 2021) (discussing the 2014 DPU-approved renewed gas-services agreement between Hopkinton LNG Corporation and NSTAR Gas).
[49] Facility capacity figures derived from PHMSA, Liquefied Natural Gas (LNG) Facilities and Total Storage Capacities (2024 reporting year), supplemented by operator filings at the Massachusetts Department of Public Utilities and Energy Facilities Siting Board.

municipal gas utilities Holyoke Gas & Electric and Middleboro Gas & Electric also operate small peak-shaving facilities on their systems.

2.4. Other LNG Resources

Repsol Saint John LNG

The Saint John LNG facility (formerly known as Canaport) is an LNG import and regasification terminal located in Saint John, New Brunswick, jointly developed by Repsol and Irving Oil and operational since 2009; since late 2021, it has been fully owned by Repsol. The terminal is best viewed as a regional storage asset for the pipeline system and is not a source of trucked LNG needed to supply peak shaving facilities.

The terminal has a maximum send-out capacity of 1.2 billion cubic feet per day and features three insulated storage tanks. Regasified LNG flows through the Brunswick Pipeline into the Maritimes & Northeast Pipeline for delivery to Maine and New England markets, reaching Massachusetts through the Dracut interconnection. Because Saint John LNG can receive international LNG cargoes and hold substantial storage volumes, it, like EMT, is a supply source structurally independent of domestic interstate pipeline constraints. Its availability to New England markets is subject to pipeline capacity and cross-border commercial arrangements, delivering at most 800 million cubic feet capacity per day to Massachusetts at Dracut. Several of the LDCs maintain contracts with Repsol for firm vapor supply at levels that exceed their firm allotments with EMT. In addition, Repsol Saint John has contributed materially more regasified LNG to New England's electric-generation gas supply in recent years than EMT has.[50]

Deepwater Ports

Two offshore LNG deepwater ports were developed in Massachusetts Bay in the mid-2000s to diversify New England's import infrastructure. These ports tie directly into the pipeline delivery system and are not a source of trucked LNG.

Northeast Gateway, commissioned in 2008 and operated by Excelerate Energy, is located 13 miles offshore and uses a dual submerged turret-loading buoy system to receive floating storage and regasification vessels, delivering gas to the existing offshore HubLine pipeline. The facility is rated to deliver natural gas at a rate of up to 800 MMcf/d.[51] In 2019, two simultaneously connected Floating Storage Regasification Units (FSRUs), exceeded this throughput.[52] Despite this large contribution,

[50] Analysis Group, Report to ISO-NE on New England Gas Availability, see report at p. 74. The methodology disaggregates pipeline inflows, LNG terminal receipts (EMT/Constellation, Northeast Gateway/Excelerate, Saint John/Repsol), and non-generator demand into hourly generation dispatch profiles.
[51] Excelerate Energy, Northeast Gateway Deepwater Port project overview (project rated for peak deliveries of up to 800 MMcf/d); see also FERC Docket CP05-419, Algonquin Gas Transmission LLC, Northeast Gateway Lateral certificate (2007).
[52] Excelerate Energy, "Excelerate's Northeast Gateway Terminal Ramps Up Send-out in Arctic Blast" (February 2019), reporting that two regasification vessels imported LNG to New England during extreme cold weather.

Northeast Gateway has operated only intermittently, primarily during extreme cold weather events. The two most recent deals (2019 and 2022) were with a power generation entity and were for short-term gas supply rather than long-term supply.

Neptune LNG, the second deepwater port located approximately 22 miles northeast of Boston, has been continuously inactive; its operating suspension has been extended through December 31, 2027,[53] while Neptune evaluates the decommissioning process.

Such facilities face similar market and operating dynamics to Everett, although they do not supply a source of trucked LNG and cannot directly serve the Boston Gas system. Like EMT requires ships that navigate to its berth, the deepwater ports require FSRU-class vessels. Both are fractional shares of the global LNG fleet. Beyond these factors, similar market dynamics and buyer sourcing objectives apply to both EMT and the Northeast Gateway.

Regional Liquefaction Facilities: Fields Point (RI) and NEC LLC Charlton Liquefaction Facility (Charlton, MA)

The Fields Point facility is operated by National Grid LNG (NGLNG), a National Grid affiliate in Providence, Rhode Island.[54] Through D.P.U. 15-129, National Grid (Massachusetts) contracted with NGLNG to add on-site liquefaction capability at Fields Point under a 20-year liquefaction-service agreement for up to 3.5 Bcf per year (17,984 Dth/day).[55] The plant comprises a single 600,000-gallon insulated LNG storage tank with a regasified equivalent capacity of approximately 150 MMcf, three vaporizers, and on-site liquefaction equipment rated at approximately 20 MMcf/day, which allows the facility to liquefy pipeline gas during off-peak periods to build inventory for peak-season vaporization. The project was expected to eliminate roughly 7,000 Dth/day of trucking, the equivalent of about 1,200 truck deliveries per year to the site.[56]

The Northeast Energy Center (NEC), located in Charlton, Massachusetts, and developed by Liberty Energy Trust, began commercial operations in April 2024 after nearly a decade of development, with Energy Facility Siting Board (EFSB) and MassDEP approvals granted in late 2021.[57] The facility receives pipeline gas from a direct interconnection with the Tennessee Gas Pipeline (TGP) and liquefies it at a rate of up to 20 MMcf per day. The LNG is stored on-site in a 165 MMcf, full-containment concrete storage tank and distributed to utility customers by truck via a four-bay loading station. The facility's primary customer base includes six gas utilities (including several outside of Massachusetts), anchored by a firm supply agreement with National Grid's Boston Gas division.[58]

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[53] U.S. Maritime Administration, Deepwater Port License: Amendment of the Neptune LNG LLC Deepwater Port License and Temporary Suspension of Operations at the Neptune LNG Deepwater Port, 90 Fed. Reg. 40466 (Aug. 19, 2025), USCG Docket No. USCG-2005-22611.
[54] CH-IV International, *Engineering Study for Liquefaction Plants Project — National Grid Site Evaluations* (Oct. 10, 2011), § 5, filed as D.P.U. 15-129, Attachment DPU-1-21.
[55] D.P.U. 15-129, Order (May 13, 2016), at 6, 17; Exh. NGRID-EDA/JEA-1, at 18, 24.
[56] D.P.U. 15-129, Order (May 13, 2016), at 6–7, 19; Exh. NGRID-EDA/JEA-1, at 25.
[57] See permitting in EFSB 18-04/D.P.U. 18-96
[58] D.P.U. 15-129

NEC's design incorporates several features that distinguish it from conventional LNG facilities. Its liquefaction train is powered by a gas/electric hybrid-drive system, a low-emissions gas turbine with an integrally geared compressor and a 4 MW electric motor-generator. This configuration reduces energy consumption by more than 20 percent compared to conventional liquefaction technology. During periods when the turbine generates surplus shaft power, the motor-generator can export up to 4 MW of electricity, effectively functioning as a distributed generation resource. The facility uses a continuous methane monitoring system.

The company's development roadmap includes interconnection of its 4 MW hybrid-drive distributed generator into the National Grid utility network, enhancement of the facility's CO_2 separation and capture system with the addition of CO_2 storage and distribution, installation of an 8 MWh containerized battery, and, the addition of 1.5 Bcf of LNG storage capacity and a 100,000 Dth/day vaporization system that would allow NEC to inject regasified LNG directly into the pipeline system.

The NEC facility represents several layers of system integration that address near-term and long-term gas supply challenges. NEC draws gas from the interstate pipeline system when pipeline capacity is underutilized and prices are lower, liquifies it, and makes it available for truck delivery to LDC storage facilities during the heating season when pipelines are constrained and prices are higher.

The addition of the Fields Point and NEC liquefaction facilities in recent years, following the lowering of domestic costs relative to international LNG, represents efforts by both utilities and private investors to expand their portfolios at lower costs. National Grid's 2015 petition in D.P.U. 15-129 for new LNG supply contracts with NEC and its Fields Point facility observed the need for a new approach to EMT, noting that after 2008, "the rates charged by GDF Suez to the Company have increased significantly," and that it "was forced to negotiate year-to-year agreements with GDF Suez at escalating rates."[59] It further testified that once the Everett terminal became part of GDF Suez's global LNG portfolio, the owner had "the opportunity to sell into markets that are at much higher landed prices than can be achieved in the United States (multiples of three to five times U.S. prices have been experienced)," and that in the spring of 2013 "GDF Suez, for the first time ever, limited the volume of gas available to the New England Market." National Grid was left to bid above historical prices, purchase supplemental volumes from a terminal in New Jersey, and fell short of fully refilling its storage for the 2013/14 winter.[60]

National Grid's response was to develop domestic liquefaction capacity that would reduce its dependence on the terminal. In D.P.U. 15-129 it sought and obtained approval for two long-term liquefaction-service contracts: a 15-year agreement with NEC, and a 20-year agreement to expand Fields Point, together providing approximately 6.1 Bcf per year of liquefaction capacity.[61] National Grid's

[59] Pre-Filed Testimony of Elizabeth D. Arangio and John E. Allocca, Exh. NGRID-EDA/JEA-1, D.P.U. 15-129, at 6, 13, 19–21; Initial Brief of National Grid, D.P.U. 15-129 (Jan. 29, 2016), at 6, 16.
[60] Exh. NGRID-EDA/JEA-1, D.P.U. 15-129, at 20–21
[61] D.P.U. 15-129, Order (May 13, 2016), at 5–7, 17; Exh. NGRID-EDA/JEA-1, at 18, 24. The Northeast Energy Center agreement is for annual liquefaction capacity of 2.6 Bcf (up to 12,240 Dth/day) for 15 years; the National Grid LNG (Fields Point) agreement is for annual liquefaction capacity of 3.5 Bcf (up to 17,984 Dth/day) for 20 years.

stated rationale was both reliability and price: the liquefaction contracts would let it "avoid singular reliance on GDF Suez, ... access typically less expensive gas from the Marcellus shale region during the refill season, ... [and] liquefy lower-cost capacity procured by the Company instead of relying on price negotiations" with the terminal's owner. These new investments also carried price caps protecting against "the yearly bidding risks" of annual negotiations with EMT.[62] The Department of Public Utilities approved the contracts in May 2016, finding that they were consistent with National Grid's portfolio objectives, "compare favorably to the range of reasonably available alternative options," and would "reduce the Company's reliance on imported LNG... and allow the Company to access less expensive gas."[63]

Despite this initiative to create a new liquid supply, National Grid has remained reliant on EMT, largely due to its direct connection to the Boston Gas system. This reliance casts a shadow over these recent efforts to expand optionality and lower costs. The design of the EMT contracts is such that most of the cost of LNG is covered by the contracts' demand charges.[64] The commodity charge (the cost of calling on the resource) is low and indexed closely to Henry Hub Prices. In testimony supporting the Attorney General in the contract approval proceedings (D.P.U. 24-25 through 24-28, Exh. AG-MLTF-1), the Brattle group estimated average costs of approximately $55/MMBtu, assuming all allotted quantities are delivered and the future prices are consistent with gas price indices established in the contract's pricing formula. This assumption is reasonable given reported usage in the first two years of the contracts. Cost-of-gas adjustment filings made by LDCs show transactions for trucked LNG indexed to the Henry Hub NYMEX at rates of approximately $4 to $4.50 per MMBtu.[65,66]

The reliance on EMT is driven simultaneously by vapor needs in Massachusetts ' constrained gas system and to provide liquid at a large scale to meet the needs of on-system peak shaving facilities. Under the current EMT contract design, each LDC can use its remaining seasonal allotment as liquid at essentially no incremental cost to refill its on-system storage. EMT's liquid supply therefore competes directly with the recently constructed liquefaction facilities: both are necessary to the system as currently configured, yet neither is fully utilized or developed.

The uneven history of LDC reliance on EMT has prompted repeated efforts to reduce that reliance, but each was conceived to solve a discrete, near-term supply problem rather than as part of a coordinated, long-term resource strategy — and none has yielded a pathway capable of fully substituting for EMT.

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[62] Exh. NGRID-EDA/JEA-1, D.P.U. 15-129, at 13–14, 25–26; Initial Brief of National Grid, D.P.U. 15-129, at 10, 19; D.P.U. 15-129, Order (May 13, 2016), at 5, 19

[63] D.P.U. 15-129, Order (May 13, 2016), at 17–20, 24.

[64] See Assessment Report Chapter 4 for an overview of the contract structure.

[65] D.P.U. 25-PGAF-FGE Form III CGAC, D.P.U. 25-PGAF-EGMA(CGAC) Form III, D.P.U. 25-PGAF-GRID CGA Recon Invoices - Redacted

[66] For comparison, an exploration of Annual Returns from two municipal utilities provides alternative benchmark costs for trucked LNG from other domestic suppliers. The Middleboro Gas and Electric 2024 Annual Reports indicate an average price of 2024 calendar year EMT-sourced supply of $55.79 per Mcf (truck + vapor) and $37.72 in 2023. Middleboro's alternative truck LNG supplier, REV LNG, offered prices of $53.70 (2024) and $19.34 (2023). Holyoke Gas and Electric's trucked liquid supply from Enegir / Gaz Metro (Montreal, QC) costs an average of $29.79 ($8.29 variable + $21.50 fixed) per MCF in 2024 and $41.96 ($10.60 variable + $31.36 fixed) + per Mcf in 2023.

The result is that EMT and the infrastructure developed to substitute for it—the new regional liquefaction facilities, and, more broadly, other supply resources such as the deepwater ports—now operate in parallel, each built under its own limited outlook and none fully utilized: a suboptimal allocation of the region's resources.

2.5. Recent Efforts to Expand Pipeline Capacity

The previous sections describe a regional gas system that is simultaneously pipeline-constrained and storage-limited yet faces substantial barriers to addressing these constraints. A reasonable question follows: why has the region not simply built more pipeline capacity?

The answer is more complex than the public debate has typically acknowledged, with its focus on opposition from environmental advocates, state officials, and affected landowners. Several of the most significant proposed pipeline projects in the region's recent history failed not primarily because of regulatory resistance, but because the pipeline developers could not secure sufficient commercial commitments from potential customers to make construction financially viable.[67] The structural dynamics of the gas market—declining long-run demand expectations, the cost allocation logic of firm contracts, and the availability of incremental alternatives—have had influence in determining which projects proceed.

Pipeline developers finance construction through long-term contracts with shippers, typically fifteen- to twenty-year agreements that commit customers to fixed demand charges sufficient to service project debt. The challenge here is that there may be insufficient interest to justify a pipeline project development at the time it is proposed. Generators may be uninterested or incapable of entering into long-term contracts; and while one gas utility may find the pipeline expansion valuable, another, hypothetically, could have made an on-system LNG investment or contracted elsewhere for the supply that could be served by that pipeline expansion.

Project Maple scales back to Project RARE

Project Maple illustrates this dynamic clearly. Proposed by Enbridge in 2023, the project would have added approximately 250,000 Dth per day of firm capacity on the Algonquin at Salem.[68] Project Maple was never filed with FERC; Enbridge solicited bids through an Open Season that closed in November 2023, and as of mid-2026 no Project Maple certificate application has been submitted. After the Open Season closed in late 2023, the project did not publicly advance at full scale, apparently for lack of sufficient customer interest.

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[67] Notable examples include the Northeast Energy Direct project (Kinder Morgan), suspended in April 2016 after the company concluded it had not secured sufficient firm shipper commitments; and Access Northeast (Spectra/Eversource/National Grid), withdrawn in 2017 after the Massachusetts Supreme Judicial Court's August 2016 decision in Engie Gas & LNG LLC v. Department of Public Utilities, 475 Mass. 191, held that the DPU lacked statutory authority to approve electric-ratepayer-financed gas pipeline capacity contracts.

[68] Lamson, Jon. "Enbridge Announces Project to Increase Northeast Pipeline Capacity." *RTO Insider*, 21 Sept. 2023, www.rtoinsider.com/56274-enbridge-project-increase-ne-pipeline-capacity/.

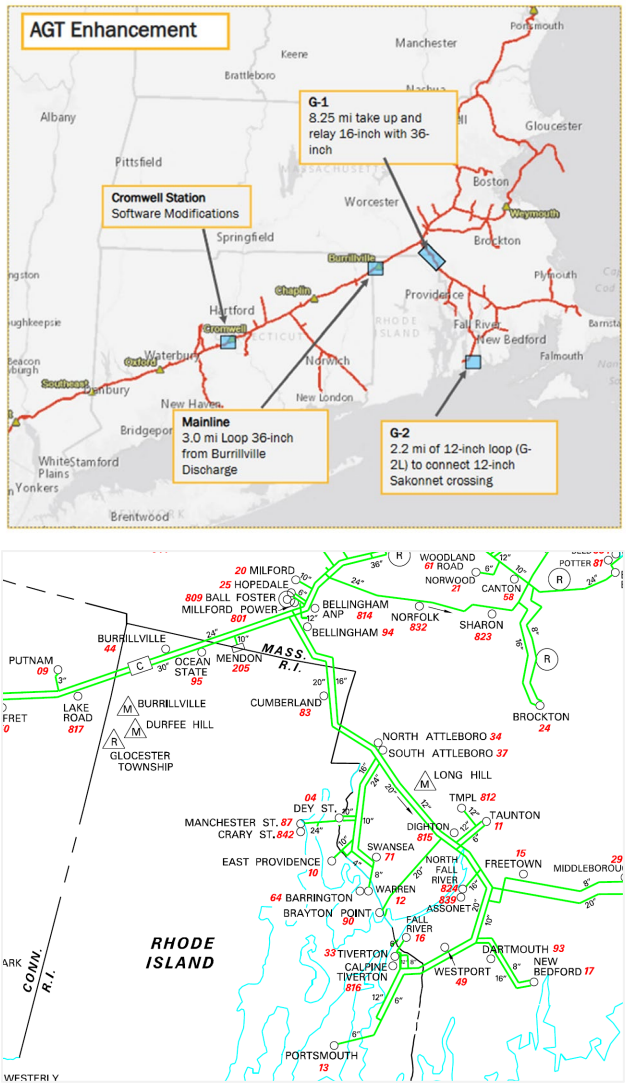

Figure 10. Map of upgrades associated with the AGT "Project RARE" Enhancement (left) and system diagram (right). Source: Enbridge

Facing this inability to garner interest for the full scope of Maple, Enbridge has since pursued smaller, segmented upgrades on the same laterals under existing blanket authority rather than refiling Maple as a single project. The most recent significant development in New England pipeline infrastructure reflects a different approach. Enbridge's Reliable Affordable Resilient Enhancement (RARE or AGT Enhancement) is a targeted upgrade to the Algonquin G-System serving southeastern Massachusetts and eastern Rhode Island (Figure 10).[69] Where large-scale expansion proposals sought to add broad system capacity, Project RARE aims to address a highly specific locational constraint: the G-System's limited ability to serve peak demand in Eversource's southeastern Massachusetts territory, a system that had relied on EMT supply delivered via the Algonquin system as a backstop against lateral constraints.

