STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILIITES COMMISSION

Docket No. DG 23-087
Northern Utilities Inc.
Petition for Expedited Approval of Empress Capacity Agreements

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Department of Energy, Division of Regulatory Support
November 3, 2023

The New Hampshire Department of Energy ("DOE" or the "Department") submits this preliminary technical statement in compliance with the New Hampshire Public Utilities Commission's ("NHPUC" or the "Commission") Commencement of Adjudicative Proceeding and Notice of Prehearing Conference dated October 12, 2023 in Docket No. DG 23-087. *See also* Procedural Order Re: Request to Extend Deadline (Oct. 13, 2023).

In advance of the prehearing conference scheduled for November 9, 2023 at 1:00 p.m., the current statement aims to provide the Commission with:
- DOE's preliminary summary of facts and observations based on Northern Utilities, Inc. ("Northern" or "the Company")'s filing; and
- DOE's preliminary analytical framework for understanding the Departments initial assessment of the case.

DOE intends to further review Northern's instant Petition (filed October 6, 2023) and any supplementary filing(s), technical session information, and/or responses to data request(s) either filed into the docket, received in informal discovery, or to be submitted through the formal discovery process in the future. Upon review of all information, consistent with an approved procedural schedule, DOE will make a final recommendation on Northern's petition for Expedited Approval of Empress Capacity Agreements ("Empress Agreements" or the "Agreements").

As explained below, after review and preliminary technical analysis, DOE identifies a list of observations (please see Section 3 below, at pg. 12-13) that the Department intends to explore through the discovery process.

This technical statement is organized as follows:
1. Background
2. Facts as Identified by Northern
    - Salient Features of the Filing
    - The Agreements

- Implications of the TPCL Agreements
- Northern's Experience with TPCL
- Northern's Capacity Portfolio
- Resource Balance: Methodology and Calculation
- Northern's Planning Load and Current and Future Projected Deficiencies
- Resource Evaluation
- Regional Energy Market Backdrop

3. DOE Initial Observations
4. Other Issues
5. Conclusion

1. Background

Northern Petition (filed October 6, 2023) states that the Company has participated in pipeline Open Seasons bidding process conducted by TransCanada Pipelines Limited ("TCPL") and Portland Natural Gas Transmission System ("PNGTS"). *See* Empress Capacity Resource Assessment (the "ECR Assessment"), Exhibit[1] 2, pg. 3. The process led to multiple bilateral agreements between Northern and TCPL (Attachment 4 – the TCPL 2024 Precedent Agreement, Attachment 5 – the TCPL 2024 Firm Transportation Contract, and Attachment 6 – the CONFIDENTIAL TCPL 2027 Precedent Agreement – all of which are in Exhibit Unitil-FXW-2), and PNGTS and Northern (Attachment 2 – the PNGTS 2024 Firm Transportation Contract in Exhibit Unitil-FXW-2) for the Company to have access to firm natural gas pipeline transportation path from Empress, Alberta to Granite State Gas Transmission, Inc. ("Granite") interconnects. *See* ECR Assessment, Exhibit 2, pg. 3.

This new capacity path is expected to add <u>12,500 Dekatherm (Dth)</u> per day of <u>incremental</u> capacity to Northern's New Hampshire and Maine gas supply portfolio with service starting April 1, 2024 for a <u>thirty-year (30) term</u>. Through its petition Northern submits that the access to this incremental capacity will result in "relatively low-cost supply, while reducing Northern's peaking supply requirements." *See* ECR Assessment, Exhibit 2, pg. 3. As such, Northern seeks an expedited Commission pre-approval of the recovery of costs under these agreements on or before January 26, 2024. Of relevance, the Company has also filed a concurrent petition to the Maine Public Utilities Commission (MPUC) for similar pre-approval for the same Empress Agreements.[2]

To-date Northern, DOE, and the Office of the Consumer Advocate ("OCA"), collectively the "Parties", met in an ad-hoc technical session on November 1, 2023 and had a preliminary

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[1] Note- To date no exhibits have been accepted by the Commission in this docket. Northern refers to its filing, and has labeled components as "exhibits" however, and so DOE adopts those labels here.

