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Empress Capacity Resource Assessment

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I. INTRODUCTION

A. Empress Capacity Overview

Northern Utilities, Inc. d/b/a Unitil ("Northern" or the "Company") has participated in pipeline open seasons conducted by TransCanada Pipelines Limited ("TCPL") and Portland Natural Gas Transmission System ("PNGTS") under which it has executed agreements that will provide a firm natural gas pipeline transportation path from Empress, Alberta to Granite State Gas Transmission, Inc. ("Granite") interconnects. As discussed in greater detail below, Northern was awarded this capacity by TCPL and PNGTS through open seasons. This new capacity path would add 12,500 Dth per day of incremental capacity to Northern's gas supply portfolio with service starting April 1, 2024 for a thirty-year term. This capacity will provide access to relatively low-cost supply, while reducing Northern's peaking supply requirements. This Empress Capacity Resource Assessment ("Assessment") provides Northern's analysis supporting this decision. Northern respectfully requests pre-approval of the recovery of costs under these agreements on or before January 26, 2024, as discussed in greater detail in Northern's Petition in this proceeding.

Northern has a significant unmet peaking supply need, on both a peak day and seasonal basis, as documented in Northern's 2023 Least Cost Integrated Resource Plan ("2023 IRP") and provided herein. The proposed new capacity will reduce Northern's 2024-2025 peak day requirements not met with long-term capacity from 47,431 Dth to 34,975 Dth and reduce Northern's 2024-2025 seasonal peaking supply needs not met with long-term capacity from 672,537 Dth to 302,037 Dth. As documented in Northern's 2023 IRP and reiterated herein, the regional gas supply market continues to be heavily reliant upon LNG imports during periods of high demand combined with uncertainty related to the future availability of LNG import facilities.

Northern believes the proposed Empress capacity path will improve its gas supply portfolio by decreasing the need for peaking supply at reasonable pricing. Notwithstanding the proposed capacity, Northern will continue to have an unmet need for long-term capacity to meet peaking requirements. Accordingly, Northern continues to seek additional capacity as described further herein. Beyond the Empress Capacity for which Northern seeks approval with this filing, the Company still has a deficiency in resources needed to meet design requirements and continues to develop portfolio additions that are cost effective, reliable, operationally flexible and diverse.

B. Request for Approval of Empress Capacity Agreements

Northern has entered into the Empress Capacity Agreements, which are described in detail below. Northern requests approval of the Empress Capacity Agreements from both the Maine Public Utilities Commission ("MPUC") and the New Hampshire Public Utilities Commission ("NHPUC"), including the ability to recover costs under these agreement through the respective cost of gas recovery mechanisms. Northern requests a decision from the MPUC and NHPUC by January 26, 2024. The date of this request corresponds to Northern's option to terminate the PNGTS portion of the Empress Capacity Agreements, which expires on February 1, 2024. This request for approval and cost-recovery is explained in more detail in the Petition. The purpose of this Assessment is to provide the MPUC, NHPUC and other interested stakeholders with Northern's analysis supporting its decision to enter the Empress Capacity Agreements.

C. Description of the Empress Capacity Agreements

1. Overview

Northern Utilities, Inc. d/b/a Unitil ("Northern" or the "Company") has entered into agreements with Portland Natural Gas Transmission System ("PNGTS") and TransCanada Pipelines Limited ("TransCanada" or "TCPL") for a firm natural gas pipeline transportation path from Empress, Alberta to Granite State Gas Transmission, Inc. ("Granite") interconnects (the full capacity path is referred to herein as "Empress Capacity"; the agreements are collectively referred to herein as the "Empress Capacity Agreements" or the "Agreements") subject to regulatory approval. The Empress Capacity Agreements will provide Northern the ability to transport 12,500 Dth/day of natural gas from Empress to Granite for a 30-year initial term. The Empress Capacity is anticipated to commence on April 1, 2024.

2. PNGTS Capacity – 12,500 Dth

Northern acquired the PNGTS portion of the Empress Capacity through an Open Season, issued by PNGTS on June 6, 2023 ("PNGTS Open Season"). A copy of the PNGTS Open Season is provided as Attachment 1. Through the PNGTS Open Season, PNGTS offered approximately 59,000 Dth of additional capacity to be available as soon as November 1, 2023, "subject to all necessary approvals and satisfaction of all applicable regulatory requirements of the Federal Energy Regulatory Commission ("FERC")."[1] As a result of discussions with PNGTS, Northern was aware that no construction would be required for service awarded under the PNGTS Open Season, as existing facilities, which were part of PNGTS' most recent WXP capacity expansion, were capable of transporting this additional volume. The firm

[1] See Page 1 of Attachment 1.

transportation offered was for service from Pittsburg, New Hampshire, the location where PNTGTS receives gas onto its system from TransCanada, to either the interconnection between PNGTS and Maritimes in Westbrook, Maine or delivery points on the PNGTS system from Westbrook, Maine to Dracut, Massachusetts (including the interconnections between PNGTS and Granite). Northern accesses PNGTS via the Granite pipeline.

Bidders in the PNGTS Open Season were required to bid a minimum rate of $0.82 per Dth per day for firm transportation service from Pittsburg, New Hampshire to the Granite pipeline, which is the same as the WXP project rate, with a minimum term of 15 years. Bidders were required to bid a rate, term, receipt and delivery points as well as a capacity volume. Bids were evaluated by PNGTS based on the net present value of these parameters, consistent with Section 6.13 of PNGTS' Tariff. Due to the limited amount of capacity available and the scarcity of available incremental supply options in New England, Northern decided to request service for longer than the 15-year minimum term. Pursuant to the PNGTS Open Season, Northern bid the minimum rate of $0.82 per Dth per day for a term equal to 30 years beginning April 1, 2024 for 12,500 Dth of capacity from Pittsburg, New Hampshire to Dracut, Massachusetts. As part of this bid, Northern requested the option to terminate the contract without penalty should if fail to receive regulatory approvals from the MPUC and the NHPUC. This bid was accepted by PNGTS, resulting in a Firm Transportation Agreement between PNGTS and Northern, which is provided as Attachment 2 ("PNGTS FT Contract"). Northern must exercise its option to terminate the PNGTS FT Contract for failure to obtain acceptable regulatory approvals by February 1, 2024.

3. TransCanada Capacity – 13,600 GJ (12,890 Dth)

Northern acquired the TransCanada portion of the Empress Capacity through a New Capacity Open Season issued by TransCanada on May 17, 2023 ("TransCanada Open Season"). A copy of the TransCanada Open Season is provided as Attachment 3. Under the TransCanada Open Season, TransCanada offered up to 63,100 GJ (59,807 Dth) of delivery capacity to East Hereford, which is the point at which TransCanada delivers gas onto PNGTS. TransCanada offered either Empress, Alberta or Parkway, Ontario as points where gas could be received. The tolls charged for any service requests would be based on the tariff rates, as approved by the Canadian Energy Regulator ("CER") from time to time. This capacity offering was available as early as April 1, 2024, subject to TransCanada's ability to secure "necessary commercial and operational arrangements" until new facilities are constructed.

TCPL expects to construct new facilities to support this capacity offering prior to November 1, 2027. The TransCanada Open Season required a minimum service request term equal to 15-years from November 1, 2027. Service requests would be evaluated in accordance with TransCanada's Transportation Access Procedures, which stipulate that service requests are prioritized based on the product of the demand toll in effect at the time of the open season and the term of the service request. Due to the limited amount of capacity available and the scarcity of available incremental supply options in New England, Northern decided to request service for longer than the 15-year minimum term. Northern's service request through the TransCanada Open Season was 13,600 GJ (12,890 Dth) of capacity from Empress to East Hereford through this Open Season with a 30-year term commencing April 1, 2024.

a) TransCanada Service Prior to In-Service Date of New Facilities

Service from April 1, 2024 through October 31, 2027 (or later, if facilities required by TransCanada are not yet in service and TransCanada maintains the commercial and operational arrangements to continue interim service beyond October 31, 2027) is documented by the 2024 Precedent Agreement ("2024 TCPL PA") and the 2024 Firm Transportation Service Contract ("2024 TCPL FT Contract"). The 2024 TCPL PA and 2024 TCPL FT Contract are provided as Attachment 4 and Attachment 5, respectively. The conditions precedent for service under the 2024 TCPL FT Contract set forth in the 2024 TCPL PA are summarized below.

1.) Northern has provided any Financial Assurance required pursuant to TransCanada's tariff.

2.) TransCanada has determined that it has sufficient facilities and/or operational or other arrangements to provide service under the 2024 TCPL FT Contract.

3.) The precedent agreement for service beginning November 1, 2027 ("2027 TCPL PA"), which will be discussed in more detail below, has not been cancelled.

4.) Northern has bid in the PNGTS Open Season.

The 2024 TCPL PA shall remain in force until one or more of these conditions precedent have not been satisfied or waived or the 2024 TCPL FT Contract has commenced. The 2024 TCPL FT Contract shall commence on the later date of April 1, 2024 or all conditions precedent to the 2024 TCPL PA have been satisfied.

b) TransCanada Service Upon In-Service Date of New Facilities

TCPL service from November 2027 through March 2054 is documented by the 2027 TCPL PA, which is provided as CONFIDENTIAL Attachment 6. TCPL's obligation to provide service under the 2027 TCPL PA is subject to the conditions precedent that TCPL increases its capacity in order to provide the service requested by Northern and awarded by TCPL in the Open Season and it receives authorizations required to do so. The 2027 TCPL PA requires TCPL to use all reasonable efforts to obtain the required authorizations and increase its capacity. The

2027 TCPL PA requires Northern to enter into a Firm Transportation Service Contract for service from November 2027 through March 2054, upon TCPL either satisfying or waiving its conditions precedent and to use all reasonable efforts to obtain all authorizations it requires to do so.

If TCPL is unable to either obtain its required authorization to increase its capacity prior to May 1, 2027, then the 2027 TCPL PA would be cancelled. TCPL will require project approvals from the CER and other various provincial agencies. If Northern is unable to obtain its required authorizations, fails to execute the Firm Transportation Service Contract, or withdraws its service request, then the 2027 TCPL PA would be cancelled. Specifically, Northern is seeking approval of the Empress Capacity Agreement from both the MPUC and the NHPUC. Paragraph 13 of the 2027 TCPL PA provides a complete list of events that would result in an event of cancellation. If the 2027 TCPL PA is cancelled for any reason, TCPL would have the right to recover termination cost from Northern. Termination costs are explained in detail in paragraph 15 of the 2027 TCPL PA. In summary, if Northern cancels the 2027 TCPL PA, whether due to Northern's inability to gain approvals for the Agreements or any other reason, or if TCPL cancels the 2027 TCPL PA, whether due to TCPL's inability to gain approvals or inability to increase its capacity needed to fulfill Northern's service request, then TCPL will charge Northern for the portion of the project development costs attributable to Northern's service request at the time of cancellation.