[69] The AGT Enhancement project is undergoing prefiling review with FERC under Docket No. PF-26-7-000: https://www.ferc.gov/Algonquin-Gas-Transmission-Enhancement-Project

RARE has attracted firm-transportation precedent agreements from three regional LDCs: Eversource Gas of Massachusetts (EGMA), NSTAR Gas (Eversource's other Massachusetts gas utility, serving central and southeastern Massachusetts), and Rhode Island Energy. The two Eversource agreements were filed at the Massachusetts DPU in September 2025—D.P.U. 25-133 for EGMA[70] and D.P.U. 25-134 for NSTAR Gas[71]—and approved on January 30, 2026. Rhode Island Energy publicly announced a signed precedent agreement in October 2025.[72] The Eversource companies project that the RARE-supplied capacity will displace their EMT firm-transportation needs for the Algonquin G-lateral after 2029, with associated winter supply-cost reductions on the order of 17 percent and lifetime savings to customers in the hundreds of millions of dollars; the same testimony makes clear, however, that the agreements do not eliminate the companies' need for EMT supply on the Algonquin J-System (which serves Eversource's Cambridge division) or other regional roles for the facility, and frames the region's longer-term need for EMT as dependent on market evolution over the next several years. Project RARE itself remains in FERC's pre-filing process;[73] Enbridge has signaled October 2026 as the target date for filing a certificate application, with a 2029 in-service date, though the project has not been authorized by FERC.

The G-System upgrade does not resolve the regional peak supply challenge; it resolves a specific locational constraint for a specific set of customers. Ultimately, that specificity represents both its commercial strength and its broader implication for EMT and the gas system as a whole. By addressing the G-System constraint directly, Project RARE substantially reduces the justification for a larger comprehensive pipeline project that might otherwise have cited southeastern Massachusetts load as a basis for need.

Project Beacon (Algonquin 2026 Open Season)

With the RARE upgrades now reasonably expected to be implemented, Enbridge has again pursued an incremental capacity project. On May 18, 2026, Algonquin Gas Transmission, LLC ("Algonquin") opened a six-week Open Season for firm transportation service on "Project Beacon," a system-wide capacity expansion of the AGT mainline. The project promises to provide increased firm transportation services throughout the entire Algonquin system (presumably including points on the J-system). The project will entail replacing existing smaller diameter pipes with larger diameter pipes, extending pipeline loops, and adding compression at existing compression stations. No specific details were made available at the time of the announced open season. The scale of such upgrades may depend on expressed interest.

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[70] Eversource Gas Company of Massachusetts, Petition for Approval of Firm Transportation Precedent Agreement, D.P.U. 25-133 (filed Sept. 2025; approved Jan. 30, 2026).
[71] NSTAR Gas Company d/b/a Eversource Energy, Petition for Approval of Firm Transportation Precedent Agreement, D.P.U. 25-134 (filed Sept. 2025; approved Jan. 30, 2026). In a substantively identical Response to Information Request DPU-2-3 (Nov. 6, 2025) filed in both D.P.U. 25-134 (NSTAR Gas) and D.P.U. 25-133 (Eversource Gas Company of Massachusetts).
[72] Rhode Island Energy, "Rhode Island Energy signs agreement to enhance gas capacity for customers," press release, October 2025. As of May 2026, the precedent agreement had not been filed for review at the Rhode Island Public Utilities Commission and could not be confirmed in the RI PUC docket index.
[73] Federal Energy Regulatory Commission, Algonquin Gas Transmission, LLC, AGT Enhancement Project (Project RARE), Docket No. PF26-7-000 (pre-filing initiated Feb. 24, 2026). Enbridge has indicated a target of October 2026 for filing a Section 7 certificate application, with a 2029 in-service date. The project has not been authorized by FERC.

3. Operational Context of The Everett Marine Terminal

This section reviews the operational, financial, and regulatory aspects of EMT, including topics on the import of LNG, sendout of vapor and liquid, the historical relationship between EMT and the Mystic Generating Station, the regulation of EMT, the cost of operations at EMT, and its workforce.

3.1. Ownership Structure and Timeline

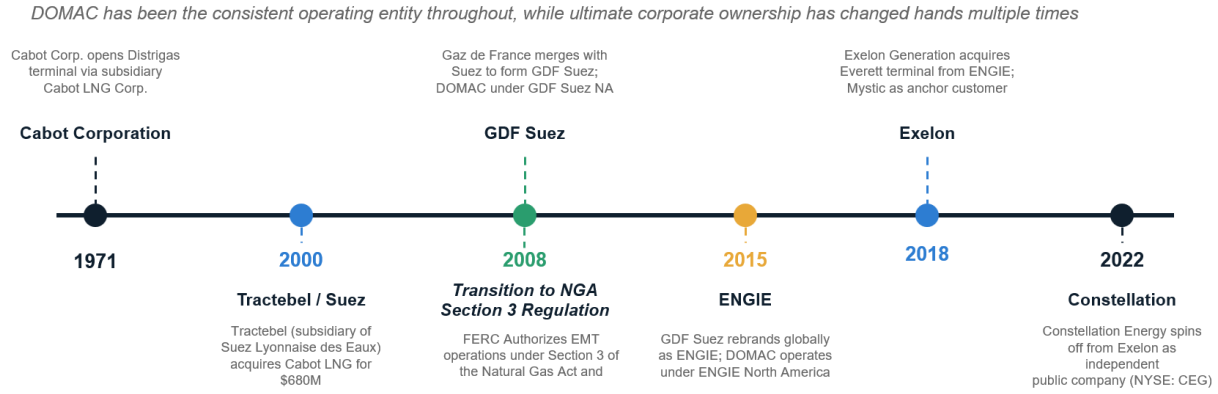

Figure 11. Timeline of EMT ownership.

EMT is owned and operated by Distrigas of Massachusetts LLC (DOMAC), a wholly owned subsidiary of Constellation Energy Corporation (Constellation Energy). Since October 1, 2018, Constellation LNG has been the entity responsible for purchasing LNG and is the importer of record for LNG purchases delivered to EMT. A corporate ownership timeline is provided in Figure 11.

3.2. The Import of International LNG

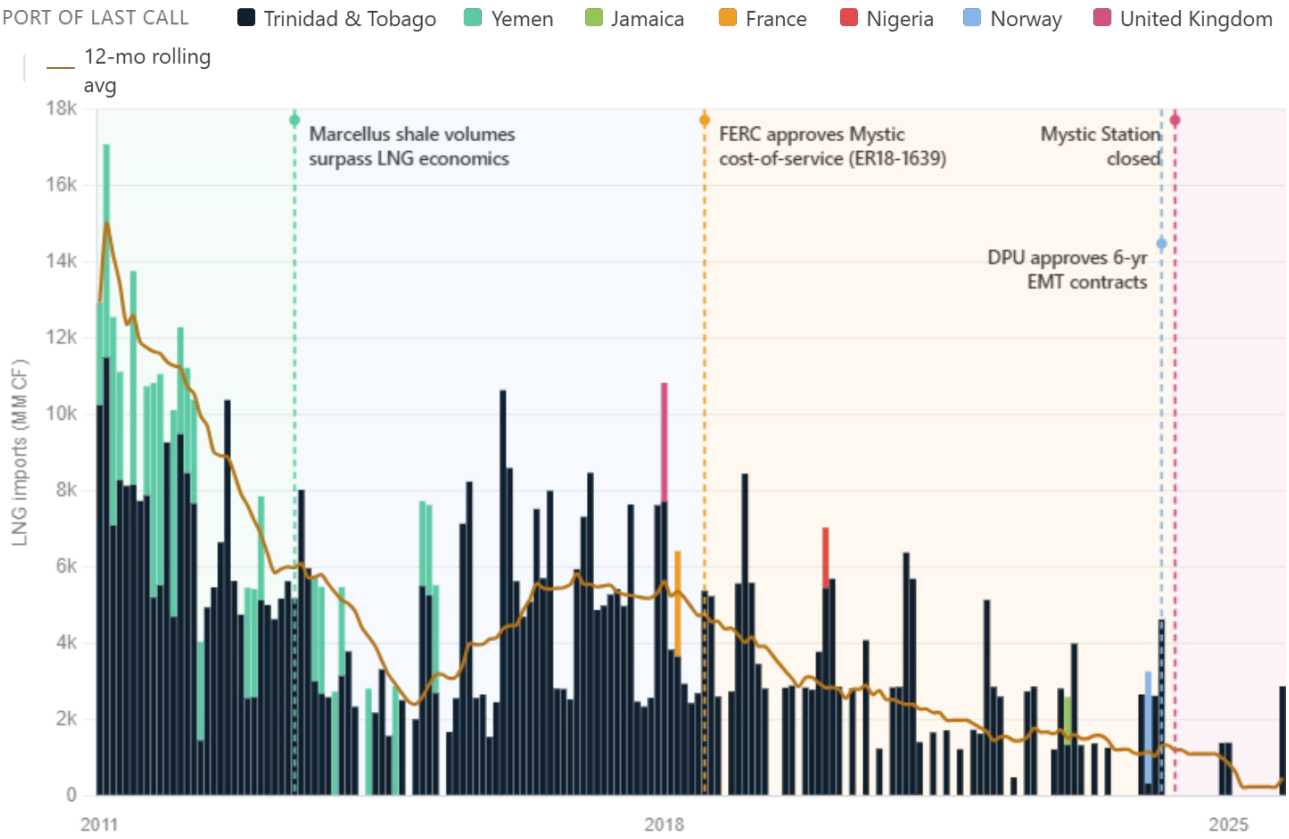

Figure 12. Monthly imports of LNG based on Source: EIA Natural Gas Imports by Point of Entry.

Tanker Scheduling and Procurement

Constellation LNG secures volumes through a combination of long- and short-term supply contracts and spot purchases, with post-Mystic supply sourced primarily through long-term contracts.[74] Atlantic LNG in Trinidad and Tobago has served as EMT's primary source in recent years, though the supply mix has occasionally included cargoes from Norway, France, Nigeria, and Yemen, as well as a single controversial Russian-origin cargo under previous ownership in January 2018 (Figure 12).[75]

Each delivery requires coordination across a wide network of stakeholders. Carriers must notify EMT at least 72 hours in advance to allow tank preparation and piping pre-cooling. Scheduling must also account for tidal conditions on the Mystic River and Coast Guard security protocols governing harbor

[74] U.S. DOE EIA. Natural Gas Imports & Exports Monthly Reports, 2021-2026.
[75] The January 2018 cargo, attributed to the Yamal LNG project in Russia, generated controversy. Russia's Yamal LNG is primarily owned by Novatek, which is subject to U.S. sanctions, although natural gas shipments were not sanctioned at the time. See Chesto, J. (2018, January 29). Russian LNG is unloaded in Everett; the supplier (but not gas) faces US sanctions. The Boston Globe. https://www.bostonglobe.com/business/2018/01/29/tanker-unloads-lng-everett-terminal-that-contains-russian-gas/rewj1wKjajaKtLp79irzTI/story.html.

transit, which require a moving security zone extending ahead of the vessel.[76] At the facility's historic peak, more than 70 tankers arrived annually,[77] but under the current seasonal LDC contracts, deliveries have declined sharply. In 2024, the terminal received cargoes only in January, February, March, and December, consistent with the November-through-March operating profile established under the new agreements.[78]

LNG unloading is a procedure-driven cryogenic operation. The liquid transfer itself takes 12 to 20 hours for a full cargo, while total berth time (including docking, safety checks, pre-cooling, and undocking) extends to 24 to 36 hours per vessel. A critical byproduct of storage is boil-off gas (BOG), as LNG stored at atmospheric pressure continuously vaporizes at roughly 0.05 percent by weight per day under normal conditions.[79] BOG must be managed continuously, either by compression for pipeline injection, or consumption as terminal fuel gas, as the BOG rate increases substantially during and immediately after cargo receipt.

The Jones Act and Domestic LNG Sourcing Constraints

The Merchant Marine Act of 1920 (the Jones Act) requires that vessels transporting cargo between U.S. ports be U.S.-built, predominantly U.S.-crewed, and at least 75 percent U.S.-owned.[80] No Jones Act-compliant LNG tanker exists: the United States has not constructed an LNG carrier in over four decades, and domestic shipbuilding costs run three to five times higher than foreign-built equivalents.[81]

As a consequence, EMT cannot receive domestically produced LNG by sea from any U.S. port, including the Cove Point LNG export terminal in Maryland approximately 700 nautical miles away. Despite the United States' position as the world's largest natural gas producer and a major LNG exporter, Everett's waterborne supply must originate from foreign producers or U.S.-origin cargoes transshipped through a foreign port. Congressional exceptions have not resulted in actual domestic coastwise LNG shipping.[82] On March 17, 2026, the Trump administration issued a 60-day Jones Act waiver covering LNG, oil, fertilizer, coal, and a range of other commodities. It later extended the waiver for an additional 90 days

[76] U.S. Coast Guard security zone regulations for LNG transits in Boston Harbor. See 33 CFR Part 165. Historically, the Tobin Bridge was closed when a tanker ship passed underneath, but that is no longer the case since 2019. Security escort includes Coast Guard, Massachusetts State Police, and Massachusetts Environmental Patrol.
[77] Defense Media Network, "U.S. Coast Guard: Countering Maritime Security Risk," quoting Clay Harris, President and CEO of GDF SUEZ Energy North America, noting more than 70 LNG tanker arrivals at Everett in 2010. Cf. U.S. Energy Information Administration, Natural Gas Imports & Exports by Point of Entry (Everett, MA), series NA1278_YEVTT_2, which shows 2010 receipts in the range consistent with that figure given typical cargo volumes of approximately 2–3 Bcf per tanker.
[78] U.S. Energy Information Administration, "Today in Energy: New England Utility Closes Import-Dependent Gas-Fired Power Plant, Keeps LNG Import Option," June 24, 2024.
[79] Global LNG Services, "LNG Receiving Terminal Process." https://globallngservices.com/lng-receiving-terminal-process/
[80] 46 U.S.C. § 55102. The Merchant Marine Act of 1920, Section 27.
[81] Congressional Research Service, "Shipping Under the Jones Act: Legislative and Regulatory Background," R45725.
[82] In 1996, Congress allowed certain foreign-flag tankers to transport LNG to Puerto Rico from other U.S. ports (P.L. 104-324). In 2011 (P.L. 112-61), Congress allowed three U.S.-built LNG tankers that had become foreign-flagged to re-enter the Jones Act trade. Neither provision resulted in actual coastwise LNG shipping. See CRS, R45725.

beginning May 18, 2026. However, no LNG shipments have moved under the waiver to date, and the practical near-term impact on EMT procurement remains uncertain.[83]

Domestic LNG supply to EMT via truck delivered LNG has been viewed as a viable pathway for enhancing supply diversification. Previous owners of EMT advanced efforts to develop a domestic liquefaction facility intended to be integrated with the terminal, proposals that were never built. However, this approach would not enable full replenishment of EMT storage inventories within a single day.

Trends in EMT Import Volumes and Pricing

EIA data document a pronounced shift in Everett's utilization over the past decade with annual imports declining substantially (Figure 12).[84] Deliveries are now concentrated in the November-through-March heating season, with delivery timing governed by operational and logistical efficiencies, as well as inventory management considerations.

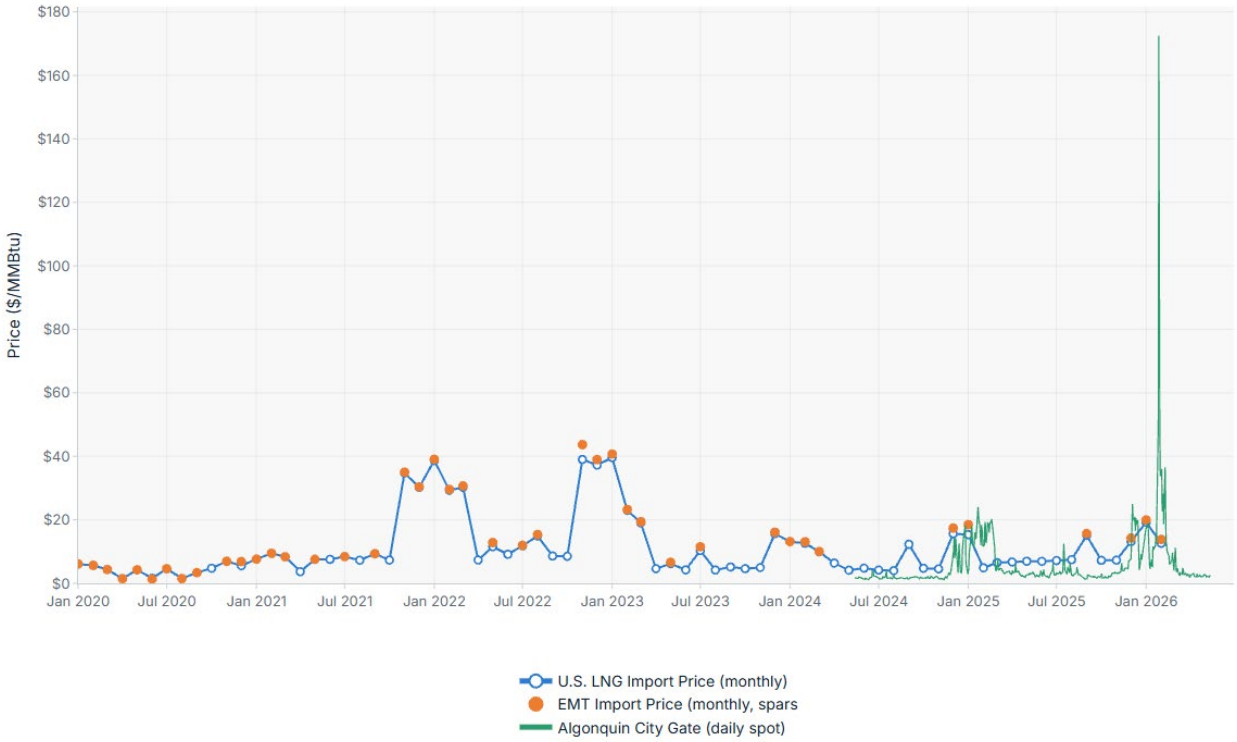

Figure 13. LNG and Algonquin Citygate prices. Source: EIA[85]

[83] U.S. Customs and Border Protection, Bulletin on Jones Act Waiver (March 17, 2026), implementing a Department of Homeland Security waiver of 46 U.S.C. § 55102 issued under 46 U.S.C. § 501(a) following a Department of War request. On the subsequent extension, see U.S. Department of Homeland Security, Notice of Extension (April 29, 2026), extending the waiver for an additional 90 days beginning May 18, 2026.
[84] U.S. Energy Information Administration, Natural Gas Monthly, Series NA1278_YEVTT_2 (Everett, MA Liquefied Natural Gas Total Imports). Data through December 2025.
[85] Daily Algonquin City Gate spot prices from EIA New England Natural Gas Dashboard, https://www.eia.gov/dashboard/newengland/naturalgas. Monthly LNG import prices from U.S. Energy Information

LNG import prices have become more volatile in recent years (from prices well below $10 per MMBtu prior to 2020). Global events, including the military activity in Ukraine and Iran, have created both demand and supply shocks in recent years, along with heightened demand for LNG more broadly. Such volatility should be viewed in the context of regional market conditions, particularly the winter constraints on pipeline supply to New England (Figure 13). Despite this volatility, international LNG sourced through EMT offers a hedge against city-gate price volatility and other peaking contracts that can exhibit significant price volatility.