[2] MPUC Case No. 2023-00254 Northern Utilities, Inc. d/b/a Unitil Inc., Request for Approval of Precedent Agreement Pertaining to Northern Utilities Inc. d/b/a Unitil Inc. (case start date Sept. 29, 2023), available at the following link, Docket No. 2023-00254.

discussion on different aspects of this petition. This technical statement is also informed by that session.

2. Facts Identified by Northern

Based on the initial filing, DOE notes the following facts:

- **Salient Features of the Filing**

  i) ***The Capacity Volume*****:** The proposed Empress Agreements would add *net* 12,500 Dth/day volume of *incremental* capacity to Northern's New Hampshire and Maine gas supply portfolio.

  ii) ***Agreements Timeframe*****:** According to the Company, the proposed Agreements have a 30-year term starting on April 1, 2024 to March 31, 2054, with an option for renewal rights that would allow Northern to control over the "Empress Capacity" path[3] following the initial term of the Agreements. *See* ECR Assessment, Exhibit 2, pg. 51.

  iii) ***Transportation Path*****:** According to Northern, this volume would be transported via multiple pipelines. The gas would travel from Empress, Alberta via TransCanada pipeline to Pittsburg, New Hampshire, the location where PNGTS receives gas onto its system from TCPL. The commodity would then be transported via PNGTS pipelines to – either the interconnection between PNGTS and Maritimes in Westbrook, Maine; or delivery points on the PNGTS system from Westbrook, Maine to Dracut, Massachusetts. This includes the interconnections between PNGTS and the Granite State Gas Transmission, Inc. ("Granite") pipeline. *See* Exhibit Unitil-FXW-1, pg. 4 and the map on pg. 17. Northern accesses PNGTS via the Granite pipeline to service its territories both in New Hampshire and Maine. *See* also Attachment 8 (Northern Capacity Paths). For the purposes of current filing, Northern referred to the full capacity path as "Empress Capacity" that includes the Granite State Gas Transmission, Inc. interconnects. *See* Exhibit Unitil-FXW-1, pg. 2.

- **The Agreements**

  iv) ***The PNGTS Agreement*****:** As explained by the Company, in its Open Season, PNGTS offered approximately 59,000 Dth/Day of additional capacity to be available as soon as November 1, 2023. The minimum bidding requirements included a rate of $0.82/Dth, and a 15-year term for a firm transportation service agreement. Northern successfully bid for 12,500 Dth/Day with the minimum rate ($0.82/Dth), but for a term of 30 years (ending on March 31, 2054). Northern has the option to terminate the Firm Transportation ("FT") Agreement without penalty by February 1, 2024, should the

[3] Please see 2iii) above for Northern's definition of "Empress Capacity" path.

Company not obtain acceptable regulatory approvals from the NHPUC and the MPUC. The PNGTS transportation service rate is a negotiated, fixed rate for the term of the Agreement.[4] The Agreement also allows Northern to have the right of first refusal.

v) ***The TCPL Agreements***: The Company explained that, in its Open Season, TCPL offered up to 59,807 Dth/Day of delivery capacity to be available as early as April 1, 2024. However, the offering was subject to TCPL'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. *See* Exhibit Unitil-FXW-1, pg. 5.

Northern explained that TCPL tolls are regulated by the Canada Energy Regulator ("CER") along with various provincial regulatory agencies (collectively the "Canadian Energy Regulators"). The tolls are rolled into the system rate implying that the expansion capacity customers would pay the average system rate, rather than an incremental project rate. *See* ECR Assessment, Exhibit 2, pg. 52.

Northern states that TCPL asked the bidders to bid with a <u>minimum service term of 15 years</u> from November 1, 2027. Northern successfully bid for 12,890 Dth/Day for <u>a term of 30 years</u> (commencing April 1, 2024 and ending on March 31, 2054).