CONFIDENTIAL Attachment 7 provides an estimated exposure profile attributable to the 2027 TCPL PA termination cost by quarter, which gives an indication of the level of termination costs that would be incurred by Northern if the 2027 TCPL PA were cancelled. Please note that the estimated costs provided in Attachment 7 are denominated in Canadian

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dollars. Northern has requested approval decisions from both the MPUC and NHPUC by January 26, 2024, which is during Q1 2024. Northern's estimated liability for project development costs as of Q1 2024 would be [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION], assuming an $Cdn to $USD exchange rate equal to 1.3. [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]

It should be noted that Northern has participated in several TCPL New Capacity Open Seasons with success. The following contracts in Northern's portfolio have been added through TCPL precedent agreements with similar treatment of pre-service costs.

- Beginning November 2017, Northern acquired 6,333 GJ of TCPL Capacity from Parkway to East Hereford (TCPL Contract No. 57055). This capacity was coordinated with the PNGTS C2C expansion project.
- Beginning November 2020, Northern acquired 10,568 GJ of TCPL Capacity from Parkway to East Hereford (TCPL Contract No. 63265). This capacity was coordinated with the PNGTS PXP expansion project.
- Beginning November 2022, Northern acquired 10,669 GJ of TCPL Capacity from Parkway to East Hereford (TCPL Contract No. 67167). This capacity was coordinated with the PNGTS WXP expansion project.

These contracts are all part of Northern's Dawn Hub Storage Capacity Path, which provides significant benefit to Northern's customers. Northern has had good success with TCPL as a project developer, and believes this success demonstrates that TCPL has the experience and capability to gain the needed approvals and complete the construction of all required facilities. As such, Northern assesses the probability that TCPL would cancel the project and trigger termination costs to Northern as quite low.

D. Overview of the Filing

This Assessment is divided in to the following sections.

1. Section II provides the Regional Market Overview, which updates the information included in Northern's 2023 IRP with additional information discussed at the New England Winter Gas-Electric Forum, hosted by the FERC. This section provides an overview of challenges within the New England energy market and the need for Northern to be proactive to assure current and future availability of supply for our customers at reasonable prices.
2. Section III provides an overview of Northern's current portfolio.
3. Section IV provides an overview of Northern's demand forecast, its design planning standards, and the balance between Northern's current portfolio of resources with its design day and design year requirements. This section will demonstrate that Northern's long-term portfolio is insufficient to meet its design day and year requirements. This gap is currently met with short-term Off-System Peaking Contracts.
4. Section V provides an overview of potential incremental resources, which Northern continues to evaluate to balance Northern's resources with its design day and year demand. While Northern seeks approval of only the Empress

Capacity Agreements at this time, Northern has not ruled out future contracting with any of these potential incremental resources.

5. Section VI provides Northern's qualitative assessment of the Empress Capacity along with the potential incremental resources and its quantitative assessment of the Empress Capacity, including both landed cost and modelled cost analysis.
6. Section VII provides the conclusion to this petition.

II. REGIONAL MARKET OVERVIEW

On June 20, 2023, FERC, officials from each of the New England states, market experts and stakeholders from the power and gas industries convened in Portland, ME for the second annual New England Winter Gas-Electric Forum to discuss possible solutions to the challenges faced in the electric and gas markets in New England, reliability risks, and resource adequacy. The discussion was focused largely on a study conducted by ISO-NE which analyzed the winters 2023-2024 and 2024-2025 and the necessity of the Everett Marine Terminal within the market.[2] Many variables such as weather, operating conditions of gas pipelines, demand, and the presence of gas flowing from LNG import facilities were addressed, and those discussions highlighted an extremely tight balance between supply and demand that provides very little margin to sustain the loss of a critical supply source. The discussions throughout the day were informative and highlighted that there is no single or clear solution to New England's energy challenges. What is clear, however, is that New England's energy needs continue to rely upon natural gas, including both North American supplies delivered via pipeline and imported LNG, during peak winter conditions. Natural gas pipelines that feed New England are heavily constrained and demand from LDC's and the electric grid is strong. New infrastructure builds face significant challenges and a clear takeaway from the Forum is that there is much uncertainty surrounding the long-term future of the Everett Marine Terminal as well as St. John LNG import terminal, which are two critical infrastructure and supply sources with their own unique characteristics and capabilities that allow the regional power and gas systems to operate reliably.

The proposed Empress Capacity Path provides access to supply that is not reliant upon imported LNG that may be at risk. As mentioned, the proposed Empress capacity will improve

[2] 2023 New England Winter Gas-Electric Forum Transcript, June 20, 2023

Northern's portfolio, but Northern will still require additional peaking supply resources to meet design day and year requirements.

This Regional Market Overview discusses New England natural gas market conditions to provide context for the Company's resource planning process and activities. The region is experiencing a period of expected long-term volatility and periodic supply constraints brought about by market (supply/demand) dynamics and policy effects described below. Consistent with its planning principles, the Company seeks additional supply resources and highly values resource flexibility to ensure its ability to continue providing reliable and reasonably priced supply.

There is unprecedented uncertainty with respect to future natural gas demand and supply, natural gas pricing implications, including the role and impact of climate-related policies in New England, which will impact the Company's long-term resource planning and strategy. Since Northern's 2019 IRP, significant challenges associated with the natural gas market environment in the New England region, particularly during the winter period, have continued to impact the Company's resource plans. Specifically, overall demand for natural gas in New England has continued to be strong, however, the various natural gas supply issues previously discussed in the Regional Market Overview of the 2019 IRP have continued to be a major challenge for market participants. The regional natural gas market demand and supply conditions have resulted in extremely volatile New England natural gas prices during the winter period, with natural gas demand and associated market area prices oscillating between relatively low demand with low gas prices and high demand with extremely high gas prices. In addition, the regional trends in energy and environmental policy to address climate change have continued to impact the availability of new infrastructure.

The remainder of this section is organized as follows:

Part 1, Natural Gas Demand Trends, reviews natural gas demand growth over the past 20 years;

Part 2, Natural Gas Supply Issues, reviews U.S. and Canadian production and reserves in supply basins that are deliverable to New England, constraints on the existing pipeline system and concerns over the ongoing viability of the region's imported LNG facilities, upon which the New England region is heavily dependent;

Part 3, Implications for Regional Natural Gas Prices, reviews the regional natural gas prices and the impact of energy market conditions on New England natural gas prices and basis values;

Part 4, Energy and Environmental Policy, discusses uncertainty stemming from energy and climate policy, which highlights the fact that Northern needs to maintain flexibility within its resource portfolio notwithstanding its need to also build and maintain a portfolio that meets its Planning Load.

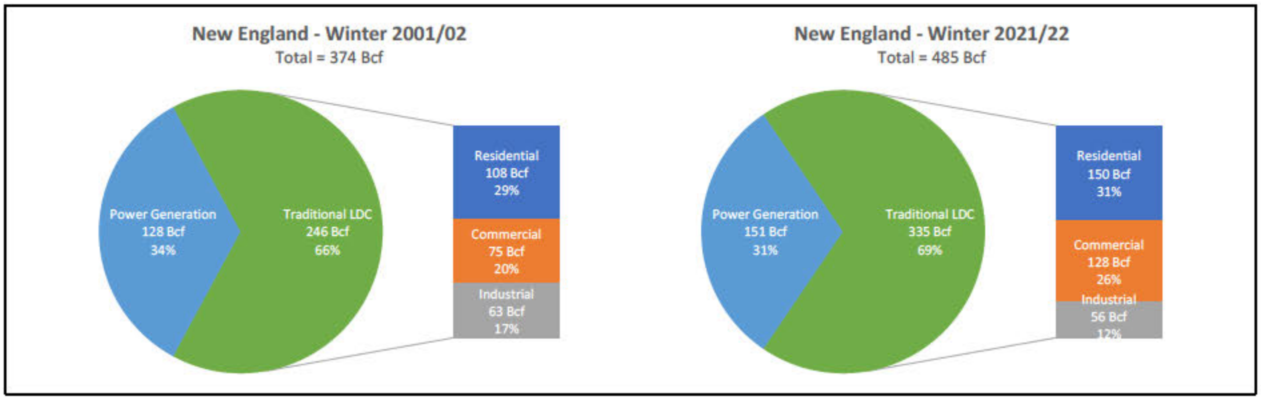
A. Natural Gas Demand Trends

In the New England region, natural gas is the leading fuel for electric power generation and space heating, with natural gas consumption peaking during the winter period.[3] As depicted in Figure II-1 (below), both the traditional LDC and power generation sectors have experienced increases in winter natural gas consumption over the past 20 years. Specifically, winter natural gas consumption by the traditional LDC sector in the region increased from approximately 246 Bcf in 2001/02 to approximately 335 Bcf in 2021/22, or by approximately 36 percent. Over that same time period, winter natural gas consumption by the power generation sector in New England increased from approximately 128 Bcf to approximately 151 Bcf, or by approximately 18 percent.

[3] Throughout this section, the winter period refers to the five months from November to March and the summer period refers to the seven months from April to October.

Thus, in total, natural gas demand in New England increased from approximately 374 Bcf in winter 2001/02 to 485 Bcf in winter 2021/22, or by approximately 30 percent, with demand from gas LDCs growing at twice the rate as demand of power generation. Within the LDC sector, it is noteworthy that industrial customer demand dropped, with a 20-year compound annual growth rate ("CAGR") of -0.6% while residential demand grew at a 20-year CAGR of 1.7% and commercial demand led the way with a 20-year CAGR of 2.7%.

Figure II-1: Winter Natural Gas Consumption in New England[4]