3.3. Vapor Distribution of Gas

Vaporization Process and Emissions

EMT regasifies stored LNG using submerged combustion vaporizers (SCVs) and shell and tube vaporization systems, which burn natural gas to heat a water bath through which LNG-carrying tubes pass, absorbing the heat which drives the phase change from liquid to gas. The SCV process consumes approximately 1.5 to 2 percent of throughput as burner fuel, generating CO_2, NOx, and other combustion byproducts although the modern SCVs have pollution control systems that greatly reduce NOx. Under the current low-utilization, winter-seasonal operating profile, annual vaporization fuel consumption is estimated at 50,000 to 72,000 Dth, generating approximately 3,000 to 4,200 tonnes of CO_2 per year.[86]

Pipeline Interconnections

The direct National Grid tailgate connection (135 MMSCF per day), which has been operational since 1971, enables EMT to deliver gas into Boston metropolitan distribution mains without routing through an interstate pipeline. This is the primary mechanism for local pressure support on design days, when the distribution system is most vulnerable to pressure loss.

The Algonquin Gas Transmission interconnection—via a receipt point on the J-System lateral at 150 MMSCF per day—extends EMT's reach into Plymouth, Norfolk, and Bristol counties and southward along the Algonquin mainline, providing pipeline supply across the southeastern Massachusetts corridor.

The Tennessee Gas Pipeline interconnection (150 MMSCF per day), constructed in the late 1990s as a deliberate expansion of EMT's geographic footprint, added access to the western and northern New

Administration, Natural Gas Navigator: "Price of U.S. Natural Gas LNG Imports," series N9103US3M, https://www.eia.gov/dnav/ng/hist/n9103us3m.htm; and "Price of U.S. Liquefied Natural Gas Imports From Trinidad and Tobago," series N9103TD3M, https://www.eia.gov/dnav/ng/hist/n9103td3m.htm; both accessed May 2026.

[86] Estimates based on 1.5–2 percent of reported sendout volumes. Actual emissions vary with throughput and ambient conditions; cold-climate operations tend toward the higher end of the fuel consumption range. The default CO_2 emission factor for pipeline-quality natural gas combustion is 53.06 kg CO_2/MMBtu (≈ 117 lb. CO_2/MMBtu) on a higher-heating-value basis. See 40 C.F.R. pt. 98, subpt. C, tbl. C–1 (Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel). Applying the mid-range fuel-consumption estimate of approximately 72,000 Dth yields roughly 4,200 tonnes of CO_2 per year.

England corridor served by the Tennessee Gas Pipeline.[87] Together, the Algonquin and Tennessee connections provide redundancy: EMT can deliver regasified gas through two independent interstate systems, mitigating the risk that a single pipeline constraint could interrupt service.

Firm Transport Contracts

Constellation LNG holds firm transport contracts on both interstate systems totaling 130,000 Dth per day as of the most recent FERC Form 549B filings (Q2 2025).[88] Constellation holds this capacity, not the downstream LDCs, which receive gas at their meters under separate supply agreements and reimburse Constellation for transport costs. These contracts can support deliveries from New York to New Hampshire (Figure 14), demonstrating EMT's ability to top off the New England operational zones of the Tennessee and Algonquin. Both contracts expire on May 31, 2030, coinciding with the expiration of the six-year LDC supply agreements approved by the DPU in May 2024. Although the contracts do not roll over automatically, Constellation holds rights of first refusal (ROFR) on its existing capacity on both Algonquin Gas Transmission and Tennessee Gas Pipeline under each pipeline's FERC tariff, a contractual mechanism that allows the incumbent to retain its capacity by matching any competing bid at expiration.[89]

[87] Construction of the pipeline proved contentious. Tennessee was required to exercise eminent domain along the Saugus Branch of the former Boston & Maine Railroad right-of-way. See Tennessee Gas Pipeline Co. v. Massachusetts Bay Transportation Authority, 2 F. Supp. 2d 106 (D. Mass. 1998); Tennessee Gas Pipeline Co. v. New England Power, 6 F. Supp. 2d 102 (D. Mass. 1998).
[88] FERC Form 549B, Index of Customers, Q2 2025 filing (April 1, 2025). Tennessee Gas Pipeline Co., LLC (C000020); Algonquin Gas Transmission, LLC (C000084).
[89] See 18 CFR § 284.221 and FERC Order No. 712 et seq. (governing capacity release and rights of first refusal for interstate pipeline firm-transportation capacity holders); rights of first refusal are implemented through each pipeline's FERC Gas Tariff, General Terms and Conditions.

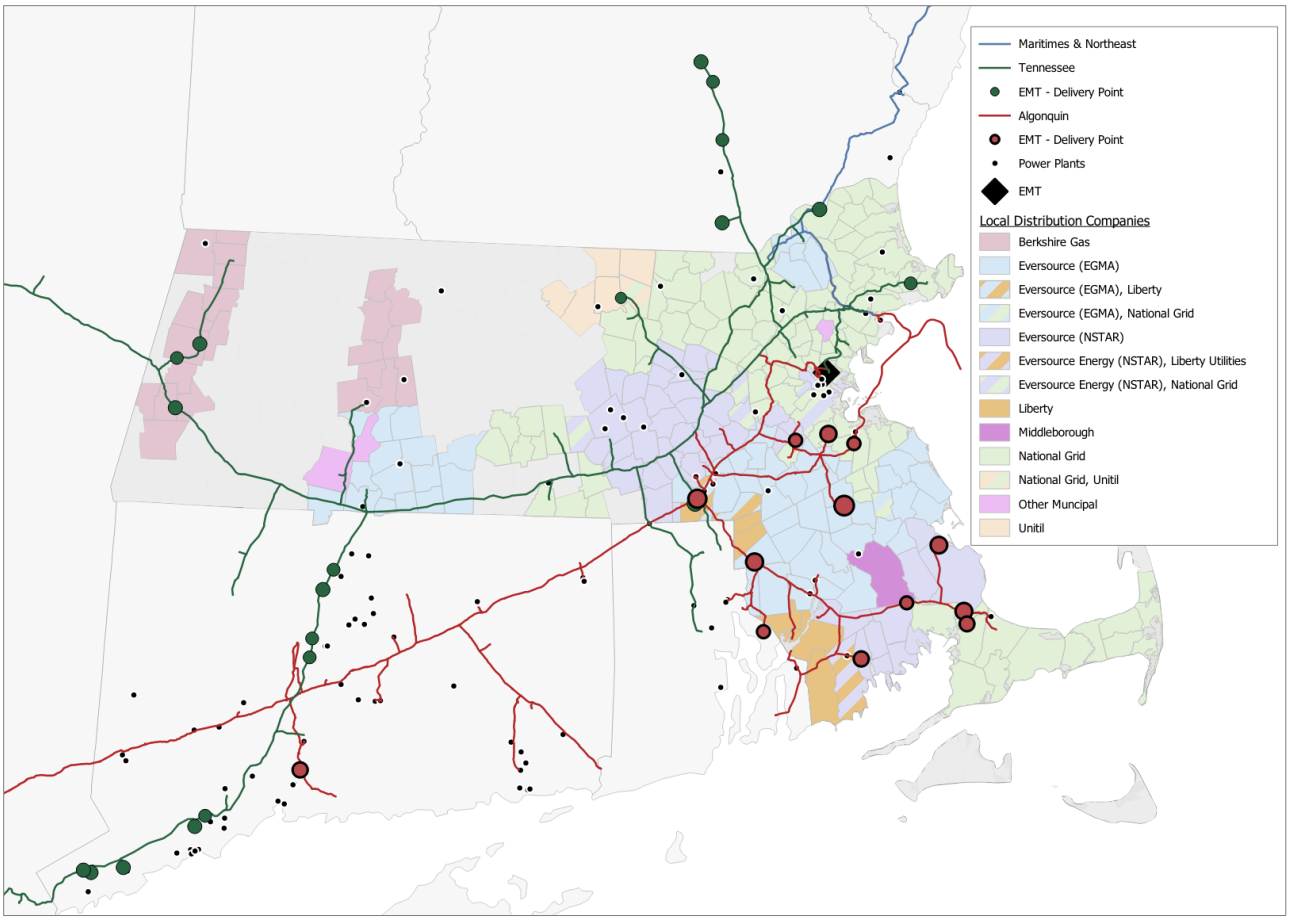

Figure 14. Location of transport contracts (EMT – Delivery Points) held by Constellation for delivery on the Algonquin and Tennessee Pipelines.

3.4. Truck Distribution

Figure 15. Truck loading bays at EMT (right).

EMT's four truck loading bays (Figure 15) allow LNG to be delivered by truck to 24 LNG permanent storage facilities and several portable injection rigs in New England.[90] The bays have a combined daily liquid sendout capacity equivalent to roughly 100 trucks, and at peak operations, the facility has loaded more than 10,000 trucks in a single year.[91]

The logistics of LNG trucking impose practical constraints that differ fundamentally from pipeline delivery. A single truck can make only one or two round-trips per day, depending on distance, and each delivery requires specialized drivers trained in cryogenic handling, loading and unloading protocols, and emergency response procedures. DOMAC also operates an LNG fueling station at the EMT site where LNG-powered commercial vehicles can refuel.

[90] Pipeline and Hazardous Materials Safety Administration (PHMSA). "Liquefied Natural Gas (LNG) Annual Data – 2010 to Present." U.S. Department of Transportation. Last modified May 11, 2026. https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

[91] Northeast Gas Association, "About LNG"; POWER Magazine, "Everett LNG Terminal at the Crossroads," July 2013 (describing four truck loading bays and combined truck sendout capacity equivalent to roughly 100 MMcf/d, or approximately 100 truckloads per day at typical cargo volumes). Peak annual loading figure from WBUR, "Old System, New Solution?," March 2015, reporting 2014 figures.

3.5. EMT & The Mystic Generating Station

Figure 16. Mystic Generating Station (left), vaporization equipment (center), LNG storage tank (right)

Boston Edison built the first coal-fired units on the Mystic River site in 1943; over subsequent decades the station expanded to ten generating units with a combined nameplate capacity exceeding 2,000 MW, making it at its peak the largest power plant in Massachusetts.[92] Although adjacent to the existing plants, EMT's early commercial framework centered on long-term LDC arrangements. The construction of the dual-fuel Mystic 7 unit in 1975 created a situation where EMT-sourced gas could be used to generate electricity, although such utilization depended on market conditions. The construction of Mystic units 8 and 9 in 2003 included a direct connection to EMT alongside the installation of new vaporization equipment (Figure 16).

LDC utilization was variable during the early years of operation of Mystic units 8 and 9. National Grid, then Keyspan Gas, did not list any purchased gas in its annual returns from 2001-2004.[93] During this time and for a number of years prior, it used a propane-air facility at an adjacent parcel for peak shaving in the Boston Gas system.[94] Thus, Mystic quickly became the dominant user of EMT and eventually its anchor customer until its retirement in May 2024 (Figure 17).

[92] Mystic Generating Station's history is summarized in U.S. Energy Information Administration, "New England utility closes import-dependent gas-fired power plant, keeps LNG import option," Today in Energy, June 24, 2024, https://www.eia.gov/todayinenergy/detail.php?id=62404. See also U.S. Energy Information Administration, "Retirements of U.S. electric generating capacity to slow in 2024," Today in Energy, February 20, 2024, https://www.eia.gov/todayinenergy/detail.php?id=61425.
[93] Review of Boston Gas Annual Returns 2000–2007 showing utilization. Reporting on annual returns appears to be inconsistent across this period, and in recent years the public returns no longer itemize purchased-gas volumes in a directly comparable form.
[94] MA D.P.U. Order 04-91

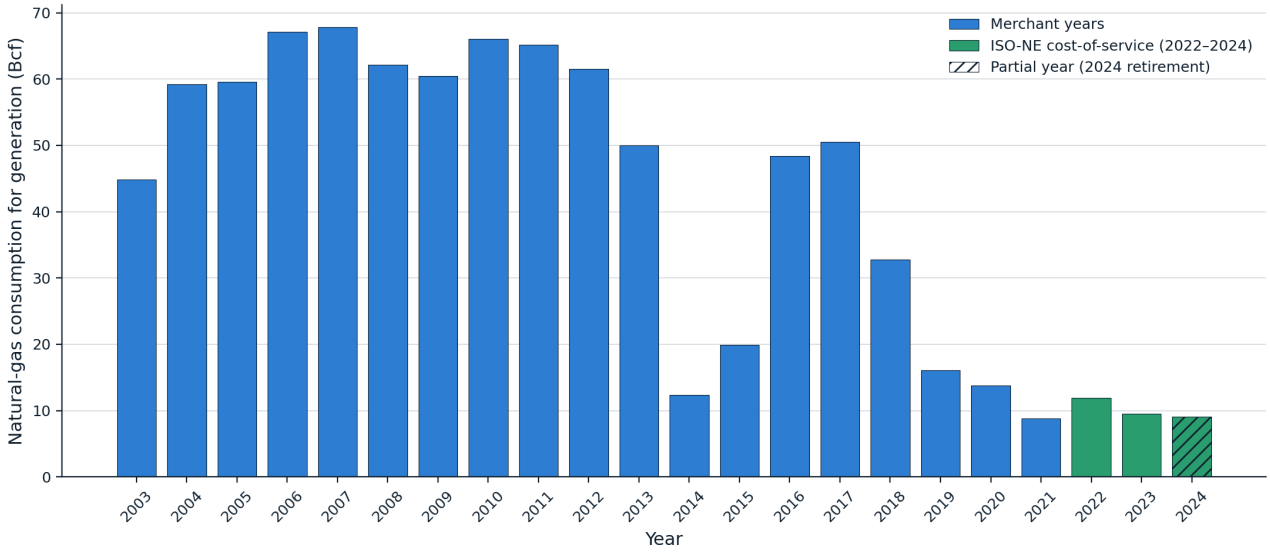

Figure 17. Consumption of gas at Mystic 8 & 9. Source: EIA Form EIA-923. For reference LDC's 2030 allotment is approximately 4.4 Bcf.

However, given regional market challenges, in 2018, Exelon (later Constellation Energy, following the 2022 corporate spin-off) filed plans with ISO New England to retire the facility, citing its inability to operate profitably under prevailing market conditions.[95] EIA reported that the long-term contract with Atlantic LNG was anticipated to expire in March of 2019. ISO-NE determined that Mystic 8 and 9—with a combined capacity of approximately 1,414 MW—remained critical for fuel security and system reliability in the Boston metropolitan load pocket and could not be retired on the timeline Constellation proposed.[96] The Commission established a two-year Cost of Service Agreement (COSA), funded by New England electric ratepayers, to retain the units through May 2024 while Eversource and National Grid completed transmission upgrades sufficient to maintain grid reliability without Mystic's generation.[97] Under the COSA, 91 percent of EMT's fixed costs were allocated to the agreement, with ISO-NE effectively substituting for Mystic as the facility's cost-of-service anchor. The arrangement preserved operational continuity but significantly constrained EMT's commercial flexibility: spot sales and

[95] Exelon Corporation, Form 8-K (August 2, 2018), Exhibit 99.1, https://www.sec.gov/Archives/edgar/data/0001109357/000162828018010253/exc20180802991.htm . Exelon Generation filed with FERC on May 16, 2018 to establish cost-of-service compensation for Mystic units 8 and 9 for the period June 1, 2022 – May 31, 2024, following ISO-NE's May 1, 2018 waiver request.

[96] ISO-NE filed its waiver petition on May 1, 2018 in Docket No. ER18-1509, asserting that the retirement of Mystic 8 and 9 would create unacceptable fuel-security risks. Exelon Generation filed the related cost-of-service agreement on May 16, 2018 in Docket No. ER18-1639, covering the period June 1, 2022 – May 31, 2024. On July 2, 2018, FERC accepted ISO-NE's conclusion that "retirement of Mystic units 8 and 9 could cause a violation of mandatory reliability standards as soon as 2022," ordering ISO-NE to file a short-term cost-of-service agreement and extending the deadline for Generation's retirement decision to January 4, 2019. On July 13, 2018, FERC issued an order accepting the cost-of-service agreement for filing on an expedited schedule. The Commission conditionally accepted the agreement in its December 2018 order, Constellation Mystic Power, LLC, 165 FERC ¶ 61,267 (2018), subject to compliance filings and a paper hearing on return on equity.

[97] Eversource and National Grid, "Eversource and National Grid Applaud ISO-New England's Choice of the Ready Path Solution to Ensure Reliability When Mystic Generating Station Retires in 2024," joint press release, July 27, 2020, https://www.nationalgridus.com/News/2020/07/Eversource-and-National-Grid-Applaud-ISO-New-England-8217-s-Choice-of-the-Ready-Path-Solution-to-Ensure-Reliability-When-Mystic-Generating-Station-Retires-in-2024/.

ancillary revenue opportunities available in the pre-COSA period were substantially curtailed by the cost-of-service rules.

When the COSA expired on May 31, 2024, and the Mystic plant closed permanently, Constellation faced the prospect of operating EMT without any anchor customer. The terminal's economics under a purely market-based structure with approximately $62.5 million per year in operating costs[98] and no guaranteed off-taker were not viable without new long-term commitments.[99] Constellation indicated it would close the facility absent new contracts. On an expedited timeline, the LDCs petitioned the DPU to approve 6-year contracts with EMT, and the DPU approved them in May 2024. Those agreements transferred EMT's fixed-cost anchor from Mystic and New England electric ratepayers to the Massachusetts LDC ratepayer base. The expedited timeline also exposed the contract to volatility in the LNG markets that could have been avoided with a longer contracting timeline.

3.6. The Regulation of EMT Under the Natural Gas Act

EMT opened in 1971 as one of the first LNG import terminals in the United States. The Federal Power Commission (FPC), FERC's predecessor, regulated the facility under Section 7, a classification reflecting the prevailing view that LNG regasification and pipeline sendout were inseparable from interstate natural gas transportation and therefore subject to the full suite of Section 7 obligations.[100] In 2008, FERC approved the transition of EMT to be regulated under Section 3 instead. The following review explains the distinction between those two classifications and the resulting consequences for EMT today.

Statutory Framework: Sections 3 and 7 of the Natural Gas Act

The Natural Gas Act (NGA) provides two principal authorization pathways for interstate natural gas infrastructure subject to Federal Energy Regulatory Commission (FERC) jurisdiction: Section 7, governing interstate pipelines, and Section 3, governing facilities used to import or export natural gas.[101]

Facilities governed under Section 7 are subject to substantial FERC oversight, most notably FERC-approved cost-based rate regulation. Under Section 7, a facility operator must also obtain a certificate of public convenience and necessity and provide non-discriminatory open access to all customers. These requirements treat the regulated facility as a public utility, with its rates, terms, and continuity of service

[98] Brattle estimate, $375 million over the 2022–2030 LDC contract period
[99] Lamson, Jon. "Everett LNG Contracts Face Skepticism in DPU Proceedings." *RTO Insider*, April 3, 2024. https://www.rtoinsider.com/75338-everett-lng-contracts-skepticism-dpu-proceedings/.
[100] Under the Federal Power Commission's pre-1977 framework, LNG facilities that regasified imported gas and delivered it into the interstate pipeline system were treated as components of interstate natural gas transportation infrastructure subject to Section 7 cost regulation and tariff oversight. See Distrigas Corp., 47 F.P.C. 752 (1972) (FPC import and Section 7 treatment of the Distrigas/Everett project); Distrigas Corporation v. Federal Power Commission, 495 F.2d 1057 (D.C. Cir. 1974) (reviewing FPC jurisdictional theories over Distrigas' Everett operations).
[101] Natural Gas Act § 7(c), 15 U.S.C. § 717f(c).

subject to ongoing federal oversight. Interstate pipelines are the classic infrastructure class governed under Section 7.

