REDACTED

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

Supplemental Position Statement of Ashraful Alam, Utility Analyst, &
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Department of Energy, Division of Regulatory Support
December 14, 2023

The New Hampshire Department of Energy ("DOE" or the "Department") submits this supplemental position statement in compliance with the approved procedural schedule. *See* New Hampshire Public Utilities Commission's ("NHPUC" or the "Commission") *Procedural Order Re: Proposed Procedural Schedule* (November 16, 2023).

Please note that this statement should be read in conjunction with DOE's earlier (preliminary) technical statement dated November 3, 2023. While DOE's preliminary technical statement identified facts of the original petition and attempted to summarize the overall contexts, this current position statement furthers that by providing additional facts and observations along with the Department's recommendations for the petition. As such, in advance of the hearing scheduled for January 18, 2024, this position statement is based upon review of all information submitted into the docket to-date (including discovery incorporated in attachments to this statement). This statement aims to provide the Commission with:

- DOE's summary of facts and observations based on Northern Utilities, Inc. ("Northern" or "the Company")'s filing to-date; and

- DOE's recommendations.

Upon review of all information submitted into the docket to-date, DOE makes additional observations and provides its recommendations.

In summary, the Department supports Northern's request for Approval of "Empress Capacity Agreements"[1], which includes a pre-approval of pre-service and (potential) cancellations costs, subject to certain conditions described below. *See* Petition for Expedited Approval of Empress Capacity Agreements ("Empress Agreements" or the "Agreements").

[1] As defined in Northern's petition, the "Empress Capacity Agreements" include certain agreements with Portland Natural Gas Transmission System ("PNGTS") and TransCanada Pipelines Limited ("TCPL") (the agreements are collectively referred to herein as the "Empress Capacity Agreements"). *See* Petition dated October 6, 2023.

The remainder of this position statement is organized as follows:

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1. Background

Northern's 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* Petition (Oct 6, 2023), Confidential Unitil FXW-2 at 3 (Empress Capacity Resource Assessment, hereinafter "ECR Assessment").

The process led to multiple bilateral agreements between Northern and TCPL and PNGTS and Northern. *See* Petition Unitil FXW-2, Attachment 4 – the TCPL 2024 Precedent Agreement, Attachment 5 – the TCPL 2024 Firm Transportation Contract, Attachment 6 – the CONFIDENTIAL TCPL 2027 Precedent Agreement, and Attachment 2 – the PNGTS 2024 Firm Transportation Contract. These agreements are designed to provide the Company with access to firm natural gas pipeline transportation paths from Empress, Alberta to Granite State Gas Transmission, Inc. ("Granite") interconnects. *See* ECR Assessment, p. 3. This new capacity path is expected to add

12,500 Dekatherm (Dth) per day of incremental capacity to Northern's New Hampshire and Maine gas supply portfolio.

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, p. 3. As such, Northern seeks an expedited Commission pre-approval of the pre-service and (potential) cancellation costs under these agreements on or before January 26, 2024.

The Company has also filed a concurrent petition with the Maine Public Utilities Commission (MPUC) seeking similar pre-approval for the same Empress Agreements[2] and has requested an expedited order from the MPUC by January 26, 2024.

2. Activities to-date

Given the expedited nature of the petition, Northern, DOE, and the Office of the Consumer Advocate ("OCA"), collectively the "Parties", met multiple times. The Parties first met for an ad-hoc technical session on November 1, 2023, followed by two additional technical sessions dated November 9 and 28, 2023. DOE has filed two sets of data requests.

The current supplemental position statement is informed by discussions held during these sessions along with the filings and responses to Data Request (DR)s exchanged among the Parties to-date. DOE has provided Northern's responses to some of DOE's Data Request (DR) Set 1 as Attachment A and some of Northern's Responses to DOE Technical Session (TS) DR Set 1 as Attachment B. The DOE has also provided Northern's Response to data request in the MPUC docket as a separate Attachment C and the email from PNGTS re FERC approving certification as Attachment D for ease of reference, although these responses were provided by Northern in response to DOE DR 1-2. Where supportive of the analysis, specific responses within each Attachment are cited. In addition, a number of responses have simply been provided to support the expedited nature of this docket.

3. Features of the Empress Capacity Filing by Northern

Based on the filing and DRs to-date, DOE notes the following:

3.1 Capacity Volume

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

[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.

3.2 Capacity Distribution between NH and ME

Applying the Company's latest design year forecast for the 2023-24 gas year, approximately 5,007 Dth/day (i.e., 40.1%) of the proposed capacity will be supported by New Hampshire Division customers and 7,493 Dth/day (i.e., 59.9%) will be supported by Maine Division customers[3]. Northern would support the use of the Modified Proportional Responsibility Allocator to allocate contract costs at issue in this docket between New Hampshire and Maine. *See* DOE Attachment A, DOE 1-11.

3.3 Agreement Timeframe

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 control over the "Empress Capacity" path[4] following the initial term of the Agreements. *See* ECR Assessment, p. 51.

3.4 Transportation Path

Northern explains that the incremental capacity volume of 12,500 Dth/day 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* Petition Attachment Unitil-FXW-1, p. 4 and the ECR Assessment, p. 17 ("map").

Northern currently accesses PNGTS via the Granite pipeline to service its territories both in New Hampshire and Maine. *See* Petition 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* Petition Attachment Unitil-FXW-1, p. 2.

3.5 Company's Assessment of Supply Needs

i) ***Design Day Planning Load & Deficiency***: Northern provided an estimate of its design day planning load in Table IV-1 of the ECR Assessment. *See* ECR Assessment, p. 36. The design day load is estimated to be 146,989 Dth in the 2024-25 Winter Period, increasing to 152,149 Dth in 2027-28. Given that Northern reported ongoing deficiency in its resource balance,

[3] The Modified Proportional Responsibility Allocator, which is used to allocate demand costs, is based on the Design Year utilization as estimated by Northern.
[4] Please see the Section 3.4 'Transportation Path' for Northern's definition of "Empress Capacity" path.

without the Empress Capacity, the Company estimates that the deficiency will increase overall, from 47,431 Dth in 2024-25 to 52,591 Dth in 2027-28. With the Empress Capacity, the Company estimates that the deficiency will *decrease* from 47,431 Dth to 34,975 Dth in 2024-25, and from 52,591 Dth 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 1: 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)

ii) ***Design Year Planning Load & Deficiency***: Northern also provided forecasts for the design year planning load in Table IV-2. *See* ECR Assessment, p. 38. Northern used PLEXOS energy optimization software to develop the estimates. As reported by the Company, the design year load is estimated to increase from 17,403,633 Dth in 2024-25 to 18,054,513 Dth in 2027-28. Without the Empress Capacity, Northern estimates deficiency will increase from 672,536 Dth in 2024-25 to 824,692 Dth in 2027-28. With the Empress Capacity, the deficiency is *reduced* from 672,536 Dth to 302,037 Dth in 2024-25, and from 824,692 Dth to 389,974 Dth in 2027-28. These projections along with the estimated growth rates in planning load are provided below:

Table 2: 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

	2024-2025	2025-2026	2026-2027	2027-2028
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)

iii) ***Overall Deficiency*:** The DOE gives significant weight to Northern's report of a current deficiency in resource balance both *with and without* Empress Capacity under both the design day and the design year projection scenarios. The access to Empress Capacity significantly *reduces* Northern's reported current resource balance deficiency projections.

iv) **Qualitative Assessment:** Northen uses several qualitative metrics to assess the non-price features of the proposed Empress Capacity Agreements. The Company asserts that the proposed agreements demonstrate flexibility and reliability improvements to Northern's capacity portfolio by addressing upstream and downstream issues, project development and deployment risks and providing control over contract renewal rights. The Company claims that the Empress Agreements will also help to mitigate demand charges and price volatility and improve rate and cost sharing processes. In Northern's view the Empress Agreements will provide [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION] diversity to Northern's supply portfolio. *See* ECR Assessment, pp. 43-54.

4. The Empress Agreements

Based on the filing to-date, DOE notes the following features of the Empress Agreements:

4.1 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 PNGTS Firm Transportation ("FT") Agreement without penalty by February 1, 2024, should the Company not obtain regulatory approvals from the NHPUC and the MPUC in a form and substance acceptable to the Company. *See* DOE Attachment A, DOE 1-19 Supp. The PNGTS transportation service rate is a negotiated, fixed rate for the term of the Agreement[5]. The Agreement also allows Northern to have the right of first refusal. The FT Agreement does not mention anything regarding the cancellation costs.

[5] 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,

DOE observes that PNGTS capacity requires approval only from the Federal Energy Regulatory Commission (FERC) to increase their certificated capacity by 59,100 Dth. The physical facilities PNGTS needs to provide the level of service, which PNGTS awarded through its Open Season bidding process, appears to be already in place. *See* DOE Attachment A, DOE 1-08. The Department notes that, based on the information received from Northern, it appears that PNGTS received the requisite FERC approval. *See* DOE Attachment D and FERC Docket No. CP23-548-000.

4.2 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* Petition Attachment Unitil-FXW-1, p. 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, p. 52.

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

Overall, the TCPL Agreements are inclusive of two separate sets of agreements, each having a Precedent Agreement and a Firm Transportation Service Contract:

a. The 2024 Precedent Agreement ("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, and TransCanada maintains the commercial and operational arrangements to continue interim service beyond October 31, 2027). *See* Petition Attachment Unitil-FXW-1, p. 6. This set of agreements stipulate Northern and TCPL's contractual obligations for transportation services until 2027; and

b. The 2027 Precedent Agreement to service the 30-year contract from November 2027 through March 2054. *See* Petition, Attachment 6 CONFIDENTIAL. 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* Unitil-FXW-1, p. 6.

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the rate will remain somewhat variable and responsive to market forces. *See* Petition Attachment 2 (PNGTS FT Contract), p. 1

4.3 TCPL Conditions Precedent

Both the 2024 and 2027 TCPL Precedent Agreements contain conditions precedent:

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* Unitil-FXW-1, p. 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* Unitil-FXW-1, p. 7. The 2027 PA also contains a *Sunset Date* of May 1, 2027. *See* Petition Attachment 6 (TCPL 2027 PA), Section 13 (h), p. 12 of 29 and DOE Attachment B, Northern Response to DOE TS 1-02.

4.4 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* Petition Unitil-FXW-2 CONFIDENTIAL Attachment 6 (TCPL 2027 PA). 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;

b. PNGTS is unable to obtain FERC certification (this condition appears to have been met. *See* Attachment D, DOE TS 1-03);

c. Northern:
    i) is unable to obtain approval of the 2027 TCPL PA from NHPUC or MPUC in a form and substance acceptable to the Company;
    ii) fails to execute the Firm Transportation (FT) Service Contract; or
    iii) withdraws its service request prior to May 1, 2027;

    then the 2027 TCPL PA will be deemed cancelled.

As identified above and in conjunction with 4.3(b), it appears that, with FT Service Contract put in place, beyond the *Sunset Date* of May 1, 2027, all 2027 TCPL PA conditions precedent would be construed satisfied, and consequently, the cancellation costs provisions of the 2027 TCPL PA would be deemed moot.

4.5 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* Petition Unitil FXW-2, CONFIDENTIAL Attachment 6 (TCPL 2027 PA). [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]

5. DOE Observations

Based on the filing, and responses from all DRs to-date, DOE notes the following:

5.1 Capacity Addition

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. Using its latest design year forecast from 2023-24 gas season, Northern estimates that approximately 40.1% (i.e., 5,007 Dth/day) of this incremental capacity be utilized to serve customers in its New Hampshire Division. *See* Petition, pp. 1-2.

In the context of regional gas market with limited supply options, and given Northern's current supply needs, and the Company's obligation to reliably serve its customers, the Department views Northern's proposal regarding the Empress Capacity Agreements, i.e., pre-approval of the contracts proposed in this case, which provide for potential payment of pre-service and cancelation costs, as reasonable.

5.2 Capacity Paths

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

5.3 Length of Empress Capacity Agreements

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. Northern chose to structure its bid with a 30-year term in order to increase the likelihood that it would be successful in the open season. The Company submits that, in inviting bids through its Open Season, TCPL's criteria for determining winning bidders incorporated: 1) the term of each bid; and 2) the current toll for the requested path[6]. Bids were then ranked based on the product of 1) and 2). The implication of this process is that TCPL's open season process favored bids with longer terms. *See* DOE Attachment C, Response to MPUC, 2023-00254 EXM Set 1 Responses EXM-01-008. As such, according to the Company, bidding a shorter term with renewal rights would have increased the likelihood that Northern would not be awarded any capacity through the Open Season process. *See* DOE Attachment C, Response to MPUC, 2023-00254 EXM Set 1 Responses EXM-001-017. [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION]

5.4 <u>Demand Cost Mechanism</u>

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, pp. 53-54.

5.5 <u>Cancelation Costs vis-à-vis the Agreements</u>

DOE observes that 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. Hence, the petition requests a pre-approval of the proposed PNGTS and TCPL Agreements by January 26, 2024. The provision of "regulatory out" date implies that Northern can cancel the PNGTS Agreement without incurring any cancellation costs emanating from that specific agreement. *See* DOE Attachment A, DOE 1-06. Such a cancellation, however, will trigger an event of cancellation within the context of the TCPL Precedent Agreements[7].

Conversely, the TCPL Agreements[8] do not have a "regulatory out" date per se. *See* DOE Attachment A, DOE 1-05. As such, Northern has the right to terminate the Precedent Agreement provided that the Company pays the cancellation costs or the estimated liability limit. *See* DOE Attachment A, DOE 1-10; DOE 1-10 Attachment 1. [BEGIN CONFIDENTIAL INFORMATION] [redacted]

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[6] The price that Northern pays will ultimately be determined by the CER-approved tolls that will be in effect at the time of service. They will not be based on the tolls in effect at the time of the bids that were used solely for the purpose of evaluating bids. *See* Attachment C, Response to MPUC, 2023-00254 EXM Set 1 Responses, EXM-01-008
[7] Please refer to Section 4.3 and 4.4 above.
[8] TCPL Agreements include three separate agreements – the 2024 TCPL Precedent Agreement (PA), the Firm Transportation (FT) Service Contract over 2024-2027 period, and the 2027 TCPL PA. The FT Service Contract covering the period 2027-2054 is not yet in place.

[redacted] [END CONFIDENTIAL INFORMATION].

The Department further observes that the 2027 TCPL PA has a *Sunset Date* of May 1, 2027. *See* CONFIDENTIAL Attachment 6 of Unitil-FXW-2. In light of this and based on the information provided by Northern to-date, it appears that beyond May 1, 2027, and/or once the TCPL facilities intended to serve Northern (and other shippers) over 2027-2054 timeframe are put in place the cancellation costs provisions of the 2027 TCPL PA would be deemed moot. Consequently, if no event of cancellation occurs by May 1, 2027, Northern will not have to pay any termination fees beyond that date to cease purchase and transportation of any gas through TCPL pipelines.

5.6 <u>Proposed Distribution of Cancellation Costs</u>

Northern states that the reported TCPL cancellation costs are an estimated total amount for the whole Company (i.e., inclusive of customer groups both in its New Hampshire and Maine Divisions). As such, in the event of project cancellation, Northern proposes the costs be allocated between New Hampshire and Maine Divisions using the Modified Proportional Responsibility Allocator ("MPRA") in effect at the time of the cancellation event, as is done with the Company's other fixed costs. *See* Attachment A, Northern Response to DOE 1-09, DOE 1-11, and Attachment B, Northern Response to DOE TS 1-07.

In the event of a cancellation, the Department supports Northern's proposal to use the MPRA to allocate appropriate share of cancellation costs assuming that the Company is successful in obtaining approval of its concurrent petitions by both the NHPUC and the MPUC.

5.7 <u>Likelihood of Cancellation</u>

DOE notes, Northern highlights the fact that TCPL has extensive experience with pipeline project approval processes. Northern submits that, of all proposed projects between 2012 and 2022[9], TCPL and its affiliate pipelines have cancelled only 2 out of 189 projects. This renders a failure rate of 1.06% or an overall probability of success for the TCPL portion of the contract as 98.94%. Northern further submits that no projects have been cancelled by TCPL or its affiliates since 2014. *See* DOE Attachment A, DOE 1-08 CONFIDENTIAL and DOE 1-22.

The Department also observes Northern's historical engagement with different precedent agreements. In February 2015, Northern entered into a precedent agreement with TransCanada for service on the Vaughan project and no cancellation costs were incurred in this agreement. In January 2019, Northern entered into precedent agreements with both

[9] In its response to DR, Northern notes that seven of the TCPL projects were not placed into service because the customer requesting service withdrew their request for service or there was a delay on the customer's end. TransCanada and/or its affiliates were able to gain their approvals in these cases. There were three projects that have been proposed in 2023 by the NGTL system, but those approvals processes have not been completed. For that reason, these projects were not included in the table. *See* Attachment A, DOE 1-08.

TransCanada and Enbridge to fill Northern's PNGTS WXP capacity. The Company was exposed to cancellation costs under each of these agreements. These precedent agreements were filed with the Commission under Docket No. DG 19-116. As with the 2027 TCPL PA, the TransCanada precedent agreement in the WXP capacity expansion allowed Northern the option to terminate the precedent agreement, subject to cancellation costs. However, for the Enbridge precedent agreement, Northern was exposed to possible cancellation costs, but only had the ability to terminate if it was unable to meet certain conditions precedent, such as state regulatory approvals. No cancellation costs were incurred under the January 2019 precedent agreements. *See* DOE Attachment A, DOE 1-14 and ECR Assessment, p. 10. These demonstrate a history of successful contractual engagements between Northern and TCPL (i.e., TransCanada) without having to resort to invocation of any cancellation costs.

As such, consistent with the analysis used by Northern for calculating the success rate, the Department observes that the likelihood of cancellation of current Empress Capacity Agreements would be low.

5.8 Cost Recovery Mechanism

Since Northern did not incur cancellation costs, the Department notes that the Company has not previously sought recovery of such costs. In Docket No. DG 19-116 the parties to that proceeding filed a settlement, which stated that "pre-service and cancellation costs associated with the Precedent Agreements accrued as of the date of this Order and for which the Company is liable, are reasonable and appropriately recoverable through the Northern's rates" and pertaining to pre-service costs that may have accrued after the date of the Order that "to the extent that the Company is found to have acted reasonably and prudently in incurring costs associated with the Precedent Agreements, such costs will be recoverable through Northern's rates." These settlement provisions were accepted by the Commission. *See* Order No. 26,309. However, the mechanism that such costs would be recovered was not identified in that docket. *See* DOE Attachment A, DOE 1-14.

5.9 Other Risks

The Department observes that, under the 2027 TCPL PA, Northern has the right to trigger an event of cancellation earlier than May 1, 2027. DOE further notes that the Company has not developed a formalized decision-making process for assessing termination of its participation in the projects [BEGIN CONFIDENTIAL INFORMATION] [redacted] [END CONFIDENTIAL INFORMATION] *See* DOE Attachment A, DOE 1-13 Attachment 1 CONFIDENTIAL.

6. Recommendations

In light of the current review of Northern's filing, the observations made by the Department, and the foregoing discussion, DOE believe the proposed pre-approval of the Empress Capacity Agreements is reasonable and in the public interest. As such the Department recommends approving the petition subject to the following conditions, which may continue to be modified or expanded in what DOE anticipates will be settlement discussions with the Company, and are similar to conditions agreed upon in Docket No. DG 19-116:

- In the event of cancellation, the recovery of costs associated with the Precedent Agreements, other than pre-service and cancellation costs, should be addressed through the Company's annual Cost of Gas filings.

- Northern should monitor and evaluate the prudency of continuing with or terminating any or all of the Precedent Agreements at certain decision points outlined in the Company's response to DOE 1-13 CONFIDENTIAL, or in light of any new information or change in circumstances which becomes known. The prudency of the Company's decisions to continue with or terminate any of the Precedent Agreements should be evaluated in light of existing circumstances known to the Company at each decision point. *See* DOE Attachment A, DOE 1-13 Attachment 1 CONFIDENTIAL. To the extent that the Company is found to have acted reasonably and prudently in incurring costs associated with the Precedent Agreements, such costs should be recoverable through the Company's rates.

- Provided that Northern is successful in obtaining approval of its petitions by both the NHPUC and the MPUC, and if an event of cancellation occurs, the Company should use the Modified Proportional Responsibility Allocator (MRPA) to allocate the appropriate share of the cancellation costs and be allowed to recover the costs through its rates so long as the Company is found to have acted reasonably and prudently in incurring such costs associated with the Precedent Agreements.

- Decision points should include, but are not limited to, unfavorable regulatory decisions, a material increase in actual or projected project costs, and material changes in cost allocation due to decisions or actions of the transporter and/or other shippers. The Company must inform the Commission of regulatory approvals related to the projects and/or material changes in actual and projected costs Northern would be responsible for under the terms of the Precedent Agreements.