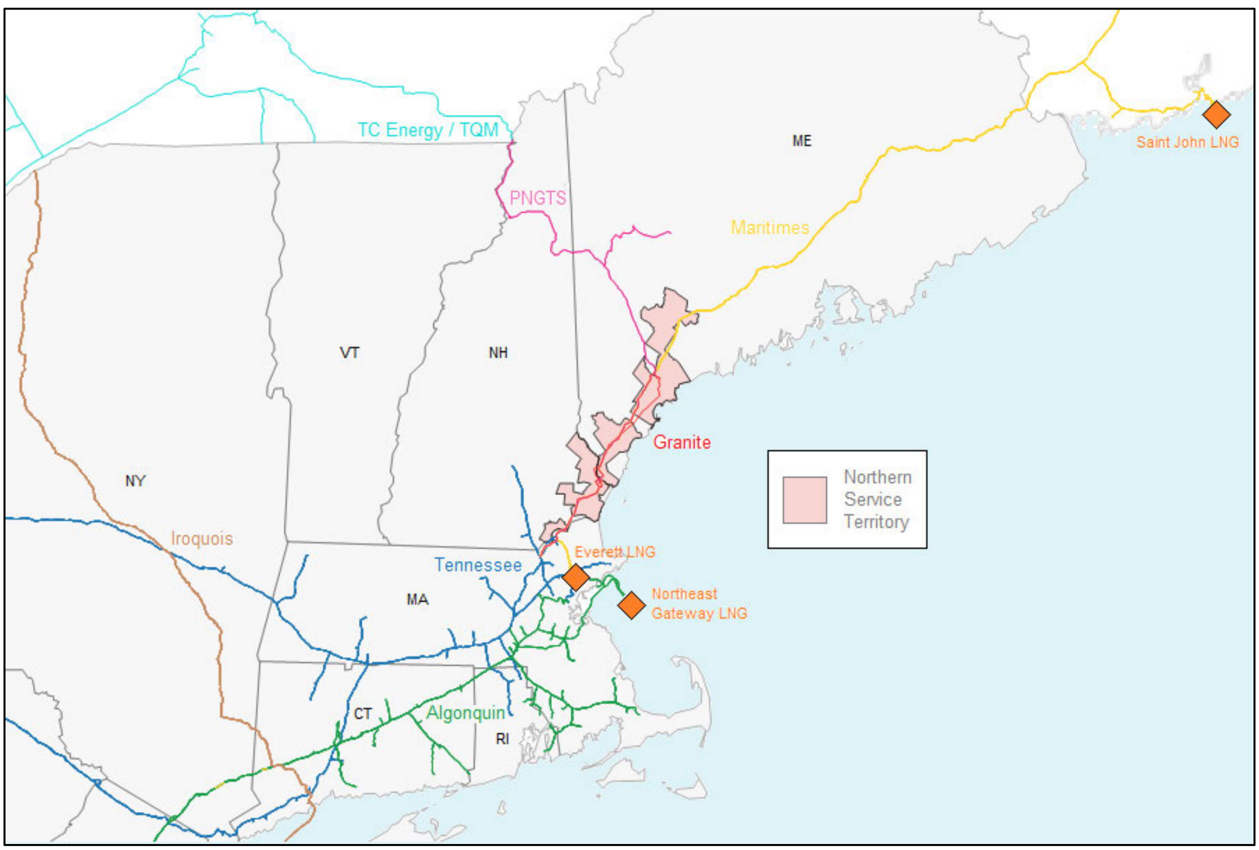
B. Natural Gas Supply Issues

Since New England is not a natural gas-producing region and has no underground natural gas storage, the New England region relies on natural gas supplies that are primarily delivered to the region via interstate pipelines from the U.S. production areas (i.e., the Appalachian and Gulf Coast regions) and Canada, as well as imported LNG. The five major interstate pipelines serving the New England region are Algonquin Gas Transmission ("Algonquin"), Iroquois Gas Transmission ("Iroquois"), Maritimes and Northeast Pipeline ("Maritimes"), Portland Natural Gas Transmission System ("PNGTS"), and Tennessee Gas Pipeline ("Tennessee"). As shown in Figure

[4] Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, February 28, 2023. Represents combined data for Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, and Vermont with estimated data for certain months in 2021/22.

II-2 (below), the New England region is essentially at the "end of the line" with respect to interstate pipeline infrastructure. Also illustrated in Figure II-2 (below) is the Company's service territory in Maine and New Hampshire, which is served by the Maritimes, PNGTS, and Tennessee pipelines, each of which deliver to Northern directly or via Granite State Gas Transmission ("Granite") and provide the Company with access to the various upstream natural gas supply sources.

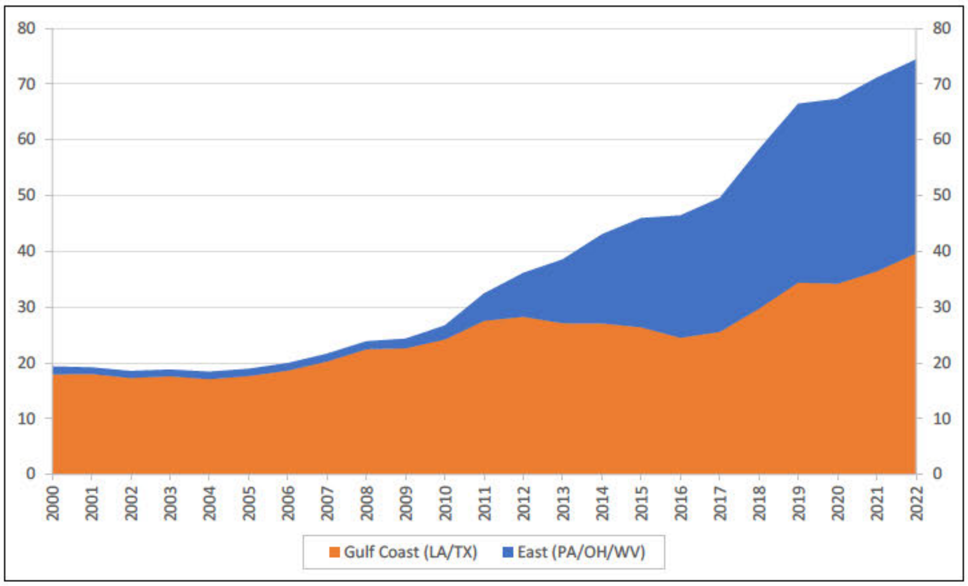
Figure II-2: Northern Service Territory and Regional Natural Gas Infrastructure



a) U.S and Canadian Gas Production

The primary natural gas supply basins in North America are the U.S. Appalachian (i.e., Marcellus and Utica), U.S. Gulf Coast, and Western Canadian Sedimentary Basin ("WCSB"). Figure II-3 (below) illustrates the significant increase in U.S. natural gas production from the East (i.e., Appalachian region) since 2010, as well as the historical natural gas production from the U.S. Gulf Coast region.

Figure II-3: U.S. Gulf Coast and East Natural Gas Marketed Production (Bcf/day)[5]



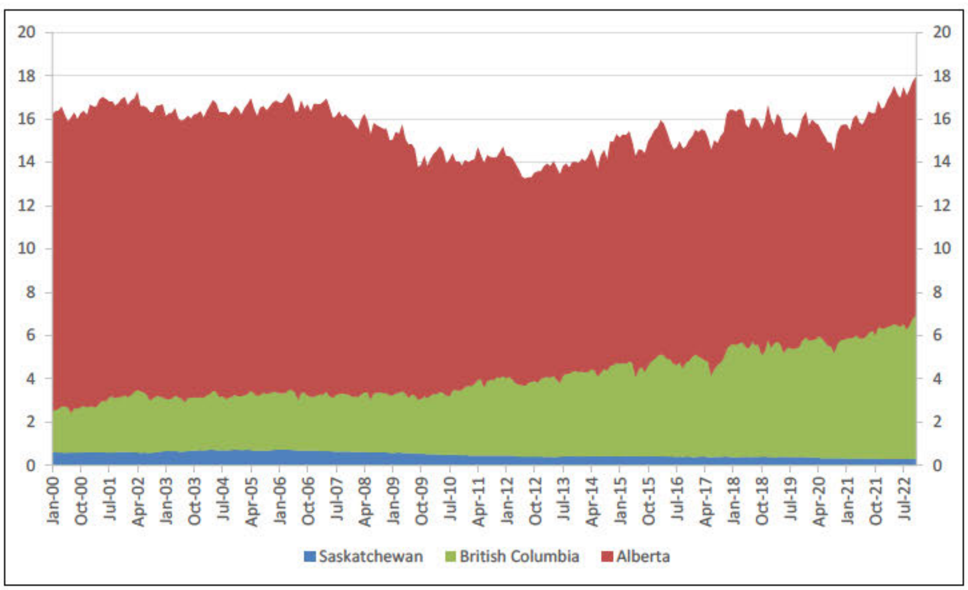
Based on the most recent estimates published by the Potential Gas Committee ("PGC"), there is over 1,300 Tcf of potentially recoverable gas resources in the Atlantic region, which encompasses the Marcellus and Utica supply basins, and over 500 Tcf in the Gulf Coast.[6] In addition, the U.S. EIA provides estimates of proved reserves that are demonstrated with reasonable

[5] Source: U.S. Energy Information Administration, Natural Gas Marketed Production, February 28, 2023.
[6] Source: Potential Gas Committee, "Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee (December 31, 2020)," October 19, 2021.

certainty (i.e., 90 percent probability or greater) to be recoverable under existing economic and operation conditions, which are supplemental to the PGC estimates. According to the most recent estimate from the U.S. EIA, the level of proved reserves in the major U.S. shale plays include the Appalachian (i.e., Marcellus and Utica shale basins) at approximately 177 Tcf and Gulf Coast (i.e., Haynesville/Bossier and Eagle Ford) at approximately 86 Tcf.[7]

With respect to Canadian gas supply, the WCSB natural gas production basin is situated in the Alberta, British Columbia, and Saskatchewan provinces. As illustrated in Figure II-4 (below), total WCSB natural gas production has increased from 2009-2014 levels (i.e., approximately 13 Bcf/day to 14 Bcf/day) to a record high of nearly 18 Bcf/day in November 2022.

Figure II-4: WCSB Natural Gas Marketed Production (Bcf/day)[8]



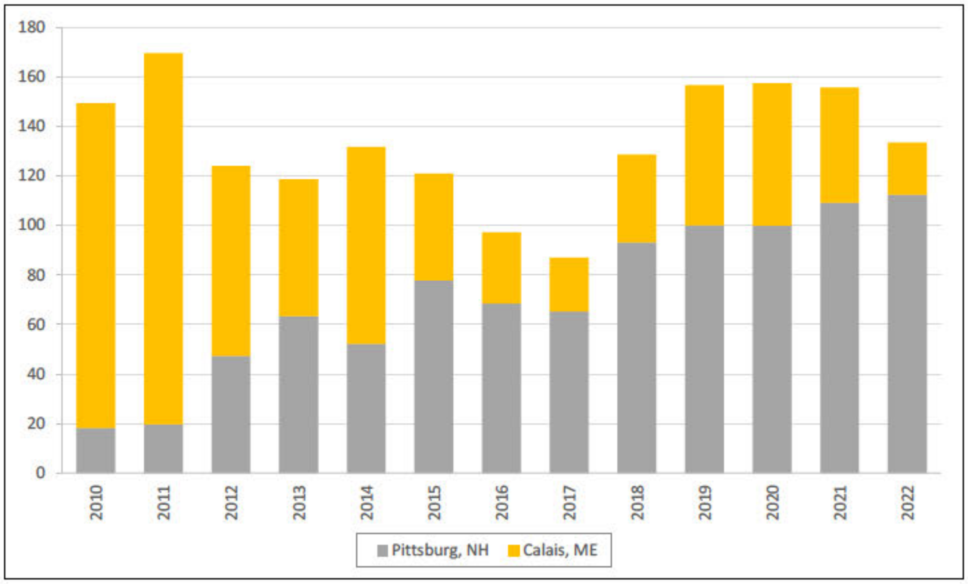
[7] Source: U.S. Energy Information Administration, Proved Reserves of Crude Oil and Natural Gas in the United States, Year-End 2021, December 30, 2022.
[8] Source: Canada Energy Regulator, Marketable Natural Gas Production in Canada, February 22, 2023.

As noted by the CER, the most recent estimate of ultimate natural gas potential in the WCSB is well over 1,000 Tcf.[9] While estimates of potential gas resources, in general, may be considered speculative and dependent on natural gas prices and extraction technologies, the substantial volume of natural gas potential in the WSCB demonstrates the considerable abundance of gas supply from the basin.

As shown in Figure II-5 (below), while natural gas deliveries from Canada to the New England region via Maritimes (i.e., imports at Calais, ME) have decreased from their 2010-2011 levels, natural gas deliveries to the region via PNGTS (i.e., imports at Pittsburg, NH) have increased significantly. The increase in the level of natural gas imports from Canada to the New England region via PNGTS has been supported by the successful development of pipeline expansion projects on Enbridge (Union Gas System) and TC Energy from the Dawn Hub[10] (in conjunction with several pipeline expansions on PNGTS). As illustrated in Figure II-5 (below), the level of natural gas imports from Canada to the interconnection with PNGTS at Pittsburg, NH has increased by over six-fold, from 18 Bcf in 2010 to approximately 112 Bcf in 2021.