Overall, the TCPL Agreements are inclusive of two separate agreements:

a. The <u>2024 Precedent Agreement</u> ("PA"), and 2024 Firm Transportation ("FT") Service Contract for service from April 1, 2024 through October 31, 2027 (or later, if facilities required by TransCanada are not yet in service, <u>and</u> TransCanada maintains the commercial and operational arrangements to continue interim service beyond October 31, 2027). *See* Exhibit Unitil-FXW-1, pg. 6; and

b. The <u>2027 Precedent Agreement</u> to service the 30-year contract from November 2027 through March 2054. *See* CONFIDENTIAL Attachment 6 of Exhibit Unitil-FXW-2. The 2027 TCPL Precedent Agreement also 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. *See* Exhibit Unitil-FXW-1, pg. 6.

vi) ***TCPL Conditions Precedent***: As explained by Northern, both 2024 and 2027 TCPL Precedent Agreements contain <u>conditions precedent</u>:

[4] Although the transportation rate is negotiated, it is largely governed by the applicable FERC tariff rate(s) and is also subject to the rate discount provisions of the bilateral Agreement between Northern and PNGTS. Therefore, the rate will remain somewhat variable and responsive to market forces.

a. For the 2024 Precedent Agreement, the conditions precedent include a determination that TCPL has sufficient facilities and/or operational, or other arrangements to provide service under the 2024 TCPL FT Contract, and that the 2027 TCPL PA has not been cancelled. *See* Exhibit Unitil-FXW-1, pg. 6.

b. For the 2027 Precedent Agreement, the conditions precedent include TCPL receiving authorization to increase its capacity in order to provide the service awarded to Northern. It further requires Northern to enter into a FT Contract for service from November 2027 through March 2054 upon TCPL – either satisfying, or waiving its conditions precedent. *See* Exhibit Unitil-FXW-1, pg. 7.

- **Implications of the TCPL Agreements**

vii) ***Violation of the Conditions Precedent*****:** Northern states that Paragraph 13 of the 2027 TCPL PA provides a complete list of events that would construe an event of cancellation. *See* CONFIDENTIAL Attachment 6 of Exhibit Unitil-FXW-2. Essentially, these include the following:

a. TCPL is unable to obtain required authorizations to increase its capacity from the Canadian Energy Regulators prior to May 1, 2027; or

b. Northern is:
   i. unable to obtain approval of the 2027 TCPL PA from NHPUC or MPUC;
   ii. fails to execute the Firm Transportation Service Contract; or
   iii. withdraws its service request

then the 2027 TCPL PA will be deemed cancelled.

viii) ***Cancellation Costs*****:** Northern explains that the violation of the conditions precedent would result in cancellation costs. Paragraph 15 of the 2027 TCPL PA explains the termination or cancellation costs. *See* CONFIDENTIAL Attachment 6 of Exhibit Unitil-FXW-2. [redacted] *See* ECR Assessment, Exhibit 2, pg. 10.

- **Northern's Experience with TCPL**

ix) ***Evidence of Success*****:** In its ECR Assessment, Northern reported several new capacity Open Seasons contractual engagements with TCPL leading to success. *See* ECR Assessment, Exhibit-2, pg. 10. These include: the PNGTS C2C expansion project (of 6,333 GJ) in November 2017; the PNGTS PXP expansion project (of 10,568 GJ) in November 2020; and the PNGTS WXP expansion project (of 10,669 GJ) in November 2022. In light of these successes in recent years, Northern believes that TCPL has experience and capability to gain the requisite approvals and complete the construction of all required facilities, ultimately leading to a very low probability of project cancellation and the triggering of termination charges and cancellation costs.

- **Northern's Capacity Portfolio**

x) ***Portfolio Summary***: Table III-1 of the ECR Assessment presents a summary of Northern's design day portfolio for the 2023-2024 Winter Period. *See* ECR Assessment, Exhibit 2, pg. 31. This is summarized below:

Table 1: Design Day Capacity, 2023-2024 Winter Period[5]

	Dth/Day	%
Pipeline Capacity Paths	30,621	21.4%
Storage Capacity Paths	62,437	43.7%
Peaking Capacity Paths		
LNG – On-System	6,500	4.6%
Granite Capacity	43,286	30.3%
Total Design Day Capacity	142,844	100.0%

xi) ***Flexibility and Reliability***: Northern asserted that the contracts in the long-term portfolio offer the Company long-term control of the capacity either through periodic renewal rights or the right of first refusal. *See* ECR Assessment, Exhibit 2, pg. 31. Conversely, the short-term supply contracts do not provide Northern with control over access to the resource beyond the end date of the contract and as such lack the flexibility in resource planning. The lack of control and flexibility together result in unfavorable impacts on Northern's ability to service its customers in a reliable manner.