- Northern should not waive the conditions precedent under the Empress Capacity Agreements that allow Northern to terminate said TCPL Precedent Agreements prior to May 1, 2027 without liability to the Company unless the Company receives approval of the Precedent Agreements in a form acceptable to the Company of its respective petitions from the Commission (and also from the Maine Public Utilities Commission, if applicable).

The DOE provides the following information for the Commission's review.

CONFIDENTIAL and REDACTED versions of these attachments have been filed. In a few cases, Northern has not provided redacted versions and DOE will defer to Northern to provide redacted versions or to identify the information as inextricably intertwined/not capable of redaction.

Attachment A: Northern's Response to DOE Set 1 (in numerical order)

DG 23-087 DOE 1-05
DG 23-087 DOE 1-06
DG 23-087 DOE 1-07 CONFIDENTIAL
DG 23-087 DOE 1-08 CONFIDENTIAL.
DG 23-087 DOE 1-09
DG 23-087 DOE 1-10
DOE 1-10 Attachment 1 CONFIDENTIAL (replaces Attachment 7 in Northern's initial filing)
DG 23-087 DOE 1-11
DG 23-087 DOE 1-12
DG 23-087 DOE 1-13 CONFIDENTIAL
DG 23-087 DOE 1-13 Attachment 1 CONFIDENTIAL
DG 23-087 DOE 1-14
DG 23-087 DOE 1-15
DG 23-087 DOE 1-16
DG 23-087 DOE 1-17
DG 23-087 DOE 1-18
DG 23-087 DOE 1-19
DG 23-087 DOE 1-19 Supplemental Answer provided 12.12.23
DG 23-087 DOE 1-20
DG 23-087 DOE 1-20 Attachment 1
DG 23-087 DOE 1-24 CONFIDENTIAL
DG 23-087 DOE 1-26

Attachment B: Northern's Responses to DOE Set TS 1

DG 23-087 DOE TS 1-01
DG 23-087 DOE TS 1-03
DG 23-087 DOE TS 1-04
DG 23-087 DOE TS 1-05
DG 23-087 DOE TS 1-06 w/ original CONFIDENTIAL Attachment? **and** DG 23-087 DOE TS 1-06 – SUPPLEMENTAL AND REVISED DG 23-087 DOE TS 1-06 Attachment 1 CONFIDENTIAL
DG 23-087 DOE TS 1-07
DG 23-087 DOE TS 1-08

Attachment C: Northerns Data Responses in Maine PUC Docket

List by File name from Maine Public Utilities Commission (Northern's data response in that docket)

2023-00254 CLF Set 1 Responses
2023-00254 EXM Set 1 Responses
2023-00254 ODR Responses 11.22.23
2023-00254 OPA Set 2 Response
CLF-001-001 Attachment 1
CLF-001-005 Attachment 1
CLF-001-006 Attachment 1 (CONFIDENTIAL)
CLF-001-006 CONFIDENTIAL
CLF-001-007 Attachment 1 (CONFIDENTIAL)
DG 23-087 DOE 1-02 Supplemental 11.28.23
EXM-001-001 Confidential Attachment 1
EXM-001-005 Confidential Attachment 1
EXM-001-010 Attachment 1 CONFIDENTIAL
EXM-001-024 Attachment 2
ODR-001-001 Attachment 1
ODR-001-004 Attachment 1
ODR-001-004 Attachment 2
OPA-001-001 Attachment 1
OPA-001-001 Attachment 2
OPA-001-001 Attachment 3
OPA-001-009 Attachment 1 CONFIDENTIAL
OPA-001-013 - Confidential Attachment 1
OPA-001-015 - Confidential Attachment 1

Attachment D:

Letter dated December 14, 2023 from David A. Alonzo, Manager, Project Authorizations - PNGTS.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-05 **Witness:** Francis X. Wells

Request:

Please identify the "regulatory out" date for the TCPL Agreement(s), if any.

Response:

The TCPL Agreements do not have a "regulatory out" date. Northern does have the right to terminate the Precedent Agreement, but exercising that right may require Northern to pay cancellation costs.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-06 **Witness:** Francis X. Wells

Request:

Do the PNGTS Agreements have any cancellation cost(s) or the equivalent (before and/or after the regulatory out date of February 1, 2023)? If yes, please identify. If not, why not?

Response:

If Northern cancels the PNGTS Agreement because regulatory approvals have not been received by February 1, 2024, there are no cancellation costs.

If Northern receives approvals by February 1, 2024, there is no right to terminate the agreement, therefore there are no cancellation costs.

REDACTED

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23
Request No. DOE 1-07

Date of Response: 11/17/2023
Witness: Francis X. Wells

Request:

Reference: Pre-filed Testimony of Francis X. Wells, Exhibit Unitil-FXW-1, pg. 8

a) Please provide supporting analysis for the statement "Northern assesses the probability that TCPL would cancel the project and trigger termination costs to Northern as quite low," Including but not limited to a numeric range for "quite low."
b) Please identify salient components potentially contributing to the "probability of project cancellation" and possible remedies. Also, please identify responsibilities of transporter and/or shippers for each component.
c) Does the project plan include risk minimization measures? Please provide details.
d) Please confirm that there are six shippers in total and identify them. Is the project cancellation risk (for TCPL and PNGTS) heavily based on other shippers getting regulatory approvals and permits? If so, is this increasing the associated project cancellation risk for Northern?

Confidential Response:

a. Northern's response to DOE 1-08 provides the requested data.

b. The salient components contributing to the probability of project cancellation include the following:

1. Potential loss of downstream PNGTS capacity due to failure of PNGTS to obtain FERC Certificate. If PNGTS were to fail to obtain its FERC Certificate, then neither Northern nor the other shippers would be able to meet the TCPL Tariff requirement that the shipper obtain all necessary downstream capacity and the project would be cancelled. This filing was made on September 26, 2023 under FERC Docket No. CP23-548. PNGTS expects a decision by November 28, 2023.
2. Potential failure of TCPL to obtain all necessary approvals to construct any of the facilities listed in Northern's response to Maine Data Request OPA-001-009. TransCanada's has extensive experience with pipeline project approval processes, which mitigates this risk. Please refer to Northern's response to DOE 1-8. One new risk factor is that TransCanada must seek approval from the Quebec government for the power supply it requires for the added compression contemplated by the project, which was not a requirement during TransCanada's last capacity expansion to East Hereford. [redacted]

REDACTED

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-07 **Witness:** Francis X. Wells

3. Upon receiving these approvals, potential failure of TCPL to construct these facilities. TransCanada has extensive experience with pipeline construction, as its organization has built and placed many projects into service, which mitigates this risk. Please refer to Northern's response to DOE 1-8.

c. Please refer to Northern's response to part b. of this request. TCPL also has a duty to use commercially reasonable efforts to minimize costs. (See Maine Data Request EXM-001-009.)

d. There are three shippers in total. They are Emera Energy Services, Inc. ("Emera"), New England Green Gas LLC ("NEGG"), and Northern. This information was publicly disclosed in PNGTS' FERC approval filing. TCPL does not typically disclose shipper identities until commencement of firm transportation service agreements, but it is known that Emera and NEGG are also the TCPL shippers because PNGTS' tariff requires that shippers obtain upstream capacity[1]. Because the other two shippers are not regulated utilities, like Northern, they are not required to seek regulatory approval or permits and there is no project cancelation risk attributable to their ability to do so.

[1] TCPL's tariff also requires that shippers have corresponding downstream capacity on PNGTS.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-08 **Witness:** Francis X. Wells

Request:

Did Northern, transporters, or any other party perform a risk analysis (es) regarding the potential cancellation of the Project (inclusive of TCPL and PNGTS or for either TCPL or PNGTS individually? If not, why not? If yes, please provide the details of the analysis.

Response:

Northern is not aware of risk analyses performed by other parties. In response to this data request, Northern has performed the following analysis.

As discussed in the Empress Capacity Resource Assessment, PNGTS capacity requires only approval from the FERC to increase their certificated capacity by 59,100 Dth. The physical facilities PNGTS needs to provide the service requests that were awarded through the PNGTS Open Season are already in service. Therefore, Northern believes that FERC will approve PNGTS' request.

TransCanada provided Northern the following data relative to pipeline expansion projects that it has proposed from 2012 through 2023 across its affiliate pipelines operating in Canada.

	No. of Applications				
Year	NGTL	Foothills	TCPL	TQM	Total
2012	6	1	2	0	9
2013	16	0	0	0	16
2014	19	0	2	2	23
2015	22	1	5	0	28
2016	6	0	5	0	11
2017	30	0	5	1	36
2018	21	0	1	0	22
2019	16	0	6	2	24
2020	5	2	2	0	9
2021	7	1	0	0	8
2022	2	0	1	0	3
Total	150	5	29	5	189
Projects Cancelled By Pipeline	1	0	1	0	2
Percent Projects Cancelled	0.67%	0.00%	3.45%	0.00%	1.06%

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-08 **Witness:** Francis X. Wells

Based on this data, TransCanada and its affiliate pipelines have cancelled only 2 out of 189 projects (1.06%) that have been proposed from 2012 through 2022[1]. No projects have been cancelled by TransCanada or its affiliates since 2014. Therefore, 1.06% is a reasonable estimate of the probability that TransCanada would cancel its Precedent Agreement with Northern due either to its inability to gain approvals or inability to create the new capacity it requires to fulfill Northern's requested service for 13,600 GJ of firm transportation service, which would trigger cancellation costs.

TCPL expects decisions from the CER by the end of Q4 2025 and, at that time, the Estimated Liability Limit ("ELL") would be [redacted] USD. Assuming that Northern is able to obtain approvals from the NH PUC and the ME PUC, the Company believes it is unlikely that TCPL would cancel the project before the CER would issue its decisions on its proposed facilities, so that would be a reasonable lower limit of the cancellation cost risk. The upper limit of the ELL for the 2027 TCPL PA is [redacted] USD in Q4 2027. Assuming for the sake of analysis that the timing of cancellation by TransCanada would be random, the average between the lower and upper limits of the TransCanada cancellation risk of [redacted] would be the expected risk amount.

Using the assumed probability of project cancellation by TransCanada equal to 1.06% and the expected risk amount equal to [redacted], the expected value of the project cancellation by TransCanada would be equal to $219,054.

Relative to the expected benefits provided in the Modelled Cost Analysis (Attachment 9) and the estimated Asset Management Revenue provided in response to Maine Data Request CLF-001-006, the expected value of project cancellation by TransCanada is reasonable.

In addition to the reasonable balance between benefits and risk in the 2027 TCPL PA, Northern's response to EXM-001-009 provides an overview of tools that Northern has to mitigate cancellation cost risk, which include audit rights and TCPL's duty to minimize costs.

[1] Seven of the projects were not placed into service because the customer requesting service withdrew their request for service or there was a delay on the customer's end. TransCanada and/or its affiliates were able to gain their approvals in these cases. There were three projects that have been proposed in 2023 by the NGTL system, but those approvals processes have not been completed. For that reason, these projects were not included in the table.

Northern Utilities, Inc.
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Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-08 **Witness:** Francis X. Wells

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-09 **Witness:** Francis X. Wells

Request:

Reference: Pre-filed Testimony of Francis X. Wells, Exhibit Unitil-FXW-1, pg. 5
Northern states that "[it] has the option to terminate the Firm Transportation Agreement without penalty if it does not obtain acceptable regulatory approvals from the New Hampshire Public Utilities Commission and the Maine Public Utilities Commission. Northern must exercise this option by February 1, 2024."

a) What would be the penalty/cancellation charges after the regulatory approval is obtained? Does Northern have any estimates on the size/extent of these costs? (Assuming that risk of cancellation depends on project approval and other permits.)
b) How does the Company expect the cancellation costs to be apportioned between Northern's two divisions (New Hampshire and Maine) in the event of project cancellation?
c) How many shippers are involved in this capacity agreements and for what quantify of gas? Did the transporter provide any information on that?

Response:

a) Northern does not have a right to terminate other than a regulatory out. There is no right to terminate after the regulatory out date of February 1, 2024 if regulatory approvals have been obtained.
b) In the event of a project cancellation, Northern will use the modified proportional responsibility allocator to apportion cancellation costs between Northern's Maine and New Hampshire Divisions as is done with other fixed costs.
c) There are three shippers in total in this project. The total quantity of gas capacity is 59,000 Dth. PNGTS has filed its application to certificate its capacity in FERC Docket CP23-548. The table below is an excerpt from that filing and provides the requested information.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23
Request No. DOE 1-09

Date of Response: 11/17/2023
Witness: Francis X. Wells

Table 1: Contracted Capacity Resulting from Open Seasons

Shipper	Path	Contract Amount Mcf/d (Volumetric)*	Contract Amount Dth/d (Thermal)
Northern Utilities, Inc.	Pittsburg, New Hampshire to Dracut, Massachusetts	12,363 Mcf/d	12,500 Dth/d
Emera Energy Services, Inc.	Pittsburg, New Hampshire to Dracut, Massachusetts	4,945 Mcf/d	5,000 Dth/d
New England Green Gas LLC	Pittsburg, New Hampshire to Dracut, Massachusetts	41,048 Mcf/d	41,500 Dth/d
Total Contracted		58,356 Mcf/d	59,000 Dth/d

*1.011 conversion factor. Volumes differ from certificated amount due to rounding.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-10 **Witness:** Francis X. Wells

Request:

In case of project cancellation, does the transporter assume any liability for costs due to cancellation?

a) Please identify scenarios where the transporter assumes all, or partial costs, if any.
b) In the case of the transporter assuming partial costs, please explain how the proportion between transporter and shippers will be determined.

Response:

TransCanada does not assume any liability upon project cancelation up to the Estimated Liability Limit in effect for the quarter that the project was cancelled. These quarterly amounts can be found in the Estimated Exposure Profile, provided as CONFIDENTIAL DOE 1-10 Attachment 1, which replaces CONFIDENTIAL Attachment 7 to the Empress Capacity Resource Assessment. TransCanada has the right to update both the overall Estimated Liability Limit set in the 2027 TCPL PA (CONFIDENTIAL Attachment 6) and the quarterly Estimated Liability Limits set in the Estimated Exposure Profile should TransCanada's updated estimate of the liability increase by 20%. In this case, TransCanada could require Northern to amend the 2027 TCPL PA to update the Estimated Liability Limit with the updated data.

DOE 1-10 Attachment 1 has been marked entirely confidential by Northern. Accordingly there is no redacted version for Bates page 0000026

Northern Utilities, Inc.
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Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-11 **Witness:** Francis X. Wells

Request:

Reference: Pre-filed Testimony of Francis X. Wells, Exhibit Unitil-FXW-1, pg. 7
How are the pre-service and cancellation costs to be apportioned between Northern's two divisions (New Hampshire and Maine) in the event of any violation of the conditions precedent from the TCPL's Precedent Agreements.

Response:

If Northern incurs cancellation costs under the 2027 TCPL Precedent Agreement, Northern would propose that the cost be allocated between New Hampshire and Maine Divisions using the Modified Proportional Responsibility Allocator in effect at the time of the cancellation.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-12 **Witness:** Francis X Wells

Request:

Have PNGTS, and TransCanada made the necessary filings in order to start the regulatory approval process for the proposed capacity projects? If yes, what is the current status of each approval process? If not, when is it expected that these filings will be made, and approvals received, and from whom will approvals be received?

Response:

PNGTS submitted an application to FERC to certify the proposed capacity on September 25, 2023 and received notice of receipt on September 27, 2023 at which point the two month comment period commenced. The comment period will conclude on November 27, 2023. PNGTS expects to receive the Order on November 28, 2023.

TransCanada will make its initial filing with the Quebec Government for approval of the electricity that is needed to operate the compressor for this proposed capacity project. TransCanada expects this filing to be made in May or June of 2024 and to receive the Quebec Government's decision within 4 to 6 months from the date of filing. Upon receiving the decision from the Quebec Government, TransCanada will then submit all of the remaining applications to the Canadian Energy Board (CER) on behalf of TQM and TCPL.

REDACTED

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/20/2023
Request No. DOE 1-13 **Witness:** Francis X. Wells

Request:

Please provide the following:
a) Please identify all decision points in the schedules when the Company will evaluate whether to proceed with the agreements or not.
b) Please provide details of the decision-making process that the Company will use to evaluate whether to initiate a cancellation event.
c) Please explain what criteria will be used in the decision-making. If the criteria are different at each decision point, please identify the differences.

Response:

Regarding the 2027 TCPL PA, provided as Attachment 6 to the Empress Capacity Resource Assessment, pursuant to Section 13(g), the Company has the right to withdraw its service request under the Precedent Agreement at any time and may incur Cancellation Charges accrued at that time. Withdrawal from the 2027 TCPL PA would trigger a termination of the 2024 Early Start capacity as well. CONFIDENTIAL DG 23-087 DOE 1-13 provides a list of anticipated events related to the PNGTS FT Contract and the 2027 TCPL PA, a description of the relevant decisions that would be made at that time and the estimated liability at the time of that event.

a) The Company cannot foresee all circumstances under which it might seek to terminate the precedent agreements early. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

b) The Company has not formalized a decision-making process for assessing termination of its participation in the projects, but anticipates [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/20/2023
Request No. DOE 1-13 **Witness:** Francis X. Wells

c) Specific decision-making criteria have not been developed. Project cancellation or a failure to obtain regulatory approval on the part of one of the pipelines would jeopardize the capacity path and unless a viable replacement project is anticipated, early termination by Northern of the other projects may be possible although the Company would weigh the consequences of such cancellation carefully. Once regulatory approvals for all projects have been obtained, the risk of cancellation would drop significantly, though the cost of an early termination would increase as project construction progresses.

DOE 1-13 Attachment 1 has been marked entirely confidential by Northern. Accordingly there is no redacted version for Bates page 000031-000035.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-14 **Witness:** Francis X. Wells

Request:

Has the Company been party to similar agreement and have these similar agreements/ projects been subject to cancellation fees (or a similar cost arrangement)? If yes,
a) Please provide a brief summary of the projects and corresponding arrangements.
In any of the cases, did the Company face the consequences of fees or costs? If yes, please provide details, including the recovery mechanism used.

Response:

Yes, the Company was party to a similar precedent agreement with TransCanada in 2015 and with both TransCanada and Enbridge in 2019.

In February 2015, Northern entered into a precedent agreement with TransCanada for service on the Vaughan project. Northern's participation in this project was tied to a turnback of capacity whereby Northern replaced Parkway to Waddington capacity with Parkway to East Hereford capacity. The contract quantity was 6,333 GJ/day. This capacity was utilized to fill Northern's PNGTS C2C capacity. No cancellation costs were incurred under the February 2015 precedent agreement.

In January 2019, Northern entered into precedent agreements with both TransCanada and Enbridge to fill Northern's PNGTS WXP capacity. Northern was exposed to cancellation costs under each of these agreements. These precedent agreements were filed with the Commission under Docket No. DG 19-116. As with the 2027 TCPL PA, the TransCanada precedent agreement in the WXP capacity expansion allowed Northern the option to terminate the precedent agreement, subject to cancellation costs. However, for the Enbridge precedent agreement, Northern was exposed to possible cancellation costs, but only had the ability to terminate if it was unable to meet certain conditions precedent, such as state regulatory approvals. No cancellation costs were incurred under the January 2019 precedent agreements.

Since Northern has not incurred cancellation costs, as discussed in this response, Northern has not previously sought recovery of such costs. In Docket No. DG 19-116 the parties to that proceeding filed a settlement, which stated that "pre-service and cancellation costs associated with the Precedent Agreements accrued as of the date of this Order and for which the Company is liable, are reasonable and appropriately recoverable through the Northern's rates" and pertaining to pre-service costs that may have accrued after the date of the Order that "to the extent that the Company is found to have acted reasonably and prudently in incurring costs associated with the Precedent

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-14 **Witness:** Francis X. Wells

Agreements, such costs will be recoverable through Northern's rates." These settlement provisions were accepted by the Commission. (See Order No. 26,309 at 14.) However, the mechanism that such costs would be recovered was not identified in that docket.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-15 **Witness:** Francis X. Wells

Request:

Please identify any currency exchange risks or exposure the Company may be subject to as a result of the proposed agreements. Has the Company developed mechanisms to mitigate this risk or exposure? Please explain.

Response:

Please refer to Maine Data Request OPA-001-003, which has been provided in DOE 1-02.

Northern has not developed risk management procedures related to currency exchange. Northern has focused on managing reliability risk and exposure to volatile New England delivered supply pricing.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-16 **Witness:** Francis X. Wells

Request:

What is the status of regulatory approval processes for other shippers? Is Northern involved in any of those proceedings? Please provide web links for the associated proceedings

Response:

The other two shippers that were awarded capacity in TCPL's and PNGTS' open seasons for this project are not regulated and therefore they are not seeking regulatory approvals.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-17 **Witness:** Francis X. Wells

Request:

a) Did the Company run resource mix optimization analyses of any alternative supply options? If not, why not? If yes, please provide a summary of the results with a copy of the SENDOUT report/output. If already provided, please identify the information/filing time, date, and format (i.e., via filing, email etc.)
b) Please explain how the cancellation charges are treated in the Company's comparison of supply alternatives.