Section 3 governs facilities used for the import or export of natural gas, including principally LNG terminals that enable shipment overseas.[102] Under Section 3, FERC approves facility siting, construction, and operation, but does not regulate the rates at which terminal services are provided; instead, the operator of a Section 3 facility and its customers negotiate bilateral commercial contracts. FERC also does not impose open-access obligations or require a public convenience and necessity finding on Section 3 regulated facilities. Thus, FERC's ongoing role is limited to safety oversight and approval of material modifications to facilities.

The Hackberry Ruling and EMT's Transition to Section 3

The regulatory treatment of LNG import terminals changed fundamentally in December 2002, when FERC issued its ruling in the *Hackberry* proceeding.[103] The Commission established a new policy treating LNG import terminals as the functional equivalent of natural gas production facilities rather than interstate pipelines, from a regulatory perspective. FERC reasoned that LNG terminals conduct foreign commerce within a competitive global market and therefore lack the characteristics that merit restrictive public-utility-equivalent regulatory treatment; Section 7 treatment thus represented an unjustified barrier to investment for LNG import terminals. The Commission made clear that this policy applied to existing terminals as well as proposed ones, meaning facilities already regulated under Section 7 would no longer be required to maintain cost-based rates or open-access tariffs, though FERC would retain jurisdiction over siting and safety under Section 3.[104] The Energy Policy Act of 2005 codified this framework by granting FERC exclusive authority over LNG terminal siting and expressly preempting inconsistent state or local laws.[105] As a result, EMT transitioned from Section 7 to Section 3 regulation in 2008 following the *Hackberry* ruling. [106]

It is worth noting that the legal basis for *Hackberry* was articulated by FERC directly in the context of the EMT-Distrigas facility: as elaborated in the ruling, foreign gas imported to the Everett terminal does not enter the domestic interstate gas market until it physically leaves the facility, either loaded onto a truck or regasified and delivered to the pipeline at the tailgate.[107,108] Because terminal operations up to that

[102] Natural Gas Act § 3, 15 U.S.C. § 717b.
[103] Dynegy LNG Production / Hackberry LNG Terminal LLC, 101 FERC ¶ 61,294 (December 2002) (Hackberry).
[104] Id. at P 23.
[105] Energy Policy Act of 2005, Pub. L. 109-58, § 311 (amending NGA § 3).
[106] Distrigas of Massachusetts LLC, 124 FERC ¶ 61,039 (2008) (Order Approving Abandonment and Granting Authorization Under Section 3 of the Natural Gas Act), Docket No. CP08-49-000 (issued July 17, 2008).
[107] Cove Point LNG, LP, 187 FERC ¶ 61,038, at 8–9 (April 25, 2024) (CP23-539-000). The Commission cited Distrigas of Massachusetts LLC as one of two precedents for Section 3 reauthorization, noting the Commission's finding that 'foreign gas imported to Distrigas's terminal did not enter the domestic interstate gas market until it left the facility, and therefore the terminal did not need to be regulated under section 7.'
[108] Id. at 9. FERC explained: 'transportation of natural gas in interstate commerce subject to NGA section 7 only begins when liquid loaded onto a truck leaves an LNG import terminal or when regasified LNG is delivered to a pipeline at the tailgate of a terminal.'

point involve gas in foreign commerce, Section 7 jurisdiction does not apply, and the terminal does not require a Section 7 certificate of public convenience and necessity.

FERC's re-characterization of EMT was confirmed in the April 2024 FERC order in the Cove Point LNG proceeding.[109] Cove Point LNG Terminal in Maryland sought to convert from Section 7 to Section 3, invoking the Distrigas precedent. FERC granted the Section 3 reauthorization but denied Cove Point's accompanying request to abandon Section 7 jurisdiction due to the presence of a liquefier on-site that provides domestic peaking service. This liquefaction capability enabled domestic gas to both enter and exits the terminal in interstate commerce, justifying ongoing Section 7 treatment.[110] By contrast, EMT's exclusively import-oriented operations, with no entry point for domestic gas due to the lack of on-site liquefaction capacity, are precisely the category for which Section 3 rather than Section 7 regulation is appropriate under *Hackberry*.

FERC also reaffirmed this status as recently as November 2025 when it issued an amended Section 3 authorization for the Distrigas boil-off gas compressor project.[111]

Regulatory Consequences of Section 3 Status

EMT's Section 3 status has four concrete regulatory consequences that directly shape the policy environment examined by the FAWG, defining both the limits of federal jurisdiction over the facility and the scope of state authority available for transition planning. These are summarized in Table 2.

Table 2. Regulatory consequences of EMT's Section 3 status under the Natural Gas Act, with policy implications for the FAWG.

Dimension	Regulatory position	Policy implication
Rate regulation	None. FERC does not exercise jurisdiction over terminal service rates.[112] Constellation negotiates bilateral contracts at market prices with no federal or state standing for cost-of-service oversight or enforcement.	There is no mechanism to compel cost-reflective pricing on EMT itself. Instead, DPU approval of LDC contract terms and oversight of utility procurement decisions are the state's primary cost-control levers.
Continuity of service	No federal obligations related to abandonment. Section 7 facilities cannot cease service without FERC approval,[113] but no comparable requirement applies to Section 3.	Constellation may idle or close EMT without a FERC proceeding, and without any regulatory or policy mechanism to require continued operations.

[109] Id. at 10. The Commission distinguished Cove Point from the Distrigas and Lake Charles precedents, finding the Cove Point terminal 'is not exclusively dealing with gas in foreign commerce' because it continues to provide domestic interstate storage and peaking services through a Section 7-certificated liquefier.
[110] Id. at 9–10. The Commission's finding—that Section 7 obligations cannot be abandoned so long as any domestic interstate service runs through the terminal—underscores that EMT's exclusively import-oriented operations place it outside FERC's rate and access jurisdiction under current doctrine.
[111] Distrigas of Massachusetts LLC, Docket No. CP25-207-000, Order Amending Authorization Under Section 3 of the Natural Gas Act (November 2025).
[112] Under Section 3, FERC does not exercise rate jurisdiction over terminal service agreements. Constellation Energy (the terminal operator) negotiates bilateral contracts at market-based prices. There is no federal regulatory backstop for cost-based pricing.
[113] NGA § 7(b), 15 U.S.C. § 717f(b).

Dimension	Regulatory position	Policy implication
Siting and facility modifications	FERC retains authority over all material facility modifications (new storage, throughput changes, footprint alterations, etc.) each of which requires an amended Section 3 authorization and NEPA review. State and local agencies retain independent permitting jurisdiction.	Any capital expansion at EMT requires a federal environmental review. FERC issued a Notice of Inquiry on November 20, 2025 seeking comment on whether to establish blanket or tiered authorizations for routine LNG facility activities under Section 3, which would streamline review for some classes of modifications;[114] the rulemaking is pending.
Ownership transfer	Under post-*Hackberry* doctrine, a change in ownership of a Section 3 facility does not require the abandonment-and-recertification proceeding that applies to a Section 7 interstate pipeline. FERC retains authority over material facility modifications regardless of ownership, but a change in the identity of the Section 3 licensee does not trigger a Section 7-style FERC proceeding. The Department of Energy, however, separately reviews any external change in control of the underlying NGA Section 3 import authorization, such as that held by DOMAC, under its 2014 Change-in-Control Procedures.[115]	Under current regulatory doctrine, an entity purchase of DOMAC (through which a public authority of state entity could acquire the terminal) would be the lowest-friction acquisition pathway. A direct equity transfer would not require a Section 7-style FERC abandonment-and-recertification proceeding, though it would still trigger DOE Change-in-Control review of DOMAC's import authorization. The federal regulatory process risk for such a process relating to a Section 3 facility is meaningfully lower than for a Section 7 asset acquisition, but is not zero.

Other Regulatory Requirements

While EMT's operating authorization derives from FERC under the NGA, the facility is subject to a broad array of additional federal, state, and local requirements spanning air quality permitting, stormwater and discharge control, LNG facility safety standards under NFPA 59A and 49 C.F.R. Part 193, coastal zone and land use restrictions under the Coastal Zone Management Act (16 U.S.C. § 1451 *et seq.*), and environmental review obligations under NEPA and the Massachusetts Environmental Policy Act. A comprehensive inventory of regulations is provided in Appendix A. Implications for air quality, land use, and the Designated Port Area are discussed in Chapter 5.

Regulatory Implications for EMT Pause or Closure

Constructing EMT today would face substantial regulatory permitting barriers that could potentially also be triggered if the facility were to go offline. From a regulatory perspective, the question of whether a paused EMT could return to service depends primarily on how it is taken offline. A partial mothball (which occurred in the mid-1980's, with tanks maintained and sendout continuing but marine deliveries paused) would preserve EMT's 1971-vintage grandfather status under 49 CFR § 193.2051.[116] On the other hand, a full physical decommissioning followed by reconstruction of a similar facility on site or elsewhere would be treated as new construction, placing the rebuilt plant under relatively highly stringent modern siting standards.[117] However, a changing energy policy environment nationwide could

[114] Docket RM26-2-000
[115] 79 Fed. Reg. 65,541
[116] 49 CFR § 193.2051 (Scope), incorporating NFPA 59A-2001 by reference, applies modern siting standards only to facilities "designed, constructed, replaced, relocated, or significantly altered after March 31, 2000." See 65 Fed. Reg. 10,950 (Mar. 1, 2000) (Pipeline Safety: Incorporation of Standard NFPA 59A in the Liquefied Natural Gas Regulations)
[117] 49 CFR § 193.2057 (Thermal radiation protection); 49 CFR § 193.2059 (Flammable vapor-gas dispersion protection); 49 CFR § 193.2007 (definition of "exclusion zone"). The Mystic River parcel is bounded by occupied off-site structures within hundreds of feet (Encore Casino, Distrigas Street commercial/residential, MBTA Orange Line), making the legal-control test effectively impossible to satisfy without large off-site easements or acquisitions.

bring with it a more flexible regulatory approach to restarting critical energy infrastructure. Restarts in progress or proposed at Three-Mile Island and Indian Point nuclear plants, for example, demonstrate that restarting dormant infrastructure is possible even with existing regulatory regimes.

3.7. Cost of Operations at EMT

The Mystic Cost of Service Agreement proceedings (FERC Docket No. ER18-1639) produced the most detailed public record of EMT's operating costs and capital requirements. Because EMT is not subject to rate regulation—its commercial agreements with gas customers are negotiated bilaterally and treated as confidential—the Mystic proceeding, which required Constellation to submit detailed cost filings to FERC and submit to independent audits, offers a unique factual basis for understanding what it costs to keep the facility running.[118] While comparing these costs with those of other facilities is challenging, they are incurred to meet various regulatory and operational requirements that similar infrastructure also faces.

EMT Capital Investment Needs

EMT is an aging industrial facility and requires ongoing capital investment to maintain safe and reliable operations. Capital projects identified during the Mystic COSA period fell into several categories:

Cryogenic infrastructure, including replacement of liquid level gauges, cryogenic valves, cryogenic insulation, and tank base heaters. These components operate in extreme temperature conditions and degrade over time.

Marine and structural systems, including replacement of the forward bollard and mooring hooks on the LNG receiving jetty, firewater main replacement, and structural support upgrades for conduit. These systems are essential for safe vessel berthing and unloading operations and for meeting Coast Guard and safety requirements.

Emissions and environmental controls, including refurbishment of the selective catalytic reduction (SCR) system and hot air bypass replacement. These systems are required to meet air quality permits.

Electrical and balance-of-plant systems, including medium-voltage electrical system replacement and general balance-of-plant capital for motors, pumps, and valves.[119]

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[118] The Mystic Cost of Service Agreement was filed May 16, 2018 among Constellation Mystic Power, LLC, Exelon Generation Company, LLC, and ISO New England Inc. FERC accepted the agreement in Constellation Mystic Power, LLC, 165 FERC ¶ 61,267 (2018), reh'g denied, 172 FERC ¶ 61,044 (2020). All filings, audit reports, and challenge documents are posted at https://www.iso-ne.com/committees/key-projects/implemented/forward-capacity-market--retain-resources-for-fuel

[119] The full list of EMT capital projects and their costs is drawn from the ENECOS Informal Challenges to Constellation Mystic Power, LLC's April 1, 2021 Informational Posting, August 2, 2021, Informal Challenge No. 2021-4(B), and the NESCOE Informal Challenges to Mystic's April 2021 Informational Posting, August 2, 2021, Section II.B. Public versions of both are posted at https://www.iso-ne.com/static-assets/documents/2021/08/public_enecos_informal_challenges-8_2_21.pdf

Between Constellation's acquisition of the facility in November 2018 and December 2021, approximately $33.1 million in capital was invested in the terminal.[120] Projected capital expenditures during the Mystic COSA term were $6.4 million for 2022, $6.4 million for 2023, and $1.0 million for 2024, totaling roughly $13.8 million over the two-year agreement.[121]

Boil-off gas management. LNG in storage continuously generates boil-off gas (BOG) that must be captured and compressed for injection into the pipeline system or consumed on-site. EMT currently operates two BOG compressors, each rated at 75 thousand standard cubic feet per hour (MSCFH). Events such as ship arrivals, maintenance outages, or LNG storage system upsets can overwhelm this capacity, resulting in excess methane venting to the atmosphere. In October–December 2022, an extended outage of one compressor due to a failed internal part reduced compression capacity to 50 percent for several weeks, causing a significant increase in venting. In April 2025, DOMAC filed an application with FERC (Docket No. CP25-207-000)[122] to install a third, redundant BOG compressor rated at 150 MSCFH, along with associated improvements, all within the existing facility footprint. FERC granted the authorization at its November 2025 meeting. DOMAC's application states that the project implements capital investments contemplated in the long-term LDC contracts approved by the DPU in May 2024. The project cost was filed under confidential treatment and is not publicly available.

Costs may also emerge in relation to EMT's compliance with federal, state, and local climate and resilience requirements. Like similarly situated resources, EMT may require expanded emissions monitoring and mitigation equipment to comply with potential future state of federal regulations on carbon dioxide or methane emissions.

EMT's Present and Future Cost Structure

The Mystic COSA filings disclosed the following annual cost structure for EMT.

EMT's total fixed operating costs—covering staff, maintenance, insurance, return on investment, and other overhead—produced a gross annual revenue requirement of approximately $50 million per year[123] of which fixed O&M and return on investment component charged through the Fuel Supply

[120] ENECOS, Informal Challenges to Constellation Mystic Power, LLC's April 1, 2021 Informational Posting, Informal Challenge No. 2021-4. ENECOS noted that Mystic's April 2021 posting implied $33,075,000 in rate base additions to the Everett Marine Terminal over the period from acquisition through December 31, 2021. Mystic declined to provide project-level detail during the information exchange.
[121] NESCOE, Answer to Mystic's Motion to FERC, Docket No. ER18-1639-019, December 7, 2022, citing September 2022 Informational Filing, Attachment B, Everett Schedule A. Available at https://nescoe.com/resource-center/answer-mystic-motion-remand/. RMR CapEx represented approximately 13 percent, 12.7 percent, and less than 2 percent of the gross revenue requirement in 2022, 2023, and 2024 respectively.
[122] Distrigas of Massachusetts LLC, Application to Amend Authorization Under Section 3 of the Natural Gas Act, FERC Docket No. CP25-207-000, Public Application Volume IA and Volume IB (filed April 14, 2025), at 5–8; Order Amending Authorization Under Section 3 of the Natural Gas Act issued at the November 2025 Commission Meeting. The October–December 2022 compressor outage is described in the application at 6. Project cost information was filed under confidential treatment in Application Volume III.
[123] NESCOE, Answer to Mystic's Motion to FERC, December 7, 2022, citing September 2022 Informational Filing, Attachment B, Everett Schedule A, line 23. Available at https://nescoe.com/resource-center/answer-mystic-motion-remand/

Agreement was approximately $47.1 million per year.[124] The administrative services fee added approximately $1.5 million annually.[125] Corporate administrative and general expenses allocated from Constellation's parent organization through a formula-based overhead allocation added approximately $9.3 million per year.[126] Firm pipeline transportation charges on the Tennessee and Algonquin systems, costs that would be otherwise incurred by other shippers or resources, were approximately $17.6 million per year.[127]

Taken together, these disclosed cost components suggest that maintaining EMT as an operational facility sum to approximately $78–80 million per year in fixed costs during the 2022–2024 period, before accounting for commodity costs (the price of LNG cargoes themselves), variable pipeline charges, and capital expenditures. Annual capital needs during this period averaged roughly $6–7 million per year for routine maintenance capital, with larger episodic investments—such as the $33 million invested between acquisition and 2021—required to address accumulated deferred maintenance and facility upgrades.

3.8. Workforce

EMT supports a workforce of 57 full-time employees directly employed by Constellation, supplemented by a roster of contractor personnel providing security, custodial, and specialized trade services on a daily or annual basis (Table 3). The facility's operations and maintenance staff are represented by the Utility Workers Union of America, AFL-CIO, Local 369. Operations run in shifts of four to five operators, and twelve maintenance workers follow standard 40-hour weeks. Additional direct-employee job classifications—including Security, Safety, Marine Operations, Regulatory Compliance, Engineering, and Administration—are non-represented salaried positions. In addition to regular staff, EMT employs contracted workers such as daily security and rotating union tradespeople for maintenance, inspection, and repairs (Table 4).

[124] Levitan & Associates, Inc., Mystic FSA Audit Report, April 2024 (Public/Redacted Version), June 4, 2024. The monthly Fixed O&M charge was $3,921,685.00, consistent with the 2023 Informational Posting to FERC. The implied total EMT fixed O&M, before the 91 percent allocation, was approximately $51.8 million. Available at https://www.iso-ne.com/static-assets/documents/100013/2024_04_redacted_levitan_audit_initial.pdf
[125] *Id.* The Admin Services Fee was $127,750.00 per month, fixed through May 31, 2024.
[126] ENECOS, Informal Challenges, Informal Challenge No. 2021-5. Corporate A&G was $9,301,457 as shown on Everett Schedule A, line 14. ENECOS challenged these charges as fundamentally unrelated to the provision of fuel supply to Mystic.
[127] ENECOS, Informal Challenges to Constellation Mystic Power, LLC's April 1, 2021 Informational Posting, Informal Challenge No. 2021-6. The 2022 projected annual fixed pipeline transportation charges shown on Everett Schedule B, line 7 were $17,598,473. Available at https://www.iso-ne.com/static-assets/documents/2021/08/public_enecos_informal_challenges-8_2_21.pdf

Table 3. Employees directly employed by Constellation. Data provided by Constellation

Job Classification	Staffing Notes	Labor Representation
Operations	4–5 per shift (16 union; plus 5 management ops)	Utility Workers Union of America, AFL-CIO, Local 369
Maintenance	12 workers (12 union; plus 5 management maintenance)	Utility Workers Union of America, AFL-CIO, Local 369
Marine Operations	3	Non-represented (salaried)
Security	4	Non-represented (salaried)
Regulatory Compliance	3 (Regulatory & Environmental)	Non-represented (salaried)
Engineering	6	Non-represented (salaried)
Administration	2	Non-represented (salaried)
Terminal Management	1	Non-represented (salaried)

Note: Commercial employees supporting the Constellation business are employed off-site and are not counted among the 57 on-site FTEs.

Table 4. Contractor FTE supported by EMT.