- **Resource Balance: Methodology & Calculation**

xii) ***Resource Balance***: Northern calculated their portfolio resource balance 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. *See* ECR Assessment, Exhibit 2, pg. 34. As such, the projected demands under design scenarios and winter conditions beyond this level of capacity requirement are held to be the additional resource requirements.

xiii) ***Customer Types***: Two types of Northern customers are included in its planning load forecasts – the sales service customers (who purchase their natural gas supply from Northern), and the capacity-assigned delivery service customers (who purchase their natural gas supply from a retail marketer). [6] *See* ECR Assessment, Exhibit 2, pg. 34-35.

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[5] For the purpose of ECR Assessment, 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.

[6] Capacity-exempt customers, who are supplied by retail marketers are not included in Northern's planning load. *See* ECR Assessment, Exhibit 2, pg. 35.

xiv) ***Planning Criteria***: Northern's utilizes a 1 in 30-year standard. That is, to ensure reliable supply of gas, in its planning, Northern reports that it seeks to secure sufficient natural gas resources so that the probability that the peak winter daily demand could exceed the maximum daily gas supply resources is less than or equal to 1/30 or 3.33%. The same 3.33% probability is used for its design day, design ten-day cold snap, and design winter planning criteria. *See* ECR Assessment, Exhibit 2, pg. 35-36.

- **<u>Northern's Planning Load and Current & Future Projected Deficiencies</u>**

xv) ***Design Day Planning Load & Deficiency***: Northern provided a forecast of the design day planning load in Table IV-1 of the ECR Assessment. *See* ECR Assessment, Exhibit 2, pg. 36. The design day load is estimated to be 146,989 Dth in the 2024-25 Winter Period, rising to 152,149 Dth in 2027-28. Given Northern reported ongoing deficiency in its resource balance, without the Empress Capacity, the Company estimates that the deficiency will increase from 47,431 Dth in 2024-25 to 52,591 Dth in 2027-28. With the Empress Capacity, the deficiency is reduced from 34,975 Dth in 2024-25 to 40,135 Dth in 2027-28. A summary of these forecasts along with the growth rates in design day planning load are provided below:

Table 2: Design Day Planning Load, 2024-25 to 2027-28 Winter Period

	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
Growth in Design Day Planning Load		1.2%	1.1%	1.1%
Design Day Resource Balance **w/o** Empress Capacity	(47,431)	(49,226)	(50,908)	(52,591)
Empress Capacity	12,500	12,500	12,500	12,500
Estimated Granite Fuel Use	44	44	44	44
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)

xvi) ***Design Year Planning Load & Deficiency***: The Company also provided forecasts for the design year planning load in Table IV-2. *See* ECR Assessment, Exhibit 2, pg. 38. Northern uses PLEXOS energy optimization software to develop the estimates. As reported by the Company, the design year load is estimated to be 17,403,633 Dth in 2024-25 to 18,054,513 Dth in 2027-28. Without the Empress Capacity, the deficiency is estimated to increase from 672,536 Dth in 2024-25 to 824,692 Dth in 2027-28. With the Empress Capacity, the deficiency is reduced to 302,037 Dth in 2024-25 to 389,974 Dth in 2027-28.

These projections along with the estimated growth rates in planning load are provided below:

Table 3: Design Year Planning Load, 2024-25 to 2027-28 Winter Period

	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 Day Planning Load	17,403,633	17,628,179	17,840,851	18,054,513
Growth in Design Day Planning Load		1.3%	1.2%	1.2%
Design Year **Resource Balance w/o** Empress Capacity	(672,536)	(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
Growth w/ Empress Capacity		1.1%	1.0%	1.2%
Impact of Empress Capacity	370,499	402,350	431,412	434,718
Growth due to Empress Capacity		8.6%	7.2%	0.8%
Design Year **Resource Balance w/** Empress Capacity	(302,037)	(339,701)	(380,487)	(389,974)

xvii) ***Overall Deficiency*:** It is important to note that Northern reports having current deficiency in resource balance both with and without Empress Capacity under both design day and design year projections. However, the access to Empress Capacity significantly reduces Northern's reported resource balance deficiency.