Response:

a) Northern has utilized PLEXOS rather than SENDOUT for about three years, so it did not utilize a resource mix optimization of alternative supply options. PLEXOS allows users to model "expansion" pipelines whereby the maximum daily volume is determined by the model within the constraints input by the user, which is similar to SENDOUT's resource mix optimization functionality. Rather than use expansion pipelines in PLEXOS, I opted for using discreet volumetric scenarios, as described in the Modelled Cost Analysis section of the Empress Capacity Resource Assessment. I made this decision in order to best ensure accuracy of results due to the limited amount of time between issuance of the TCPL Open Season and the bid due date.
b) Please refer to Northern's response to DOE 1-8.

DG: 19-116
Exhibit:
Date:
H.O.:

Northern Utilities d/b/a Unitil
Department of Public Utilities
Docket No: DG 19-116
Petition for Approval of Precedent Agreement for Westbrook Xpress Phase III Staff Discovery Requests - Set 3

Request:

Please provide lists of pipeline projects initiated by TransCanada and PNGTS in the last 10 years.
a) Please include the following information for each of the projects:
i. initial planned capacity,
ii. status of the project,
iii. planned completion date,
iv. actual completion date, and
v. actual capacity.
b) Please identify all cancelled projects with explanation/reasons of cancellations, if any.

Response:

a. Please see the following tables.

Portland Natural Gas Transmission System

Project	i. Planned Capacity	ii. Status of Project	iii. Planned Completion Date	iv. Actual Completion Date	v. Actual Capacity
Continent to Coast Project (C2C)	82,404 Dth/d	In Service	Nov 1, 2017	Dec 1, 2017*	82,404 Dth/d
Portland XPress Project Phase I	39,841 Mcf/d	In Service	Nov 1, 2018	Nov 1, 2018	39,841 Mcf/d
Portland XPress Project Phase II	11,321 Mcf/d	Approved By FERC	Nov 1, 2019	Nov. 1, 2019	36,702 Dth/d
Portland XPress Project Phase III	24,375 Mcf/d	Approved By FERC	Nov 1, 2020	Nov 1, 2020	127,378 Dth/d
Westbrook XPress Project Phase I	42,651 Dth/d	Approved By FERC	Nov 1, 2019	Nov. 1, 2019	36,702 Dth/d
Westbrook XPress Project Phase II	63,242 Dth/d	Preparing FERC filing	Nov 1, 2021	Nov 1, 2021	69,191 Dth/d
Westbrook XPress Project Phase III	18,080 Dth/d	Preparing FERC filing	Nov 1, 2022	Nov 1, 2022	18,080 Dth/d

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-18 **Witness:** Francis X. Wells

* Delay due to lack of FERC quorum. PNGTS affected C2C implementation on Nov 1, 2017.

TransCanada Pipelines Limited

Project	i. Planned Capacity	ii. Status of Project	iii. Planned Completion Date	iv. Actual Completion Date	v. Actual Capacity
Parkway Loop	446.4 TJ/d	Constructed	2012/13	2012/13	446.4 TJ/d
Station 130 B1/B2	130.1 TJ/d	Constructed	2013/14	2013/14	130.1 TJ/d
Greater Golden Horseshoe	347.7 TJ/d	Constructed	2015/16	2015/16	347.7 TJ/d
King's North	339.5 TJ/d	Constructed	2015/16	2016/17	339.5 TJ/d
Station 130 B3	467.0 TJ/d	Constructed	2016/17	2016/17	467.0 TJ/d
Station 211	399.3 TJ/d	Suspended at customer's request	2016/17		
St. Sebastien	10.0 TJ/d	Constructed	2017/18	2018/19	10.0 TJ/d
Vaughan	418.7 TJ/d	Constructed	2017/18	2017/18	418.7 TJ/d
Station 130 C4	215.5 TJ/d	Under Construction	2019/20	2019/20	215.5 TJ/d
Station 119	226.1 TJ/d	Under Construction	2019/20	2019/20	226.1 TJ/d

Enbridge / Union Gas

Project	i. Planned Capacity	ii. Status of Project	iii. Planned Completion Date	iv. Actual Completion Date	v. Actual Capacity
2015 - Installation of 2 new compressors and 14 km of NPS 48 pipeline from Brantford to Kirkwall	433 TJ/day	Completed	November 1, 2015	November 1, 2015	436 TJ/day
2016 - Installation of 1 new compressor, 20 km of NPS 48 pipeline from Hamilton to Milton	443 TJ/day	Completed	November 1, 2016	November 1, 2016	443 TJ/day
2017 - Installation of 3 new compressors	457 TJ/day	Completed	November 1, 2017	November 1, 2017	457 TJ/day

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-18 **Witness:** Francis X. Wells

a. There have been no project cancellations.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 | **Date of Response:** 11/17/2023
Request No. DOE 1-19 | **Witness:** Francis X. Wells

Request:

a) Please indicate whether both precedent agreements under review in this docket require regulatory approval from both New Hampshire and Maine Public Utilities Commissions.
b) If Northern is unable to get regulatory approval from either the New Hampshire Commission and/or the Maine Commission for one or more agreements, how would the Company proceed?

Response:

a) Both precedent agreements under review in this docket require regulatory approval from both New Hampshire and Maine Public Utilities Commissions.

b) In the event that Northern did not receive approval from the New Hampshire Commission and/or the Maine Commission, the Company would explore all available options, including seeking approval of the full contract by either the New Hampshire Commission or the Maine Commission, other potentially available commercial alternatives, or terminating the contract.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Revised Response:** 12/12/2023
Request No. DOE 1-19 **Witness:** Francis X. Wells

Request:

a) Please indicate whether both precedent agreements under review in this docket require regulatory approval from both New Hampshire and Maine Public Utilities Commissions.
b) If Northern is unable to get regulatory approval from either the New Hampshire Commission and/or the Maine Commission for one or more agreements, how would the Company proceed?

Response (11/17/23):

a) Both precedent agreements under review in this docket require regulatory approval from both New Hampshire and Maine Public Utilities Commissions.

b) In the event that Northern did not receive approval from the New Hampshire Commission and/or the Maine Commission, the Company would explore all available options, including seeking approval of the full contract by either the New Hampshire Commission or the Maine Commission, other potentially available commercial alternatives, or terminating the contract.

Revised Response (12/12/23):

a) The PNGTS agreement allows Northern to terminate the agreement without liability if the Company has not obtained regulatory approval from the New Hampshire and Maine Public Utilities Commissions in form and substance acceptable to the Company by February 1, 2024. Under the TCPL agreement, Northern has the right to declare an Event of Cancellation if the Company is unable to obtain regulatory approval in New Hampshire and Maine. In light of these provisions, as well as the long-term nature of the PNGTS and TCPL agreements, the Company believes that requesting regulatory approval in both jurisdictions is necessary. The Company's request for regulatory approval of the PNGTS and TCPL agreements is consistent with recent precedent in New Hampshire and Maine. See, e.g., Northern Utilities, Inc., DG 19-116, Order No. 26,309 (November 19, 2019); Northern Utilities, Inc., MPUC 2019-00101, Order (November 7, 2019).

b) In the event that Northern did not receive approval from the New Hampshire Commission and/or the Maine Commission, the Company would explore all

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Date Request Received: 11/07/23 **Date of Revised Response:** 12/12/2023
Request No. DOE 1-19 **Witness:** Francis X. Wells

available options, including seeking approval of the full contract by either the New Hampshire Commission or the Maine Commission, other potentially available commercial alternatives, or terminating the contract.

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Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-20 **Witness: Francis X. Wells**

Request:

Please provide annual cost estimates, including annual demand costs, for each agreement during the contract period.

Response:

DOE 1-20 Attachment 1 provides the requested data. Please note that as discussed in the Empress Capacity Resource Assessment, the TCPL actual tolls will be the applicable toll each year of the agreement, subject to TCPL's tariff rates, as approved by the Canadian Energy Regulator. USD/CAD exchange rates are subject to market conditions at the time invoice payments are made. PNGTS' rates are fixed for the term of the agreement.

From	To	Number of Months	TCPL Volume (GJ)	TCPL Toll $CAD per GJ per Month (Estimated)	TCPL Demand Cost ($CAD)	USD / CAD Exchange Rate (Estimated)
Apr-24	Oct-24	7	13,600	52.56619	$ 5,004,301	1.304
Nov-24	Oct-25	12	13,600	52.56619	$ 8,578,802	1.304
Nov-25	Oct-26	12	13,600	52.56619	$ 8,578,802	1.304
Nov-26	Oct-27	12	13,600	52.56619	$ 8,578,802	1.304
Nov-27	Oct-28	12	13,600	52.56619	$ 8,578,802	1.304
Nov-28	Oct-29	12	13,600	52.56619	$ 8,578,802	1.304
Nov-29	Oct-30	12	13,600	52.56619	$ 8,578,802	1.304
Nov-30	Oct-31	12	13,600	52.56619	$ 8,578,802	1.304
Nov-31	Oct-32	12	13,600	52.56619	$ 8,578,802	1.304
Nov-32	Oct-33	12	13,600	52.56619	$ 8,578,802	1.304
Nov-33	Oct-34	12	13,600	52.56619	$ 8,578,802	1.304
Nov-34	Oct-35	12	13,600	52.56619	$ 8,578,802	1.304
Nov-35	Oct-36	12	13,600	52.56619	$ 8,578,802	1.304
Nov-36	Oct-37	12	13,600	52.56619	$ 8,578,802	1.304
Nov-37	Oct-38	12	13,600	52.56619	$ 8,578,802	1.304
Nov-38	Oct-39	12	13,600	52.56619	$ 8,578,802	1.304
Nov-39	Oct-40	12	13,600	52.56619	$ 8,578,802	1.304
Nov-40	Oct-41	12	13,600	52.56619	$ 8,578,802	1.304
Nov-41	Oct-42	12	13,600	52.56619	$ 8,578,802	1.304
Nov-42	Oct-43	12	13,600	52.56619	$ 8,578,802	1.304
Nov-43	Oct-44	12	13,600	52.56619	$ 8,578,802	1.304
Nov-44	Oct-45	12	13,600	52.56619	$ 8,578,802	1.304
Nov-45	Oct-46	12	13,600	52.56619	$ 8,578,802	1.304
Nov-46	Oct-47	12	13,600	52.56619	$ 8,578,802	1.304
Nov-47	Oct-48	12	13,600	52.56619	$ 8,578,802	1.304
Nov-48	Oct-49	12	13,600	52.56619	$ 8,578,802	1.304
Nov-49	Oct-50	12	13,600	52.56619	$ 8,578,802	1.304
Nov-50	Oct-51	12	13,600	52.56619	$ 8,578,802	1.304
Nov-51	Oct-52	12	13,600	52.56619	$ 8,578,802	1.304
Nov-52	Oct-53	12	13,600	52.56619	$ 8,578,802	1.304
Nov-53	Mar-54	5	13,600	52.56619	$ 3,574,501	1.304

TCPL Demand Cost ($USD)	PNGTS Volume (Dth)	PNGTS Negotiated Rate $USD per Dth per Day	PNGTS Demand Cost ($USD)	Empress Capacity Demand Cost ($USD)
$ 3,837,654	12,500	0.82	$ 2,193,500	$ 6,031,154
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 6,578,836	12,500	0.82	$ 3,751,500	$ 10,330,336
$ 6,578,836	12,500	0.82	$ 3,741,250	$ 10,320,086
$ 2,741,182	12,500	0.82	$ 1,547,750	$ 4,288,932

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Date Request Received: 11/07/23 **Date of Response:** 11/17/2023
Request No. DOE 1-24 **Witness:** Francis X. Wells

Request:

Reference: CONFIDENTIAL Attachment 6
Is the TCPL 2027 Precedent Agreement subject to an Estimated Liability Limit? If yes, please identify the amount.

Out of an abundance of caution, recognizing that Attachment 6 is confidential, the DOE asks Northern to indicate whether it considers this question or Northern's response "confidential" in the event this data request were to be marked as an exhibit for hearing.

CONFIDENTIAL Response:

Please refer to DOE 1-10. The Estimated Liability Limit is found on CONFIDENTIAL Attachment 6 to the Empress Capacity Resource Assessment. The total Estimated Liability Limit is [redacted] CAD, which is equal to approximately [redacted] USD based on the average exchange rate equal to 1.304.

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NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Response:** 11/20/2023
Request No. DOE 1-26 **Witness:** Francis X. Wells

Request:

Reference: CONFIDENTIAL Attachment 6, paragraph 13 and 15

a) How typical are the cancellation costs in the context of TCPL Precedent Agreements? Please explain and provide any supporting documentation.
b) Does TCPL have similar provisions/clauses in their typical Precedent Agreements and/or "conditions precedent"? Please explain and provide any supporting documentation.

Response:

a) Please refer to Northern's response to DG 23-087 DOE 1-8, which provides supporting documentation related to the frequency of cancellation costs in the context of TCPL Precedent Agreements. Since 2012, there have been 192 projects managed by TCPL and its affiliate Canadian pipelines. Nine of these have not been placed into service. Only two of these nine were attributable to failure of the transporter to obtain approvals. The remaining seven were attributable to customer withdrawal from the project.

b) Please refer to DG 23-087 DOE 1-26 Attachment 2, which is TCPL's sample Precedent Agreement, provided to Northern by TCPL. This is very similar in form and substance to the TCPL PAs Northern has entered and is seeking approval.

PRECEDENT AGREEMENT

THIS PRECEDENT AGREEMENT made as of the «As_of_Date»___.

BETWEEN:

TRANSCANADA PIPELINES LIMITED
a Canadian corporation
(“**TCPL**”)

AND:

«As of Date»
«As_of_Date»
«ProvinceState»
(“**Customer**”)

WHEREAS:

A. TCPL owns and/or operates a natural gas pipeline system extending from a point near the Alberta/Saskatchewan border where TCPL’s facilities interconnect with the facilities of NOVA Gas Transmission Ltd. easterly to the Province of Quebec with branch lines extending to various points on the Canada/United States of America International Border (the “**TCPL System**”);

B. TCPL utilizes capacity available from the TCPL System and from its firm transportation service contracts on the natural gas transmission systems of the TBO Pipelines (the “**TBO Contracts**”) to enable it to provide transportation service to its customers (such capacity from the TCPL System and the TBO Contracts is collectively defined as the “**Combined Capacity**”);

C. Pursuant to a new capacity open season which closed on «Open_Season_Date»___ (the “**New Capacity Open Season**”), Customer requested TCPL to transport up to _______ GJ/d of natural gas from the «Receipt_Pt» receipt point (the “**Receipt Point**”) to the «Delivery_Pt» delivery point (the “**Delivery Point**”) for delivery for the account of Customer commencing ________________, 20___ or as soon as possible thereafter (the “**In-Service Date**”) and terminating ______________, 20____ (the “**Requested Service**”);

D. Others may have requested gas transportation services pursuant to the New Capacity Open Season (the “**Other Requests**”);

E. TCPL is willing to use reasonable efforts to increase the Combined Capacity, if required, in order to provide the transportation services for the Requested Service and the Other Requests (the “**Required Increase**”);

F. Customer will support TCPL's efforts to provide the Requested Service, Other Requests and Required Increase using the most efficient manner, including without limitation, consideration of options which may or may not require the installation of additional pipeline facilities;

G. Upon an Event of Cancellation, Customer has agreed to be liable for all reasonably incurred costs, expenses and charges in connection with TCPL's efforts to increase the Combined Capacity to the extent necessary in order to provide the Requested Service and Other Requests, subject to the cost allocations and limitations set forth herein; and

H. Subject to the terms and conditions of this Precedent Agreement, TCPL and Customer desire to enter into a firm transportation service contract substantially in the form attached hereto as Exhibit "A" (the "**Firm Transportation Service Contract**").

NOW THEREFORE THIS CONTRACT WITNESSES THAT, in consideration of the covenants and agreement contained herein, the Parties hereto covenant and agree as follows:

1. **Definitions.** Except where the context expressly states otherwise, the following capitalized terms, when used in this Precedent Agreement, shall have the following meanings:

(a) "**Additional Information**" shall have the meaning given to it in Paragraph 2(b).

(b) "**Affiliate**" means, in relation to a Party, any person which:

(i) directly or indirectly controls the Party;

(ii) is directly or indirectly controlled by the Party; or

(iii) is directly or indirectly controlled by another person which directly or indirectly controls the Party;

where "controls" and "controlled by" mean the possession directly, or indirectly through one or more intermediaries, of more than 50% of the outstanding voting equity or ownership interests of the person in question, or the power to direct or cause the direction of the business and affairs of any person, whether through ownership of equity, as a general partner or trustee, by contract or otherwise.

(c) "**AFUDC**" means allowance for funds used during construction;

(d) "**AFUDC Rate**" means the rate used to record AFUDC on TCPL System projects.

(e) "**Allocated Termination Costs**" means all Termination Costs which are not included in the definition of Customer Specific Termination Costs.

(f) "**Availability Provisions**" shall have the meaning given to it in Paragraph 2(a).

(g) "**Banking Day**" shall have the meaning ascribed thereto in the General Terms and Conditions of TCPL's Canadian Mainline Transportation Tariff, as amended from time to time.

(h) "**Cancellation Charges**" means all reasonable costs, expenses and charges that arise from, are attributable to or are incurred in respect of an Event of Cancellation which TCPL incurs or becomes obligated to pay as a result of:

(i) not fulfilling all or any of its obligations under; or

(ii) cancelling or terminating all or any portion of;

any contract or agreement entered into in respect of, in whole or in part, the design, engineering, procurement, manufacture, construction or supply of any property, equipment, services or other components whatsoever related to, arising from or attributable to Customer's request for the Requested Service, regardless of whether such costs, expenses or charges are incurred prior to or after an Event of Cancellation.

(i) "**CER**" means the Canada Energy Regulator and any successor or replacement agency thereof.

(j) "**Class 5 Estimate**" means the Class 5 Estimate as recognized by AACE International recommended practices.

(k) "**Combined Capacity**" shall have the meaning given it in Recital B.

(l) "**Customer Authorizations**" shall have the meaning given to it in Paragraph 2(c).

(m) "**Customer Specific Termination Costs**" means the Termination Costs which relate to, arise from or are attributable to contemplated facilities which are solely attributable to the Customer's request for the Requested Service, if any.

(n) "**Delivery Point**" shall have the meaning given to it in the Recital C.

(o) "**Effective Date**" shall mean •.

(p) "**Estimated Liability Limit**" shall have the meaning given to it in Paragraph 11(a).

(q) "**Event of Cancellation**" shall mean the occurrence of any of the events or circumstances described in Paragraph 13.

(r) "**Exposure Profile**" shall have the meaning given it in Paragraph 10(a).

(s) “**Financial Assurances**” shall have the meaning given to it in Paragraph 8.

(t) “**Financial Assurances Agreement**” means the financial assurances agreement between Customer and TCPL pertaining to the financial security that TCPL may require from Customer in connection with the payment of transportation charges for the provision of the Requested Service.

(u) “**Financial Assurances Request**” shall have the meaning given to it in Paragraph 8.

(v) “**Financial Loss**” means, to the extent arising from, attributable to or incurred in respect of an Event of Cancellation, any negative variance between cash proceeds received by TCPL from the sale, disposal or return of property, equipment or materials related to, arising from or attributable to Customer’s request for the Requested Service (less any reasonable costs and expenses of TCPL related to such sale, disposal or return), and TCPL’s reasonable costs and expenses (including, without limitation, costs and expenses for design, engineering, procurement, manufacture, construction, supply and any related costs and expenses) incurred in originally acquiring same, regardless of whether such amounts are incurred prior to or after an Event of Cancellation.

(w) “**Firm Transportation Service Contract**” shall have the meaning given to it in the Recital H.

(x) “**GJ**” shall mean gigajoule, being 1,000,000,000 joules and include the plural as the context requires.

(y) “**In-Service Date**” shall have the meaning given to it in the Recital C.

(z) “**Increase Amendment**” shall have the meaning given to it in Paragraph 11(b).

(aa) “**Losses**” means losses, liabilities, obligations, suits, damages, claims, demands, actions, law suits, proceedings, costs (including solicitor and his own client fees), expenses, charges, injuries, deaths and all other losses whatsoever, howsoever caused and whether direct, indirect, contractual, tortious or otherwise.

(bb) “**Monthly Carrying Costs**” means the monthly financial costs and expenses that TCPL shall charge Customer in respect of Retained Equipment and Materials, which costs and expenses shall be calculated, for any calendar month, by multiplying the aggregate amount of all out-of-pocket expenses incurred in the acquisition of Retained Equipment and Materials (calculated on the last day of such month) by that percentage amount equal to one twelfth (1/12) of the sum of the Royal Bank of Canada’s prime lending rate per annum for Canadian dollar commercial loans in effect on the last day of such month plus one (1) percent.