[9] Source: Canada Energy Regulator, "Published Estimates for Ultimately Recoverable Natural Gas in the WCSB," July 5, 2022.
[10] Enbridge's Dawn Hub is one of the largest integrated natural gas storage facilities in North America. As discussed in Northern's 2019 IRP, natural gas supply at the Dawn Hub, which has access to Appalachian (i.e., Marcellus and Utica) and WCSB natural gas production, has continued to increase and diversify.

Figure II-5: Natural Gas Import Volumes on PNGTS and Maritimes (Bcf)[11]



b) Regional Pipeline Capacity Constraints

As illustrated in Figure II-5 (above), there are a limited number of interstate pipelines serving the New England region. In addition, the existing interstate pipeline infrastructure into the region is fully subscribed. LDCs have contracted for the majority of the pipeline capacity via long-term contractual arrangements for firm pipeline transportation service to meet their customers' natural gas demand requirements. In contrast, as highlighted by the FERC in its fall 2022 Winter Energy Market and Reliability Assessment, "many natural gas-fired generators in the region historically have not contracted for long-term firm pipeline capacity;" thus, power generators and other customers without firm pipeline service typically rely on remaining available capacity on the pipelines.[12]

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[11] Source: U.S. Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, February 28, 2023.
[12] Federal Energy Regulatory Commission, Winter Energy Market and Reliability Assessment, updated October 25, 2022, at 37-38.

During the winter period when natural gas demand from the power generation sector coincides with demand for space heating from the LDCs' customers, the interstate pipelines into the New England region often experience capacity constraints as they reach their maximum capacity. These pipeline capacity constraints lead to less flexibility for shippers (including LDCs) on the interstate pipeline systems and places upward pressure on New England natural gas prices. For example, Tennessee has indicated restrictions have been in place for nearly all of the winter period over the past four split-years at key points on their pipeline system that transport supplies to the New England market area.[13] In addition, the length (in days) and number of operational flow orders ("OFOs") affecting deliveries to the New England market area on Tennessee have generally increased.[14]

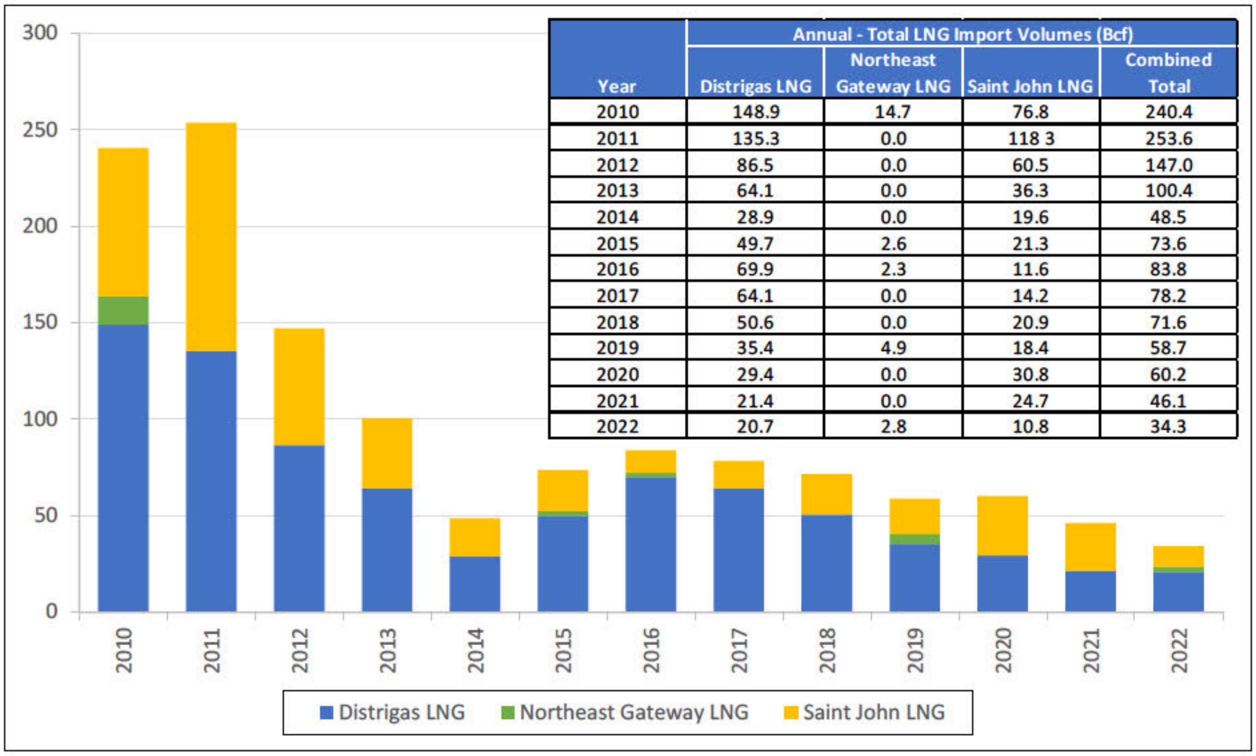
While natural gas demand in the region has increased, there have been limited expansion projects to increase pipeline capacity to serve the New England region, in general, and the Company, in particular. Only three pipeline projects, which provide incremental capacity into the New England region, have successfully been placed in-service since the Company's 2019 IRP.[15] These projects include the PNGTS Portland XPress, PNGTS Westbrook XPress, and Algonquin Atlantic Bridge projects; and, notably, the Company has contracted for firm pipeline service on all three projects. Indeed, the open seasons on TCPL and PNGTS that led to the proposed Empress capacity represent the first opportunity since Westbrook Xpress project for Northern to add capacity.

[13] For example, Tennessee's Station 245 was restricted 100 percent of the days in the winters of 2018/19 to 2021/22 and 99 percent of the days in winter 2021/22. See, Kinder Morgan, 2022 NGA Pre-Winter Briefing Meeting, November 17, 2022, at 5.
[14] See, Kinder Morgan, 2022 NGA Pre-Winter Briefing Meeting, November 17, 2022, at 6.
[15] As noted in Northern's 2019 IRP, the TGP 261 Upgrade project on the Tennessee system was limited to LDCs located in western Massachusetts and did not provide incremental supply to New England region.

c) Reliance on Imported LNG for Peaking Supplies

During the peak winter period, the New England region relies on incremental supplies from the regional LNG import terminals to meet natural gas demand requirements. There are currently three active LNG import terminals that serve the New England and Atlantic Canada region; specifically, the Constellation LNG, LLC ("CLNG") Distrigas LNG facility in Everett, MA; Excelerate Energy's offshore Northeast Gateway LNG facility in Cape Ann, MA; and Repsol Energy North America's ("Repsol") Saint John LNG facility in Atlantic Canada (formerly, the Canaport LNG facility). As discussed in the Company's 2019 IRP, the LNG import volumes at the Distrigas LNG and Saint John LNG facilities have decreased significantly from their 2011 levels; and the LNG import volumes at the Northeast Gateway LNG facility have been limited. Figure II-6 (below) illustrates the combined annual LNG import volumes at the three active regional LNG import terminals, which ranged between approximately 30 Bcf and 60 Bcf over the most recent four years.

Figure II-6: Annual LNG Import Volumes (Bcf)[16]



Year	Annual - Total LNG Import Volumes (Bcf)			
	Distrigas LNG	Northeast Gateway LNG	Saint John LNG	Combined Total
2010	148.9	14.7	76.8	240.4
2011	135.3	0.0	118 3	253.6
2012	86.5	0.0	60.5	147.0
2013	64.1	0.0	36.3	100.4
2014	28.9	0.0	19.6	48.5
2015	49.7	2.6	21.3	73.6
2016	69.9	2.3	11.6	83.8
2017	64.1	0.0	14.2	78.2
2018	50.6	0.0	20.9	71.6
2019	35.4	4.9	18.4	58.7
2020	29.4	0.0	30.8	60.2
2021	21.4	0.0	24.7	46.1
2022	20.7	2.8	10.8	34.3

Pricing and availability of imported LNG supplies for the New England region are heavily influenced by global LNG market dynamics. The New England region competes with international markets, such as Europe and Asia, for LNG import volumes to meet peak winter demand requirements and, thus, global LNG prices impact the winter natural gas prices in New England. Prior to the most recent winter, the Governors of the six New England states indicated in a July 27, 2022 letter to the U.S. Department of Energy Secretary Jennifer Granholm, "[t]he Russian invasion of Ukraine has exacerbated the pricing of nearly all energy commodities which is directly impacting energy consumers in our respective states" and emphasized that "[t]he increase in global

[16] Source: U.S. Department of Energy, LNG Annual Reports for 2011-2021; U.S. Department of Energy, LNG Monthly Report for 2022, February 15, 2023; and Canada Energy Regulator, LNG Exports and Imports Detail, February 12, 2023.

liquified natural gas (LNG) pricing has been particularly acute." Notably, the global LNG supply chain issues led to record high global LNG prices and winter natural gas futures prices for New England in the summer of 2022.

Finally, due to certain commercial changes, there is uncertainty regarding the long-term availability of natural gas supplies from the Distrigas LNG and Saint John facilities for the New England region. As discussed in Northern's 2023 IRP, there is significant uncertainty regarding the future of CLNG's Distrigas LNG facility, which currently provides delivered natural gas supplies (i.e., vapor and liquid) to certain LDCs in the region and is the sole source of natural gas supply for Constellation Mystic Power, LLC ("Mystic") generating units 8 and 9. While CLNG had received FERC approval for a cost-of-service agreement to support the continued operation of Mystic, the generating units are set to retire in mid-2024. Coinciding with the retirement of Mystic, CLNG's existing firm pipeline capacity contracts on Algonquin and Tennessee are set to expire in October 2024 and November 2024, respectively. CLNG has indicated that cost recovery associated with the continued operation and maintenance of the Distrigas LNG facility is uncertain after the retirement of Mystic, thus adding significant uncertainty with respect to the future availability and associated pricing of natural gas supplies from the Distrigas LNG facility. At the FERC 2023 New England Winter Gas-Electric Forum on June 20, 2023, Constellation warned that it was still looking for "sufficient bilateral contract support for the facility."[17] Notably, Northern typically purchases LNG for its Lewiston LNG vaporization plant from CLNG.[18] Specifically, with respect to the Saint John LNG facility, in Northern's 2023 IRP, it was reported that Repsol was assessing the feasibility of expanding the facility to add liquefaction capability to facilitate LNG exports,

[17] 2023 New England Winter Gas-Electric Forum Transcript, Page 38, lines 18 and 19.
[18] Comments of Constellation Energy Generation, LLC. "New England Winter Gas-Electric Forum", Docket No. AD22-9-000, at 5.