- **Resource Evaluation**

xviii) ***Overall Assessment*:** The Company uses both quantitative and qualitative assessment tools to qualify its need for accessing the Empress Capacity. This is summarized in the next two sections.

xix) ***Quantitative Assessment*:** Northern uses two separate tools for its quantitative assessment, both of which, the Company reports, demonstrate cost effectiveness under modelled assumptions.[7] These models are described below:

a. The Landed Cost Analysis – which evaluates the delivered cost of various alternative natural gas supply resources to Northern's system; and

b. The Modelled Cost Analysis – this evaluates the impact of having the Empress Capacity based on the total delivered portfolio cost, the utilization rate of newly acquired capacity, and the impact on utilization rate of other resources). [redacted]

[7] Please see the ECR Assessment, Exhibit 2, pg. 55-57 [CONFIDENTIAL] for the list of assumptions.

[redacted]

xx) ***Qualitative Assessment***: The Company uses several qualitative metrics to evaluate the non-price attributes of the proposed Empress Capacity and, according to Northern, these metrics demonstrate the flexibility and reliability improvements they bring to Northern's capacity portfolio. These qualitative criteria include:

a. Upstream/Downstream issues;
b. Project development risks and deployment timing;
c. Price volatility mitigation;
d. Contributions to flexibility and diversity;
e. Contract renewal rights;
f. Rate/Toll and cost-sharing; and
g. Demand charge mitigation opportunity.

- **Regional Energy Market Backdrop**

xxi) ***Regional Market Overview***: As a backdrop, the ECR Assessment includes a substantive discussion of Northern's view of the New England's regional energy market realities along with the current and future market conditions. In addition to the energy and environmental policy issues, these include: the natural gas demand trends, gas supply issues, and the implications for regional natural gas prices. These are summarized below.

xxii) ***Natural Gas Demand Trends***: Recognizing natural gas as the leading fuel for electric power generation in the New England region, the discussions in the ECR Assessment identify a clear growth in the demand for natural gas over the last 20 years. In particular, the natural gas demand for the region increased from approximately 374 Bcf in Winter 2001-02 to 485 Bcf in Winter 2021-22. *See* ECR Assessment, Exhibit 2, pg. 16. As reported by Northern, this registers a 30% increase over the period, or a compound annual growth rate of 1.3% over the last 20 years. This is summarized in Figure II-1 of the ECR Assessment.

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

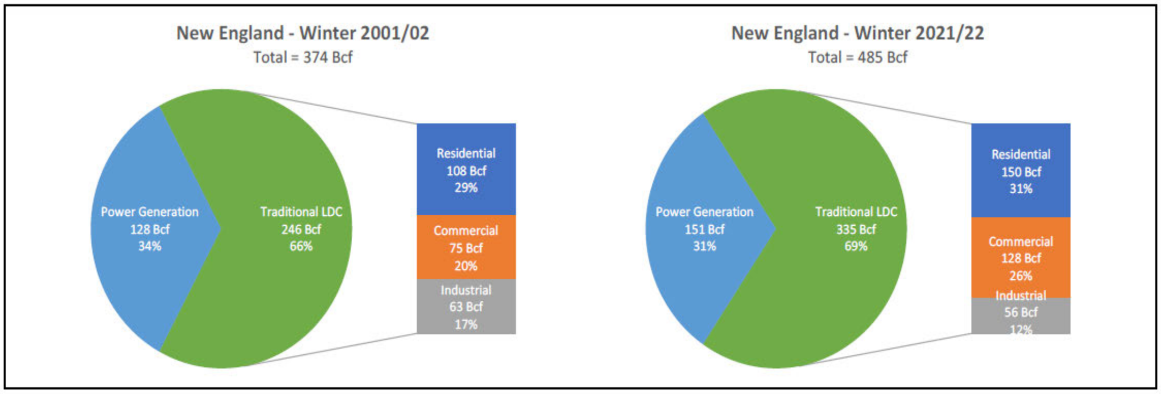


Table 4 and 5 below summarized the sectoral distribution over the same 20-year period.[8]

Table 4: Distribution of Gas Consumption over 2001-02 to 2021-22

	2001-02		2021-22	
	Bcf	Sectoral %	Bcf	Sectoral %
Power Generation	128	34.2%	151	31.1%
Traditional LDCs	246	-	334	-
Residential	108	28.9%	150	30.9%
Commercial	75	20.1%	128	26.4%
Industry	63	16.8%	56	11.5%
Total	374	100.0%	485	100.0%