(cc) “**New Capacity Open Season**” shall have the meaning given to it in Recital C.

(dd) “**Notice**” shall have the meaning given to it in Paragraph 21.

(ee) “**Other Request Allocated Termination Costs**” means, with respect to each of the Other Requests, the “Allocated Termination Costs” as defined in the Other Request Precedent Agreements.

(ff) “**Other Requests**” shall have the meaning given to it in the Recital D.

(gg) “**Other Request Precedent Agreement**” means a precedent agreement between TCPL and a shipper (other than the Customer) that was entered into pursuant to an Other Request.

(hh) “**Parties**” means TCPL and Customer, and “**Party**” means either one of them.

(ii) “**Precedent Agreement**” means this precedent agreement between TCPL and Customer.

(jj) “**Project Costs**” means:

(i) the reasonable internal and third party costs, expenses and charges of TCPL arising from, attributable to or incurred in respect of:

(A) any regulatory proceedings to the extent related to, arising from or attributable to Customer’s request for the Requested Service, including the preparatory work effected in connection therewith; and

(B) all engineering, design, procurement, manufacturing, supply and construction related costs, expenses and charges to the extent related to, arising from or attributable to Customer’s request for the Requested Service; and

(ii) AFUDC calculated against the amounts in subparagraph (i) of this definition;

regardless of whether such amounts are incurred prior to or after an Event of Cancellation. Internal costs, expenses and charges shall only be included in the definition of Project Costs if such amounts are directly and exclusively attributable to the Customer’s request for the Requested Service.

(kk) “**Receipt Point**” shall have the meaning given to it in the Recital C.

(ll) "**Representatives**" means the directors, officers, consultants, agents, contractors or employees of a Party.

(mm) "**Requested Service**" shall have the meaning given to it in the Recital C.

(nn) "**Required Increase**" shall have the meaning given to it in the Recital E.

(oo) "**Retained Equipment and Materials**" means real property, equipment and materials that relate to, arise from or are attributable to Customer's request for the Requested Service that TCPL, acting in a commercially reasonable manner, elects to retain rather than return, sell, cancel or otherwise divest, in the event that TCPL has elected to cancel the construction of facilities into which such real property, equipment and materials were to be incorporated herein pursuant to Paragraph 14.

(pp) "**TBO Contracts**" shall have the meaning given to it in the Recital B.

(qq) "**TBO Costs**" means any costs, expenses and charges TCPL incurs or becomes obligated to pay to the TBO Pipeline(s) attributable to the Requested Service including, without limitation, any and all costs, expenses and charges:

(i) to cancel the TBO Contract or any other contract TCPL is required to enter into with a TBO Pipeline; and

(ii) payable throughout the term of the TBO Contract or any other contract TCPL is required to enter into with a TBO Pipeline if TCPL is unable to cancel or assign same.

(rr) "**TBO Pipelines**" means any person or entity that owns and/or operates a natural gas transmission system that TCPL has or may enter into a TBO Contract with including, but not limited to, Great Lakes Gas Transmission Limited Partnership, Great Lakes Pipeline Canada Ltd., Union Gas Limited, Enbridge Gas Inc. and Trans Quebec & Maritimes Pipeline Inc.

(ss) "**TCPL Authorizations**" shall have the meaning given to it in Paragraph 3(a)(i).

(tt) "**TCPL System**" shall have the meaning given to it in Recital A.

(uu) "**Termination Costs**" mean the sum of all the following amounts, whether such amounts were incurred prior to or after the Effective Date, without duplication,:

(i) all Cancellation Charges; plus

(ii) all Financial Loss; plus

(iii) all Monthly Carrying Costs until such time as all Retained Equipment and Materials are utilized or otherwise disposed of by TCPL; plus

(iv) all Project Costs not otherwise accounted for pursuant to subparagraphs (i), (ii) or (iii) of this definition; plus

(v) TBO Costs; plus

(vi) any other costs, expenses and charges incurred by TCPL not otherwise accounted for pursuant to subparagraphs (i), (ii), (iii), (iv) or (v) of this definition to the extent they arise from, are attributable to or are incurred in respect of Customer's request for the Requested Service, regardless of whether such costs, expenses and charges are incurred prior to or after an Event of Cancellation; plus

(vii) Termination Cost Carrying Charges as calculated against the amounts identified in subparagraphs (i), (ii), (iii), (v) and (vi) of this definition, where applicable.

For greater clarity, Termination Costs are equal to the sum of Allocated Termination Costs and Customer Specific Termination Costs.

(vv) "**Termination Cost Carrying Charges**" means charges applied to Termination Costs at the AFUDC Rate.

2. **Customer Authorizations.** Customer shall use reasonable efforts to do, or cause to be done, all lawful acts that may be necessary to:

(a) qualify Customer for service under the Firm Transportation Service Contract by complying, *inter alia*, with Section 1.1 (b) of the "Availability" provisions of the FT Toll Schedule as set out in TCPL's Canadian Mainline Transportation Tariff as amended from time to time (the "**Availability Provisions**");

(b) present to TCPL, any information requested by TCPL, including information pertaining to Customer's natural gas supply, markets, and upstream and downstream transportation arrangements that are related to Customer's request for the Requested Service that TCPL determines necessary to fulfill the requirements of the Canadian Energy Regulator Act and the CER Filing Manual (both as amended or replaced from time to time) in seeking approval for TCPL's facilities application(s) in relation to Customer's request for the Requested Service (the "**Additional Information**");

(c) as applicable, obtain, or have others obtain, such certificates, permits, orders, licenses and authorizations from regulators or other governmental agencies in the United States and Canada, as the case may be, as are necessary to enable Customer, or others designated by Customer, to receive and make use of the Requested Service, including, if required, the authority to: (i) purchase the gas to be transported and to export from the United States and to import and deliver into Canada to TCPL at the Receipt Point(s) and to receive from TCPL, to export from Canada, and to import and deliver into the United States at the Delivery Point(s) the quantities of natural gas to be transported by TCPL under the Firm Transportation Service Contract and (ii) construct any facilities required to utilize the Requested Service (individually, a "**Customer Authorization**" and collectively, the "**Customer Authorizations**"); provided that nothing herein shall obligate Customer to appeal any decision of a regulatory or judicial authority which has the effect of denying any such certificate, permit, order, license or authorization or granting same on conditions unsatisfactory to the Parties hereto; and

(d) facilitate the obtainment of the Customer Authorizations in a timely manner to align with the In-Service Date. Customer shall advise TCPL as soon as it reasonably determines, or upon request from TCPL, if it anticipates it will not obtain its Customer Authorizations to facilitate alignment with the In-Service Date.

3. **TCPL Authorizations.**

(a) TCPL shall, taking into account Customer's request for the Requested Service, Other Requests and Required Increase, use reasonable efforts to do, or cause to be done, all lawful acts it considers necessary, to:

(i) obtain, or cause to be obtained, such certificates, permits, licenses, orders, approvals and other authorizations TCPL determines are necessary on terms and conditions satisfactory to TCPL to: (A) enable it to provide the Requested Service, Other Requests and Required Increase in the most efficient manner, and (B) construct, own, operate and maintain any pipeline facilities, if required, in connection therewith (individually, a "**TCPL Authorization**" and collectively the "**TCPL Authorizations**"); provided that nothing herein shall obligate TCPL to appeal, or seek a review of, any decision of a regulatory or judicial authority which has the effect of denying any such certificate, permit, order, license or authorization or granting same on conditions unsatisfactory to TCPL. Notwithstanding anything to the contrary herein, the CER's leave to open with respect to the Required Increase shall not be included within the definition of TCPL Authorizations; and

(ii) facilitate the obtainment of the TCPL Authorizations in a timely manner to align with the In-Service Date.

(b) Customer shall actively support TCPL's efforts to obtain the TCPL Authorizations, provided however that Customer is not obliged to do so, if it would not be reasonable or prudent for Customer to do so having regard to any material adverse impact TCPL's efforts may have on Customer.

4. **Notice Of Customer's Authorizations**. If, after having exercised all avenues of appeal or review, Customer has rejected or not obtained a Customer Authorization, Customer shall promptly give Notice thereof to TCPL. If Customer does not provide TCPL with any such Notice, Customer shall be deemed to have obtained and accepted the Customer Authorizations; provided that Customer shall provide such Notice if requested by TCPL. Any Notice of rejection of a Customer Authorization shall be accompanied by written reasons for such rejection. Acceptance of any Customer Authorization by Customer shall not be unreasonably withheld, and shall be deemed satisfactory if it is granted in form and substance as requested, or as may be otherwise acceptable to Customer, and does not contain any conditions which are unacceptable to Customer, acting reasonably, or result in a material adverse effect to Customer. Further, Customer shall not reject an otherwise acceptable Customer Authorization in the nature of an import or export permit by reason only that such permit is for a term which is shorter than the term of the Firm Transportation Service Contract.

5. **Notice Of TCPL's Authorizations.** If, after having exercised all avenues of appeal or review with respect to each TCPL Authorization as TCPL, in its sole discretion, decides to undertake, TCPL has rejected or not obtained a TCPL Authorization, TCPL shall promptly provide Notice thereof to Customer. Any Notice of rejection of a TCPL Authorization shall be accompanied by written reasons for such rejection. Acceptance of any TCPL Authorization by TCPL shall not be unreasonably withheld, and shall be deemed satisfactory if it is granted in form and substance as requested, or as may be otherwise acceptable to TCPL, and does not contain any conditions which are unacceptable to TCPL, acting reasonably, or result in a material adverse effect to TCPL.

6. **Authorization To Spend; No Title.**

(a) Customer hereby authorizes TCPL, prior to the receipt of all TCPL Authorizations, to acquire all property, equipment and materials, enter into all agreements and take such other actions which TCPL, acting reasonably, considers necessary: (i) for the timely commencement of the Requested Service by the In-Service Date; and (ii) for the timely commencement of the service requested pursuant to the Other Requests by the in-service dates requested pursuant to the Other Requests, or as soon as possible thereafter.

(b) Customer acknowledges that it does not have and will not acquire, any right, title or interest in the facilities to be constructed in connection with the Requested Service and Other Requests, or in any data, information, drawing, plan, equipment, materials, service or work, relating thereto.

7. **Provision and Timing Of Requested Service; Customer's Representation.**

(a) Customer acknowledges and agrees that:

(i) TCPL shall determine, in its sole discretion, how the Requested Service, Other Requests and Required Increase will be provided, and the extent and magnitude of the Required Increase; and

(ii) the provision of the Requested Service may rely on the installation of facilities which are required for both the provision of service for the Requested Service and for one or more of the Other Requests, and that TCPL's actions may be influenced by any obligations it has with respect to the Other Requests.

(b) TCPL will use reasonable efforts to facilitate the alignment of the In-Service Date with the in-service date of upstream and downstream pipeline systems (if applicable). Each Party shall promptly inform the other Party of any delays that may impact the In-Service Date.

(c) Notwithstanding anything in this Precedent Agreement or the Firm Transportation Service Contract to the contrary, Customer agrees it shall have no cause of action or claims against TCPL if TCPL fails to meet the In-Service Date for any reason whatsoever, provided TCPL has used reasonable efforts.

(d) In the event that TCPL has entered into a TBO Contract in connection with the Requested Service, Required Increase and Other Requests, if any, and the in-service date of such TBO Contract occurs before the In-Service Date, Customer agrees it shall take temporary assignment of its pro rata share of the contract demand under the TBO Contract until the In-Service Date occurs or as the Parties may otherwise agree. Customer's pro rata share of the contract demand of the TBO Contract shall be equal to the total volume under the TBO Contract multiplied by a fraction, the numerator of which equals Customer's contract demand pursuant to the Requested Service (in GJ/Day), and the denominator of which equals the sum of the numerator plus the sum of the contract demand for each of the Other Requests that require the TBO Contract.

(e) Customer represents that neither Customer nor any third party acting on behalf of Customer have executed arrangements with other parties with respect to the acquisition of natural gas which would have the effect of eliminating Customer's need for the Requested Service, and Customer agrees that it shall not enter into any such arrangements without the prior written consent of TCPL.

8. **Financial Assurances.** TCPL may request at any time, by Notice to Customer, that Customer provide financial assurances in an amount, type and form acceptable to TCPL for the performance and payment of its obligations under this Precedent Agreement or, if applicable, request that Customer replace, increase or otherwise amend any financial assurances for the

performance and payment of its obligations under this Precedent Agreement previously provided by Customer to TCPL ("**Financial Assurances**"), such Financial Assurances are to be in an amount that does not exceed TCPL's estimate of the maximum payment obligations Customer could be subject to upon an Event of Cancellation (the "**Financial Assurances Request**"). At any time, TCPL may assess or reassess, as applicable, the Customer's creditworthiness related to the performance or payment of its obligations pursuant to this Precedent Agreement. When performing any such assessment or reassessment, TCPL shall apply the same criteria in assessing Customer's creditworthiness as it applies when determining whether to request Financial Assurances pursuant to TCPL's Canadian Mainline Transportation Tariff (as amended from time to time) from a Customer on the TCPL System. TCPL shall not require Financial Assurances unless TCPL makes a determination that Customer is not creditworthy. Customer shall provide TCPL with the requested Financial Assurances within four (4) Banking Days of receipt of the Financial Assurances Request. The obligation of Customer under this Paragraph 8 is independent of and separate from the obligation of Customer under Article XXIII of the General Terms and Conditions of TCPL's Canadian Mainline Transportation Tariff (as amended from time to time) for the gas transportation service.

9. **Execution Of The Firm Transportation Service Contract.**

(a) TCPL's obligation to provide the Firm Transportation Service Contract to Customer is subject to the following conditions precedent to be fulfilled or performed, which conditions are for the exclusive benefit of TCPL and may be waived, in whole or in part, by TCPL, in its sole discretion,:

(i) TCPL has received and accepted all of the TCPL Authorizations;

(ii) TCPL has obtained and executed any TBO Contracts it determines necessary for the Requested Service and/or Required Increase on terms and conditions satisfactory to TCPL, in its sole discretion; and

(iii) Customer has supplied to TCPL (where necessary) the financial assurances required pursuant to Section 1 of the Financial Assurances Agreement.

(b) Upon all of the conditions precedent in Paragraph 9(a) being satisfied or waived, TCPL shall provide the Firm Transportation Service Contract to Customer, and Customer shall execute and return it to TCPL within fifteen (15) days of receipt thereof by Customer.

10. **Exposure Profile**.

(a) Customer acknowledges that it has been provided an exposure profile specified by quarter for each year, which reflects all estimated Project Costs and TBO Costs anticipated to be incurred by TCPL for the Requested Service plus all future commitments that would result from an Event of Cancellation occurring (such exposure profile as it may be updated as contemplated herein, the "**Exposure Profile**").

(b) TCPL shall update the Exposure Profile when it obtains a Class 5 Estimate for Project Costs.

(c) Additionally, where Customer requests from TCPL a status update related to the Exposure Profile, TCPL shall provide an update of (i) the key milestones and (ii) the Project Costs spent to date if they materially exceed the Exposure Profile at that time. TCPL shall provide the status update within a reasonable time after the end of the calendar quarter of such request. Customer may only request status updates twice in a calendar year.

(d) Customer acknowledges and agrees that the Exposure Profile is an estimate provided for information purposes only, and is subject to actual costs, expenses and charges incurred to date for the Requested Service and the Required Increase.

11. **Estimated Liability Limit.**

(a) Customer's total liability upon an Event of Cancellation shall be the actual amount payable pursuant to Paragraph 15. Subject to Paragraph 11(c), the estimated liability limit is «ELL_Amount»•, plus applicable taxes (the "**Estimated Liability Limit**"). TCPL and Customer acknowledge and agree that the Estimated Liability Limit is an estimate provided for information purposes only based upon the calculation described in Paragraph 12, and that to the extent Customer's actual liability pursuant to Paragraph 15 is greater than or less than the Estimated Liability Limit, Customer's obligation to pay such amounts shall not be impacted by the provisions of this Paragraph 11. Customer acknowledges that as of the Effective Date, TCPL's design of the facilities and the Estimated Liability Limit are preliminary, and are based upon the assumption that all of the Other Requests, if any, will result in signed Other Request Precedent Agreements.

(b) If TCPL determines at any time that the currently applicable Estimated Liability Limit has been or will be exceeded by 20% or more, then TCPL shall forward to Customer an amendment to this Precedent Agreement (the "**Increase Amendment**") to increase the Estimated Liability Limit. Customer shall execute the Increase Amendment within 10 Banking Days of receipt of the Increase Amendment.

(c) No Increase Amendment will be required for aggregated increases of less than 20% of the Estimated Liability Limit. Customer shall be liable for such increases in accordance with the terms and conditions of this Precedent Agreement as if such increases were included in the Estimated Liability Limit including, but not limited to, with respect to additional Financial Assurances that may be requested in connection with such increases as contemplated by Paragraph 8.

12. **Estimated Liability Limit Calculation.** The Estimated Liability Limit is equal to the sum of the following:

(a) with respect to any:

(i) TBO Costs; and

(ii) contemplated facilities on the TCPL System;

which, pursuant to TCPL's current design, arise from or are attributable only to Customer's request for the Requested Service, TCPL's estimate of all internal and third-party costs, expenses and charges TCPL will incur in respect of such TBO Costs and such facilities; and

(b) with respect to any:

(i) TBO Costs; and

(ii) contemplated facilities on the TCPL System;

which, pursuant to TCPL's current design, arise from or are attributable to both Customer's request for the Requested Service and the Other Requests, TCPL's estimate of all internal and third party costs, expenses and charges TCPL will incur in respect of such TBO Costs and such facilities, multiplied by a fraction, the numerator of which equals Customer's contract demand pursuant to the Requested Service (in GJ/Day), and the denominator of which equals the sum of the numerator plus the sum of the contract demand for each of the Other Requests; provided that in calculating such fraction, if calculated after the execution and delivery of this Precedent Agreement, the calculation of the denominator shall only be based upon the Other Requests which have resulted in a signed Other Request Precedent Agreement.

13. **Events Of Cancellation.** The occurrence of any of the following events or circumstances shall result in an Event of Cancellation:

(a) **Failure To Actively Support.** If Customer fails to actively support TCPL's efforts to obtain the TCPL Authorizations pursuant to Paragraph 3(b), as determined by TCPL in its sole discretion, and TCPL declares an Event of Cancellation by Notice to Customer.

(b) **Failure To Provide Additional Information.** If Customer does not provide TCPL with the Additional Information requested pursuant to Paragraph 2(b) in a form satisfactory to TCPL, and TCPL declares an Event of Cancellation by providing fifteen (15) days' Notice to Customer.

(c) **Failure To Obtain Or Rejection Of Customer Authorizations.** If Customer rejects or fails to obtain any Customer Authorization, and either Party declares an Event of Cancellation by providing thirty (30) days' Notice to the other Party.

(d) **Failure To Obtain Or Rejection Of TCPL Authorizations.** If TCPL fails to obtain or rejects any TCPL Authorization, and it declares an Event of Cancellation by providing thirty (30) days' Notice to Customer.

(e) **Bankruptcy.** The occurrence of any bankruptcy, winding-up, liquidation, dissolution, insolvency or other similar proceeding affecting Customer or its assets or upon the commencement of any proceeding relating to the foregoing.

(f) **Failure To Execute Firm Transportation Service Contract.** If Customer fails to execute and return to TCPL the Firm Transportation Service Contract within fifteen (15) days of receipt thereof by Customer as required by Paragraph 9, and TCPL declares an Event of Cancellation by providing five (5) days' Notice to Customer.

(g) **Withdrawal.** At any time prior to the execution of the Firm Transportation Service Contract by Customer, if Customer withdraws its request for the Requested Service and declares an Event of Cancellation by providing Notice to TCPL.

(h) **Sunset Date.** Notwithstanding any other provision in this Precedent Agreement,

(i) if by [•]«Sunset_Date», any of the requirements referred to in Paragraphs 2(a) or 9 have not been satisfied, and TCPL declares an Event of Cancellation by providing fifteen (15) days' Notice to Customer; or

(ii) if at any time TCPL is of the opinion, acting reasonably, that any of the requirements referred to in Paragraphs 2(a) or 9 will not be satisfied by [•]«Sunset_Date», despite the use of reasonable efforts, and TCPL declares an Event of Cancellation by providing thirty (30) days' Notice to Customer.

(i) **Failure To Amend Estimated Liability Limit**. If Customer does not execute an Increase Amendment pursuant to Paragraph 11(b), and TCPL declares an Event of Cancellation by providing Notice to Customer.

(j) **Failure To Provide Financial Assurances.** If Customer fails to provide Financial Assurances pursuant to Paragraph 8, and TCPL declares an Event of Cancellation by providing Notice to Customer.