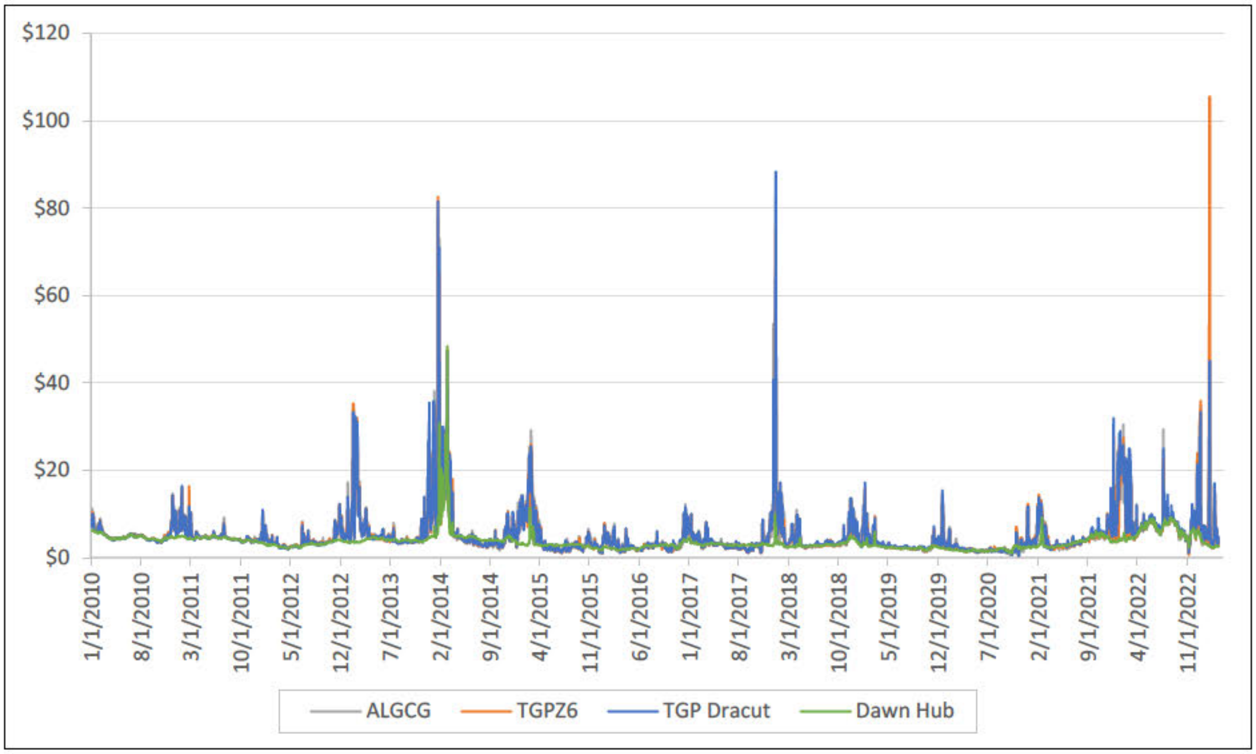
and had received approval from the Canada Energy Regulator to extend the commencement date of LNG exports to May 2032.[19] Since Northern's 2023 IRP has been filed, Repsol has determined that adding liquefaction capability to the Saint John LNG facility could not be completed economically and was no longer pursuing this project.[20] At the FERC 2023 New England Winter Gas-Electric Forum, Repsol indicated that any "out of market solution favoring Everett" would ultimately "threaten the participation of existing electric and natural gas assets in those markets."[21]

C. Implications for Regional Natural Gas Prices

Natural gas prices in the New England market area, as represented by the Algonquin Citygate ("ALGCG"), Tennessee Zone 6 ("TGPZ6"), and TGP Dracut prices indices, have exhibited significant volatility at high price levels during the winter period relative to other supply regions, such as the Dawn Hub, as illustrated in Figure II-7 (below). As noted by the U.S. EIA, the key market drivers for the high winter natural gas prices in the New England region include: the weather-driven demand increases (for both space heating and electric power generation); the constraints on the region's interstate natural gas pipelines; and the limited incremental LNG supplies (all of which are discussed above).[22]

[19] See, Saint John LNG Development Company, Ltd., Application for a Variation of License GL-318 and GL-319 to the Canada Energy Regulator, September 14, 2022; and Canada Energy Regulator, Letter and Order AO-001-GL-318, January 24, 2023.
[20] https://www.bloomberg.com/news/articles/2023-03-16/repsol-scraps-bid-to-ship-canadian-gas-to-europe-citing-costs
[21] 2023 New England Winter Gas-Electric Forum Transcript, Page 38, lines 18 through 25.
[22] U.S. Energy Information Administration, "New England natural gas and electricity prices increase on supply constraints, high demand," February 3, 2022.

Figure II-7: Daily Spot Gas Prices ($/MMBtu)[23]



As illustrated in Figure II-7 (above), the New England market area price indices experience significant daily price spikes during the winter period. As shown in Table II-1 (below), the simple average daily price levels during the winter period of the New England market area indices have exceeded the simple average daily prices at the Dawn Hub by more than 50 percent in 9 of the last 13 winters. Focusing on the simple average daily prices over the most recent five winter periods, the simple average daily price at the Dawn Hub has been approximately $3/MMBtu below the simple average daily prices of the New England market area indices.

[23] Source: S&P Capital IQ.

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Table II-1: Average Winter Spot Prices and Volatility[24]

Winter	Average Spot Prices ($/MMBtu)					Price Volatility				
(Nov-Mar)	Henry Hub	TGP Dracut	TGPZ6	ALGCG	Dawn Hub	Henry Hub	TGP Dracut	TGPZ6	ALGCG	Dawn Hub
2010/11	$ 4.10	$ 6.46	$ 6.52	$ 6.57	$ 4.59	32%	228%	249%	227%	23%
2011/12	$ 2.77	$ 3.85	$ 3.86	$ 3.86	$ 3.24	35%	180%	171%	171%	22%
2012/13	$ 3.47	$ 9.28	$ 9.31	$ 9.64	$ 3.83	24%	327%	298%	312%	20%
2013/14	$ 4.63	$ 15.76	$ 14.93	$ 15.09	$ 8.06	89%	452%	472%	473%	287%
2014/15	$ 3.26	$ 8.95	$ 8.88	$ 9.27	$ 3.87	43%	358%	370%	385%	143%
2015/16	$ 2.00	$ 3.07	$ 2.97	$ 3.02	$ 2.10	49%	267%	272%	321%	45%
2016/17	$ 3.04	$ 4.92	$ 4.82	$ 4.69	$ 3.27	45%	294%	231%	268%	48%
2017/18	$ 3.01	$ 8.71	$ 8.28	$ 8.13	$ 3.08	109%	418%	421%	514%	129%
2018/19	$ 3.38	$ 5.77	$ 5.45	$ 5.40	$ 3.38	59%	315%	318%	329%	108%
2019/20	$ 2.13	$ 3.46	$ 3.21	$ 3.16	$ 2.03	43%	260%	291%	280%	38%
2020/21	$ 3.13	$ 4.46	$ 4.79	$ 4.48	$ 2.71	174%	356%	363%	382%	121%
2021/22	$ 4.55	$ 11.68	$ 9.73	$ 10.53	$ 4.40	62%	436%	531%	505%	54%
2022/23	$ 4.07	$ 8.47	$ 9.52	$ 7.05	$ 3.95	97%	439%	568%	501%	102%

With respect to gas price volatility (i.e., a measure of the degree of price variations),[25] as shown in Table II-6 (above), the volatility level for the New England market area price indices have been well above 100 percent every winter, with the simple average daily prices during the winter period exceeding $5/MMBtu in 8 of the 13 winters. Stated differently, the New England market area prices have experienced large price fluctuations at high price levels in 8 of the last 13 winters. In contrast, the Dawn Hub index has only one observation with relatively high volatility, which reflected certain price spikes at the Dawn Hub in the colder-than-normal winter of 2013/14; five observations with volatility levels between 100 percent and 150 percent and price levels below $4/MMBtu; and seven observations with volatility levels well below 100 percent and price levels between $2-5/MMBtu.

[24] Based on ScottMadden's analysis of data from S&P Capital IQ. Note: Winter 2022/23 includes data through March 14, 2023.
[25] Historical price volatility is calculated as the standard deviation of daily relative changes in natural gas prices. Source: U.S. Energy Information Administration, An Analysis of Price Volatility in Natural Gas Markets, August 2007.

D. Energy and Environmental Policy

Federal and many state policymakers, including in the New England region, are promoting a major energy transition away from fossil fuels and toward a decarbonized energy system. At the federal level, recent climate-related policies are aimed at accelerating the reduction in emissions (e.g., Inflation Reduction Act Methane Emissions Charge) and supporting the growth of clean energy sources (e.g., EPA's proposed rule changes to the Renewable Fuel Standard). At the regional level, the six New England states have been working to reduce GHG emissions through state goals and legislative mandates, as well as regional agreements.[26] For example, in Maine, an Act to Promote Clean Energy Jobs and to Establish the Maine Climate Council, which was passed in 2019, requires the state to reduce GHG emissions to 45 percent below 1990 levels by 2030 and 80 percent by 2050.

For Northern and its parent (Unitil Corporation), the trends in energy and environmental policy to address climate change continue to influence and inform its approach to decarbonization and GHG emissions reductions. As discussed in Unitil Corporation's *2022 Corporate Sustainability and Responsibility Report*,[27] the Company and its parent fully embrace the imperative to achieve net-zero emissions by 2050. Efforts to achieve net-zero emissions over the coming decades include: increasing Energy Efficiency, reducing the percentage of leak prone pipe on its distribution system and level of emissions from its fleet and facilities, decarbonizing gas supply (e.g., opportunities to decrease the carbon content of the gas supply portfolio by procuring

[26] See, ISO Newswire, "The New England states' frameworks for reducing greenhouse gas emissions continue to evolve," January 19, 2021.
[27] See, https://unitil.com/reports/2022-Sustainability-Report/. Unitil's Carbon emissions reduction target is company-wide direct greenhouse gas emissions reduction from 2019 levels by at least 50 percent by 2030, and to net-zero emissions by 2050.

and utilizing renewable gas and certified gas), and promotion of environmentally-friendly heating sources and technologies.

Nevertheless, given the level of uncertainty regarding the impact of climate-related policies on long-term natural gas demand and supply, it is imperative that Northern's resource portfolio achieves resource adequacy (the Company's resource portfolio is capable of meeting its Planning Load) and that the Company preserves flexibility and optionality as the natural gas market landscape continues to evolve to address state and regional climate goals and policies, and customer preferences.

III. CURRENT PORTFOLIO

Table III-1 provides an overview of the sources of supply available to Northern through its portfolio of contracts, including transportation contracts, storage contracts, baseload and peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table III-1. Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	30,621
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Dawn Hub Storage	59,793
Total Storage Capacity	62,437
Peaking Capacity Paths	
LNG - On-System	6,500
Granite Capacity	43,286
Total Peaking Capacity	49,786
Total Design Day Capacity	142,844

Table III-1 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2023-2024 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above. Contracts in the long-term portfolio offer Northern long-term control of the capacity either through periodic renewal rights or the right of first refusal. Short-term supply contracts do not provide Northern with control over access to the resource beyond the end date of the contract. The Pipeline and Storage Capacity Paths in Northern's portfolio are comprised of long-term contracts which access liquid supply points where there is sufficient supply and market activity such that Northern has confidence in its ongoing ability to access supply to fill these capacity contracts for ultimate delivery to Northern's system. However, Northern's Peaking Capacity Paths, including the on-system LNG plant, rely on the ongoing availability of imported LNG, which Northern has had to purchase under short-term contracts in recent years. As discussed in the Regional Market Outlook, the ongoing availability of these supplies is not assured.