Table 5: Growth Rate of Gas Consumption over 2001-02 to 2021-22

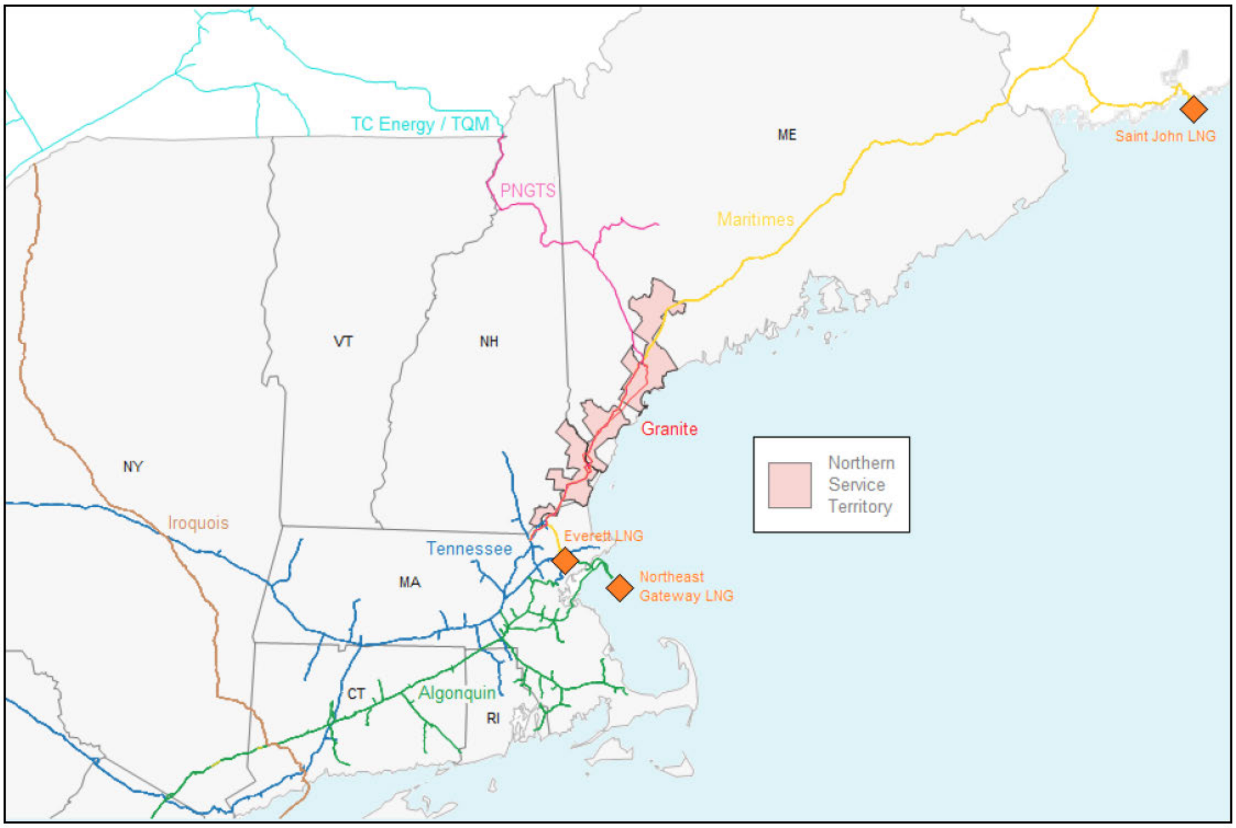
	2001-02	2021-22	Growth Rate over the period	Compound Annual Growth Rate
Power Generation	128	151	18.0%	0.8%
Traditional LDCs	246	334	35.8%	1.5%

As shown in Table 4, the New England region witnessed increased gas consumption both in Power Generation and in Traditional LDC sectors. While the total consumption in Power Generation increased from 128 Bcf in 2001-02 to 151 Bcf in 2021-22, the LDC's consumption increased from 246 Bcf to 334 Bcf over the same time horizon. In terms of the annual compound growth rate, the Power Generation sector grew 0.8% year-over-year as compared to 1.5% for the LDCs over the last 20 years.

[8] Please note, as the figure comes directly from Northern's filing, the reference to footnote 4 in the title could not be removed, yet does not reference an actual footnote.

xxiii) ***Gas Supply Issues*:** Figure II-2 of the ECR Assessment provides a map of the Regional Natural Gas Infrastructure.