Trade / Function	Frequency	FTEs	Union Affiliation
Security	Daily	24	Non-union
Custodial	Daily	2	SEIU Local 32BJ
Painting	Annual	2	Intl. Union of Painters and Allied Trades, District Council 35
Insulation	Annual	2	Intl. Assoc. of Heat and Frost Insulators and Allied Workers, Local 6
Pipefitter/HVAC	Annual	2	United Association of Plumbers and Gasfitters, Local 537
Boilermaker	Annual	1	International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers, Local 29
Carpenter	Annual	1	New England Regional Council of Carpenters, Locals 328/339
Laborer	Annual	1	Laborers' International Union of North America (LIUNA), Local 22
Fire Protection	Annual	1	Non-union

4. EMT's Community Relevance

EMT occupies a site at the confluence of the Island End River and the Mystic River, within a state-regulated Designated Port Area on the Mystic waterfront. This chapter describes that environment, the evolving land uses and development activity in EMT's immediate vicinity, the terminal's fiscal and civic relationship with its host community, and the location-specific environmental justice dimensions of EMT's operation and the contracts that sustain it.

4.1. The Evolving Local Landscape

For most of the twentieth century, the Mystic River corridor in Everett was defined by contiguous heavy industrial infrastructure: petroleum storage, fossil fuel power generation, LNG handling, and bulk commodity distribution. However, what was once a band of fuel tanks, generating stations, and industrial yards is undergoing a transformation, being replaced by a mix of residential towers, hospitality and entertainment venues, clean energy assets, and public open space, all set alongside various industrial facilities expected to continue operating for the foreseeable future.

The largest marker of this shift is the closure of the ExxonMobil tank farm, the former site of the Beacon Oil Company. The closure was instigated under sustained pressure from a Conservation Law Foundation federal lawsuit alleging violations of the Clean Water Act and the Resource Conservation and Recovery Act, including ongoing discharges into the Mystic River and failure to prepare the facility for climate-related flood risk.[128] The parties settled in December 2023; a central term of the settlement is an deed restriction permanently prohibiting the property from being used for bulk fossil fuel storage.[129] The Davis Companies, a Boston-based developer, completed a $72.5 million acquisition of the site in late 2023 in partnership with Global Partners LP, forming Everett Landco LLC to undertake what is expected to be a multi-year, $100-million-plus environmental remediation effort.[130] By the date of publication of this report, all of the site's 22 storage tanks had been removed, and the joint venture had begun raising site elevations to address climate-related flood risk. Currently planned development on the parcel includes residential construction near Sweetser Circle and industrial, life sciences, and high-tech manufacturing uses along Beacham Street.[131] Table 5 summarizes the major recent and proposed development projects in EMT's immediate vicinity and their relevance to the terminal's operating context. Figure 18 provides an illustrative rendering of a vision for development of the area.

[128] Conservation Law Foundation v. ExxonMobil Corp., No. 1:16-cv-11950 (D. Mass., filed Sept. 30, 2016).
[129] "CLF Settles Landmark Climate Lawsuit Against Exxon," Dec. 5, 2023, https://www.clf.org/newsroom/clf-settles-landmark-climate-lawsuit-against-exxon/;
[130] The Massachusetts Attorney General entered a Brownfields Covenant Not to Sue Agreement with the developers in May 2024, providing liability protection in exchange for a commitment to remediate and redevelop the property. Jon Chesto, "Davis Cos. Completes $72.5 Million Acquisition of Nearly 100-Acre Exxon Tank Farm in Everett," Boston Globe,
[131] Dec. 5, 2023; Boston Real Estate Times, "Davis Sets Stage for Transformative Development After Acquiring 100 Acre Exxon Site," Dec. 14, 2023, https://bostonrealestatetimes.com/davis-sets-stage-for-transformative-development-after-acquiring-100-acre-exxon-site/.

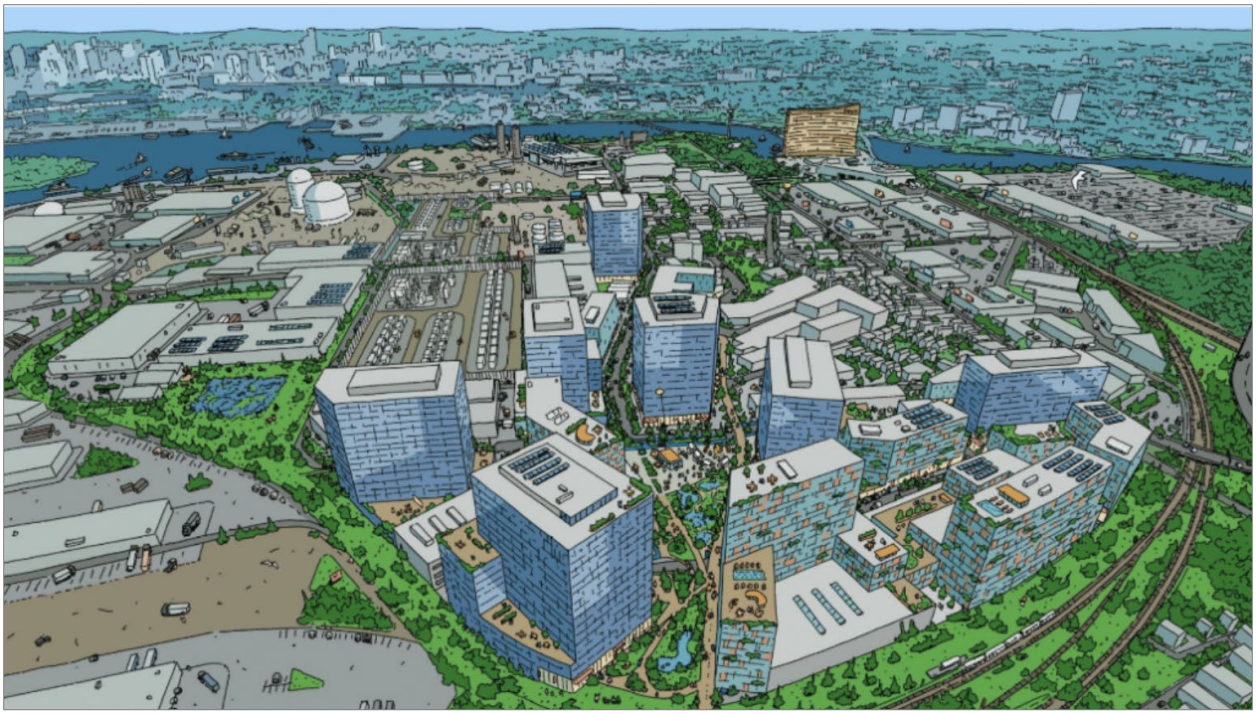

Figure 18. Artist's rendering of developments surrounding EMT on the site of the Former Beacon Oil / ExxonMobil tank farm. EMT is visible on the top left of the image. Image obtained from StreetsBlogMass[132] provided by the City of Everett.

[132] MilNeil, Christian. A New Neighborhood Could Replace Oil Tanks in Everett, But Plans Hinge On Uncertain MBTA Expansion Projects. StreetsBlog Mass. September 30, 2024. https://mass.streetsblog.org/2024/09/30/a-new-neighborhood-could-replace-oil-tanks-in-everett-but-plans-hinge-on-uncertain-mbta-expansion-projects

Table 5. Major development activity in EMT's immediate vicinity, 2019–2025.

Project	Status	Relevance to EMT Context
Encore Boston Harbor	Opened 2019	$2.6B casino/resort on former industrial waterfront; first major marker of Everett's redevelopment era. Wynn continues to acquire adjacent parcels for expansion of the resort complex.
New England Revolution Soccer Stadium	Agreements signed Dec. 2025	$500M privately funded 25,000-seat stadium on Mystic Station site; includes 4-acre waterfront park and environmental cleanup. DPA carve-out legislated Nov. 2024.
Trimount BESS (Figure 19)	EFSB review (25-05); construction 2026; commercial ops ~2028	700 MW/2,800 MWh battery storage on former ExxonMobil land; selected in MA's first Section 83E large-scale storage procurement.
ExxonMobil Site Remediation	Remediation underway; all tanks removed by summer 2026	Davis Companies/$72.5M acquisition; $100M+ remediation; deed restriction permanently prohibits fossil fuel storage. Mixed-use (residential, life sciences, industrial) planned.
Eversource / Mystic Acquisition	Completed Dec. 2024	$70M acquisition of 26-acre Mystic 8 & 9 site; clean energy interconnection hub; potential landing point for offshore wind and hydro transmission.
New Residential Development	Multiple projects underway or permitted	1,700+ units from Greystar; Sky Everett (397-unit, 21-story tower); 230- and 85-unit V10 projects; thousands of new residents within proximity of EMT.
Silver Line Extension / Transit	Planning stage	Potential transit expansion through Everett and Assembly-to-Encore pedestrian bridge expected to accelerate residential and commercial growth.

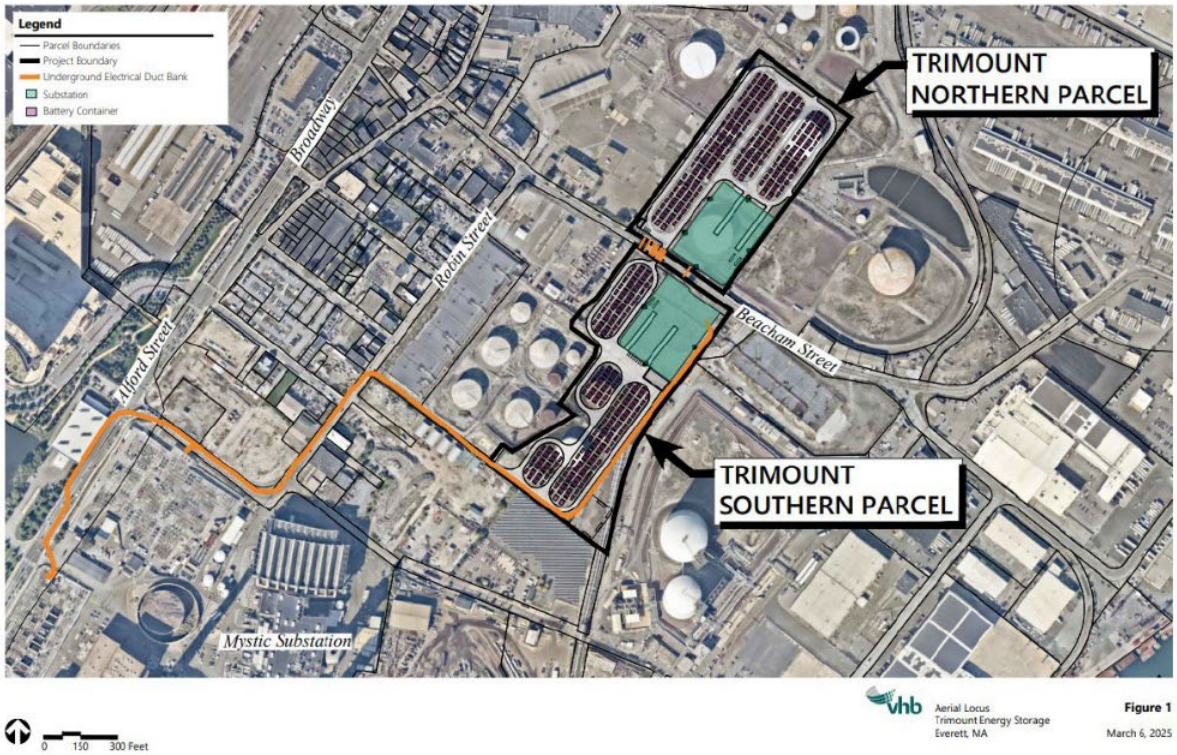

Figure 19. Plan of the Trimount Battery Energy Storage System project.

Designated Port Area Status

EMT and most surrounding properties fall within the **Mystic River Designated Port Area** (DPA), one of a network of DPAs established by the Massachusetts Office of Coastal Zone Management in 1978 to preserve water-dependent industrial uses along the Commonwealth's coastline.[133] Within a DPA, new construction is essentially limited to marine industrial operations, power infrastructure, shipping facilities, and similar uses. Residential buildings, hotels, sports venues, and most commercial development are not permitted.

A January 2025 report commissioned by the Boston Waterfront Partners (a coalition that includes the Conservation Law Foundation, Boston Harbor Now, and the Mystic River Watershed Association) concluded that the regulatory frameworks governing Boston's Inner Harbor DPAs are outdated, failing to account for current economic, climate, and public health concerns.[134] The report found that competing cross-sector pressures have weakened the integrity of the DPA framework and called for the first comprehensive review of DPA regulations since their establishment nearly fifty years ago to ensure responsiveness to present-day dynamics, including blue economy industries, climate resilience infrastructure, and environmental justice objectives.

The DPA designation (Figure 20) has been a central friction point in Everett's redevelopment trajectory. In November 2024, the Massachusetts Legislature passed an economic development bill that carved out a 43-acre parcel of the former Mystic Station property from the DPA to enable the proposed Revolution soccer stadium, while requiring the Kraft Group to negotiate community impact agreements with both Everett and Boston before proceeding. EMT itself remains within the DPA, and its water-dependent industrial function is one of the uses the designation was created to protect.[135]

[133] Massachusetts Office of Coastal Zone Management, Designated Port Area Fact Sheet, https://www.mass.gov/doc/designated-port-area-dpa-fact-sheet-overview-and-contact-information/download.
[134] Boston Waterfront Partners, Strengthening the Urban Harbor: Policy & Investment Recommendations for Boston's Working Ports (Jan. 28, 2025), barrfdn.issuelab.org/resource/strengthening-the-urban-harbor-policy-investment-recommendations-for-boston-s-working-ports.html.
[135] Massachusetts Office of Coastal Zone Management (CZM). "Designated Port Area Boundary Maps". https://www.mass.gov/info-details/designated-port-area-boundary-maps

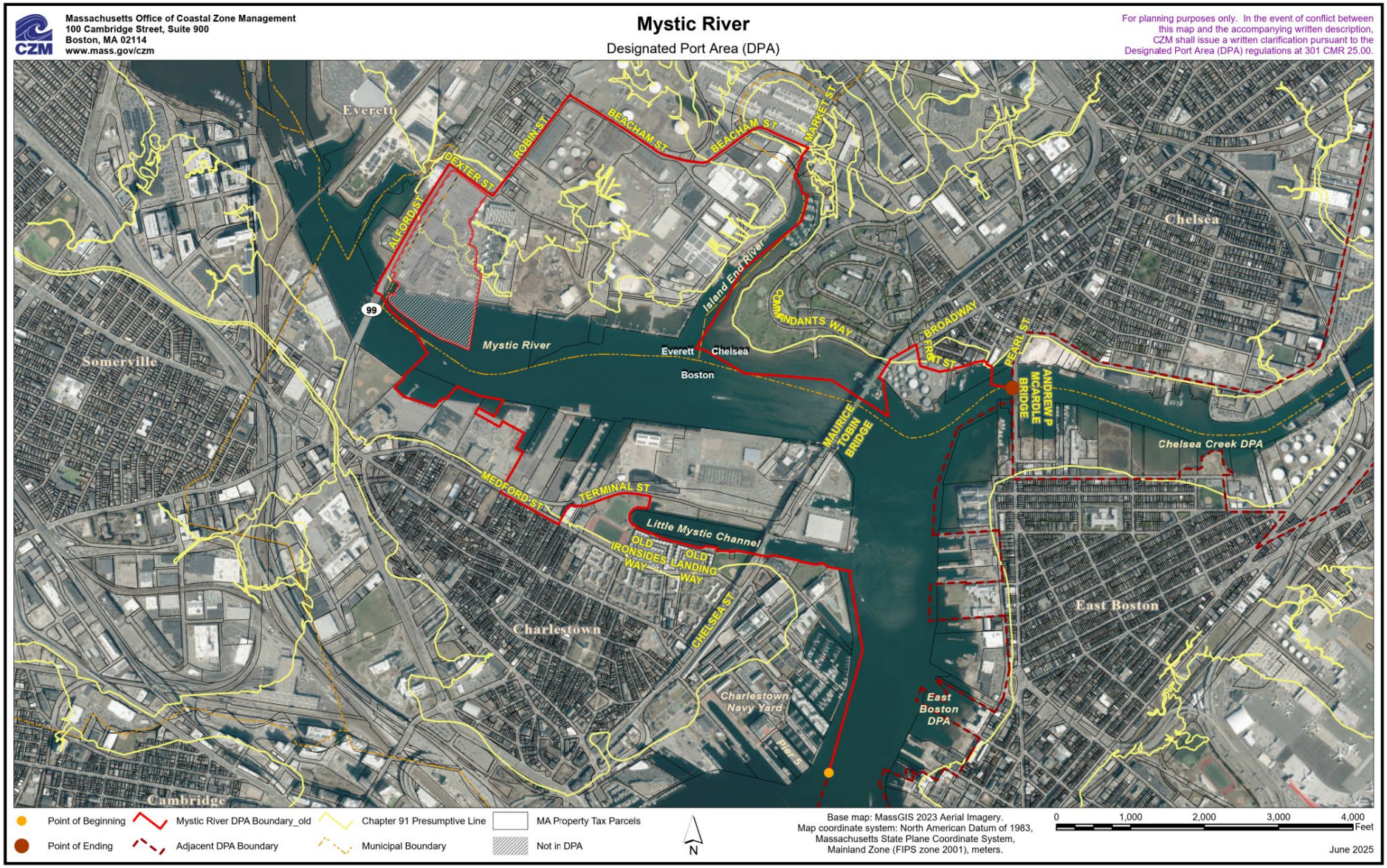

Figure 20. Massachusetts Office of Coastal Zone Management Map of the Mystic River Designated Port Area

4.2. EMT's Relationship with the Host Community

EMT contributes property tax revenue to the City of Everett, though its fiscal significance has historically been secondary to the much larger Mystic Generating Station, which at its peak generated approximately $15 million per year in tax revenue.

Constellation's Everett LNG Facility website states that the facility "supports local nonprofit organizations benefiting the City of Everett, Boston Harbor, and the City of Chelsea," with funding focused on STEM education, health and human services, recreational access, and environmental improvement (Table 6).

Table 6. Organizations receiving funding from Constellation's Everett LNG community program. List provided by Constellation LNG LLC.

Organization	Organization
Boston Harbor Now	Boston Parks & Recreation
Boston Seaman's Friend Society	Boys & Girls Club of Boston
Charlestown Mothers Association	City of Everett Science Fair
City of Everett STEM Project	City of Everett Public Schools
The Community Family	Courageous Sailing Center Charlestown
HarborCOV	Inversant (now La Vida Scholars)
Mystic River Watershed Association	Piers Park Sailing Center
Save the Harbor/Save the Bay	Mystic YMCA / Everett Boys & Girls Club
Salvation Army Chelsea	Everett Chamber
Greater Boston Salvation Army	USS Constitution Museum

Constellation also coordinates emergency response planning with local officials under federal safety regulations (49 CFR 193), maintaining preparedness protocols involving local fire departments and first responders through an ongoing relationship established with the facility's construction in 1971.

4.3. Environmental Justice

Everett is a designated Environmental Justice Community under M.G.L. c. 30, §62. A community profile is provided in Table 7.

Table 7. Environmental justice profile for the EMT host community.