Table III-1 can also be found on page 1 of Attachment 8, Northern's Capacity Path Diagrams. Subsequent pages of Attachment 8 include capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Maritimes & Northeast Pipelines, L.L.C. ("MNUS" or "Maritimes"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), PNGTS, TCPL, Enbridge Gas, Inc. ("Enbridge" or "Union") , Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Enbridge and Tennessee. Northern's gas supply portfolio for 2023-2024 includes additional capacity on Granite, which is currently filled utilizing short-term peaking contracts that deliver supply from imported LNG. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which Northern relies on to produce 6,500 Dth per day with a storage capacity of approximately 12,000 Dth of LNG. Northern procures an LNG Contract on an annual basis with a typical volume being up to 3,000 Dth per day with an annual contract quantity of up to 75,000 Dth in order to supply this facility. The gas supply portfolio includes an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement"), which is needed to bring the Iroquois Receipts, Leidy Hub Supply and Transco Zone 6, non-NY capacity path supplies into Northern's system, as the delivery points on these capacity paths are on the Bay State Gas Company system.

The capacity path diagrams and capacity path details in Attachment 8 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, in order to move natural gas supplies from the sources of supply listed in Table III-1 to Northern's distribution system. The diagrams in Attachment 8 list and display contracts by segment for each capacity path, showing how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity, contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

IV. RESOURCE BALANCE

A. Overview

In order to demonstrate the need for additional resources, Northern compared the capabilities of its current long-term portfolio to its planning load forecast under design day, design ten-day cold snap, and design year conditions. Currently, Northern requires off-system peaking supply contracts in addition to its long-term capacity portfolio to meet its portfolio design standards[28]. As discussed above, Northern does not have the right to extend these supply contracts beyond the end dates. As such, beyond the 2023-2024 Winter Period, Northern continues to require additional resources as the current long-term portfolio cannot meet the design planning load requirements without additional resources. For the purpose of calculating the resource balance for determining the need for the Empress Capacity Agreements, Northern is assuming that all Pipeline (30,621 Dth), Storage Capacity (62,437 Dth), and the on-system LNG capacity (6,500 Dth) have sufficient supply and are fully available, totaling 99,558 Dth. Projected demands under design day and winter conditions above this level are considered additional resource requirements for the purpose of calculating resource balance. Both the Design Day and Design Year Resource Balance are recalculated, showing the impact of the Empress Capacity to these metrics.

B. Planning Load Forecast

Northern estimated its planning load requirements, which reflect the demand of sales service customers, who purchase their natural gas supply from Northern, and capacity-assigned delivery service customers, who purchase their natural gas supply from a retail marketer. Northern

[28] Northern also contracts annually for an LNG Contract, which provides LNG that can be trucked to Northern's Lewiston LNG Facililty.

allocates its portfolio between retail marketers serving capacity-assigned delivery service customers and Northern serving sale service customers on an equitable basis, pursuant to the Delivery Service Terms and Conditions provisions of both Maine and New Hampshire Divisions, respectively. Capacity-exempt customers, who are supplied by retail marketers and are not subject to the capacity assignment provisions of the respective Maine and New Hampshire Delivery Service Terms and Conditions are not included in Northern's planning load. These estimates were provided to both the MPUC and NHPUC in Northern's 2023 IRP, which was filed under MPUC Docket No. 2023-00078 and NHPUC Docket No. DG 23-041, respectively. The long-term planning load forecast accounts for recent trends in customer growth and use per customer. Northern created customer count and use per customer models for residential, high load factor C&I, and low load factor C&I customer segments for both the Maine and New Hampshire Divisions. These models utilized historic billing customer count and usage data, historic weather, as well as appropriate economic and demographic data. These customer segment models are then adjusted for projected energy efficiency savings.

C. Planning Criteria

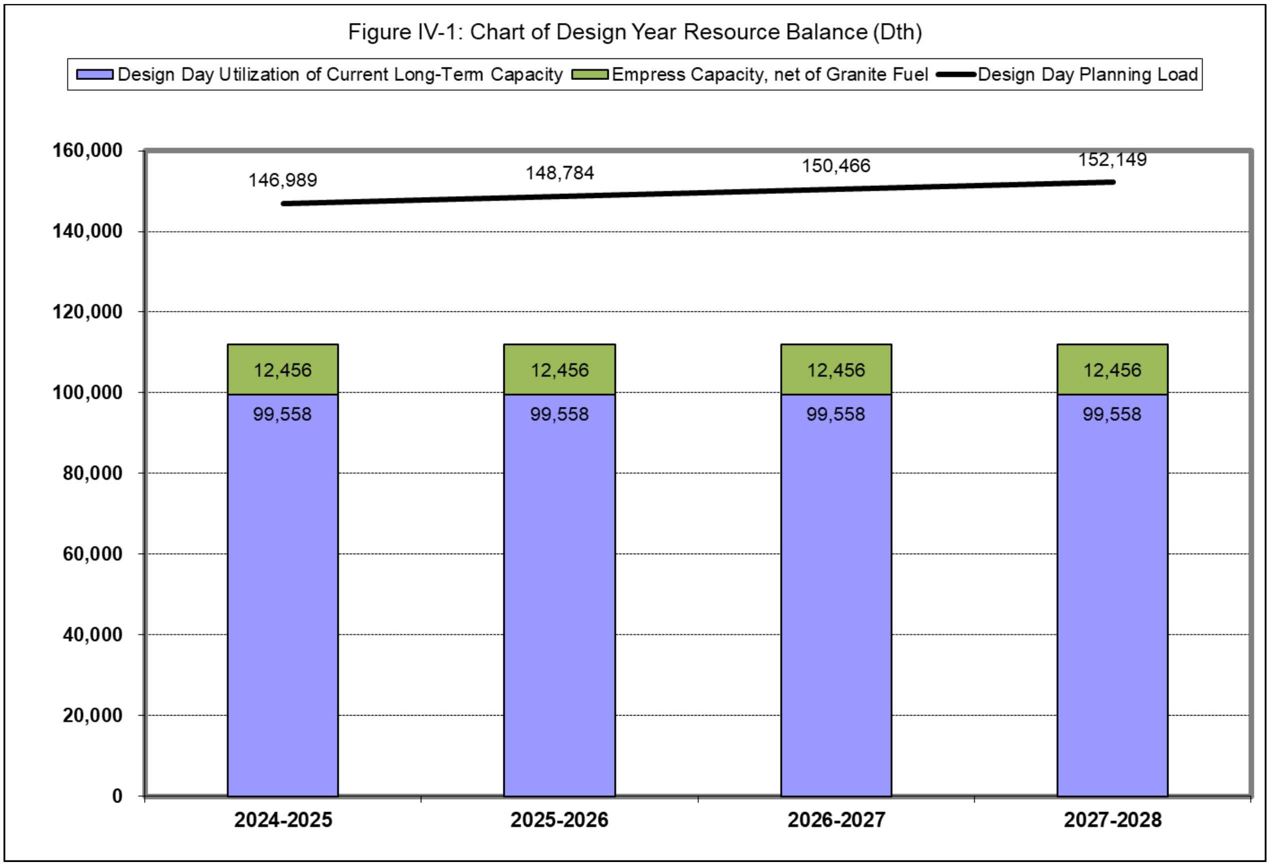
Northern's utilizes a 1 in 30 year standard for its design day, design ten-day cold snap and design winter planning criteria. In other words, Northern seeks to secure sufficient natural gas resources so that the probability that the peak winter daily demand will exceed the maximum daily gas supply resources is no greater 1/30 or 3.33%. Similarly, Northern seeks to secure that sufficient natural gas resources so that the probability that the total peak seasonal winter demand will exceed maximum seasonal gas supply resources is no greater than 1/30 or 3.33%. The planning criteria probability (1-in-30 year) is applied to peak day, ten-day cold snap and winter period (Nov-Mar) effective degree day ("EDD") data then factored into the planning load forecast models to determine the respective design day, design cold snap and design year demand levels.

D. Design Day Resource Balance

The design day resource balance beginning with the 2024-2025 Winter Period through the 2027-2028 Winter Period are summarized below in both tabular and graphic formats in Table IV-1 and Figure IV-1, respectively. Northern's forecasted design day planning load is equal to 146,989 Dth in the 2024-2025 Winter Period, resulting in a resource balance deficiency equal to 47,431 Dth. Adding the Empress Capacity reduces the 2024-2025 design day resource balance deficiency to 34,975 Dth. By the 2027-2028 Winter Period, the projected design day planning load increases to 152,149 Dth, resulting in a resource balance deficiency growing to 52,591 Dth. Adding the Empress Capacity reduces the 2027-2028 design day resource balance deficiency to 40,135 Dth.

Table IV-1: Design Day Resource Balance (Dth)

	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Utilization of Current Long-Term Capacity	99,558	99,558	99,558	99,558
Design Day Planning Load	146,989	148,784	150,466	152,149
Design Day Resource Balance w/o Empress Capacity	**(47,431)**	**(49,226)**	**(50,908)**	**(52,591)**
Empress Capacity, net of Granite Fuel	12,456	12,456	12,456	12,456
Design Day Resource Balance w/ Empress Capacity	**(34,975)**	**(36,770)**	**(38,452)**	**(40,135)**



E. Design Year Resource Balance

Using the design year forecast and current portfolio, discussed above, Northern utilized PLEXOS® to determine the dispatch of the current long-term resources to determine design year resource balance[29]. Table IV-2 summarizes the projected design year utilization of the Pipeline Capacity, Storage Capacity, and on-system LNG capacity from the 2024-2025 Winter Period through the 2027-2028 Winter Period for Northern's long-term portfolio, both with and without Empress Capacity.

[29] PLEXOS is an energy optimization software package, which was developed by Energy Exemplar.