(k) **Failure To Obtain Internal Approval.** If TCPL fails to obtain any internal approvals it determines necessary, including Board of Director approval, for the transactions contemplated herein on or before [•],and TCPL declares within ten (10) days of such date, an Event of Cancellation by providing five (5) days' Notice to Customer.

(l) **Failure To Obtain TBO Contract.** If TCPL fails to obtain any TBO Contract it determines is necessary for the Requested Service and/or the Required Increase on terms and conditions satisfactory to TCPL, in its sole discretion, and TCPL declares an Event of Cancellation by providing fifteen (15) days' Notice to Customer.

(m) **Failure To Temporarily Assign TBO Contract.** If Customer fails to take temporary assignment of a TBO Contract as required under Paragraph 7(d), and TCPL declares an Event of Cancellation by providing five (5) days' Notice to Customer.

(n) **Change In Law.** If at any time TCPL determines, acting reasonably,:

(i) that any introduction of any applicable law or any change or introduction of a change in any applicable law (whether or not having the force of law) or in its interpretation or application by any court or by any governmental agency or other authority or entity charged with the administration of any applicable law, or change in compliance of TCPL with any applicable law; or

(ii) compliance by TCPL with any applicable law or direction, requirement or request from any governmental agency or regulatory authority given after the date of execution of this Precedent Agreement, whether or not having the force of law;

has or would have, as a consequence of TCPL's obligations under this Precedent Agreement and taking into consideration TCPL's internal policies, the effect of increasing TCPL's costs, expenses or charges or has a material adverse effect on the Requested Service, the Other Requests, the Required Increase, TCPL or the TCPL System, then, TCPL may declare an Event of Cancellation by providing 10 days' Notice to Customer.

During any applicable notice period in this Paragraph 13, an Event of Cancellation may be cancelled if the Parties agree to cancel such Event of Cancellation or if the defaulting Party cures the breach that resulted in the Event of Cancellation to the satisfaction of the non-defaulting Party, in both cases, prior to the termination of the applicable notice period, if any.

14. **Effect of Event of Cancellation.**

Upon the occurrence of an Event of Cancellation:

(a) TCPL's and Customer's obligations pursuant to Paragraphs 2, 3, 4, 5, 7(d) and 9 shall terminate.

(b) TCPL may, at its sole discretion, decide to cancel or continue with, in whole or in part, the construction of facilities which arise from or are attributable to Customer's request for the Requested Service. In making such decision, TCPL shall have regard to all materially relevant matters, including any obligations TCPL has with respect to the Other Requests. Customer acknowledges that any decision made by TCPL as described above may be influenced by any obligations TCPL has with respect to the Other Requests, that such decisions may impact Customer's obligations under this Precedent Agreement and that such decisions are subject to change.

(c) Subject to the other provisions of this Paragraph, TCPL shall use commercially reasonable efforts to minimize all costs, expenses and charges payable by Customer to TCPL pursuant to Paragraph 15 below, which shall include (i) efforts to minimize costs, expenses and charges committed to prior to TCPL receiving and accepting all of the TCPL Authorizations and (ii) efforts to sell, dispose or utilize in a prospective expansion within a reasonable time period, all property, equipment, materials or internal or third party work product arising out of facilities contemplated on account of the Requested Service and the Other Requests (the construction of which has been cancelled); provided that such efforts shall be subject to TCPL's obligations with respect to the Requested Service, the In-Service Date, the Other Requests and the in-service date for the Other Requests.

15. **Payment Of Termination Costs.** If an Event of Cancellation is declared, Customer shall pay to TCPL the sum of the following amounts:

(a) 100% of the Customer Specific Termination Costs, if applicable; plus

(b) the product of:

(i) the sum of the Allocated Termination Costs plus the Other Request Allocated Termination Costs for each of the Other Request Precedent Agreements where an "Event of Cancellation" (as defined therein) has occurred; multiplied by

(ii) a fraction, the numerator of which equals Customer's contract demand pursuant to the Requested Service (in GJ/Day), and the denominator of which equals the sum of the numerator plus the sum of the contract demand for each of the Other Request Precedent Agreements where an "Event of Cancellation" (as defined therein) has occurred; plus

(c) all applicable taxes.

TCPL will invoice Customer within 60 days of an Event of Cancellation and payments will be paid in accordance with Paragraph 16.

16. **Invoicing And Payment.** TCPL shall invoice and Customer shall pay all obligations and liabilities owing by it under this Precedent Agreement to TCPL as they may arise from time to time. Customer shall remit payment to TCPL within thirty (30) days following receipt of any invoice. If Customer fails to pay any invoice in full within the time required, interest on the unpaid portion shall accrue from the date such payment is first overdue until payment is made at a rate of interest equal to the prime rate of interest per annum of the Royal Bank of Canada applicable to Canadian dollar commercial loans on the date such payment is first overdue, plus one (1) percent in addition thereto (with the exception of interest for TBO Costs which shall be determined pursuant to the TBO Contract), and such interest shall be immediately due and payable.

17. **Audit Rights.** Provided Customer has paid to TCPL all amounts invoiced hereunder, no earlier than thirty (30) days after TCPL has received a written request from Customer, Customer

shall have the right, at its cost and expense, to examine TCPL's supporting documentation related to the particular invoice(s) to verify its accuracy. Each invoice may only be audited once. Customer's audit rights shall be granted during normal business hours. Customer's audit rights shall not include any right to break down the standard labour rates or overhead rates charged by TCPL. The total number of audits commenced in any calendar year shall not exceed one. Any audit request by Customer must be received by TCPL within a period of two years after the invoice in question was received. Prior to any audit, Customer and/or its auditors shall execute a confidentiality agreement, in form acceptable to TCPL, to protect the confidential nature of any information reviewed under the audit.

18. **Retained Equipment And Materials.** TCPL will use reasonable efforts to dispose of or utilize the Retained Equipment and Materials within three (3) months from the date TCPL cancels construction of the facilities pursuant to Paragraph 14(b), and TCPL shall credit Customer for any Retained Equipment and Materials it is able to dispose of or utilize within such time period. TCPL shall not have an obligation or duty to dispose of or utilize the Retained Equipment and Materials beyond such three (3) month time period.

19. **Term.** This Precedent Agreement shall remain in effect until the earlier of:

(a) the date that the Parties have both entered into the Firm Transportation Service Contract for the Requested Service; or

(b) where an Event of Cancellation has occurred, the date that both (i) TCPL has utilized or disposed of all the Retained Equipment and Materials pursuant to Paragraph 18, and (ii) TCPL has been paid by Customer for all obligations payable by Customer pursuant to this Precedent Agreement, including all Termination Costs.

20. **Waiver Of Default.** No waiver by TCPL of any Event of Cancellation or default by Customer in the performance of any provision of or obligation under this Precedent Agreement shall operate or be construed as a waiver of any continuing or future Event of Cancellation or default, whether of a like or different character.

21. **Notice.** Any notice, request or demand ("**Notice**") to or upon the respective Parties hereto shall be in writing and shall be validly communicated by the delivery thereof to its addressee, either personally or by courier, first class mail, e-mail (return receipt or confirmation required), facsimile or other telecommunication to the address hereinafter mentioned:

IN THE CASE OF TCPL	**TRANSCANADA PIPELINES LIMITED**
(i) Mailing Address:	450 - 1st Street SW Calgary, AB T2P 5H1
(ii) Delivery Address:	450 - 1st Street SW

Calgary, AB T2P 5H1

Attention: Director, Commercial Services and Modernization
Facsimile: (403) 920-2446
Email: mainline_contracting@tcenergy.com

IN THE CASE OF CUSTOMER •

(i) Mailing Address: •
«Address_2»
•
•

(ii) Delivery Address: Same as above

Attention: •
Facsimile: •
Email: •

Such Notice sent as aforesaid shall be deemed to have been received by the Party to whom it is sent: (a) at the time of its delivery, if personally delivered, (b) at the time of its delivery if sent by facsimile or e-mail (provided return receipt or confirmation has been provided), during normal business hours on a Banking Day, and if not, on the next Banking Day, or (c) on the day following transmittal thereof if sent by courier, or (d) on the third day following the transmittal thereof if sent by first class mail; provided however, that in the event normal or first class mail service, courier service, e-mail service or facsimile service shall be interrupted by a cause beyond the control of the Parties hereto, then the Party sending the Notice shall utilize any service that has not been so interrupted or shall personally deliver such Notice. Each Party shall provide Notice to the other of any change of address for the purposes hereof.

22. **Assignment and Enurement.**

(a) Neither Party may assign this Precedent Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, provided however that either Party:

(i) shall be entitled to assign its rights and obligations under this Precedent Agreement to its Affiliate without the consent of the other Party, provided such assigning Party remains liable for its obligations under this Precedent Agreement; and

(ii) either Party may at any time, without the consent of the other Party, pledge its interest pursuant to this Precedent Agreement as security to any lender providing financing to such Party.

(b) This Precedent Agreement shall be binding upon and enure to the benefit of the respective successors and permitted assigns of the Parties hereto.

23. **Applicable Law.** This Precedent Agreement shall be construed and applied in accordance with, and be subject to, the laws of the Province of Alberta, and, where applicable, the laws of Canada, and shall be subject to the rules, regulations, decisions and orders of any regulatory or legislative authority having jurisdiction over the matters contained herein. Each of the Parties irrevocably submits to the exclusive jurisdiction of the courts of the Province of Alberta for interpretation and enforcement of this Precedent Agreement.

24. **Severance.** If any provision of this Precedent Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall apply only to such provision and all other provisions hereof shall continue in full force and effect.

25. **Headings and Further Assurances.**

(a) Headings are included solely for convenience of reference, and are not intended to be full or accurate descriptions of the contents.

(b) Each Party covenants and agrees to provide such data and information, to execute and deliver such further documents and instruments, to give further assurances and to perform such acts as may be reasonably required by the other Party in order to carry out the purposes, intentions and provisions of this Precedent Agreement.

26. **Sole Benefit.** TCPL and Customer hereby stipulate and agree that this Precedent Agreement is executed for the sole benefit of TCPL and Customer, including all successors and assignees permitted under the terms of this Precedent Agreement. TCPL and Customer expressly intend that no rights under this Precedent Agreement enure to any other parties.

27. **Entire Agreement and Amendments.**

(a) This Precedent Agreement and the Firm Transportation Service Contract set forth the entire agreement between the Parties, and supersedes and replaces all previous discussions, understandings and agreements respecting the subject matter.

(b) Subject to Paragraph 11(c), this Precedent Agreement may not be amended except by a written amending agreement signed by TCPL and Customer.

28. **Limitation Of Liability.** TCPL and its Representatives are not liable to Customer or its Representatives for any Losses including:

(a) Losses for loss of profit and loss of revenue; and

(b) indirect, consequential, punitive, exemplary or similar damages;

whether or not such Losses could have reasonably been foreseen on entry into this Precedent Agreement, arising from, in connection with or in relation to this Precedent Agreement that are asserted against or suffered or incurred by Customer or its Representatives, except and to the extent that such Losses are caused by the gross negligence or willful misconduct of TCPL.

29. **Survival**. The provisions of Paragraphs 6(b), 7(c), 17, 20, 21, 23, 24, 25, 26, 27, 28, 29 and 30, and any other provisions of this Precedent Agreement which, either by their express terms or by operation of their terms, are intended to be performed in whole or in part after termination or expiration of this Precedent Agreement, shall survive such termination or expiration.

30. **Counterpart Execution**. This Precedent Agreement may be executed in counterparts, which together constitute one and the same agreement. A facsimile or electronic pdf copy of this Precedent Agreement containing the signature of a Party will be deemed to be an originally signed document.

IN WITNESS WHEREOF, the duly authorized Parties hereto have executed this Precedent Agreement as of the date first above written.

«Signature_Block»	**TRANSCANADA PIPELINES LIMITED**
By: ______________________	By: ______________________
Name:	Name:
Title:	Title:
By: ______________________	By: ______________________
Name:	Name:
Title:	Title:

TCE Approved as to Form and Content:	
Business	
Legal	

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-01 **Witness:** Francis X. Wells

Request:

Reference: PNGTS FT Contract, Article III; and Technical Session (TS) discussions

a) Please provide Northern's understanding of the implication(s) of Article III (Attachment 2, page 2 of 7) of the PNGTS Firmed Transportation (FT) contract.

b) In light of the "Empress Capacity Agreements" (as a whole), what would be the overall financial (e.g., allocation of peak capacity costs) and non-financial (e.g., contractual) implications?

c) Assuming the contracts go into effect, will Northern be able to sell any peak or off-peak transportation capacity to other entities if, for any reason, Northern is unable to use the 12,500 Dth/day at issue in New Hampshire and/or Maine?

Response:

a) Article III of the PNGTS Firm Transportation contract speaks to the "Allocation of Off-Peak Capacity". Because PNGTS is fully subscribed to its maximum capacity year round, Northern's understanding of Off-Peak Capacity is that it is not available. Historically, when PNGTS sold winter only FT contracts, Off Peak Capacity was available April – October.
b) There would be no financial or non-financial implications that are the result of Article III of the PNGTS Firm Transportation contract, because there are no winter only contracts on PNGTS and therefore there is no Off-Peak Capacity available.
c) Assuming the contracts go into effect, Northern will not elect to sell any peak (or off-peak) transportation capacity to other entities, but will instead include the Empress Capacity contracts as part of an asset management arrangement (AMA) similar to how the rest of Northern's portfolio is managed. An AMA allows Northern to have access to the capacity when it is needed to cover requirements, and allows the asset manager to optimize any remaining capacity that is not called on by Northern. Northern is also able to make off-system sales with its capacity as part of an AMA. The asset manager pays a fee for the right to manage the AMA.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-02 **Witness:** Francis X. Wells

Request:

Reference: "Empress Capacity Agreements" (as a whole); and TS discussions

a) Do the TCPL Precedent Agreements (both 2024 PA and 2027 PA) contain "sunset dates" with respect to any waiver provisions?

b) If yes, please identify those "sunset dates" and where/how they could be applied.

Response:

a) The 2024 TCPL PA has no sunset date. However, Section 4(b) of the 2024 TCPL PA found on page 2 of Attachment 4 indicates that any Event of Cancellation under the 2027 TCPL PA would result in automatic termination of the 2024 TCPL PA. Operation of the sunset date provision of the 2027 TCPL PA, as discussed below, would be an Event of Cancellation, effectively cancelling both the 2024 TCPL PA and the 2027 TCPL PA.

   The 2027 TCPL PA has a sunset date, which can be found on Page 12 of 29 in Attachment 6 (2027 TCPL PA Confidential), Paragraph 13 "Events of Cancellation", under h) "Sunset Dates".

b) Per this section of the TCPL 2027 PA, the sunset date is May 1, 2027. TCPL could declare an event of cancellation if by May 1, 2027, if any of the requirements of Paragraph 2(a) or 9 have not been satisfied providing 15 days' notice to the customer. Additionally, if at any time, TCPL is of the opinion, acting reasonably, that any of the requirements referring to Paragraph 2(a) or 9 will not be satisfied by May 1, 2027, despite the use of reasonable efforts, TCPL could declare an event of cancellation providing 30 days' notice to the customer.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23	**Date of Response:** 11/20/2023
Request No. DOE TS 1-03	**Witness:** Francis X. Wells

Request:

Reference: “Empress Capacity Agreements” (as a whole); and TS discussions

Please envision a hypothetical scenario where TCPL is able to continue fulfilling its PA and FT agreements, but PNGTS is unable to do so.

a) How likely is this scenario given Northern’s past historical engagements with both of these entities?

b) Are there any financial implications (such as similar to termination costs)? If no, why not? If yes, why and how much over what period of time?

c) Under the scenario, would Northern be able to (or be required to) still continue with TCPL?

   a. If no, please identify all possible implications.

   b. If yes, please describe how and identify the implication(s).

   c. When responding to “a” and “b” please respond separately for “able to” and “required to.”

Response:

a) PNGTS expects to receive a decision regarding their application with FERC for the certification of the capacity needed to fulfill the FT capacity agreements for this project by November 28, 2023. FERC’s decision will determine whether or not PNGTS is able to fulfill its obligations to provide shippers with Firm Transportation Agreements. If FERC were to decide not to certificate the PNGTS capacity, TCPL would cancel the project.
b) Under this hypothetical scenario, Northern would not be subject to termination costs from PNGTS. Northern would be responsible for its proportional share of the costs incurred by TCPL as of the date of project cancellation, which would be minimal given the early timing.
c) Under this scenario, Northern would not be required to nor would Northern be able to continue with TCPL.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-04 **Witness:** Francis X. Wells

Request:

Reference: "Empress Capacity Agreements" (as a whole); and TS discussions

a) What would be Northern's obligations under the 30-year Firmed Transportation (FT) Agreement with PNGTS under a hypothetical scenario, where Northern enters into that 30-year FT Agreement with PNGTS and TCPL withdraws or cancels its PA?

b) How would Northern mitigate supply and transportation costs in such a scenario?

c) Would Northern continue to transport 12,500 Dth/day on PNGTS?

Response:

a) Under a hypothetical scenario in which Northern enters into the 30 year Firm Transportation Agreement with PNGTS and TCPL withdraws or declares an event of cancellation, Northern would not have the option to terminate its FT contract with PNGTS. Therefore, Northern expects that in this hypothetical situation, it would continue to transport 12,500 Dth per day on PNGTS.
b) In the event that TCPL were unable to avoid this scenario, Northern would explore various options for utilizing the 12,500 Dth/day of PNGTS capacity such as but not limited to the following:

- Seek supply contracts at East Hereford (Pittsburg, NH on the US side of the border) at the interconnect between TCPL and PNGTS.
- Seek supply contracts at the Westbrook, ME interconnect between Maritimes and PNGTS.
- In the event that Northern were to contract for an on system LNG peak shaving facility, Northern could utilize this 12,500 dth of capacity to transport supply to and from that facility.
- Explore making a permanent assignment or capacity release of the PNGTS capacity to third party.
- If TCPL were to issue an open season for a new expansion project that might have an alternate path that was not contemplated in this particular project, Northern would entertain participating in that open season to acquire the necessary upstream capacity.

c) See response to part a).

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-05 **Witness:** Francis X. Wells

Request:

Reference: “Empress Capacity Agreements” (as a whole); and TS discussions
Please provide Northern’s understanding of the implications of Article XI of the Northern/PNGTS FT Agreement (Attachment 2, page 4 of 7)

Response:

Article XI of the Northern/PNGTS FT Agreement (“Law of Contract”) stipulates that the interpretation and performance of the contract will be in accordance with and controlled by the laws of the State of Maine. To the extent that any issues of contract interpretation arise in connection with the FT Agreement, it is the parties’ intent that the laws of the State of Maine shall govern. Similarly, to the extent that any issues arise regarding the parties’ performance obligations. under the contract, it is the parties’ intent that the laws of the State of Maine shall govern.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-06 **Witness:** Francis X. Wells

Request:

Reference "Empress Capacity Agreements" (as a whole); and TS discussions

a) Please identify the risk New Hampshire would face if, hypothetically, Maine were to refrain from contract review or from preliminary approval at this time.

b) Please provide a narrative response and any cost-benefit analysis based on the percentage of the 12,500 Dth/day Northern proposes that New Hampshire would accept, ranging from 40% (or any lower percentage) up to 100% of the supply.

Response:

a) The Maine PUC is currently engaging in a contract review of the Empress Capacity Agreements in Maine PUC Docket No. 2023-00254.

   If the Maine PUC refrained from reviewing the contracts in that proceeding, it is possible that Northern would terminate the PNGTS FT Contract and the 2027 TCPL PA. Cancellation of these agreements would trigger cancellation of the 2024 TCPL PA. In Northern's view, the Empress Capacity Agreements help to mitigate the risk of supply availability, particularly peaking supplies. Therefore, to the extent that Northern elected to terminate the Empress Capacity Agreements, the risk to New Hampshire would be the lost opportunity to mitigate the risk of supply availability, particularly peaking supplies.