Indicator	Value / Finding
Population (City of Everett)	~49,000
Environmental Justice Designation	EJ community under M.G.L. c. 30, §62
Proximity to Major Roadways	Junction of I-93 and Route 1; tens of thousands of vehicles daily
Historical Industrial Burden	NEGC coke works, ExxonMobil tank farm (~100 acres), Mystic Generating Station, LNG terminal (1971–present)
EMT Vaporization and Associated Emissions Impact	~4% of total City gas consumption (upper bound, assuming all vaporization at Everett)
Adjacent Cumulative Emissions Sources	I-93 and Route 1 traffic; Amazon and USPS distribution facilities and produce terminal as well as associated trucking
Local EJ Organizations	Everett Community Growers, La Comunidad Inc., Mystic River Watershed Association, GreenRoots

Environmental Justice Group Perspectives

The most developed articulation of EJ concerns in the formal regulatory record appears in the joint comments filed by the Conservation Law Foundation and Acadia Center in the D.P.U. 24-25 through 24-28 proceedings.[136] CLF and Acadia Center observed that Everett and neighboring municipalities have long borne the burdens of hosting fossil fuel energy infrastructure and other highly polluting commercial and industrial operations. The comments noted that the DPU itself implicitly acknowledged this history when it held its first public hearing in the EMT contract proceedings at Everett City Hall. CLF's comments argued that these communities should not be expected to continue bearing the environmental and health impacts of EMT's continued operation, and advanced an affirmative proposition: Everett and communities like it[137] should be among the *first* to host the transition to clean energy resources, to ensure that populations who have historically suffered most from energy planning decisions will benefit from the energy system built for the next half century.

[136] Joint Comments of Conservation Law Foundation and Acadia Center, D.P.U. 24-25, D.P.U. 24-26, D.P.U. 24-27, and D.P.U. 24-28 (Mar. 18, 2024) ("CLF/Acadia Comments"). The comments were filed in response to the February 23, 2024 Orders of Notice in consolidated proceedings on the LDC petitions for approval of gas supply agreements with Constellation LNG, LLC pursuant to G.L. c. 164, § 94A.

[137] It is worth noting that many of the facilities across the Commonwealth that are most dependent on EMT, including the LDCs' LNG storage facilities and injection sites, are themselves situated in dense EJ communities (for example, National Grid's Salem, Lynn, and Haverhill LNG Storage facilities), exacerbating the facility's network effect of negative impacts from an EJ perspective.

The development of the neighboring parcel for the Trimount Battery Energy Storage System (BESS) offers a useful case for comparison to elucidate equity concerns regarding the future of EMT. The Trimount project was subject to the EFSB review.[138] In the review of the Trimount project proposal, both Conservation Law Foundation[139] and the EFSB[140] noted that: (1) the project was being developed in an EJ community, and represents the type of facility necessary to pursue an environmentally just, clean-energy future; (2) the project does not have any impact on air quality or other environmental impacts that would disproportionately affect the EJ population; (3) the project would redevelop underutilized land for productive purposes including jobs and beneficial community impact for the EJ community; and (4) Trimount solicited substantial community input as part of project development, including community-requested engagement with the Everett fire department on how to effectively handle BESS-associated risk.

Historic Environmental Incidents and Remediation Need

In 1949, the Massachusetts Attorney General's Office began considering enforcement proceedings against Everett's gasworks and other local industries for their unrestrained pollution of the Island End River, the Mystic River, and Boston Harbor.[141] An independent auditor hired by the gas company reported in 1950 that seven of seventeen drain outlets serving the Everett complex were periodically discharging tar, oil, or scum into the rivers, and that large quantities of tar were entering the ground through leaking pipes and broken manholes.[142] Everett Station implemented the recommended controls without AG enforcement action, but by 1959, the weakening domestic steel industry led the company to shut down the coke and blast-furnace operations, laying off approximately 800 workers.[143] By that time, Boston Gas had begun its transition to natural gas, further slashing demand for Everett's services. The demolition process only worsened the facility's environmental harm, as rubble disposed in the Island End River seeded the site with contaminated materials that would be subject to decades of environmental litigation. Massachusetts DEP reports indicate that virtually the entire former Everett gasworks site exhibits some degree of contamination.[144]

Nearby, the Beacon Oil refinery was plagued by catastrophic incidents throughout its operational history, including at least four major explosions and fire at least four major explosions and fires in the 1920s alone. The worst was the February 1928 disaster when ten stills detonated, igniting 500,000

[138] EFSB 25-05 / D.P.U. 24-152
[139] Initial Brief of the Conservation Law Foundation EFSB 25-05 / D.P.U. 24-152, Sept. 17, 2025
[140] Final Decision of the Energy Facilities Siting Board in EFSB 25-05/D.P.U. 24-152, Feb. 27, 2026.
[141] Allen W. Hatheway and Thomas B. Speight, Manufactured Gas Plant Remediation: A Case Study, 1st ed. (Boca Raton, FL: CRC Press, 2017).
[142] Hatheway and Speight, Manufactured Gas Plant Remediation: A Case Study.
[143] "Eastern Enterprises History," International Directory of Company Histories, vol. 6 (St. James Press, 1992), reproduced at FundingUniverse, https://www.fundinguniverse.com/company-histories/eastern-enterprises-history/ (describing 1950s closure of Everett blast furnace and New Haven/Everett coke plants in response to declining domestic steel demand and rail-industry shift to diesel).
[144] Massachusetts Department of Environmental Protection, Waste Site / Reportable Releases Database ("WSC Sites"), records for Everett, MA, https://www.mass.gov/info-details/waste-site-reportable-releases-lookup; see also Allen W. Hatheway, Remediation of Former Manufactured Gas Plants and Other Coal-Tar Sites (Boca Raton, FL: CRC Press, 2012), tables 4.7–4.9 (Massachusetts MGP plant histories).

gallons of oil, killing 14 employees and injuring 36.[145] The facility remained in operations through 1965, when it closed due to financial losses; but the oil tank complex on the northern half of the peninsula persisted nearly to the present day, until recent efforts to redevelop the site.

Air Quality

Chapter 4.4 and Appendix A provide background on the air quality regulations applicable to EMT. EMT is regulated as a point source emitter of criteria air pollutants arising from the gas combustion process (principally nitrogen oxides or NOx) and is required to operate appropriate pollution control systems.

EMT holds a Title V Operating Permit issued by the Massachusetts Department of Environmental Protection (MassDEP), which classifies the facility as a major source of nitrogen oxides (NOx) and greenhouse gases within an EJ community.[146] The permit covers twenty-one emissions units that include 3 original Ryan Industries submerged combustion vaporizers (SCVs) without pollution control, four modern Kaldair TX120 SVCs with selective catalytic reduction pollution control, seven boilers used for vaporization, emergency generators, and fire pump engines. The SCVs consume approximately 1.5 to 2.5 percent of the LNG throughput as fuel to heat their water baths, generating on-site combustion emissions of NOx, carbon monoxide, and greenhouse gases. EMT's SCR-equipped Kaldair vaporizers achieve NOx emission rates an order of magnitude below those of typical residential and commercial gas-fired heating equipment on a per-MMBtu-of-fuel basis, though emissions of other criteria pollutants (CO, VOC, PM, and SO_2) from natural gas combustion at EMT are comparable to those from end-use appliances, as these are governed primarily by fuel chemistry rather than equipment design.[147]

The total gas combustion attributable to the LDC contracts with EMT is modest in the context of the local airshed. The total annual quantity of gas available to the utilities under the contracts is approximately 3,600,000 Dth. If all of this were vaporized at the Everett facility (an upper-bound assumption, since in practice EMT-sourced liquid is trucked and vaporized at various sites across the Commonwealth), vaporization would require combustion of up to 2% of that volume, or roughly 72,000 Dth. For reference, Everett's total natural gas consumption in 2024 was approximately 1,737,502 Dth. The vaporization of LDC contract gas thus accounts for no more than approximately 4% of the city's total natural gas consumption—and the true share is lower, given that much of the vaporization occurs outside Everett.

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[145] "Everett, Mass., Oil Explosion Kills and Injures Many," Fire Engineering, February 22, 1928, https://www.fireengineering.com/leadership/everett-mass-oil-explosion-kills-and-injures-many/; see also "Everett, MA Beacon Oil Explosion, Feb 1928," GenDisasters (compiling Associated Press wire coverage), https://www.gendisasters.com/massachusetts/12350/everett-ma-beacon-oil-explosion-feb-1928.

[146] MassDEP Title V Operating Permit, Application No. MBR-95-OPP-030R2, AQ ID 1190814.

[147] EPA AP-42 Chapter 1.4 (Natural Gas Combustion) reports uncontrolled NOx emission factors of approximately 0.10 lb./MMBtu for small commercial boilers and 0.094 lb./MMBtu for residential furnaces, with CO at 0.082 lb./MMBtu, VOC at 0.0055 lb./MMBtu, PM_{10} at 0.0075 lb./MMBtu, and SO_2 at 0.0006 lb./MMBtu. SCR-equipped submerged combustion vaporizers typically permit NOx at 0.005–0.015 lb./MMBtu, reflecting both the inherently low flame temperatures of water-quenched combustion and the additional 80–90% reduction achieved by selective catalytic reduction.

This combustion would result in approximately 3,800 metric tons of CO_2 annually. For reference, EMT's EPA- and MassDEP-reported emissions in 2023 were approximately 11,200 metric tonnes of CO_2, reflecting elevated gas consumption during the Mystic Generating Station's wind-down period.[148],[149]

At a rough approximation of 1,000 Dth per truck, the annual contract volume would generate approximately 3,600 truck movements per year, or an average of roughly 10 trucks per day. This level of activity is within the normal range for the surrounding area, given adjacent operations including an Amazon distribution facility, a produce terminal, and USPS operations.

These air quality impacts add modestly to the cumulative burden experienced by a community at the junction of I-93 and Route 1, where tens of thousands of vehicles pass through daily. Nonetheless, a reparative environmental justice framework would consider avenues to support a positive energy transition in Everett as part of any continuation of the EMT process. For example, providing electrification assistance to up to 1,000 homes in Everett and nearby communities could offset the emissions impact associated with EMT's operations.

Land Use in Potential Redevelopment

There are two primary land-use considerations salient to ensuring an environmentally just future for the Mystic River waterfront: the site remediation requirements and the regulatory structure governing EMT's land use as it pertains to redevelopment.

On-site remediation is subject to varying existing regulations, which ensure appropriate EJ outcomes by limiting future harm from contamination at the site. As previously discussed, similar remediation of gas- and oil-associated industrial facilities has taken place nearby in the past, and is ongoing at the former Beacon Oil/Exxon parcel. As such, though the path to remediating the location of EMT following any eventual closure would be substantial, the path forward for such remediation is clear from a regulatory and engineering perspective with substantial historical precedent.

The regulatory structure governing EMT's land use poses a far more complex hurdle to the potential redevelopment of Everett's waterfront. As discussed earlier in this chapter, the heart of this challenge is the current DPA classification of EMT's site. EMT's 35-acre site lies within the Mystic River DPA, which preserves waterfront land for water-dependent industrial uses. This designation serves a legitimate statewide purpose as marine industrial capacity lost to redevelopment is effectively impossible to reconstitute. Therefore, Massachusetts has an interest in preventing its few remaining DPAs from slipping away altogether, beyond EMT's needs.

The practical consequence of this regulatory structure is that the community which has borne the cumulative environmental, safety, and land use burdens of over a century of heavy waterfront industry lacks a realistic pathway to reclaim the waterfront for community-serving uses, even as the energy

[148] EMT also reports fugitive methane emissions to DEP, but these are based on standard emissions factors and are unlikely to represent actual emissions.
[149] EPA GHGRP FLIGHT ID 1003769 (Distrigas of Massachusetts), 2023

transition weakens the case for keeping some of the specific facilities enabled by the DPA in place. Furthermore, recent developments and anticipated future ones associated with the clean energy transition risk maintaining rather than resolving this difficult dynamic for Everett's population. The DPA framework classifies energy infrastructure as a permissible water-dependent industrial use, and the EMT vicinity is already attracting successor energy investments, including Trimount BESS, Eversource's acquisition of the former Mystic Generating Station site for grid interconnection, and the potential for offshore wind transmission landing points nearby. While these projects may contribute to the Commonwealth's climate goals and would not require modification of DPA status, such a redevelopment approach could constrain Everett to hosting energy infrastructure indefinitely (albeit shifting from fossil fuels to clean energy) without offering significant changes to the waterfront's industrial character or its accessibility to the local community. As a result, communities along the Mystic River and Boston Harbor have seen their waterfronts transformed through mixed-use development, public parks, and transit-oriented investment, while Everett's waterfront could remain largely inaccessible to the residents who live closest to it.

4.4. Perspectives on Community Needs

In the course of preparing this report, the FAWG convened a session to hear two community-facing perspectives on the future of the Everett waterfront: Monica Lamboy, the City of Everett's Chief Development Officer, and John Walkey, Director of Climate Justice and Waterfront Initiatives at GreenRoots, a community-based environmental justice organization active in Chelsea, East Boston, and Everett (through partnership with other organizations such as the Mystic River Watershed Association). Walkey also highlighted Everett-based organizations such as La Comunidad, Inc. and Everett Community Growers as a source for answering questions specific to the city's residents. Both speakers stressed that their focus is not on whether EMT remains operational, but on how the surrounding district evolves around it, and whether the community has a meaningful seat at the table in determining whichever future emerges.

Everett's and GreenRoots' priorities for the Mystic waterfront included:

Public access and activation of the waterfront, including a continuous park network where ownership allows. Both groups look favorably on extending a waterfront park from the Revolution stadium as far along the shoreline as possible, to enable residential access to the river and nature-based climate adaptation for the area. Current designs envision the park extending into Eversource's adjacent property but not extending into the metal salvage facility, so it would not reach EMT.

Transit access as a precondition for functional redevelopment. Introducing mass transit and reducing car dependence in Everett is a major priority for both groups. Options under discussion include a Silver Line extension from Chelsea toward Everett Square (and potentially Sullivan Square), a commuter rail platform to be sited between the Encore site and Sweetser Circle, the planned pedestrian bridge linking Encore to Assembly and its Orange Line station, and longer-term ideas as ambitious as an Orange Line

spur. The city's position is that no transit option should be off the table. Both speakers viewed transit investment as the essential factor in determining whether new development is functional or congesting, particularly given the prospect of spillover from Boston's separate Sullivan Square redevelopment after the stadium opens.

Climate resilience infrastructure, particularly addressing flood risk from the Island End River between Everett and Chelsea. A regional resilience project[150] would protect critical infrastructure including the New England Produce Center (a regional food hub serving millions of meals per day), federal facilities in Chelsea, and EMT itself. The project plans for a mix of walls, removable flood barriers, and nature-based solutions.

Economic benefits that accrue to existing residents. Both speakers were explicit that "Seaport-style" luxury redevelopment—housing and amenities that current residents would neither benefit from nor be able to access—is not the goal for any similar project in Everett. Walkey was equally clear that public-serving institutions (the stadium, public waterfront access, jobs and amenities reachable by current residents) are preferable to both the current status quo, and an alternative future dominated by a new wave of energy or industrial infrastructure.

Meaningful community engagement and creative solutions. GreenRoots cited Jupiter Power's Trimount outreach process, which brought in independent firefighting experts to address community concerns about lithium-ion battery safety, as a model for how operators of unfamiliar projects can build trust in environmental-justice communities. Walkey also pointed to GreenRoots' long campaign at the Eastern Minerals road salt facility in Chelsea, which ultimately produced community-inspired amenities on part of the operator's parcel, as an example of how industrial operations and host-community needs can be brought into balance through sustained engagement.

4.5. Synthesizing Community Priorities for EMT's Future

These environmental justice considerations provide an alternate angle from which to understand EMT's future, and the case for building infrastructure along the Mystic waterfront that benefits the surrounding community.

If EMT continues to operate, the community-facing obligations that fall on its owner and on the LDCs that rely on it are tractable but non-trivial. Continued investment in emissions controls is limits negative health impacts on Everett residents. EMT's operators must coordinate with the city and with neighboring developers on transit, flood resilience, and shared infrastructure as these projects expand, to prevent logistical challenges and maximize harmonization. Both efforts can benefit from active engagement with community organizations on the model GreenRoots described: keeping community

[150] The project is currently delayed by litigation between the Commonwealth and EPA over federal funding

groups in the loop, supporting joint outreach, and using independent third parties where appropriate to address community concerns about safety and environmental impact.

If EMT is ultimately retired, the site would join a redevelopment landscape with established expectations among residents in Everett and Greater Boston as a whole. Everett's vision calls for public waterfront access, mixed-use development that includes housing affordable to existing residents, preservation of some industrial employment, integration with neighboring transit and flood-resilience investments, and a community-driven planning process. However, as described above, EMT sits within the Mystic River DPA, and any non-industrial or maritime reuse would require either a DPA boundary review or a legislative carve-out, a process whose recent history at the adjacent stadium parcel is instructive but not directly transferable. Neither the representatives from Everett nor GreenRoots took a public position on EMT's future or on the prospect of further DPA modification, with both citing the difficulty of the prior efforts to do so unilaterally.

Both Everett and GreenRoots' representatives framed the present moment as one of opportunity to build a better future on the Mystic Waterfront, but one that depends on the process undertaken to achieve it. Walkey characterized GreenRoots' role as making sure that decision-makers actually listen to community members' voices in these conversations, while Lamboy credited the city's engagement with community organizations as a strength of the current planning effort. It is clear, therefore, that whatever pathway follows, the legitimacy of that choice in the eyes of the host community will depend on whether residents—particularly immigrant, low-income, and communities of color whose neighborhoods have historically borne the burden of waterfront industry—have a meaningful role in shaping the outcome.

5. Greenhouse Gas Emissions Associated with the LDC Use of EMT

Massachusetts General Law Chapter 21N §3(b) requires that the Commonwealth, "achieve at least net zero statewide greenhouse gas emissions; provided, however, that in no event shall the level of emissions in 2050 be higher than a level 85 percent below the 1990 level."[151] With regard to EMT, both CO_2 and fugitive methane emissions are subject to regulation under these requirements. Further, Chapter 21N §5 requires the Commonwealth in its climate planning exercises "consider whether state actions minimize leakage" or the spill-over of emissions outside the jurisdictional boundaries due to policy and technology choices. Since the production of LNG abroad requires meaningful energy inputs, the usage of LNG will typically result in higher upstream life cycle emissions relative to domestic gas. Still, as illustrated below, these emissions are lower than those of oil. Fugitive methane emissions across all steps of the LNG lifecycle are not well understood, and may result in higher net emissions intensity than oil, although such emissions may be readily mitigated with interventions to reduce leaks that are being adopted by the industry.

Overall, emissions associated with EMT are modest relative to the Commonwealth's climate targets. While methane releases and upstream emissions associated with LNG storage and production add to life-cycle emissions on a per-unit-of-energy basis, these emissions are again small due to the relatively low volumetric throughput of EMT. The policy challenge posed by EMT is therefore not primarily one of near-term emissions magnitude (although the need to monitor and manage fugitive methane emissions will be ongoing) but rather one of managing the energy system's evolving reliance on legacy gas infrastructure and the increasing concentration of its associated costs. The subsections below provide greater detail on these points.