Table IV-2: Design Year Resource Utilization (Dth)

Design Year Resource Utilization - CURRENT PORTFOLIO	2024-2025	2025-2026	2026-2027	2027-2028
Tennessee FS-MA Storage Path	964,956	964,956	964,956	967,600
Tennessee Niagara Pipeline Path	848,937	848,994	849,035	851,386
Algonquin Receipts Pipeline Path	188,901	188,901	188,901	190,152
Atlantic Bridge Ramapo Pipeline Path	2,737,500	2,737,500	2,737,500	2,745,000
Tennessee Long-Haul Pipeline Path	1,295,061	1,431,791	1,495,450	1,512,935
Union Dawn Storage Path	9,649,440	9,667,446	9,746,569	9,909,534
Iroquois Receipts Pipeline Path	971,541	971,541	971,541	977,975
Lewiston LNG	74,760	75,000	75,000	75,240
Delivered Supply Long-Term Capacity w/o Empress	**16,731,097**	**16,886,128**	**17,028,952**	**17,229,821**

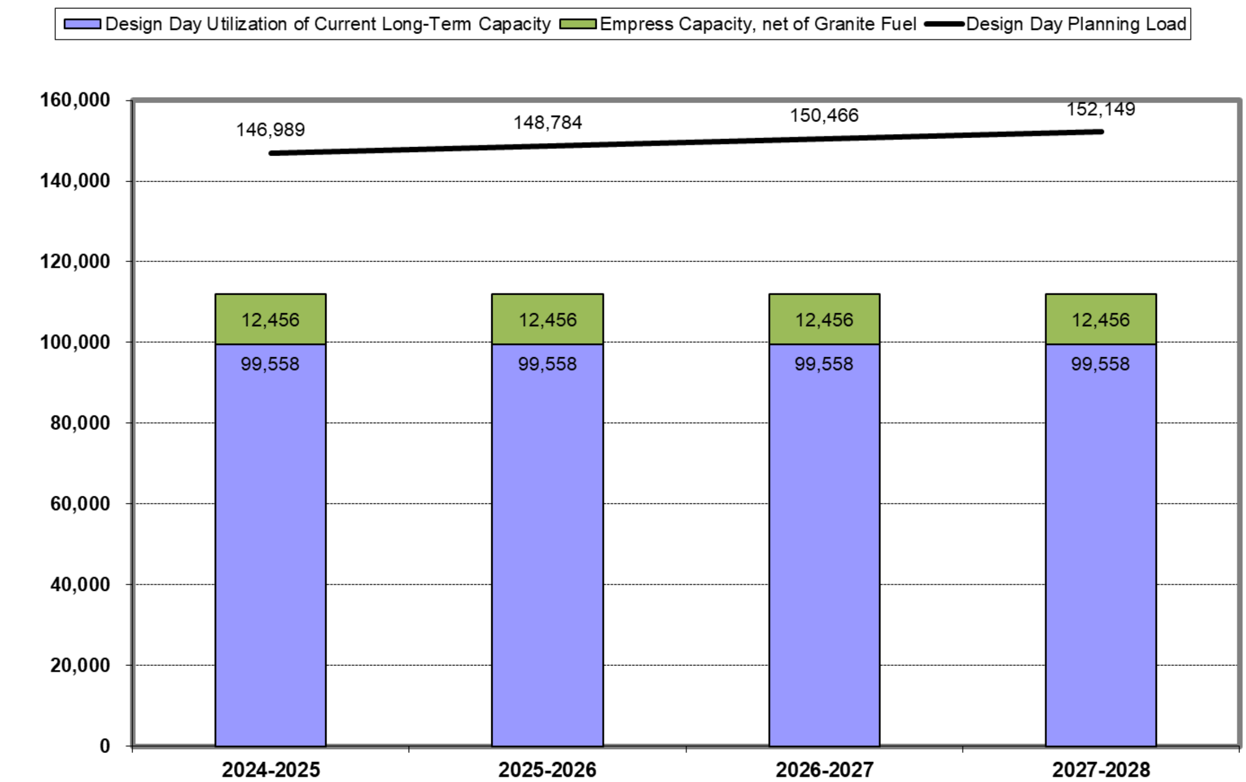
Design Year Resource Utilization - with EMPRESS CAPACITY	2024-2025	2025-2026	2026-2027	2027-2028
Empress Capacity	4,225,112	3,758,862	3,715,845	3,939,128
Tennessee FS-MA Storage Path	833,729	869,646	964,956	877,577
Tennessee Niagara Pipeline Path	530,795	533,125	536,008	541,030
Algonquin Receipts Pipeline Path	188,901	188,901	188,901	190,152
Atlantic Bridge Ramapo Pipeline Path	2,245,180	2,737,500	2,737,500	2,745,000
Tennessee Long-Haul Pipeline Path	1,191,911	1,283,220	1,356,028	1,374,668
Union Dawn Storage Path	6,839,667	6,870,683	6,914,586	6,943,769
Iroquois Receipts Pipeline Path	971,541	971,541	971,541	977,975
Lewiston LNG	74,760	75,000	75,000	75,240
Delivered Supply Long-Term Capacity w/ Empress	**17,101,596**	**17,288,478**	**17,460,364**	**17,664,539**

The design year resource balance beginning with the 2024-2025 Winter Period through the 2027-2028 Winter Period are summarized below in both tabular and graphic formats in Table IV-3 and Figure IV-2, respectively. Note that the “Delivered Supply Long-Term Capacity” both with and without Empress Capacity from Table IV-2 carries forward to Table IV-3, below. Northern’s forecasted design year planning load is equal to 17,403,633 Dth in the 2024-2025 Winter Period, resulting in a resource balance deficiency equal to 672,537 Dth. Adding Empress Capacity reduces the resource balance deficiency to 302,037 Dth. By the 2027-2028 Winter Period, the forecasted design year planning load increases to 18,054,513 Dth, resulting in a resource balance deficiency growing to 824,692 Dth. Adding Empress Capacity reduced the resource balance deficiency to 389,974 Dth.

Table IV-3: Design Year Resource Balance (Dth)

	2024-2025	2025-2026	2026-2027	2027-2028
Delivered Supply Long-Term Capacity w/o Empress	16,731,097	16,886,128	17,028,952	17,229,821
Design Year Planning Load	17,403,633	17,628,179	17,840,851	18,054,513
Design Year Resource Balance w/o Empress Capacity	**(672,537)**	**(742,051)**	**(811,899)**	**(824,692)**
Delivered Supply Long-Term Capacity w/ Empress	17,101,596	17,288,478	17,460,364	17,664,539
Impact of Empress Capacity	370,499	402,349	431,412	434,718
Design Year Resource Balance w/ Empress Capacity	**(302,037)**	**(339,702)**	**(380,487)**	**(389,974)**

Figure IV-2: Chart of Design Year Resource Balance (Dth)



F. Resource Balance Analysis Conclusions

Northern's current portfolio of long-term capacity resources is not currently sufficient to meet forecasted design day and design year planning loads. Currently, Northern meets the gap between its forecasted design day and design year loads with short-term off-system peaking contracts. The PNGTS and TCPL Open Seasons presented Northern with an opportunity to reduce its design day and design year resource balance deficiency. The volume of 12,500 Dth of Empress

Capacity significantly improves Northern's resource balance for both design day and design year planning standards.

V. INCREMENTAL RESOURCES

While Northern is currently requesting approval of the Empress Capacity Agreements, Northern is also considering the following potential incremental resources. Northern will continue working to identify and develop additional long-term resources to meet its design day and year planning requirements with a diverse and flexible portfolio of Pipeline, Storage and Peaking Capacity.

A. Off-System Peaking Contracts

Northern continues to explore the possibility of entering into a longer-term off-system peaking contract, similar in structure and operational flexibility as the off-system peaking contracts that it has entered in recent winter seasons.

B. Enbridge Project Maple

On September 12, 2023, Enbridge issued an open season for its Project Maple. However, Northern was aware of this potential resource when it was assessing the opportunity to participate in the PNGTS and TCPL Open Seasons. Project Maple offers capacity from the interconnection between the Algonquin and Millennium pipelines in Ramapo, New Jersey to existing delivery points on the Algonquin system. Service on Project Maple from Ramapo to Beverly (the interconnect between Algonquin and Maritimes pipelines) could be combined with Maritimes capacity from Beverly to Northern's system or the Granite pipeline. Northern is exploring Project Maple as an incremental resource.

C. New LNG Facility

In March 2020, the Company issued an RFP seeking proposals to develop a LNG facility. The Company sought proposals that could meet its incremental resource need of approximately

50,000 Dth/day and 500,000 Dth annually identified in the 2019 IRP. After evaluating responses, the Company negotiated for an extended period with a development team but to date no definitive project has resulted. This potential resource was discussed in Northern's 2023 IRP and Northern considers this as a potential incremental resource.

D. Incremental Energy Efficiency

Finally, Northern would consider incremental energy efficiency as an incremental resource, based on the hypothetical increase in energy efficiency savings that Northern discussed in its 2023 IRP. In its 2023 IRP, Northern modeled incremental energy efficiency, over and above the efficiency spending and savings from current customer funded programs, in order to better understand the potential impact of this resource on the Company's gas supply planning. As explained in the 2023 IRP, additional evaluative steps must be considered before pursuing this resource, including qualitative assessments of viability (e.g., project development risk) and consistency with existing energy efficiency programs and administration. Approaches to promote incremental investment in energy efficiency would need to be defined, such as providing evaluation results to the established program administrators.

E. Incremental Resource Conclusion

While Northern ultimately entered the Empress Capacity Agreements due to its assessment that the Empress Capacity Path will improve Northern's long-term portfolio of capacity contracts, Northern is mindful of the reality that the Empress Capacity Agreements alone do not close the design day or design year resource balance gaps. Therefore, Northern's decision to enter the Empress Capacity Agreements at this time is not intended to exclude a future decision to select any of the other incremental resources that are listed here or other new alternative incremental resources, which may become available.

VI. RESOURCE EVALUATION

As discussed in Northern's 2023 IRP, Northern utilizes both quantitative and qualitative tools in making resource decisions. Quantitative tools are used to assess utilization of possible resources, including impact on the utilization of other portfolio resources, to estimate average delivered costs and to assess the impact of a potential resource in satisfying or contributing to unmet design Planning Load requirements. So long as viable available projects are comparable in terms of price, Northern bases proposed resource decisions primarily on qualitative or non-price criteria. Thus, while resource decisions are informed by quantitative analyses (such as Landed Cost and Modeled Cost Analysis, discussed in greater detail below) they are not driven by the results of such analyses. As mentioned, this approach recognizes that many operational characteristics and selection criteria such as added diversity or project risk cannot be adequately quantified. Northern's decision-making approach also recognizes that price forecasts are subject to change in unpredictable ways and therefore reduces the possibility that major resource decisions are based primarily on price forecasts.

A. Qualitative Assessment

In Northern's 2023 IRP, Northern described its process for qualitative assessment of potential incremental resources. The following sections provide a summary of Northern's assessment of the Empress Capacity Path, as well as the incremental resources that Northern is continuing to consider.

Northern has concluded that the Empress Capacity Path's non-price attributes will provide benefits to Northern's customers. It is important to emphasize that none of the other incremental resources discussed in this Assessment have been ruled out for future selection, especially since the Empress Capacity Agreements will not close the gap between Northern's design day and year planning standards and the capabilities of its portfolio.

1. Upstream/Downstream Issues

Pipeline projects will not only be assessed on their own merits, but will also include a review of issues on pipelines that are either upstream or downstream of the pipeline project under review. For example, a review of an expansion on Pipeline A that receives all of its natural gas supply from Pipeline B necessitates a need to review the attributes of Pipeline B. Assessment of locational deliverability is a critical downstream issue that applies to pipeline resources and non-pipeline supply resources such as LNG or RNG facilities. Incremental resource decisions include assessment of the ability of the resulting portfolio to deliver to the specific areas the Company serves. Table VI-1 summarizes Northern's assessment of upstream/downstream issues for the potential incremental resources considered.