   If Northern were to seek to retain the Empress Capacity Agreements based only on the review of the NH PUC, there is risk of the following:
   1) Northern may be unable to find a suitable counterparty to assign the portion of the Empress Capacity Agreements that was intended to be allocated to Maine.
   2) Northern would lose some of the benefits of a single portfolio to cover both states. Specifically, any portion of the Empress Capacity that is retained could only be used to serve NH demands. In light of this, Northern would need to re-design its gas cost allocation methodology to ensure that all costs and benefits related to the Empress Capacity Agreements are allocated solely to New Hampshire.

b) CONFIDENTIAL DG 23-087 DOE TS 1-06 provides an analysis showing the effects of adding Empress Capacity on NH allocated demand and commodity costs. This analysis is based on the normal year analysis used for Attachment 9,

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-06 **Witness:** Francis X. Wells

the Modelled Cost Analysis. It does not attempt to quantify the loss of resource interchangeability addressed in part a) to this response.

a. The "Empress Assigned to NH" worksheet compares a portfolio that allocates 100% of Empress Capacity Agreements to the New Hampshire Division. This represents the 100% percentage allocation.
b. The "Empress Allocated to ME&NH" worksheet compares a portfolio that allocates Empress Capacity in a manner consistent with current cost allocation process. This represents the 40% percentage allocation.
c. The "Normal Total System Cost Data" calculates demand and commodity costs to New Hampshire as follows:
    i. Dark green header shows allocating 12,500 Dth of Empress Capacity to New Hampshire.
    ii. Bright blue header shows allocating costs with Empress to New Hampshire, consistent with the current practice
    iii. Current portfolio costs without Empress are also allocated to New Hampshire based on the current practice.
d. The "Demand Cost Allocators" worksheet provides the following calculations.
    i. The proxy allocator for the current method of demand cost allocation was based on the percentage of NH design year demand to the total Northern design year.
    ii. If 100% of Empress is allocated to New Hampshire, the rest of the portfolio would be allocated to New Hampshire on the basis of the difference between Design Year demands and Empress design year utilization.
e. The "Commodity Cost Allocators" worksheet provides the following calculations.
    i. The proxy allocator for the current method of commodity cost allocation was based on the percentage of NH normal year demand of the total Northern normal year.
    ii. If 100% of Empress is allocated to New Hampshire, the rest of the portfolio would be allocated to New Hampshire on the basis of the difference between Normal Year demands and Empress normal year utilization.
f. The 12500 Normal Expected Detail provides the Modelled Cost Detail from this scenario for reference purpose.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 | **Date of Response:** 11/20/2023
Request No. DOE TS 1-06 | **Witness:** Francis X. Wells

Northern's Attachment to Response TS 1-06 has been marked Confidential in its entirety.
There is no redacted version for Bates pages 000080-00108

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-06 **Witness:** Francis X. Wells

Request:

Reference "Empress Capacity Agreements" (as a whole); and TS discussions

a) Please identify the risk New Hampshire would face if, hypothetically, Maine were to refrain from contract review or from preliminary approval at this time.

b) Please provide a narrative response and any cost-benefit analysis based on the percentage of the 12,500 Dth/day Northern proposes that New Hampshire would accept, ranging from 40% (or any lower percentage) up to 100% of the supply.

SUPPLEMENTAL Response (11/29/23):

REVISED CONFIDENTIAL DG 23-087 TS 1-06 Attachment 1 corrects the headers on the "Empress Assigned to NH" and "Empress Allocated to ME&NH" tabs.

Throughout the attachment "Empress Assigned to NH" means that 100% of Empress cost and benefits would be passed through to New Hampshire Division customers, and "Empress Allocated to ME & NH" means that the current cost and benefit allocation process would continue. "Normal Total System Cost Data", "Demand Cost Allocators", and "Commodity Cost Allocators" tabs have been updated with this convention.

No calculations have been updated in the revised attachment. All changed cells are highlighted with red font.

Northern's Attachment to Response TS 1-06 has been marked Confidential in its entirety. There is no redacted version for Bates pages 110-138

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-07 **Witness:** Francis X. Wells

Request:

Reference "Empress Capacity Agreements" (as a whole); and TS discussions; Northern's Petition (Oct 5, 2023).

Would Northern agree that it is appropriate to limit New Hampshire ratepayers' share of termination fees (if any) to no more than the proportional share of 12,500 Dth/day that New Hampshire utilizes and/or pursuant to the Modified Proportional Responsibility Allocator, which is used to allocate demand costs, based on Design Year utilization. See Petition at 2 n.1. Please explain why or why not.

Response:

Northern would agree that it is appropriate to limit New Hampshire ratepayers' share of termination fees (if any) to no more than the proportional share of 12,500 Dth/Day that New Hampshire utilizes pursuant to the Modified Proportional Responsibility Allocator as discussed in responses to DG 23-087 DOE 1-09 and 1-11.

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
New Hampshire Department of Energy
Technical Session Data Requests - Set 1

Date Request Received: 11/13/23 **Date of Response:** 11/20/2023
Request No. DOE TS 1-08 **Witness:** Francis X. Wells

Request:

Reference Empress Capacity Agreements (as a whole) and TS discussion
Is Northern aware of any precedent agreements that include TCPL and/or PNGTS in which the terminations costs are allocated (in whole or in part) to any entity other than the Shipper(s)? If so, please provide a narrative description and documentation, if available.

Response:

Northern is not aware of any TCPL PA's in which termination costs are allocated to anyone other than shippers.

In previous projects in which there were PA's for PNGTS capacity, such as the PXP and WXP expansions, termination costs would have been borne by PNGTS unless Northern terminated these agreements for reasons other than failure to obtain regulatory approvals. In the Empress Capacity Agreements, there is no PA associated with the PNGTS capacity because there was not a requirement to build in order to create this capacity.

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REQUEST FOR APPROVAL OF PRECEDENT AGREEMENT PERTAINING TO NORTHERN UTILITIES, INC. D/B/A UNITIL INC.
2023-00254
RESPONSE TO CLF-001
BY NORTHERN UTILITIES, INC. D/B/A UNITIL INC

14-NOV-23

CLF-001-001

Q. Please provide any analysis Northern has conducted of projected regional natural gas demand trends over the duration of the agreements (until 2054).

A. Northern has not conducted any analysis of regional natural gas demand trends over the duration of the agreements. For general guidance on the range of future natural gas demand as of mid-century, the figure attached as CLF 001-001 Attachment 1 was taken from the Energy Information Administration's (EIA) 2023 Annual Energy Outlook, released in March 2023. (www.eia.gov/aeo. See Powerpoint labeled "AEO2023_Narrative_Figures", dated March 16, 2023.) The EIA chart shows a reference case level of demand slightly below recent demand levels along with a high cost of zero emission technology case, which would trigger higher demand for natural gas, and a low oil and gas supply case, which would lead to higher cost and lower demand. Please also refer to CLF-001-002, which provides a long-term forecast of Northern's natural gas demand.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. CLF-001-001 Attachment 1.pdf

14-NOV-23

CLF-001-002

Q. Please provide any forecast Northern has conducted of firm customer demand and planning load requirements over the duration of the agreements (until 2054).

A. Northern projected firm customer throughput requirements out to 2053 based on extrapolation of the forecast models presented in the 2023 Integrated Resource Plan, which leverage independent variable projections from Moody's through 2053.

CLF-001-002 Attachments 1 and 2 provide the Design Year forecast for the Maine and New Hampshire Divisions, respectively. CLF-001-002 Attachments 3 and 4 provide the Normal Year forecast for the Maine and New Hampshire Divisions, respectively.

Northern has not attempted to model customer demand based on energy and environmental policy changes. Please refer to CLF 001-001 for a recent EIA projection of natural gas demand as of mid-century under a range of policy and market conditions.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. CLF-001-002 Attachment 1.xlsx
2. CLF-001-002 Attachment 2.xlsx
3. CLF-001-002 Attachment 3.xlsx
4. CLF-001-002 Attachment 4.xlsx

14-NOV-23

CLF-001-003

Q. Please identify the "climate-related policies in New England" and "energy and environmental policy to address climate change" referenced at page 14 of the Empress Capacity Resource Assessment.

A. Part 4 of the Regional Market Overview, starting on page 29 of the Empress Capacity Resource Assessment, references federal policies including the Inflation Reduction Act and the EPA's Renewable Fuel Standard. At the state level, this section references Maine's Act to Promote Clean Energy Jobs and to Establish the Maine Climate Council and cites to an ISO Newswire article summarizing various regional policies and coordinated climate initiatives.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

CLF-001-004

Q. (a) Please provide the anticipated timing of Northern's evaluation of incremental energy efficiency as an incremental resource. (b) What are the next steps in this evaluation?

A. (a) Northern does not currently have a timeline for evaluation of incremental energy efficiency as a resource.

(b) The next steps for such an evaluation would include:

a. Determining whether incremental energy efficiency could be deployed in the State of Maine given the current construct in which energy efficiency is administered by Efficiency Maine Trust.
b. Determining whether incremental energy efficiency would provide economic benefits compared to other potential incremental resources.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

CLF-001-005

Q. How often does Northern anticipate the Empress Capacity Path will be utilized at a 100% load factor? Please provide Northern's expectations of the load factor at which it will utilize the Empress Capacity Path throughout the year.

A. CLF-001-005 provides the requested data.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. CLF-001-005 Attachment 1.pdf

15-NOV-23

CLF-001-006

Q. Please describe Northern's expectations with regard to asset management revenue. For instance, what percentage of demand costs does Northern expect to be able to offset with asset management revenue? What about other transportation costs and gas supply costs?

A. Please see the attached Confidential response and Attachments

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. CLF-001-006 CONFIDENTIAL.pdf
2. CLF-001-006 Attachment 1 (CONFIDENTIAL).pdf
3. CLF-001-006 REDACTED.pdf
4. CLF-001-006 Attachment 1 (REDACTED).pdf

14-NOV-23

CLF-001-007

Q. Please see confidential attachment.

A. CONFIDENTIAL CLF-001-007 Attachment 1 provides the requested information.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. Confidential DR CLF-007.pdf
2. CLF-001-007 Attachment 1 (CONFIDENTIAL).pdf

14-NOV-23

CLF-001-008

Q. Please see confidential attachment.

A. As explained in response to EXM 1-23, customers are looking for affordable and reliable sources of energy. Natural gas is both affordable and reliable while also reducing environmental pollution relative to delivered fuels. Northern's expectation of future growth is based on recent historical experience and consideration of the generally slow pace of development of renewable power generation and transmission, which would need to grow significantly if the wholesale electric power sector is going to be able to adequately serve added transportation and heating demands. While Northern's expectation is for continued growth in planning load, such growth is not required for the Empress Capacity to be cost effective and well utilized. As explained in the Empress Capacity Resource Assessment, Northern seeks additional supply resources beyond the Empress Capacity in order to ensure resource adequacy. As explained in response to EXM 1-24, Northern has significant flexibility with other contracts that will come up for renewal during the term of the Empress contracts. Moreover, the Company believes that natural gas will remain a dispatchable fuel that could provide service to customers during power grid constraints, even if electrified heating grows during this time period.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. Confidential DR CLF-008.pdf

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REQUEST FOR APPROVAL OF PRECEDENT AGREEMENT PERTAINING TO NORTHERN UTILITIES, INC. D/B/A UNITIL INC.
2023-00254
RESPONSE TO EXM-001
BY NORTHERN UTILITIES, INC. D/B/A UNITIL INC

13-NOV-23

EXM-001-001

Q. Please explain how Northern selected the quantity of Dth proposed under the precedent agreement(s) given both the quantity available and Northern's supply needs.

A. Please see EXM-001-001 Confidential Attachment 1.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-001 Confidential Attachment 1.pdf
2. EXM-001-001 Redacted Attachment 1.pdf

13-NOV-23

EXM-001-002

Q. Please explain how the pipelines can offer additional capacity without the need for construction.

A. PNGTS is able to offer additional capacity without construction due to capacity that was added by the WXP expansion but not certificated by FERC.

TCPL is able to offer additional capacity without construction for an interim period by entering into contracts with parties who hold capacity on the TCPL system. However, in order to provide long-term capacity TCPL will require additional construction, which is why the 2027 precedent agreement was required.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-003

Q. The PNGTS open season announcement states that it anticipated providing service at a reservation rate of at least $0.77 per Dth per day for deliveries to Westbrook, Maine or at least $0.82 per Dth per day for delivery to any point south of Westbrook, Maine. Please explain why Northern bid only at the price of $0.82 per Dth per day. See Prefiled Testimony of Francis Wells at page 5

A. PNGTS offered service at a rate of $0.77 per Dth for capacity that delivers as far south as Westbrook, ME at the meter that is the interconnect between PNGTS and Maritimes. In order to access its customers, Northern requires PNGTS capacity that delivers to the Joint Facilities south of the interconnect between PNGTS and MN to the interconnects between PNGTS and Granite at Westbrook, ME, South Berwick, ME, Eliot, ME and Newington, NH. Given this requirement, Northern bid on PNGTS capacity with a primary receipt point at Pittsburg, NH and a primary delivery point at Dracut, MA, which required a minimum bid price of $0.82 per Dth per day.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-004

Q. Please explain the rate making process followed to set rates for both PNGTS and TCPL and whether the length of Northern's contract term impacts those calculations.

A. The PNGTS rate was set through a competitive Open Season bidding process, where potential shippers submitted bids for price and term and PNGTS evaluated bids based on net present value. The term that Northern bid impacted PNGTS' assessment of its bid. The PNGTS negotiated rate is fixed for the full term.

Table VI-6 explains that incremental facility costs are rolled into TCPL's system tolls, resulting in expansion customers paying system average rates, rather than incremental project rates. The term that Northern bid impacted TCPL's assessment of its bid. TCPL tolls are not differentiated by term of the agreement. The contract rate is subject to change over the term of the agreement as TCPL's system tolls change.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-005

Q. Please explain Northern's thoughts on the likelihood that tariffed rates would decrease for PNGTS over the 30 year life resulting in Northern paying higher rates because of the length of the contract than it would if it had signed a 15 year agreement.

A. Please see EXM-001-005 Confidential Attachment 1.

A. See attached;R

A. In its initial response, the Company inadvertently attached the wrong confidential and redacted responses. The correct responses are attached to this supplemental response.;R

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-001 Confidential Attachment 1.pdf
2. EXM-001-001 Redacted Attachment 1.pdf
3. EXM-001-005 Confidential Attachment 1.pdf
4. EXM-001-005 Redacted Attachment 1.pdf

13-NOV-23

EXM-001-006

Q. Please provide a summary of any of the ownership affiliations between the Empress Express parties.

A. TransCanada Pipelines Limited ("TCPL") is wholly owned by TC Energy Corporation and Portland Natural Gas Transmission System ("PNGTS") is 61.7 percent owned by TC Energy Corporation (https://www.tcenergy.com/operations/natural-gas/portland-natural-gas-transmission-system/#:~:text=The%20system%20began%20operations%20in,Northern%20New%20England%20Investment%20Company.)

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

EXM-001-007

Q. Referring to Attachment 6, the definitions include definitions for both AFUDC (definition c) and Monthly Carrying Costs (definition aa). Please explain why including both of these items in the project costs would not result in double recovery of interest and equity costs.

A. AFUDC applies to funds used during construction, while monthly carrying charges apply to Retained Equipment and Materials, resulting after construction has been cancelled. Therefore, there is not a double recovery of interest and equity costs.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-008

Q. Referring to page 9 of the Empress Capacity Resource Assessment, please explain what the statement in the second paragraph that states "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." and how it may have impacted the pricing of Northern's capacity request.

A. In order to determine winning bidders in its Open Season, TCPL multiplied 1) the term of each bid and 2) the current toll for the requested path. Bids were then ranked based on the product of 1) and 2).

The implication of this process is that TCPL's Open Season process favored bids with longer terms and bids on paths with higher tolls. For this reason, TCPL's evaluation of bids favors 30-year bids over 15-year bids and favors bids for Empress to East Hereford over bids for Parkway to East Hereford.

However, the price that Northern pays will ultimately be determined by the CER-approved tolls that will be in effect at the time of service. They will not be based on the tolls in effect at the time of the bids that were used solely for the purpose of evaluating bids.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

EXM-001-009

Q. Please explain the tools that Northern has to limit the cancellation costs that it and ratepayers may be exposed to if the TCPL PA is cancelled. For example, does it have the right to examine or review the costs incurred to ensure those costs were necessary?

A. The Precedent Agreement gives Northern the right to audit the supporting documentation related to the invoice for Northern's share of the costs associated with an event of cancellation.
Article 17 of the Precedent Agreement - "Audit Rights" states:
Provided Customer has paid to TCPL all amounts invoiced pursuant to this Precedent Agreement, no earlier than 30 days after TCPL has received a written request from Customer, Customer shall have the right, at its cost and expense, to examine TCPL's supporting documentation related to the particular invoice(s) to verify its accuracy. Each invoice may only be audited once. Customer's audit rights shall be granted during normal business hours. Customer's audit rights shall not include any right to break down the standard labour rates or overhead rates charged by TCPL. The total number of audits commenced in any calendar year shall not exceed one. Any audit request by Customer must be received by TCPL within a period of 2 years after the invoice in question was received. Prior to any audit, Customer and/or its auditors shall execute a confidentiality agreement, in form acceptable to TCPL, to protect the confidential nature of any information reviewed under the audit.
Furthermore, Article 14 of the Precedent Agreement - "Effect of Event of Cancellation" states:
Subject to the other provisions of this Paragraph, TCPL shall use commercially reasonable efforts to minimize all costs, expenses and charges payable by Customer to TCPL pursuant to Paragraph 15 below, which shall include (i) efforts to minimize costs, expenses and charges committed to prior to TCPL receiving and accepting all of the TCPL Authorizations and (ii) efforts to sell, dispose or utilize in a prospective expansion within a reasonable time period, all property, equipment, materials or internal or third-party work product arising out of facilities contemplated on account of the Requested Service and the Other Requests (the construction of which has been cancelled); provided that such efforts shall be subject to TCPL's obligations with respect to the Requested Service, the In-Service Date, the Other Requests and the in-service date for the Other Requests.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

15-NOV-23

EXM-001-010

Q. Referring to Confidential Attachment 7, please explain the change in the last two columns of row 10 when compared to the previous columns.

A. TCPL has informed Northern that the last two columns were incorrect. CONFIDENTIAL EXM-001-010 Attachment 1 provides the revised schedule that should replace CONFIDENTIAL Attachment 7 to the Empress Capacity Resource Assessment.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-010 Attachment 1 CONFIDENTIAL.pdf
2. EXM-001-010 Attachment 1 REDACTED.pdf

13-NOV-23

EXM-001-011

Q. Referring to page 31 of the Empress Capacity Resource Assessment, Table III-1, please explain why Granite Capacity is shown only as part of the Peaking Capacity Paths.

A. The Granite Capacity shown as Peaking Capacity Table III-1 reflects only the Granite capacity that is not used to effectuate deliveries of Pipeline and Storage Capacity. Granite capacity is currently utilized for the following Pipeline and Storage Capacity Paths.

Tennessee Zone 0 and Zone L Pools: 13,109 Dth
Tennessee Niagara: 2,327 Dth
Iroquois Receipts: 841 Dth
Tennessee Firm Storage: 2,644 Dth
Dawn Hub Storage: 59,793 Dth
Total: 78,714 Dth

The total Granite capacity volume of 122,000 minus 78,714 Dth equals 43,286 Dth, which is the volume of Granite capacity that is reported under "Peaking Capacity" in Table III-1.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-012

Q. Referring to page 38 of the Empress Capacity Resource Assessment, Table IV-2, please explain the basis for the increase in the source utilization for 2027 - 2028. Specifically, please explain whether these are planned increases in the contracts or estimated increases in Northern's load.

A. There is no planned increase in the Empress Capacity over the term of the Empress Capacity Agreements.

Evaluated portfolio utilization both with and without the Empress Capacity is shown in Table IV-2. Empress Capacity utilization increases from 3,715,845 Dth in 2026-2027 to 3,939,128 in 2027-2028, an increase of 223,283. Overall projected design year demands increase from 17,460,364 Dth to 17,664,539 Dth, an increase of 204,175 Dth. So, the increase in Empress Capacity is due mostly to the increase projected demands. Some of this increase is due to reduced summer utilization of other resources, notably Tennessee FS-MA Storage Path due to lower projected Empress delivered commodity prices during that time.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-013

Q. Please provide the Excel worksheet (not pdf format) that supports Confidential Table VI-8 on page 55 of the Empress Capacity Resource Assessment.

A. CONFIDENTIAL EXM-001-013 Attachment 1 provides the requested Excel worksheet.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-013 Attachment 1 (CONFIDENTIAL).xlsx
2. EXM-001-013 Attachment 1 (REDACTED).xlsx

13-NOV-23

EXM-001-014

Q. Referring to page 57 of the Empress Capacity Resource Assessment - please either confirm that the reference to Attachment 10 was an error or correct the reference by providing Attachment 10

A. The reference to Attachment 10 is incorrect. Attachment 9 is the correct reference.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-015

Q. Please provide an update on the status of TCPL's efforts to secure the necessary commercial and operational agreements to provide service on April 1, 2024. This is a continuing request for periodic updates.

A. TCPL has made operational arrangements with one of its customers, Energir L.P., to create capacity to East Hereford from November 1, 2023 to October 31, 2027.

As a result of Energir's operational commitments, incremental capacity of up to 63,100 GJ/d to East Hereford is made available annually until facilities for the 2027 NCOS are completed.