5.1. Direct Emissions Associated with EMT Supply

Table 8. Summary of gas consumption attributable to the LDCs' contracts with EMT

Contract Cycle	2024/2025	2029/2030
Seasonal Contract Volumes (TBtu)	1.92	3.52
Boil-off gas (TBtu)	1.10	1.10
Vaporization Penalty (1% at both EMT and on-system sites)	0.02	0.04
Total (TBtu)	3.04	4.65
Share of 2023 Statewide Gas Consumption (EIA)	0.79%	1.22%
CO_2 Emissions ($MtCO_2$) from gas use	0.161	0.247
Share of MA's 2023 GHG Emissions (65.4 $MtCO_2e$)	0.25%	0.38%
Share of MA's 2050 Gross Emissions Limit (14 $MtCO_2e$)	1.15%	1.76%

[151] G.L. c. 21N, § 3(b).

Table 8 summarizes the scale of gas consumption and associated greenhouse gas emissions attributable to the Massachusetts LDC contracts with EMT across the current and later years of the approved contract period. In the statewide context, the contribution of EMT-supplied gas to overall system emissions is modest, reflecting both the limited volumetric role EMT plays annually and the fact that the facility is used primarily to address infrequent winter peak conditions rather than routine system demand.

5.2. Fugitive Methane Emissions

EMT equipment is periodically monitored for methane leaks. Fugitive methane emissions typically occur episodically through the venting of excess boil-off gas during certain events such as shipment delivery or during maintenance issues.

For example, from October to December of 2022 a boil-off compressor malfunctioned due to a mechanical failure. With one of two compressors offline, excess boil-off gas had to be vented. While an exact quantification of the methane lost is difficult, a reasonable approximation can be established. The compressor's capacity was rated at 75 MSCFH, so assuming the outage extended for 60 days and venting was continuous, 108 MMcf of gas would have been vented as an illustrative upper bound. Converting to mass (BOG is ~95%+ methane; using methane density at standard conditions of ~0.01917 kg/scf), the loss would be 2,000 metric tonnes CH_4. Applying IPCC AR5 100-year GWP of 28 would yield 55,000 tonnes CO_2e or roughly one-thousandth of the Commonwealth's accounted GHGs in 2022. This is not insignificant when compared to the emissions from the gas used (161,000 tons CO_2 in 2024/2025), but it represents a manageable episodic event rather than a continuous one. To avoid such situations in the future, Constellation anticipates placing a redundant compressor into service by the end of the first quarter of 2027.[152]

Limitations of the Commonwealth's GHG inventory with respect to fugitive emissions from EMT

The state's greenhouse gas inventory applies standard EPA emissions factors to LNG Import Terminals and LNG Storage facilities.[153] Such factors are simplistic proxies used in the absence of methods to continuously monitor, quantify, and report fugitive gases such as those from the venting described above. Under this accounting approach, such emissions are a small fraction of the Commonwealth's GHG inventory (see Table 9). In any given year, the factor-based estimate may be too low (as with the boil-off gas compressor failure) or too high. For the purposes of this report and decisions surrounding EMT, they do not provide actionable information.

[152] Constellation estimate as of April 2026.
[153] MA DEP Appendix C: Massachusetts Annual Greenhouse Gas Emissions Inventory available at https://www.mass.gov/lists/massdep-emissions-inventories

Table 9. EPA Emissions Factors for LNG Terminals. Source: MA DEP GHG Inventory

EPA Emissions Factors (2023)	tCO_2 per terminal	tCH_4 per terminal	tCO_2e 100y GWP	% State Emissions
LNG Import Terminals (leaks, compressors, flares)	679.0	20.1	1282.0	0.0019%
LNG Import Terminal Blowdowns	15.3	2.7	96.3	0.0020%
Total	694.3	22.8	1378.3	0.0039%

5.3. Indirect Emissions Associated with EMT Supply

Natural gas delivered to Massachusetts consumers via interstate pipeline and natural gas delivered as LNG share identical end-use combustion emissions, approximately 53.0–55.0 kg CO_2e/MMBtu. The meaningful differences between the two supply modes arise in the upstream and midstream segments of the supply chain: production, processing, liquefaction, transportation, and regasification. Table 10 lists lifecycle differences.

The net effect of these differences is that LNG delivered to New England carries a lifecycle emissions premium of roughly 5–15% over domestic pipeline gas, driven almost entirely by the liquefaction stage. Lifecycle emissions estimates for both pipeline gas and LNG are subject to considerable uncertainty. Three principal sources of variation should therefore be noted: (1) differences in methane management practice across production basins and along supply chains; (2) inconsistencies in emissions reporting methodologies and boundary definitions; and (3) measurement limitations across jurisdictions, particularly for fugitive methane emissions.

On the other hand, it is also worth noting that a 2024 study by Energy and Environmental Research Associates (*Well-to-Tank Carbon Intensity of European Imports*) found that the life cycle emissions for LNG from Trinidad and Tobago, the source of most shipments to EMT, were lower than other conventional sources including USA supplies.[154]

Even with this lifecycle penalty, LNG is preferable to fuel oil, which has a combustion emissions intensity of approximately 73-75 kgCO2 per MMBtu before any lifecycle factors are taken into account. Further gas electric and heating combustion systems will likely have higher operational efficiencies than oil heating and electric systems.

[154] Carr, Edward W., et al. *Well-to-Tank Carbon Intensity of European LNG Imports*. Version 2, Energy and Environmental Research Associates, LLC, 26 Aug. 2024, http://uploads.transportenvironment.org/production/files/WTT_CO2e_LNG_Imports_TE.pdf.

Table 10. Comparison of approximate life cycle emissions of international-sourced LNG and domestic interstate pipeline gas. Values represent approximations from Roman-White et al., NETL, "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States," 2024 update.

Liquified Natural Gas			Interstate Pipeline Gas		
Lifecycle Stage	**Emissions ($kg\ CO_2e/MMBtu$)**	**Percentage of Total**	**Lifecycle Stage**	**Emissions ($kg\ CO_2e/MMBtu$)**	**Percentage of Total**
Upstream Production (out of state)			**Upstream Production (out of state)**		
Gas extraction	5.0 - 8.0	7 - 11%	Gas extraction	5.0 - 8.0	8 - 13%
Processing	3.0 - 5.0	4 - 7%	Processing	3.0 - 5.0	5 - 8%
Liquefaction	6.0 - 10.0	8 - 13%			
Transportation (out of state)			**Transportation (mostly out of state)**		
Short route (25 miles by truck)	0.15	0.2%	Medium pipeline (500 miles)	1.0 - 2.5	1.6 - 4.0%
Long route (300 miles by truck)	1.78	2.4%	Long pipeline (1,500 miles)	3.0 - 6.0	4.8 - 9.6%
Overseas shipping (5,000 miles)	3.5	4.4%			
End Use			**End Use**		
Regasification	1.0 - 2.0	1 - 3%			
Local distribution	0.5 - 1.5	0.7 - 2%	Local distribution	0.5 - 1.5	0.8 - 2.4%
Combustion	53.0 - 55.0	70 - 75%	Combustion	53.0 - 55.0	85 - 88%
Total Lifecycle Emissions			**Total Lifecycle Emissions**		
Short truck transport (25 mi)	**~74**	**100%**	**Medium pipeline (500 mi)**	**~63 - 71**	**100%**
Long truck transport (300 mi)	**~76**	**100%**	**Long pipeline (1,500 mi)**	**~65 - 75**	**100%**
With overseas shipping	**~77 - 83**	**100%**			

6. The Role of EMT in Grid Operations and the Energy Transition

The scope of the EMT FAWG was to provide input on the LDC's analysis of alternatives to reduce or eliminate *their* reliance on EMT. Questions about the use of EMT by other customers (largely electric generators) and the ultimate disposition of EMT were deemed out of scope for the FAWG. However, as the FAWG progressed, it became clear that addressing its core charge required an understanding of EMT's broader role in supporting the regional grid, now and through the energy transition. Specifically, two overarching questions emerged:

- *If EMT could attract other customers, such as generators, could that growth in the market potentially help to reduce fixed costs borne by the LDC contracts, thus lowering the LDC ratepayer burden?*
- *If EMT played a specific role in ensuring grid reliability or could support elements of the energy transition, could that role provide justification for special policy interventions or cost-sharing arrangements to preserve it?*

This section reviews the current understanding of the role of EMT and gas capacity needs in the energy system today, and its anticipated role in the forthcoming transition. Table 11 lists studies focused on aspects of meeting regional peak gas demand. Not all studies explicitly examined EMT; several are regional or statewide decarbonization planning analyses whose findings on firm gas capacity carry clear implications for EMT's value and future demand trajectory.

6.1. Gas Capacity & Decarbonization

The studies reviewed in Table 11 establish a consistent finding that firm gas capacity is a cost-reducing resource across a wide range of decarbonization pathways, and the conditions under which that value diminishes depend heavily on the pace of transmission investment, renewable development, and building electrification, all of which face significant deployment execution risk over both the near and long-term planning horizon.

Table 11. Summary of studies examining the role of EMT or gas capacity needs in the regional energy system.

Title, Authors & Sponsor	Context & Approach	Key Findings Relevant to Gas Capacity & EMT
Solving New England's Gas Deliverability Problem Using LNG Storage and Market Incentives SkippingStone LLC; Greg Lander, Peter Weigand) 2015 Sponsor: Conservation Law Foundation (CLF) *Available at:* https://www.clf.org/wp-content/uploads/2016/03/Solving-New-Englands-Gas-Deliverability-Problem.pdf	Produced to challenge the prevailing regional consensus that a new interstate pipeline was the appropriate response to New England's recurring winter gas supply constraints. Used FERC-filed pipeline capacity data, Algonquin Citygate and Henry Hub market pricing, and regional LNG sendout data to construct demand and supply scenarios for 2020 and 2030 under multiple infrastructure assumptions.	• Argues that maximizing LDC LNG vaporization and storage infrastructure (a "Winter-Only LNG Pipeline" strategy) can resolve New England's peak deliverability problem at a fraction of the cost of new pipeline construction. • Calculated potential ratepayer savings of $340 million per year and up to $4.4 billion over 20 years relative to new pipeline construction. • Positions existing LNG infrastructure (including EMT-type facilities) as the cost-optimal solution for winter peak reliability, and calls on state commissions to direct LDCs to implement LNG strategies. • Establishes that LNG's value is disproportionate to its volumetric share of winter supply: a small percentage of total gas supply can represent the entire margin between system adequacy and failure on the coldest days.
Net Zero New England: Ensuring Electric Reliability in a Low-Carbon Future Energy and Environmental Economics (E3); Alex Breckel, Alex Kizer, Sam Savitz et al. November 2020 Sponsor: Energy Futures Initiative (EFI), Calpine. *Available at:* https://efifoundation.org/reports/net-zero-new-england/	Regional integrated resource planning study covering all six New England states, evaluating conditions under which electric reliability can be maintained as the region pursues net-zero economy-wide emissions by 2050. Employed long-run least-cost capacity expansion modeling across multiple scenarios: Base Case, Land Constrained, Land Unconstrained, New Nuclear & CCS, No New Gas, No Gas Generation, and 100% Hydrogen scenarios. Modeled both high-electrification and baseline load assumptions; evaluated generation, storage, transmission, and load across varying technology cost and resource availability assumptions.	• Firm gas capacity (or equivalent firm low-carbon capacity) enables cost-effective decarbonization: relying on renewables and storage alone would require dramatically more installed capacity and is significantly more costly. • Eliminating all gas generation increases the cost of achieving a zero-emissions grid by approximately $20 billion per year relative to other scenarios with modestly more emissions reductions. • As much as 46 GW of firm capacity may be needed in 2050 under high-electrification loads; the Base Case retains ~34 GW of gas generation even as those plants run at lower capacity factors. • New England's constrained geography and slow transmission planning are identified as the primary risks to meeting capacity needs.
Massachusetts 2050 Decarbonization Roadmap – Energy Pathways to Deep Decarbonization Report Evolved Energy Research (EER); Ryan Jones, Ben Haley, Jim Williams, Jamil Farbes, Gabe Kwok, Jeremy Hargreaves December 2020 Sponsor: Massachusetts Executive Office of Energy and Environmental Affairs (EEA) *Available at:* https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download	The Commonwealth's statewide analysis of pathways to net-zero GHG emissions by 2050, developed to inform the 2030 interim emissions limit and long-range climate planning. Examined eight technology pathways—ranging from "All Options" (least-cost) to "No Thermal," "Offshore Wind Constrained," "DER Breakthrough," and "100% Renewable Primary"— using integrated capacity expansion and production cost modeling across the broader Northeast (New York to New Brunswick). Evaluated pathways across cost, resource adequacy, emissions trajectories, affordability, and public health metrics.	• In scenarios with sufficient renewable capacity and transmission investment, gas demand can decline substantially without requiring new gas infrastructure, but this outcome is highly sensitive to build-out pace. • The "No Thermal" pathway (forecloses gas generation) requires dramatically more storage and carries $3.7 billion/year in higher system costs by 2050 relative to the base case. • Pathways leveraging transmission and regional coordination can be cost-neutral or slightly cost-saving.

Title, Authors & Sponsor	Context & Approach	Key Findings Relevant to Gas Capacity & EMT
The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Technical Analysis of Decarbonization Pathways Energy and Environmental Economics (E3); Scott Madden as independent consultants to the LDCs (March 2022) **Sponsor:** LDCs in fulfillment of DPU's directive in D.P.U. 20-80	Developed eight pathways to net-zero, varying assumptions about building electrification rates, networked geothermal, renewable gas supply, and industrial/transportation electrification. Used an integrated modeling framework linking the electricity, buildings, and gas distribution sectors. Directly examined the role of LDC peak day supply requirements.	• Deep electrification of all heating loads (gas, oil, LPG) could lead to a net increase in peak gas demand due to firm electric generation needs. (This study assumed gas generation continued to provide system firming through 2050, and did not explore other changes to electricity supplies as deeply as the prior two studies). • Reductions in peak gas demand could be driven by partial electrification of some gas loads.
Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study Results ISO New England; EPRI December 11, 2023 Sponsor: ISO New England (self-initiated; results presented to NEPOOL Reliability Committee) *Available here:* *https://www.iso-ne.com/static-assets/documents/100006/operational_impact_of_exteme_weather_events_final_report.pdf*	ISO-NE's probabilistic assessment of the potential impact of future extreme weather events on regional energy adequacy, the first study to systematically evaluate energy shortfall risk under extreme conditions for both the near-term (2027) and medium-term (2032) resource mix. Modeled energy adequacy under worst-case 21-day scenario applied to projected 2027 and 2032 resource mixes. Ran sensitivity scenarios varying LNG availability, oil availability, imports (NECEC), and EMT in-service status. Did not evaluate gas system hydraulics.	• Reported that "There is similar energy adequacy risk with and without the Everett Marine Terminal in service." The primary modeled difference between with/without-EMT scenarios was the maximum daily LNG injection rate, a volumetric difference that did not translate to a statistically meaningful change in energy shortfall probability under the probabilistic framework. • Top 10 highest-risk events were primarily winter scenarios for both study years; no energy shortfall was observed for any summer event in either 2027 or 2032.
Northeast Gas/Electric System Study Levitan & Associates, Inc. January 2025 Sponsor: NPCC (independent; no single commercial sponsor) *Available here*: https://cdn.prod.website-files.com/67229043316834b1a60feba3/678fee912264907c381a0f68_NPCC%20Northeast%20Gas%20Electric%20System%20Study.pdf	Analysis of the physical capability of the regional natural gas system to supply firm customers and gas-fired generators under extreme winter weather stress conditions. Examined worst-case scenarios for two three-day extreme cold periods, assessing gas system constraints and their cascading effects on the interconnected electric system. Evaluated both near-term and long-term (2032/33) scenarios, including scenarios in which EMT is unavailable concurrent with planned oil-fired plant retirements. Complements (but does not replace) ISO-NE's probabilistic PEAT analysis: the two methodologies are directionally consistent but capture different dimensions of risk. Does not assess hydraulic flows of the gas system.	• The gas system is highly constrained and vulnerable to low-probability contingencies with consequences for the interconnected gas-electric energy system. • In the study's 2032/33 long-term scenario, if EMT is unavailable concurrent with oil plant retirements, "capacity deficiency actions would be needed to maintain electric system reliability." • Northeast Gateway (off Massachusetts) and Saint John (New Brunswick) are "imperfect substitutes" for EMT due to their eastern pipeline location and inability to replicate EMT's instantaneous pressure support and direct injection capability near the Boston load center. • Without EMT, significantly more oil would need to be burned during extreme cold events to compensate for reduced LNG injection capacity.

Title, Authors & Sponsor	Context & Approach	Key Findings Relevant to Gas Capacity & EMT
Analysis of Winter Supplies from Gas-Fired Generators (series of presentations to ISO-NE stakeholders) Analysis Group; Todd Schatzki November 13, 2025; April 15, 2026; and May 13, 2026 Sponsor: ISO New England, as part of the Capacity Auction Reforms (CAR) key project www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project	A series of analyses supporting ISO-NE's Capacity Auction Reforms (CAR). The November 2025 study built a model of winter gas availability for electric generation. The April 2026 presentation specified the rules for a gas-only resource to elect "Firm Capacity" (exemption from the gas capacity constraint) via a firm pipeline or LNG contract covering a December–February Winter Contract Period. The May 2026 presentation proposed how the gas demand curve is adjusted to reflect supply that Firm Capacity elections remove from, or add to, the pool available to non-firm resources.	• Considered and modeled EMT as one of three active LNG terminals in the regional gas balance, with Repsol Saint John LNG and Northeast Gateway • Analyze historical trends of LNG sendout, showing far larger sendouts by Repsol Saint John. • Current LNG sendout is largely driven by pre-season contractual commitments, not real-time weather response, underscoring the importance of long-term LDC supply contracts (e.g., the 2024–2030 agreements) to regional LNG availability. • Put forth analytically defined product specifications for LNG contracts. • Assumed that supplies for the region's three LNG terminals can be delivered to the New England gas system under tight market conditions: supplies are backhauled, moving against the general flow of supplies.
EMT's Role in New England Levitan & Associates, Inc. May 18, 2026 Sponsor: Constellation Energy Generation, LLC (EMT's owner) www.levitan.com/publications/Everett%20Marine%20Terminal's%20Role%20in%20New%20England.pdf	An overview of the role and functionality of EMT in the regional electricity system focusing on a "but-for" analysis of EMT during Winter Storm Fern (January 16 – February 9, 2026). Levitan built a consolidated steady-state and transient model of the Algonquin and Tennessee mainlines together with the National Grid Boston distribution system, calibrated against pipeline Informational Postings observed during the event, and then re-ran the model with EMT removed. The report also reviews EMT's cost of service, benchmarks the cost of pipeline and non-pipeline alternatives, and discusses ISO-NE's Capacity Auction Reforms.	• During Winter Storm Fern, Algonquin and Tennessee scheduled approximately 3.3 Bcf of EMT vapor receipts (excluding direct deliveries to National Grid), and EMT loaded roughly 100 trucks. • Absent EMT, deliverable gas and intraday flexibility would have been materially reduced; gas-fired generators would have switched to oil at a time when regional oil inventories were at critical levels; LDCs would have faced reliability stress; and pipelines would likely have cut scheduled nominations and issued additional hourly OFOs. • Repsol Saint John LNG is characterized as an "imperfect substitute": cannot replicate EMT's direct injection near Boston load, and it operated at or near full sendout on the coldest days of the event, leaving no spare capacity to backfill EMT. • Estimates roughly $2.1 billion to build comparable pipeline capacity into eastern MA, with a total ratepayer cost on the order of $4.6 billion in-region over ten years (and potentially an additional ~$1.5 billion upstream), costs that, according to Levitan's analysis, materially exceed EMT's contracted costs. • Capacity Auction Reforms: identifies gas-only generators in southern New England as the most promising avenue to broaden customer base
Notes: • In March 2024, Argonne National Laboratory announced pending research examining the role of EMT in the regional energy system. At the FAWG's May 22, 2025 Meeting, Argonne representatives presented on the scope of the research being conducted. By the time of the publication of this report, the final results from the Argonne Study had not been publicly released and were not included in this review. (www.anl.gov/article/argonne-studies-north-american-gas-infrastructures-capacity-to-replace-lng-imports-near-boston) • ISO-NE studies prior to 2020 were reviewed but excluded from this summary as their resource mix assumptions predate the current planning horizon.		