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Table VI-1	
Incremental Resource	**Assessment of Upstream/Downstream Issues**
Empress Capacity Path	Empress is a liquid supply hub with many buyers and sellers. Proposed capacity path includes all necessary upstream and downstream capacity for ultimate delivery to Northern's system.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Energy efficiency measures allow for more efficient use of capacity upstream of Northern's system.

2. Project Development Risks and Deployment Timing

Each pipeline project, or on-system peaking facility project, will likely present a unique set of commercial and regulatory issues that need to be assessed. Project development risks include the risk that the developer is delayed in securing or unable to secure needed approvals, financing or materials, land or labor for construction, which would require cancellation of the project. The evaluation of these issues and the ability and track record of the developer to address each issue is a critical consideration. In its evaluation of additional pipeline or LNG capacity the Company carefully considers the risk that a project may be delayed or never brought into commercial operation. Deployment timing is an important consideration because some resources take longer than others to implement, and different resources may face different development risks that ultimately impact deployment. For example, while very scalable, pipeline expansion capacity can take approximately 4 years or more to bring into service. Table VI-2 summarizes Northern's assessment of project development risks and deployment timing for the potential incremental resources considered.

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Table VI-2	
Incremental Resource	**Project Development Risks and Deployment Timing Assessment**
Empress Capacity Path	PNGTS portion of Empress Capacity Path requires no construction. TCPL requires construction for additional deliveries to East Hereford, but none to receive more supply from Empress and anticipates an in-service date of November 1, 2027. TCPL has ability to commence service before facilities are in service. There is the possibility that the project may be delayed or cancelled due to project development risks. However, as discussed in the Description of the Empress Capacity Agreements, TCPL has an excellent record of project completion, reflecting a low probability of project cancellation.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Meeting energy efficiency targets requires coordination between Northern and both customers and contractors. As energy efficiency penetration increases, incremental energy savings may become more difficult to identify and implement. However, once installed, energy efficiency provides a low risk, stable resource. There may be statutory hurdles to incremental energy efficiency in both Maine and New Hampshire. For example, Northern does not plan or implement energy efficiency in the State of Maine, as Efficiency Maine Trust performs this function.

3. Price Volatility Mitigation

Possible projects are reviewed in terms of whether they help to mitigate price volatility. The Company seeks to move its receipt points away from locations where gas prices are high and/or volatile and toward receipt points where gas prices are low and/or stable. Similarly, being able to replace winter period purchases with purchases made during the summer when prices are typically lower and more stable offer price volatility mitigation. Table VI-3 summarizes Northern's assessment of the price volatility for the potential incremental resources considered.

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Table VI-3	
Incremental Resource	**Price Volatility Mitigation Assessment**
Empress Capacity Path	Empress prices are low and stable relative to New England Delivered Supplies.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Once an energy efficiency measure is installed, its cost is known for the life of the measure.

4. Contributions to Flexibility and Diversity

The Company seeks and values diversity among supply basins and diversity among delivering pipelines. Pipeline projects that add diversity by providing access to gas supply areas to which the Company has limited access are likely to add value to the portfolio. Similarly, projects that deliver along paths where the Company currently has limited volume can improve reliability of supply by adding diversity to the mix of delivering pipelines the Company relies

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upon. Table VI-4 summarizes Northern's assessment of contributions to flexibility and diversity for the potential incremental resources considered.

Table VI-4

Incremental Resource	Flexibility and Diversity Assessment
Empress Capacity Path	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]Northern's portfolio does not currently have capacity that accesses Empress, so this would increase supply diversity.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	[BEGIN CONFIDENTIAL INFORMATION] [redacted] END CONFIDENTIAL INFORMATION]
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Once installed, energy efficiency savings would increase as demand increases.

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5. Contract Renewal Rights

The flexibility of the renewal provisions of contracts, and conversely the permanence of project rights, are assessed. Renewable access to capacity is highly valued in support of fuel security and sustainable resources. Renewal options provide tools to manage long term changes that may arise. Table VI-5 summarizes Northern's assessment of contract renewal rights for the potential incremental resources considered.

Table VI-5

Incremental Resource	Contract Renewal Rights Assessment
Empress Capacity Path	The Empress Capacity Agreements provide contract renewal rights, allowing Northern control over the Empress Capacity Path following the initial term of the Agreements.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	Enbridge Project Maple would provide contract renewal rights, allowing Northern control over the capacity following the initial term of any agreement.
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Not applicable.

6. Rate/Toll and Cost Sharing

Pipeline projects may provide potential shippers with options regarding rates/tolls. For example, a pipeline may offer a fixed toll for a set time period with a construction cost sharing

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mechanism; or a cost of service toll, which could change over time. The flexibility and transparency of the pipeline rate/toll approaches will be considered in the qualitative analysis. Table VI-6 summarizes Northern's assessment of rate/toll and cost sharing for the potential incremental resources considered.

Table VI-6

Incremental Resource	Rate/Toll and Cost Sharing Assessment
Empress Capacity Path	PNGTS rate is negotiated, fixed rate for the term of the Agreement. TCPL tolls are regulated by the CER. TCPL tolls are rolled into the system rate meaning that expansion capacity customers pay the average system rate, rather than an incremental project rate.
Off-System Peaking Contracts	Prices are subject to market conditions.
Enbridge Project Maple	Enbridge Project Maple offers fixed and recourse rate options. Rates will be based on incremental cost to construct new capacity. Any cost sharing would be determined in the negotiation of any precedent agreement.
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Energy efficiency cost would be known at the time a measure is installed. However, there are significant upfront costs.

7. Demand Charge Mitigation Opportunity

The ability of Northern to mitigate demand charges by re-selling the pipeline capacity is another qualitative consideration. For example, pipeline capacity that has access to various markets and counterparties can be expected to provide value when the capacity is not utilized at

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100% load factor. Table VI-7 summarizes Northern's assessment of opportunities for demand charge mitigation for the potential incremental resources considered.

Table VI-7	
Incremental Resource	**Demand Charge Mitigation Opportunities Assessment**
Empress Capacity Path	Empress Capacity Agreements will be releasable to an asset manager and Northern expects there to be asset management revenue to partially offset demand costs.
Off-System Peaking Contracts	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Enbridge Project Maple	[BEGIN CONFIDENTIAL INFORMATION] [redacted] END CONFIDENTIAL INFORMATION]
New LNG Facility	[BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
Incremental Energy Efficiency	Not applicable.

8. Qualitative Assessment Conclusion

The Empress Capacity Agreements provide a resource that:

- Provides a full path from a liquid supply point to Northern's system
- Provides low project development risks relative to other options, since PNGTS capacity requires no construction, and TCPL has a good record of success in completing past projects;
- Helps mitigate price volatility relative to New England delivered supplies;

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- [redacted] [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]
- Improves supply source diversity of Northern's portfolio;
- Provides Northern the ability to renew the contracts at the end of their initial term;
- Has reasonable demand cost mechanisms allowing for rolled-in rate treatment of new facilities, rather than rates based on higher, incremental costs; and
- Provides good opportunity for demand cost mitigation through future asset management agreements.

In Northern's assessment, the Empress Capacity Agreements offer positive non-price attributes that will improve its portfolio of Pipeline, Storage, and Peaking Capacity, and resulting in more favorable availability, price diversity, price stability and demand cost mitigation opportunities. For informational purposes, Northern has provided a qualitative assessment of other incremental resource options, but reiterates that these other options may be selected in the future, as Northern will require further additions to its portfolio to meet its design day, cold snap, and year planning standards.

This qualitative assessment also provides an overview of other potential incremental resources. These resources may or may not be available for future selection as part of Northern's portfolio, as energy infrastructure typically requires significant contracted volume in order to reach economies of scale with regards to project development and construction costs. As such, the Empress Capacity Agreements are the only incremental resource that is executable at this time, as PNGTS and TCPL have secured sufficient contracted volumes to enter the Empress Capacity Agreements with Northern.

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B. Quantitative Assessment

1. Landed Cost Analysis

From a quantitative perspective, a landed cost analysis evaluates the delivered cost of various alternative natural gas supply resources to Northern's system. The typical landed cost approach assumes that the pipeline demand charges are evaluated at a 100% load factor (i.e., the transportation path is used every day at full volume) and variable and/or fuel charges are based on full contracted volumes. This approach allows multiple paths to be evaluated and compared in a transparent manner. [BEGIN CONFIDENTIAL INFORMATION] [redacted]

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[END CONFIDENTIAL INFORMATION]

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2. Modelled Cost Analysis

If several projects are identified as viable and the attributes and terms are known, then they are modeled in PLEXOS®. The primary output for decision-making purposes is total delivered portfolio cost, utilization rate for proposed new resource and impact on utilization rate of other resources. Prior to Northern's decision on its bid on the TCPL and PNGTS Open Seasons, Northern conducted a modelled cost analysis, [BEGIN CONFIDENTIAL INFORMATION] [redacted]

[redacted]

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- [redacted]
- [redacted]
- [redacted]
- [redacted]
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[redacted] [END CONFIDENTIAL INFORMATION]

3. Quantitative Analysis Conclusion

Northern's quantitative analysis is based on certain assumptions, including price and demand forecasts well into the future. Actual outcomes may be substantially different than these assumptions. For this reason, Northern relies on both qualitative and quantitative analysis to make resource decisions. [BEGIN CONFIDENTIAL INFORMATION] [redacted]

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[redacted] [END CONFIDENTIAL INFORMATION] More importantly, adding the Empress Capacity Path decreases Northern's planning load design year peaking service requirement 1,640,450 Dth over the first four winter periods of the Empress Capacity Agreements. As such, the Empress Capacity Path will also increase Northern's supply diversity with a potential to lower natural gas supply costs.

VII. CONCLUSION

Northern has a responsibility to maintain a reliable and flexible portfolio and to manage natural gas supply costs on behalf of the customers it serves. Given the uncertainties in the New England energy market, outlined in the Regional Market Outlook section of this Assessment, and the gap between Northern's current and projected design day and year planning loads and resources, outlined in the Resource Balance section of this Assessment, it is reasonable for Northern to enter into the Empress Capacity Agreements. The Empress Capacity Agreements represent a unique opportunity to acquire expansion pipeline capacity on an expedited basis. Northern has conducted an appropriate qualitative and quantitative assessment of this resource decision, demonstrating that the Empress Capacity Agreements will improve Northern's portfolio by reducing both the design day and design year resource balance gap with the potential to reduce costs.

Northern is currently pursuing other potential incremental resources to increase its capacity portfolio with an overall objective of securing reasonably-priced, long-term resources to meet Northern's growing planning load requirements. The decision to enter the Empress Capacity Agreements does come with some risk, specifically the potential exposure to termination costs under the 2027 TCPL PA. TCPL has been very successful in placing required facilities into service for Northern's recent capacity additions to its portfolio. For this reason, Northern believes the probability of project cancellation to be low. In addition, the qualitative analysis outlines that all potential resources present some level of risk, including the risk that they may never become available for selection due to the difficulty in attracting sufficient contract volume for a natural gas project to move forward. Considering the tight balance between supply and demand in the New England market combined with no regional plan on how to address this tightness, Northern has concluded that the risk of taking no action exceeds any risks related the Empress Capacity Agreements. For these reasons, Northern has entered into the Empress Capacity Agreements and is now requesting approval to recover costs incurred under the Empress Capacity Agreements.