All of the commercial and operational agreements to provide service on April 1, 2024 been acquired.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-016

Q. Please indicate whether Northern Utilities is the sole subscriber to TCPL's 2027 capacity expansion.

A. Northern Utilities is not the sole subscriber to TCPL's 2027 capacity expansion. Emera Energy and New England Green Gas were also awarded capacity in the open seasons on TCPL and PNGTS.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-017

Q. Did Northern consider structuring its bid as a shorter term with renewal rights? Please explain its considerations and why a longer term is preferable.

A. Northern elected to structure its bid with a 30-year term in order to increase the likelihood that it would be successful in the open season. As explained in EXM-001-005, bidding a shorter term with renewal rights would have increased the likelihood that Northern would not be awarded any capacity through the Open Season process.

Northern believes that the Empress Capacity will provide benefits to customers over the term of the agreement. Please refer to responses to EXM-001-023 and EXM-001-024.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-018

Q. Has Northern considered initiating service-related demand side peak reduction alternatives, such as service terms that would allow Northern to interrupt service to large users during cold weather events or other approaches? Please explain.

A. Northern previously had interruptible customers. These customers switched to firm service, indicating a lack of market interest in such a peak reduction alternative.

Similarly, Capacity-Exempt Delivery Service is available to new service locations and eligible customers that elected capacity-exempt service in the Capacity-Exempt Open Season that was required as part of Northern's compliance with 2014-00132, the Delivery Service Terms and Conditions proceeding that established the current capacity assignment program. Northern does not require additional capacity for these Capacity Exempt customer loads. Presumably, customers that had the ability and willingness to curtail gas usage during cold weather events would find Capacity-Exempt service attractive. However, capacity exempt customers have been switching to sales service in recent years and new service locations have not elected capacity exempt service.

For this reason, Northern has not considered demand service peak reduction programs as a potential peaking solution.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-019

Q. Please explain why Northern selected the Empress Alberta receipt point rather than the Parkway Ontario receipt point and whether these paths would have a substantial cost difference.

A. Northern values the importance of diversification of supply points within its portfolio, and does not have access to Western Canadian supply with any of its other capacity paths.

The evaluated price of the supply at Empress is lower than supply sourced from Parkway Ontario.

Also, as explained in response to EXM 1-8, a bid from Parkway to East Hereford would have had a lower probability of award from TCPL due to its lower toll than the toll from Empress to East Hereford.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

EXM-001-020

Q. Is pipeline project cancellation insurance an option for Northern?

A. Northern outlines its current understanding, strategies, timing and potential effects relative to cancellation and pre-service exposure in the direct testimony of Francis X. Wells at pages 9 and 10. Beyond the discussion contained therein, Northern is currently unaware of any other viable steps to protect against this exposure. Northern will continue to manage its exposure under the agreements as new information becomes available and as new strategies are identified, if any.

Consistent with Northern's response to a similar question in Docket 2019-00101, Northern has not sought to price insurance to cover the exposure. Northern continues to believe that insurance companies are not likely to be familiar with the particular risks presented by precedent agreements and therefore would be likely to assign a relatively high level of risk. Northern believes the most likely outcome is that the projects will go into service and Northern will face no charges related to project cancellation.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

EXM-001-021

Q. Please provide a comparison of what the cost incurred for the peaking supply purchased for the November 1, 2022, to October 31, 2023, year was to the total cost for supply under the Empress Capacity agreements if it had been available for the entire period.

A. Under the hypothetical scenario that Northern had access to the Empress Capacity during the 2022-2023 gas year as stipulated in this request, Northern would not have limited its utilization as a replacement for peaking supply. Rather, Northern would have fully-utilized the resource in both Winter and Summer periods to the extent it would have benefited customers to do so. Therefore, the unit cost data presented in this response ignores other critical hypothetical opportunities that Empress capacity might have saved Northern in commodity cost for non-peaking supply purposes. However, Northern provides the following response.

Northern had two off-system peaking supply contracts for the 2022-2023 gas year.

Peaking Contract 1 was the final year of a four-year peaking supply contract. The total unit cost of this contract, inclusive of both demand and commodity charges, is provided in CONFIDENTIAL EXM-001-021 Attachment 1 on cell D15 of the worksheet labelled, "EXM 001-021 Attachment 1." The worksheets, labelled, "2022-11 Peaking 1" through "2023-03 Peaking 1" provide supporting calculations for the actual commodity charges pursuant to this agreement.

Peaking Contract 2 was a short-term peaking supply contract from November 2022 through March 2023. The total unit cost of this contract, which included only commodity charges, is in CONFIDENTIAL EXM-001-021 Attachment 1 on cell E15 of the worksheet labelled, "EXM 001-021 Attachment 1." The worksheets, labelled, "2022-11 Peaking 2" through "2023-03 Peaking 2" provide supporting calculations for the actual commodity charges pursuant to this agreement.

For the purpose of comparing Empress Capacity and associated supply costs to Peaking Contract 1 & 2, I assumed that the Empress Capacity would only be filled on days that the actual peaking contracts were utilized. These calculations are provided in the worksheet labelled, "Daily Volumes." The Hypothetical Empress Capacity Utilization was subtotaled by month. Commodity prices were the average daily price paid for Empress supply each month plus estimated fuel and transportation charges and added to the estimated demand charges. The total unit cost of this hypothetical option, inclusive of both demand and commodity charges, is in CONFIDENTIAL EXM-001-021 Attachment 1 on cell N15 of the worksheet labelled, "EXM 001-021 Attachment 1."

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-021 Attachment 1 CONFIDENTIAL.xlsx

14-NOV-23

EXM-001-022

Q. Please provide Northern's actual peak load during both the winter (peak) and summer (off-peak) periods for the last five years.

A. EXM-001-022 provides the requested data. ME, NH, and Northern System Load data reflects winter and summer peak loads for the entire system, inclusive of Sales Service, Capacity Assigned Delivery Service and Capacity Exempt Delivery Service loads. ME, NH, and Northern Planning Load reflects winter and summer peak loads for Planning Load customers only, which includes Sales Service and Capacity-Assigned Delivery Service customers. Please note that Planning Load data for the 2023 Summer Period will be available after the October 2023 cashout and imbalance charges have been processed.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-022 Attachment 1.xlsx

14-NOV-23

EXM-001-023

Q. Regarding Section II(D) of the Resource Assessment: Please explain generally how Northern plans to manage its natural gas operations to meet Unitil's carbon and greenhouse gas emissions reduction goals, as well as Maine's policy goals.

A. Unitil is committed to reducing company-wide direct greenhouse gas emissions, including fugitive emissions, by 50% by 2030, and to achieving net zero emissions by 2050. Unitil's most recent Sustainability Report, which was issued in late October, can be accessed at https://unitil.com/reports/2023-Sustainability-Report/5/. To meet Unitil's greenhouse gas reduction targets, Northern plans complete its leak-prone pipe replacement program, increase the use and efficiency of methane recapture technology, and pilot advanced leak detection and repair technology, while continually assessing emissions factors and calculations to most accurately represent fugitive gas emissions.

Northern believes that Unitil's emissions reduction goals are consistent with those of the State of Maine as set forth in 38 MRSA ?576-A, and that the Company will manage its natural gas operations in a way that supports and contributes to the achievement of the State's policy goals. Maine's goals to decarbonize should include natural gas commodity and natural gas infrastructure as part of its portfolio in order to meet emissions reduction goals. Though the need for the Empress Capacity is not predicated upon a projected increase in customers, Northern believes that, due in part to Maine's heavy reliance on delivered fuels, there is a unique opportunity to convert many of those users to natural gas, contributing to emissions reductions in both greenhouse gas and air quality criteria pollutants in the State while being mindful of the need for affordability, equity of service, and reliability among customers. Additionally, the Company believes that the natural gas distribution system and infrastructure will continue to play a role in decarbonization as further innovation takes place and emerging technology becomes viable and affordable, including example such as renewable natural gas, gas-powered heat pumps, and hydrogen.

The Company also believes that natural gas provides customers with a wide variety of benefits as they meet their energy needs. These benefits specifically include affordability and reliability. Customers are looking for affordable sources of energy and natural gas is less costly relative to other types of fuels. It is especially important to consider affordability when looking at the energy needs of low-income and moderate-income customers. Coupled with affordability, natural gas remains a reliable commodity with its delivery system, particularly in a cold-weather climate, like Maine, that can experience severe weather events. It is paramount that when considering how Northern can contribute to meeting our own carbon and greenhouse gas emissions reduction goals, as well as those of the state of Maine, that affordability, reliability, and safe service remain the key objectives

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

EXM-001-024

Q. Please explain how Northern's resource portfolio, including its proposed acquisition of Empress pipeline capacity, will offer flexibility and optionality "as the natural gas market landscape continues to evolve to address state and regional climate goals and policies, and customer preferences." Resource Assessment at 30. Does the length of the proposed Empress Agreement work against those goals or present a greater risk to the Company and its ratepayers?

A. As explained in Northern's response to Data Request EXM-001-023, the Company believes that natural gas provides customers with a wide variety of benefits as they meet their energy needs, including affordability and reliability of service, the ability to contribute to the decarbonization goals of both the Company and the state, and future benefits in utilizing the gas system with innovative technologies. The Company believes that these benefits therefore also apply in our proposed acquisition of Empress pipeline capacity.

Northern's proposed acquisition of Empress pipeline capacity is intended to enhance reliability and affordability in covering demand requirements on its system for the foreseeable future. As explained in the Empress Capacity Resource Assessment, Northern requires additional gas supply resources beyond the Empress Capacity in order to ensure reliability and affordability of service to customers. EXM 001-0024 Attachment 2 is a memo issued jointly by FERC and NERC highlighting the importance of reliability and affordability and the importance of infrastructure in providing reliable and affordable service to customers in New England.

Northern recognizes the need for flexibility and optionality within its portfolio to respond to potential reductions in demand in the future, and has identified the ability to not renew other contracts in the portfolio in the future to be a lever upon which the Company may rely to right size the portfolio as customer demands potentially decline in future years. This approach allows the Company to reliably serve customers in a least cost manner while maintaining sufficient flexibility to respond to potential changes in demand as state and regional climate goals, policies, and customer preferences evolve.

Northern's portfolio provides a diversity of termination dates. Northern has either a renewal right or right of first refusal on its portfolio of pipeline capacity contracts, assuring that it has the right, but not the obligation, to extend its pipeline capacity contracts. Hypothetically, to the extent that natural gas demand on Northern's system declines during the term of the Empress Capacity Agreements for any reason to the point where the portfolio contains excess resources, Northern's resource portfolio provides flexibility and optionality to reduce pipeline capacity volumes of other capacity paths by terminating rather than renewing certain contracts to ensure that pipeline capacity resources best match planning load requirements. The Company believes that this is an unlikely outcome given that the Company's portfolio, even with the addition of the Empress Capacity, does not fully meet forecasted demand. Regardless, this ability provides Northern an important tool to manage risks associated with potential future changes in the demand for natural gas.

EXM-001-024 Attachment 1 provides an overview of the volume and term of the current contractual commitments in Northern's portfolio. On the EXM-001-024 Att 1 Chart worksheet, the maximum delivery quantity in terms of Dth per Day is shown on the y-axis and the length of Northern's contractual commitment on the x-axis for each Capacity Path in Northern's portfolio, including the proposed Empress Capacity. This data is presented in tabular format on the EXM-001-024 Att 1 Data worksheet. In some cases, contracts within a capacity path do not terminate on the same date. In these instances, the latest contract termination date was used. Extension beyond these dates would require Northern's agreement to renew or extend contracts. For reference, EXM-001-024 Attachment 1 also provides the contract detail for each capacity path in Northern's portfolio, including the earliest possible termination dates on a contract level.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. EXM-001-024 Attachment 1.xlsx
2. EXM-001-024 Attachment 2.pdf

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REQUEST FOR APPROVAL OF PRECEDENT AGREEMENT PERTAINING TO NORTHERN UTILITIES, INC. D/B/A UNITIL INC.
2023-00254
RESPONSE TO ODR-001
BY NORTHERN UTILITIES, INC. D/B/A UNITIL INC

22-NOV-23

ODR-001-001

Q. At the time the company did its resource options analysis, did the company know that - due to the Project Maple projected in-service date - it was not an option for the Company in 2024? When would the Project Maple capacity be available if it were on the Northern System?

A. At the time that Northern did its resource options analysis, the Company did not know that capacity through the Weymouth Compressor Station on Algonquin was fully subscribed meaning that Project Maple was not an option for Northern. In order for that project to be a viable option for Northern, deliveries through Weymouth to the interconnect with Algonquin and Maritimes at Beverly/Salem, MA would be necessary.

The Project Maple Open Season is provided as ODR-001-001 Attachment 1. The Project Service section of the Project Maple Open Season states that Project Maple "will offer delivery to existing meters on the Algonquin mainline and/or lateral systems." At the time the resource analysis was completed, Northern understood this to include the interconnect between Algonquin and Maritimes as being included as it is an existing meter on Algonquin's system.

The Open Season section of the Project Maple Open Season states, "Algonquin anticipates that Project Maple will have a target in-service date as early as November 2029", therefore the Company was aware of the targeted in-service date of November 2029.

A. Please see Attachment 1.;R

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. ODR-001-001 Attachment 1.pdf

22-NOV-23

ODR-001-002

Q. Please provide the complete discovery responses from the parallel proceeding in New Hampshire, DG 23-087; this is a continuing request

A. Please see the attached discovery responses submitted in DG 23-087. Please note, the Company's response to DOE 1-2 comprised discovery submitted in this docket, and as such has not been provided as an attachment.

Author of Response:
Patrick H. Taylor

Witness Responsible For Response:
Patrick H. Taylor

List of Attachments
1. DG 23-087 DOE Set 1 Non-Confidential.zip
2. DG 23-087 DOE 1-01 Attachment 1 (PUBLIC).zip
3. DG 23-087 DOE 1-01 Attachement 2 (CONFIDENTIAL).zip
4. DG 23-087 DOE 1-07 CONFIDENTIAL.pdf
5. DG 23-087 DOE 1-08 CONFIDENTIAL.pdf
6. DG 23-087 DOE 1-24 CONFIDENTIAL.pdf
7. DG 23-087 DOE TS Set 1 Non-Confidential.zip
8. DG 23-087 DOE TS 1-06 Attachment 1 CONFIDENTIAL.xlsx

22-NOV-23

ODR-001-003

Q. Please provide a data dictionary for the design year and normal year planning regression models, with explanations of abbreviations and units for all columns in the attachments to CLF-001-002

A. For CLF-001-002 Attachments the abbreviations and units are below:
Res_CUST - Residential class customer count, this is recorded as an average of the active meters over the course of each calendar month.
LLF_CUST - Low Load Factor class customer count, this is recorded as an average of the active meters over the course of each calendar month.
HLF_CUST - High Load Factor class customer count, this is recorded as an average of the active meters over the course of each calendar month.
Total Customers - Summation of Res_CUST, LLF_CUST, and HLF_CUST.
Res - WN THERMS - Residential class weather normalized therm totals.
LLF - WN THERMS - Low Load Factor class weather normalized therm totals.
HLF - WN THERMS - High Load Factor class weather normalized therm totals.
Res_UPC - WN UPC - Weather normalized Residential class Use Per Customer, this is the ratio of Res - WN THERMS to Res_Cust, resulting in units of Therms?Customer.
LLF_UPC - WN UPC - Weather normalized Low Load Factor class Use Per Customer, this is the ratio of LLF - WN THERMS to LLF_Cust, resulting in units of Therms?Customer.
HLF_UPC - WN UPC - Weather normalized High Load Factor class Use Per Customer, this is the ratio of HLF - WN THERMS to HLF_Cust, resulting in units of Therms?Customer.
CE_CUST - Capacity Exempt class customer count, this is recorded as an average of the active meters over the course of each calendar month.
CE_DEMAND - Capacity Exempt class therm totals.
WN_CE_DEMAND - Weather normalized Capacity Exempt class therm totals.
CE_UPC - Capacity Exempt class Use Per Customer is the ratio of CE_DEMAND to CE_CUST resulting in units of Therms?Customer.
CE_PERCENT - The Capacity Exempt class ratio in percentage of WN_CE_DEMAND to the sum of LLF - WN THERMS and HLF_WN Therms. More simply put, the ratio of Capacity Exempt demand to Commercial and Industrial customer demand.
Planning Load Demand - Total load excluding capacity exempt demand.
WN Planning Load Demand - Weather normalized total load excluding weather normalized capacity exempt demand.
Trend - Linear count used for regression analysis.
Log_Trend - Logarithmic count used for regression analysis.
BC_EDD - Billing Cycle Effective Degree Day total.
BC_EDD_DES - Billing Cycle Effective Degree Day total for given design weather. (e.g. 15, 20, or 30 year weather normal)
BC_EDD_DIFF - Billing Cycle Effective Degree Day difference between BC_EDD_DES and BC_EDD.
CAL_EDD - Calendar month effective degree day total.
CAL_EDD_DES - Calendar month Effective Degree Day total for given design weather. (e.g. 15, 20, or 30 year weather normal)
CAL_EDD_DIFF - Calendar month Effective Degree Day difference between CAL_EDD_DES and CAL_EDD.
The Months Jan thru Dec are binary operators used in regression analyses.
The months BC_Jan through BC_Dec are similarly the binary operators of Jan thru Dec multiplied by the BC_EDD column.
For the independent variables below the data was representative of Portland-South Portland Metropolitan area and Rockingham-Strafford Counties for Northern Maine and New Hampshire respectively. All independent variable data gathered from Moody's Analytics.
POP - Population total in thousands.

HH - Households in thousands.
IND PROD - Industrial Production with a baseline of 100 in 2017.
GMP - Gross Metropolitan Product in billions of U.S. dollars.
INC HH - Average Household Income in U.S. dollars.
EMP MAN - Employment in Manufacturing in thousands.
EMP NON AGR - Employment in Non Agriculture in thousands.
EMP PRIV - Employment in Private Service Providing in thousands.
RET SAL - Retail Sales in billions of U.S. dollars.
UNEMP - Unemployment rate as a percentage.
EMP TTU - Employment in Trade; Transportation and Utilities in thousands.
LABOR_FORCE - Civilian Labor Force in thousands.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

22-NOV-23

ODR-001-004

Q. Please provide the specifications of the individual regression models referenced in the attachments to CLF-001-002, indicating the variables used in each model.

A. Please see ODR-001-004 Attachment 1 and ODR-001-004 Attachment 2 which represent the regression models and statistical analyses for Northern Maine and Northern New Hampshire, respectively.

A. Please see Attachments 1 and 2;R

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. ODR-001-004 Attachment 1.pdf
2. ODR-001-004 Attachment 2.pdf

22-NOV-23

ODR-001-005

Q. Please provide for the Maine design year and normal year models presented in Attachments 1 and 3 of CLF-001-002, a comparison of the actual 2023 year-to-date values with the forecasts.

A. Please see the attached response.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. ODR-001-005.pdf

22-NOV-23

ODR-001-006

Q. In response to CLF 001-002, Northern states that it has not attempted to model customer demand based on energy and environmental changes. Please explain whether existing energy and environmental policies are included in the modeling..

A. Northern's regression analysis is primarily dependent on historical data to determine which economic, demographic, weather, season, month, or other independent variables correlate appropriately with the changes in customer demand. If any of these independent variables are being directly or indirectly affected by energy or environmental policies, then those historical values will carry that change into the regression analysis.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

22-NOV-23

ODR-001-007

Q. In response to CLF 001-008, Northern states: " Moreover, the Company believes that natural gas will remain a dispatchable fuel that could provide service to customers during power grid constraints, even if electrified heating grows during this time period". Does the Company believe that customers serviced by electrified heating will be connected to gas systems?

A. Northern believes that natural gas provides, and will continue to provide, safe, reliable, and affordable energy to customers. The Company also believes that customers should have the ability to choose the fuel source that best meets their needs. Customers that have electrified heating may desire to use natural gas for other purposes or may desire to use natural gas as a fuel source when electrified heating is not as efficient or cost-effective as natural gas heating.

Please also see the Company's response to EXM-001-023.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

22-NOV-23

ODR-001-008

Q. In response to EXM 001-023, Northern states: "the Company will manage its natural gas operations in a way that supports and contributes to the achievement of the State's policy goals." Has Northern conducted modeling of emissions reduction to support and continue the achievement of the targets? If so, please provide it in Excel if available.

A. No, the Company has not conducted modeling of emissions reduction. However, the Company has set a company-wide target and completes an annual greenhouse gas emissions inventory to track progress towards the goal.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

22-NOV-23

ODR-001-009

Q. Follow-up to EXM-001-10: Please confirm that all columns in EXM 001-010 Attachment 1 are correct even if they are different from Confidential Attachment 7 in the original filing documents and provide it as an Excel file.

A. TransCanada has confirmed that all the data provided in EXM 001-010 Attachment 1 are correct. This schedule should be used instead of Attachment 7.