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



The New England oversees a limited number of interstate pipelines that serves the region. These pipelines are generally fully subscribed through long-term contractual agreements for firm transportation services. 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. *See* ECR Assessment, Exhibit 2, pg. 22.

xxiv) ***Regional Natural Gas Price Volatility and its Reliability Implications*:** Limited pipeline infrastructure, the pipeline capacity constraints, and less flexibility for shippers (such as LDCs) on the interstate pipeline systems place an upward pressure on the New England natural gas prices relative to the other region. This translates into significantly high price volatility as is captured in Table II-1 of the ECR Assessment. *See* Exhibit 2, pg. 28.

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%

The Company has emphasized that is it pursuing additional resources in the context of significant uncertainty surrounding the long-term future of the Everett Marine and St. John LNG terminals, as asserted by Northern, the access to Empress Capacity would lead to less reliance on imported Liquefied Natural Gas ("LNG"). This would likely lead to stable long-term natural gas prices and overall less price volatility for Northern customers.[9]

3. DOE Initial Observations

In light of the above facts, the Department observes the following:

i) The proposed Empress Agreements would add *net* 12,500 Dth/day volume of *incremental* capacity to Northern's gas supply portfolio for a period of 30-years spanning April 2024 to March 2054.

ii) The Department observes that, for the Empress Capacity Agreements, Northern opted for a longer 30-year term as opposed to the 15-year minimum term bidding requirement put forth by PNGTS and TCPL in their Open Season.

iii) DOE notes that the transportation path for the Empress Capacity Agreements is long relative to the other previous contracts undertaken by Northern.

[9] Please note, as the figure comes directly from Northern's filing, the reference to footnote 24 in the title could not be removed, yet does not reference an actual footnote.

iv) DOE observes that, as reported by Northern, the Empress Capacity Agreements would provide reasonable demand cost mechanisms allowing for rolled-in rate treatment of new facilities, rather than rates based on higher incremental costs. *See* ECR Assessment, Exhibit-2, pg. 53-54.

v) Northern applied the Company's latest design year forecast from 2023-24 gas season to its proposed Empress Capacity of 12,500 Dth/Day. This translated into approximately 5,007 Dth/day (or 40.1%) of the proposed capacity be used for its New Hampshire Division customers and the remaining capacity be used to service customers in Northern's Maine Division. *See* Petition for Approval of Capacity Agreements, pg. 1-2.

vi) The PNGTS Agreements have a "regulatory out" date – i.e., the date prior to which the Company can withdraw from the agreements without a penalty for the PNGTS agreement – of February 1, 2024. As such, the request is to pre-approve the proposed PNGTS and TCPL Agreements by January 26, 2024.

vii) It is, however, unclear if the PNGTS Agreements have any cancellation cost or penalty amount beyond the regulatory out date.

viii) While it is unclear if the TCPL Agreements have a regulatory out date, they have significant cancellation costs [redacted]

ix) Based on Technical Session discussions held on November 1, 2023, DOE understands that the reported TCPL cancellation costs are an estimated total amount for the whole of Northern (i.e., both New Hampshire and Maine customer groups). It is unclear, however, how the cancellation costs are to be apportioned between the two states in the event of any violation of the conditions precedent from the TCPL's Precedent Agreements.

x) Considering Northern's experience with recent contractual engagements with TCPL, the Department recognizes the Company's assertion regarding low probability of project failure and thus low likelihood of triggering the cancellation costs. The probability, however, has not been quantified.

xi) The Department recognizes a sensitivity analysis with likely probabilistic values (of project failure) would increase the presentation of potential benefits that are missing from the current analysis. Such a sensitivity analysis could potentially quantify some of the qualitative analysis and/or assertions presented by Northern's resource evaluation in the ECR Assessment report.

4. Other Issues

The Department wishes to bring to the Commission's attention that the issues presented in the current docket are substantially similar to those of Docket No. DG 19-116, Northern Utilities, Inc. Petition for Approval of Precedent Agreements for Westbrook Xpress Phase III Project. See Order No. 26,309 (November 19, 2019) (Approving Precedent Agreements).

5. Conclusion

The current technical statement highlights Department's preliminary observations. The next step is to run the discovery process following a Commission approved procedural schedule and develop sufficient records into the docket for Commission review and consideration.