6.2. EMT's Role as a Capacity Resource

EMT's role in grid reliability looks different over short and long horizons. There are no studies that examine EMT's role over the long term (beyond 10 years, after the shift to winter-peaking). Three studies listed in Table 11 that address the immediate future reveal a complicated situation.

ISO-NE's PEAT study is a probabilistic energy adequacy analysis intended to assess the anticipated scope of energy shortfall risk across diverse weather scenarios, weighted by their likelihood of occurrence. The study applied this methodology to 2027 and 2032 resource mixes, using the most severe recorded winter event (January 22, 1961) as a stress case. Results indicated that there is a comparable energy adequacy risk with or without EMT in operation. The primary modeled distinction between these scenarios was the maximum daily LNG injection rate—a volumetric variation which, when evaluated over the full range of simulated winters—did not result in a statistically significant change in expected energy shortfall. In most winters, including those deemed particularly challenging, the presence or absence of EMT does not affect reliability outcomes.

The NPCC commissioned an assessment of the worst-case gas system contingencies examining what physically happens under two specific three-day extreme cold periods when the gas system is maximally stressed. It used hydraulic modeling to incorporate gas flow constraints across parts of the system. EMT is the only facility capable of injecting LNG directly into the regional pipeline system at the Boston load center, providing instantaneous pressure support that remote terminals (e.g., Repsol / Saint John) cannot replicate regardless of their sendout volumes. Under the NPCC's long-term 2032/33 scenario—with EMT unavailable and oil-fired generation retired—the study found that capacity deficiency actions[155] would be required to maintain electric system reliability, and that remaining LNG terminals in New Brunswick and off Massachusetts' coast would be imperfect substitutes given their distance from the load center and the hydraulic constraints of moving gas westward through the pipeline under peak demand.

A third study, also by Levitan & Associates, Inc. at the request of EMT's owner, Constellation Energy Generation, conducted an analysis of EMT's contributions during Winter Storm Fern, a cold spell from January 16 to February 9, 2026. During this time, Algonquin and Tennessee scheduled roughly 3.3 Bcf of EMT vapor receipts (excluding direct deliveries to National Grid Boston), and EMT loaded approximately 100 trucks for satellite LNG refill. Using a consolidated model of the regional gas system—calibrated against pipeline Informational Postings observed during the event and then re-run with EMT removed— Levitan concluded that, absent EMT, deliverable gas and intraday flexibility would

[155] A capacity deficiency occurs when a power system falls short of its required operating reserves — the margin of available generation above forecasted load that system operators must maintain to manage unexpected demand spikes or generator outages. When operating reserves drop below required thresholds, operators declare a capacity deficiency and implement a graduated set of actions to restore the reserve margin, including issuing voltage reduction requests, calling on demand response resources, requesting emergency assistance from neighboring grid operators, and, if necessary, implementing controlled load shedding. Importantly, a capacity deficiency is a system stress condition, not an outage: a system can experience a capacity deficiency while continuing to serve all load, and the declaration does not imply that an energy shortfall or customer interruption is imminent or inevitable.

have been materially reduced, oil-fired generation would have been called on more heavily at a time when regional residual fuel oil inventories were already at critical levels, and pipelines would likely have curtailed scheduled nominations and issued additional hourly Operational Flow Orders. The report further characterizes Repsol Saint John LNG as an "imperfect substitute," noting that its eastern interconnection cannot replicate EMT's direct injection near Boston load and that it operated at or near full sendout on the coldest days of the event, leaving no spare capacity to backfill EMT.

6.3. Relevance of ISO-NE's Capacity Auction Reforms

ISO-NE's Capacity Auction Reforms (CAR) process is a reorientation of how ISO-NE's capacity market evaluates and compensates generation resources, shifting from a framework centered on summer peak demand, which has historically defined New England's capacity needs, toward one that formally accounts for winter energy availability.[156] This shift reflects a growing recognition that the region's resource adequacy risk is concentrated in winter, not summer: as building electrification and cold-climate heat pump adoption expand, winter electric demand is rising while summer peaks grow more slowly, and the fuel availability constraints that limit gas-fired generation during cold snaps have emerged as the binding reliability risk that the existing market design does not adequately price or incentivize.[157]

The mechanism through which CAR could expand EMT's customer base is the gas market constraint currently under development. On March 31, FERC accepted ISO-NE's proposed reforms.[158] Under the proposed framework, generators that cannot demonstrate access to firm gas supply would face a cap on their accredited capacity contribution, effectively penalizing non-firm resources during the winter periods when adequacy risk is highest. Generators currently relying on interruptible pipeline gas or on-the-day spot market purchases, which represent a significant share of New England's gas-fired fleet, would have a direct financial incentive to secure firm fuel arrangements to protect their capacity market revenues. If the CAR specifications, expected to be finalized in 2026, create sufficiently strong incentives for generators to contract directly with EMT or to secure firm pipeline capacity backed by EMT supply, the commercial effect could be a meaningful broadening of the facility's revenue base beyond its current LDC anchor customers, partially addressing the cost allocation issues.

Even with CAR-induced incentives, generators face a structural mismatch between the long-term commercial commitments typical of LNG supply arrangements and the rolling-horizon commitment cycle of the capacity auction. Long-term LNG contracts impose multi-year fixed obligations that generators may resist when their capacity revenue is determined in successive auctions; this structural

[156] See ISO New England's information posting on the Capacity Auction Reforms: https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project
[157] ISO New England, 2025 Regional Electricity Outlook and 2025 CELT (Capacity, Energy, Loads, and Transmission) report. The 2025 outlook reflects a modest downward revision in heat-pump adoption pace relative to prior projections, but continues to project rising winter electric demand driven by building electrification.
[158] Order Accepting Tariff Revisions re ISO New England Inc. under ER26-925.

mismatch may limit the extent to which CAR alone broadens EMT's direct generator customer base, even as it strengthens the firm-fuel premium that LDCs are willing to pay for EMT supply.[159]

Whether this outcome materializes depends on the specific design of the firm gas resource criteria and the price differential between firm and non-firm accreditation. If the capacity market premium for firm gas supply is large enough to offset the cost of securing long-term LNG contracts, generators will act. If it is modest, the incentive may not move the market.

Currently, regional markets (gas and electric) favor the utilization of gas from Repsol Saint John (Figure 21). This dominance may enable Repsol to underprice LNG from EMT, challenging EMT's ability to attract new customers and the revenue they could provide to offset fixed costs. Dual-fuel generators, again, also have the option to switch to oil. If fuel supplies are uneconomic, generators have the option of not running.

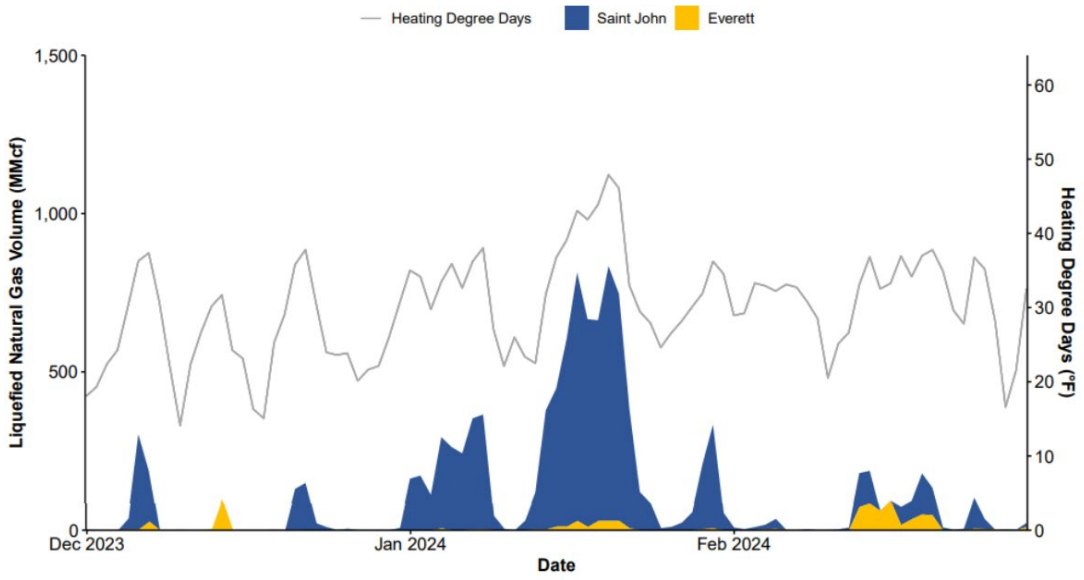

Figure 21. Daily LNG Sendout by Terminal and Heating Degree Days Winter 2023/2024 (December 1, 2023 to February 29, 2024). Source: Analysis of Winter Supplies from Gas-Fired Generators, Analysis Group for ISO-NE (Nov. 13, 2025)

6.4. Outstanding Information Gaps

In January 2025, Massachusetts EEA and the Office of Energy Transformation wrote to ISO-NE President and CEO Gordon van Welie asking how ISO-NE's prior analyses compared to the NPCC study and what steps ISO-NE was considering in response.[160] ISO-NE's February 6, 2025 reply articulated that it does

[159] Capacity Auction Reforms generator-procurement constraint noted by Brandon J. Luzar, Constellation Energy Group, in review comments on this compendium (April 2026); the structural mismatch between long-term LNG commercial commitments and the rolling-horizon capacity auction cycle creates practical obstacles to generators entering long-term LNG contracts even with CAR incentives.

[160] EEA's letter and ISO NE's response is available here: https://www.iso-ne.com/static-assets/documents/100020/combined_eea_npcc_iso_response_letters_02_05_2025.pdf

not see "clear quantitative evidence of the need to retain Everett for electric system reliability." However, ISO-NE noted that there may be "qualitative reasons to retain EMT" and previously "has urged the New England region to retain EMT" describing the loss of EMT's direct pipeline injection capability as a meaningful resilience risk that would increase dependence on the remote Saint John terminal and likely require significantly more oil burning during extreme cold events. ISO-NE's capacity auction reforms may surface some of these benefits by increasing winter firm fuel requirements and broadening EMT's customer base, although the scale of impact is unknown until the results of the first auction in 2028. Such judgments are necessarily tentative, however, because the prior literature has significant gaps. The following research questions remain substantially unaddressed in the prior literature and are directly relevant to ongoing analysis of EMT's future role in the energy system.

- **Pipeline hydraulic constraints on peak delivery capability.** The volume that can physically reach critical load centers under peak-demand conditions is constrained by downstream pipeline hydraulic limits. As shown in section 3.2 EMT currently holds delivery contracts for less than half of its total potential output load on the Algonquin[161] and Tennessee[162] pipelines. The extent to which EMT's value is driven primarily by volumetric supply versus instantaneous pressure support on these pipelines—and how much of its rated capacity is available to meet demand beyond the immediate injection point—has not been systematically quantified in the public literature. Several of the resource adequacy modeling exercises cited in this chapter analyze gas volumes available for electric generation but do not formally model gas-system hydraulics, lateral takeaway constraints, or system deliverability under stress.
- **Locational advantage relative to remote LNG sources.** The NPCC study notes that Northeast Gateway and Saint John are "imperfect substitutes" for EMT given their location at the eastern end of the pipeline system. However, no study quantifies the magnitude of this locational difference in terms of effective pressure support and deliverable supply to the Boston metropolitan load center under stressed conditions. A hydraulic analysis of the regional pipeline system comparing EMT's injection point to the alternatives would provide a more rigorous basis for assessing substitutability.
- **Impact of New Pipeline Upgrades.** The Project Beacon open season issued by Enbridge on May 18, 2026, did not specify a scale of new capacity but did indicate that upgrades will allow increased capacity at all points of the system. Final increases in capacity and impact may be determined by which entities subscribe and how much supply they subscribe to.
- **Retrofit potential of on-system satellite LNG facilities.** As firm gas demand on the LDC distribution system declines, LDCs own and operate satellite LNG storage facilities that are designed primarily for peak shaving, holding liquefied gas trucked in from off-system sources such as EMT and vaporizing it for local distribution. Whether these facilities could be expanded or operationally upgraded to substitute for or augment EMT's peak-day injection capability—either by increasing storage volume, adding truck-in logistics from alternative LNG sources, or connecting to interstate pipeline injection points—is an open engineering, policy and economic question with significant implications for the feasibility of post-2030 contract alternatives.

[161] 90,000 of 140,000 Dth per day
[162] 40,000 of 150,000 Dth per day

Appendix A: Regulations Applicable to EMT

Regulation	Authority	Applicability at EMT
Air Quality		
Title V Operating Permit (310 CMR 7.00: Appendix C)	MassDEP	Facility-wide operating permit; EMT is classified as a major source for nitrogen oxides (NOx). Consolidates all air pollution control requirements. Application No. MBR-95-OPP-030R2, AQ ID 1190814.
310 CMR 7.02(8) — Plan Approval MB-77-C-057	MassDEP	Original 1977 construction approval conditions for submerged combustion vaporizers and boilers; establishes particulate matter (PM) emission limits.
310 CMR 7.19(6) — NOx RACT	MassDEP	Reasonably Available Control Technology standards for NOx emissions from vaporizers (EU1–EU3, EU17–EU20) and boilers.
310 CMR 7.71(3)(a) — MA GHG Reporting	MassDEP	Annual greenhouse gas emissions reporting to the Commonwealth.
310 CMR 7.02 — Cumulative Impact Analysis	MassDEP	Applicable to future Comprehensive Plan Approvals for new or modified emission sources in Environmental Justice communities.
40 CFR Part 60, Subpart Dc — Small Boilers	EPA	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; applies to boilers EU8, EU12, and EU13.
40 CFR Part 63, Subpart ZZZZ — NESHAP for RICE	EPA	National Emission Standards for Hazardous Air Pollutants (HAPs) for Stationary Reciprocating Internal Combustion Engines; applies to emergency generators (EU11, EU37, EU45) and fire pump engines (EU43, EU44) as an area source of HAPs.
40 CFR Part 98 — GHG Reporting Program	EPA	Annual GHG emissions reporting to EPA. EMT Facility ID 1003769.
Water Quality		
NPDES Permit MA0020010	EPA Region 1	Individual wastewater discharge permit for process water and stormwater discharges to the Mystic River / Island End River. EPA is the issuing authority in Massachusetts.
LNG Facility Safety		
49 CFR Part 193 — LNG Facility Safety Standards	PHMSA (DOT)	Comprehensive safety standards for siting, design, construction, equipment, operations, maintenance, personnel qualification, training, fire protection, and security of LNG facilities. PHMSA conducts periodic compliance inspections. Incorporates NFPA 59A-2001 by reference.
49 CFR Part 191 — LNG Facility Reporting	PHMSA (DOT)	Requires submission of annual reports, incident reports, and safety-related condition reports. Operator data also submitted to National Pipeline Mapping System (NPMS).
NFPA 59A — Standard for LNG Production, Storage, and Handling	NFPA (incorporated by PHMSA)	Industry consensus standard incorporated by reference into 49 CFR Part 193. Governs thermal radiation exclusion zones, impoundment design, fire protection systems, and other safety measures. PHMSA ANPRM (May 2025) proposes updating to the 2023 edition.
Maritime Safety & Security		
33 CFR Part 127 — Waterfront Facilities Handling LNG	U.S. Coast Guard	Facility design, construction, equipment, operations, maintenance, training, and firefighting standards for waterfront LNG facilities. Requires USCG-reviewed Operations Manual and Emergency Manual. COTP Boston may suspend LNG transfer operations.

Regulation	Authority	Applicability at EMT
33 CFR Part 165.111 — Safety and Security Zones, Boston COTP	U.S. Coast Guard	Permanent 400-yard safety/security zone around any LNG carrier vessel moored at the Distrigas LNG facility in Everett, MA. Entry requires COTP Boston authorization.
33 CFR Parts 101 & 105 — MTSA Facility Security	U.S. Coast Guard	Maritime Transportation Security Act requirements. EMT must maintain a Facility Security Plan and comply with maritime security levels. USCG assesses safety and security of LNG carrier operations.
33 CFR Part 127, Subpart A — Waterway Suitability Assessment	U.S. Coast Guard	Risk-based assessment of LNG vessel operations within the port. USCG reviews the WSA and issues a Letter of Recommendation. Covers LNG carrier transit up the Mystic River to the EMT berth.
46 CFR Part 154 — Safety Standards for LNG Carriers	U.S. Coast Guard	Applicable to LNG vessels calling at EMT; governs vessel design, construction, equipment, and operations.
Federal Energy Regulation		
Natural Gas Act Section 3 — Import/Export Authorization	FERC	Overarching federal authorization to site, construct, and operate an LNG import terminal. DOMAC operates under NGA §3 certificate authorization. FERC serves as lead federal agency for NEPA compliance at onshore LNG facilities.
18 CFR Part 153 — Authorization to Construct, Operate, or Modify LNG Facilities	FERC	Procedural requirements for FERC applications. DOMAC filed an amendment application in April 2025.
Coastal Zone & Land Use		
301 CMR 25.00 — Designation of Port Areas	MA CZM (EEA)	EMT is within the Mystic River Designated Port Area. DPA designation constrains permissible uses to water-dependent industrial activities and supporting uses. Any boundary modification requires CZM review.
310 CMR 9.00 — Chapter 91 Waterways Regulation	MassDEP	Public Waterfront Act licensing for structures and uses on filled tidelands and flowed tidelands. Governs permissible uses, public access requirements, and building standards on the EMT site.
301 CMR 23.00 — Municipal Harbor Plans	MA CZM (EEA)	City of Everett Central Waterfront Municipal Harbor Plan approved February 2014. EMT site is south of the MHP planning area but adjacent to it within the Mystic River DPA.
Coastal Zone Management Act §307 — Federal Consistency (16 U.S.C. §1456)	MA CZM / NOAA	Federal actions at EMT (including FERC authorization amendments) are subject to CZM review for consistency with the federally-approved Massachusetts Coastal Zone Management Program.
Environmental Review		
National Environmental Policy Act (NEPA)	FERC (lead agency)	Environmental review required for major federal actions. FERC prepares Environmental Assessments or Environmental Impact Statements for LNG terminal authorizations and amendments. Coast Guard, PHMSA, and other agencies participate as cooperating agencies.
M.G.L. c. 30, §§61–62H — MEPA	EEA / MEPA Office	Massachusetts Environmental Policy Act review may be triggered by state permits or financial assistance for modifications to EMT or adjacent parcels. Requires Environmental Notification Form and potentially an Environmental Impact Report.

Note: This table reflects regulations identified as of March 2026. Permit numbers, regulatory editions, and applicability determinations may change as permits are renewed, regulations are amended, or facility modifications are proposed.