CONFIDENTIAL ODR-001-009 Attachment 1 provides this data in Excel format.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. ODR-001-009 Attachment 1 (CONFIDENTIAL).xlsx
2. ODR-001-009 Attachment 1 (REDACTED).xlsx

22-NOV-23

ODR-001-010

Q. Follow-up to EXM-001-021: Please provide the same response but showing the results if Northern had used the Empress resource throughout the year (both Winter and Summer periods) to the extent it would have benefited customers to do so, instead of just replacing the peaking supplies with the resource.

A. CONFIDENTIAL ODR-001-010 Attachment 1 provides a comparison of actual 2022-2023 Off-System Peaking Contract Costs compared to estimated costs of the Empress capacity resource, based on 2022-2023 Empress commodity prices and a reasonable estimate of Empress utilization for the 2022-2023 annual period.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. ODR-001-010 Attachment 1 CONFIDENTIAL.xlsx

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REQUEST FOR APPROVAL OF PRECEDENT AGREEMENT PERTAINING TO NORTHERN UTILITIES, INC. D/B/A UNITIL INC.
2023-00254
RESPONSE TO OPA-002
BY NORTHERN UTILITIES, INC. D/B/A UNITIL INC

13-NOV-23

OPA-002-001

Q. Does Northern see a significant risk that Saint John LNG will cease operations before Repsol's firm transportation contract with Maritimes & Northeast expires in 2034? If so, please explain the reasons for Northern's concern.

A. Northern believes there is uncertainty as to the future availability of the Saint John LNG facility as well as the Everett Marine Terminal, which is supported by the transcript from the FERC 2023 New England Winter Gas-Electric Forum which is attached hereto as OPA-001-001 Attachment 1 and Repsol's comments post FERC Forum, OPA-001-001 Attachment 2, and Unitil's comments to the Massachusetts Department of Public Utilities related to the impact of the potential loss of the Everett Marine Terminal, which is attached as OPA-001-001 Attachment 3.

A. See attached;R

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. OPA-001-001 Attachment 1.pdf
2. OPA-001-001 Attachment 2.pdf
3. OPA-001-001 Attachment 3.pdf

14-NOV-23

OPA-002-002

Q. The TCPL New Capacity Open Season offered both Empress and Parkway receipt points. Did Northern compare the proposed Empress capacity to the option of contracting with TCPL from Parkway and buying gas at Parkway, or contracting with TCPL from Parkway and Enbridge from Dawn and buying gas at Dawn? If so, please explain the assumptions Northern used for its analysis and provide the results.

A. As noted in EXM 001-008, in order to determine winning bidders in its Open Season, TCPL multiplied 1) the term of each bid and 2) the current toll for the requested path. Bids were then ranked based on the product of 1) and 2).

The implication of this process is that TCPL's Open Season process favored bids with longer terms and bids on paths with higher tolls. For this reason, TCPL's evaluation of bids favors 30-year bids over 15-year bids and favors bids for Empress to East Hereford over bids for Parkway to East Hereford. A bid at Parkway would have had to be 75 years long to be comparable to the 30-year bid at Empress.

Additionally, Northern values supply diversity and the ability to access liquid supply points when making portfolio planning decisions. Currently, Northern's portfolio does not have receipts in Western Canada and has a significant amount of Dawn receipts. Due to the low cost of supply that can be accessed at Empress, the liquidity at that point, and the opportunity to add Empress as a new supply point, Northern identified Empress as a positive addition to its capacity portfolio.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-003

Q. How did exchange rate risk factor into Northern's decision to contract for TCPL FT service from Empress for an initial term of 30 years?

A. The January 2017 through February 2023 average daily exchange rate, posted by the Bank of Canada, was assumed in Northern's decision process, which is equal to 1.304 USD per CAD. This was also used in Northern's IRP filing. As of November 7, 2023, the current exchange rate more favorable than this average, which is equal to 1.376 USD per CAD. This assured that the results in Northern's analysis were based on a broader set of exchange rate data, rather than on a single point in time.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

OPA-002-004

Q. Did Northern consider contracting for TCPL capacity from Empress when the Company signed up for the PNGTS WXP expansion? If so, please explain why Northern chose to contract with TCPL from Parkway instead of Empress at that time.

A. Circumstances have changed since Northern contracted for the PNGTS WXP expansion. The capacity offered in this Open Season was limited to 63,100 GJ, whereas there were no such limitations articulated at the time of TCPL's New Capacity Open Season issued in conjunction with PNGTS' WXP Open Season and for that reason the Company did not consider bidding on Empress receipts.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-005

Q. The open season documents for the Algonquin Project Maples expansion include an illustrative rate of $2.75 Dth/day for service from Ramapo to the "head of the G and J system and in path meters". Did Northern confirm with Algonquin that a transportation path from Ramapo to Beverly/Salem is offered under the Project Maple expansion? If so, what is the illustrative rate?

A. As part of Algonquin's Project Maple Expansion, there was no capacity offering for a path that delivers from Ramapo to the Beverly/Salem interconnect with Maritimes & Northeast, because capacity through the Weymouth Compressor Station is fully subscribed.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-006

Q. What is Northern's current understanding of Algonquin's planned in-service date for new service from Ramapo (not Salem) under the Project Maple expansion?

A. As stated in OPA-001-005, as part of Algonquin's Project Maple Expansion, there was no capacity offering for a path that delivers from Ramapo to the Beverly/Salem interconnect with Maritimes & Northeast, because capacity through the Weymouth Compressor Station is fully subscribed.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-007

Q. What information sources did Northern consult to develop the Company's long-term outlook for gas prices at Empress?

A. Northern added the settlement prices for the AB-NIT basis future, the fixed price spread between AB-NIT and Empress, as was posted by the Intercontinental Exchange ("ICE"), and the projected NYMEX last day settlement price posted on June 1, 2023.

Pages 19 and 20 of the Empress Capacity Resource Assessment also provides information on the supply outlook for the Western Canadian Sedimentary Basin, which is the source of supply for Empress.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-008

Q. How does Northern expect that LNG exports from the West Coast of Canada will affect natural gas prices at Empress?

A. Northern has not analyzed the impact of LNG exports from the West Coast of Canada on Empress natural gas prices. Northern's forecast of Empress supply prices is based on publicly available basis prices, which presumably, would reflect the market's current expectations based on all available information on future pricing.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

14-NOV-23

OPA-002-009

Q. What new pipeline facilities would need to be constructed (by TCPL or others) for TCPL to provide 13,600 GJ/day of Empress-to-East Hereford FT service for Northern beginning in 2027?

A. CONFIDENTIAL OPA-001-009 Attachment 1 provides the requested information.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. OPA-001-009 Attachment 1 CONFIDENTIAL.pdf

14-NOV-23

OPA-002-010

Q. Does TCPL currently have available capacity on the Western Mainline to provide 13,600 GJ/day of FT service from Empress to North Bay Junction?

A. The capacity contracted to East Hereford in the TCPL Open Season, including Northern's contracted quantity of 13,600 GJ/d, is facilitated by existing capacity on TCPL's western mainline system from Empress to North Bay Junction, along with the addition of new facilities on the TQM system which connects to the East Hereford delivery point. The TCPL Mainline is now fully contracted, and there is no remaining capacity available between Empress and North Bay Junction at this time.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-011

Q. At the time of the 2027 New Capacity Open Season, did Northern have reason to expect that the Company would not have been awarded 13,600 GJ/day of FT service from Empress or Parkway if the Company requested an initial term of 15 years? If the answer is yes, please explain.

A. The responses to Data Request OPA-001-004, EXM-001-005 and EXM-001-008 provide the requested information.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

15-NOV-23

OPA-002-012

Q. For each of the redactions that Northern made to Tables VI-1, VI-2, VI-3, VI-4, VI-5, VI-6, and VI-7, please explain why the Company believes that the redaction is necessary to protect commercially-sensitive non-public information.

A. In general, Northern considers its conclusions regarding qualitative and quantitative assessments to be commercially sensitive with the potential to either affect bids received in future RFPs or impact Northern's bargaining position in the context of potential contract negotiations.

Public disclosure of Northern's assessment of Empress Capacity could impact offers received in future requests for proposals.

Public disclosure of Northern's assessment of Off-System Peaking Contracts could impact bids received in Off-System Peaking RFPs.

Public disclosure of Northern's assessment of Project Maple could impact bids received on Northern's procurement of supply for its Atlantic Bridge Capacity or impact potential precedent agreement negotiations with Enbridge now or in the future.

Northern has been in discussions with a potential developer of a New LNG Facility, as discussed in the Empress Capacity Resource Assessment. Northern considers these discussions to be confidential and public disclosure could impact potential precedent agreement negotiations.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments

13-NOV-23

OPA-002-013

Q. See Confidential Data Request Attached.

A. Please see OPA-001-013 Confidential Attachment 1

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. 2023-11-08_Confidential OPA-002-013 Data Request_PO 2_2023-00254.pdf
2. OPA-001-013 - Confidential Attachment 1.pdf
3. OPA-001-013 - Redacted Attachment 1.pdf

14-NOV-23

OPA-002-014

Q. See Confidential Data Request Attached.

A. CONFIDENTIAL OPA-001-014 Attachment 1 provides the requested data.

Author of Response:
Francis X. Wells

Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. 2023-11-08_Confidential OPA-002-014 Data Request_PO 2_2023-00254.pdf
2. OPA-001-014 Attachment 1 CONFIDENTIAL.xlsx
3. OPA-001-014 Attachment 1 REDACTED.xlsx

14-NOV-23

OPA-002-015

Q. See Confidential Data Request Attached.

A. Please see OPA-001-015 Confidential Attachment 1

Author of Response:
Francis X. Wells

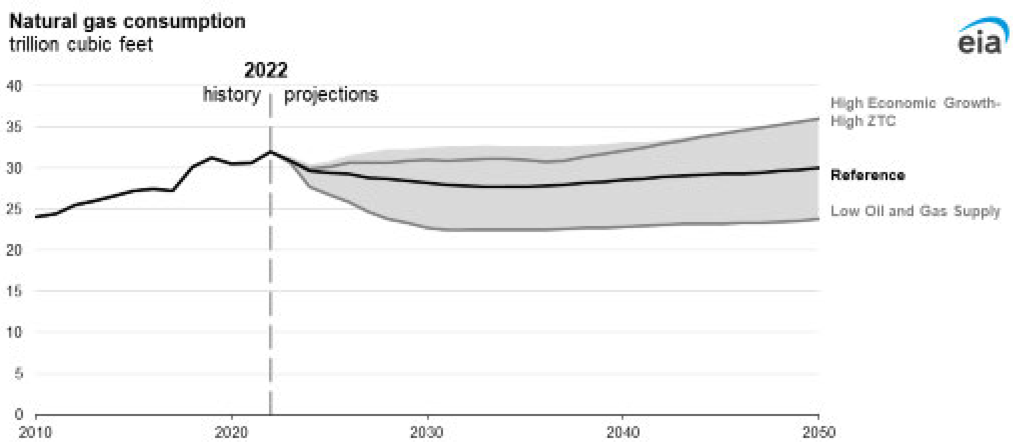
Witness Responsible For Response:
Francis X. Wells

List of Attachments
1. 2023-11-08_Confidential OPA-002-015 Data Request_PO 2_2023-00254.pdf
2. OPA-001-015 - Confidential Attachment 1.pdf
3. OPA-001-015 -REDACTED Attachment 1.pdf

Close Print

2023-00254
CLF 001-001 ATTACHMENT 1
Page 1 of 1

Figure 14



Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2023* (AEO2023)
Note: Shaded regions represent maximum and minimum values for each projection year across the AEO2023 Reference case and side cases. ZTC=Zero-Carbon Technology Cost.

Projected Normal Year Empress Utilization

Gas Year	City-Gate Volumes (Dth)	Maximum City-Gate Volumes (Dth)	Capacity Factor (City-Gate / Maximum Volumes)
2023-2024	2,539,419	2,665,638	95%
2024-2025	3,562,052	4,546,531	78%
2025-2026	3,179,605	4,546,531	70%
2026-2027	3,214,334	4,546,531	71%
2027-2028	3,381,926	4,558,988	74%

REDACTED

CLF-001-006 Attachment 1
Page 1 of 1

[redacted]

REDACTED

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Conservation Law Foundation's Data Requests – Set 1
Issue Date: November 7, 2023

Data Request CLF-001-006:

Please describe Northern's expectations with regard to asset management revenue. For instance, what percentage of demand costs does Northern expect to be able to offset with asset management revenue? What about other transportation costs and gas supply costs?

CONFIDENTIAL Response:

Asset Management is a form of supply agreement whereby 1) Northern releases capacity to the Asset Manager and 2) the Asset Manager sells delivered supply to Northern using this capacity. In return for the opportunity to optimize any capacity not nominated by Northern, the Asset Manager pays Northern a fixed asset management fee, typically paid in monthly installments during the term of the agreement. In other words, asset management revenue represents the value of this residual capacity.

Northern's asset management agreements pertain only to capacity available to Northern to serve its Sales Service customers after it has allocated capacity to retail marketers serving Capacity-Assigned Delivery Service customers. The utilization analysis provided in this proceeding relates to Planning Load, inclusive of both Sales Service and Delivery Service customer loads, so it is important to understand that any projections of Asset Management revenue relative to Planning Load require some extrapolation as Northern's historic Asset Management revenue pertains to capacity that is allocated to Sales Service customers only.

[redacted]

REDACTED

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Conservation Law Foundation's Data Requests – Set 1
Issue Date: November 7, 2023

[redacted]

[redacted]

[redacted]

CONFIDENTIAL Attachment 9 to the Empress Capacity Resource Assessment provides an analysis of the impact of adding Empress Capacity to portfolio costs under design and normal weather conditions, which includes the impact of changes in portfolio transportations and gas supply costs. Addition of Empress Capacity has no impact on the transportation costs associated with other resources.

Date: November 15, 2023 **Person Responsible:** Francis X. Wells

State of Maine
Public Utilities Commission **Confidential**

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Conservation Law Foundation's Data Requests – Set 1
Issue Date: November 7, 2023

Data Request CLF-001-007:

Please describe the daily flexibility of the Empress Capacity Path.

CONFIDENTIAL Response:

[redacted]

[redacted]

Date: November 14, 2023 **Person Responsible:** Francis X. Wells

Northern Utilities, Inc.
DG 23-087
Petition for Expedited Approval of Empress Capacity Agreements
NH Department of Energy Data Requests - Set 1

Date Request Received: 11/07/23 **Date of Supplemental Response:** 11/28/2023
Request No. DOE 1-02 **Witness: Patrick Taylor (Counsel)**

Request:

Please provide copies of all data request (i.e., interrogatory) responses the Company has or will file in the parallel Maine docket, Case Number 2023-00254.

Response:

The Company has provided all responses to EXM Set 1, CLF Set 1, and OPA Set 2, with attachments, submitted in Maine Public Utilities Commission Docket 2023-00254. Please note, OPA Set 1 was deleted and resubmitted as OPA Set 2; there is no Set 1.

Included with the responses are certain Confidential responses and attachments that are subject to Protective Orders issued in Docket 2023-00254. The Company has a good faith basis for seeking confidential treatment of these documents pursuant to Puc 203.08 and intends to submit a motion for confidential treatment regarding these documents at or before the commencement of the hearing in these proceedings.

Supplemental Response (11.28.23):

The Company has provided all responses to ODR (Oral Data Request) Set 1, submitted in Maine PUC Docket 2023-00254 on November 28, 2023. The Company has not provided the attachments to ODR 1-2, which requested all discovery submitted in DG 23-087.

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Examiner's Data Requests – Set 1
Issue Date: November 6, 2023

Data Request EXM-001-001:

Please explain how Northern selected the quantity of Dth proposed under the precedent agreement(s) given both the quantity available and Northern's supply needs.

REDACTED Response:

[BEGIN REDACTED] [redacted] [END REDACTED]

Date: November 13, 2023 **Person Responsible:** Francis X. Wells

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Examiner's Data Requests – Set 1
Issue Date: November 6, 2023

Data Request EXM-001-005:

Please explain Northern's thoughts on the likelihood that tariffed rates would decrease for PNGTS over the 30 year life resulting in Northern paying higher rates because of the length of the contract than it would if it had signed a 15 year agreement.

CONFIDENTIAL Response:

As discussed in Section I.C.2 of the Empress Capacity Resource Assessment, PNGTS' Open Season stipulated that 15 years was the minimum term that would be considered. However, it also stated that bids would be evaluated on the basis of net present value. A 15-year bid would have a lower net present value than a 30-year bid. Bidding a 15-year term rather than a 30-year term would have increased the likelihood that Northern would not be awarded any capacity through the Open Season process. It is important to note that bidders, including Northern, did not have insight into what term and price that would be offered by other bidders. [BEGIN REDACTED] [redacted] [END REDACTED].

While it is certainly possible that PNGTS' tariff rate may decrease over the term of the PNGTS FT Contract, in Northern's view, bidding the minimum 15-year term was not an option that would have been likely to result in a successful award of capacity.

Date: November 13, 2023 **Person Responsible:** Francis X. Wells

REDACTED

Estimate of Shared Facilities Costs ($)
for 2027 Eastern System Expansion
(Confidential)
November 14, 2023

The following is an estimate provided for information purposes only and on a without prejudice basis. Shipper is liable for the actual amount payable as calculated pursuant to the terms of the Precedent Agreement.

Northern Utilities, Inc. - 13,600 GJ/d, Empress to East Hereford from Apr. 1, 2024 to Mar. 31, 2054 (Estimated Exposure Profile for Required Facilities)

[redacted]

FEDERAL ENERGY REGULATORY COMMISSION
Office of the Chairman

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

November 6, 2023

Comments of Chairman Willie L. Phillips and NERC CEO James B. Robb

We remain concerned about the potential loss of the Everett Marine Terminal (Everett) in New England and the consequences that it might have for the reliability and affordability of the region's energy supplies.

At the September 2023 Open Meeting, Federal Energy Regulatory Commission (Commission) and North American Electric Reliability Corporation (NERC) staff presented preliminary findings and recommendations regarding Winter Storm Elliott. During the storm, both electric and natural gas systems throughout much of the eastern half of the United States were subjected to significant stress, resulting in significant unplanned generating unit losses, with nearly 90,000 megawatts out at the same time. Indeed, the Winter Storm Elliott findings demonstrate the importance energy infrastructure plays in ensuring that we have reliable, affordable supplies of all types of energy.

While the New England Winter Gas-Electric Forum (Forum) largely focused on the Commission-jurisdictional bulk power system and interstate natural gas system, the Winter Storm Elliott report illustrates the extent to which such winter events can also have significant consequences for infrastructure subject to state jurisdiction, such as the local gas distribution system.

For example, although much of the attention has focused on the electric outages, the storm's effects on the natural gas system, and the local gas distribution system in particular, cannot be overlooked. During the storm, flows of natural gas into the pipelines were reduced, while at the same time, shippers requested increased volumes of natural gas, which dramatically lowered line pressures. That dynamic put significant stress on the natural gas system, which only narrowly avoided significant outages. By way of illustration, Consolidated Edison, Inc. (ConEd) faced reliability-threatening low pipeline pressures during the storm, forcing it to declare an emergency and use its own liquid natural gas facility to maintain necessary pressure. Without those emergency efforts, ConEd potentially faced system collapse, and it would have taken "many months" to restore service, leaving hundreds of thousands of natural gas customers without heat in the middle of winter.

This point is especially relevant considering the evidence presented at the Forum regarding Everett. With respect to the natural gas system, the evidence raised what we view as serious concerns about certain local gas distribution systems' ability to ensure reliability and affordability in the region without Everett. And, although there was evidence that the retirement of Everett would be "manageable" for the electric system, at least in the near-term, given anticipated new resource deployments and transmission development, minimal load growth, limited resource retirements, and increased reliance on non-natural gas generators, the evidence indicates that, should those expectations not materialize as anticipated, ensuring reliability and affordability could become challenging in the face of a significant winter event.

As discussions regarding the future of Everett continue, we encourage all parties to keep reliability and affordability at the center of those negotiations. With respect to electric reliability, we encourage ISO-New England and its stakeholders to pursue reforms aimed at ensuring that the electric system remains reliable by incentivizing resources to obtain the energy supplies, e.g., fuel, necessary to perform during extreme weather conditions. To the extent that Everett or other infrastructure plays a role in supporting electric reliability by making needed energy supplies available, in the near-term or the future, such reforms should consider how to ensure that any needed reliability contributions are appropriately valued.

With respect to the natural gas system, we recognize that the reliability needs turn, at least for the foreseeable future, largely on facilities subject to the New England states' jurisdiction. If our organizations can be any help to state regulators and other stakeholders as they address those needs, we are, of course, available to assist in any way we can.

Willie Phillips

Willie L. Phillips Chairman

James B Robb

CEO James B. Robb

Project Maple

Enhancing the energy future of New England by providing a direct connection to clean and abundant regional supplies of natural gas

Open Season Notice for Firm Service

September 12 , 2023 – November 17 , 2023

Project Maple

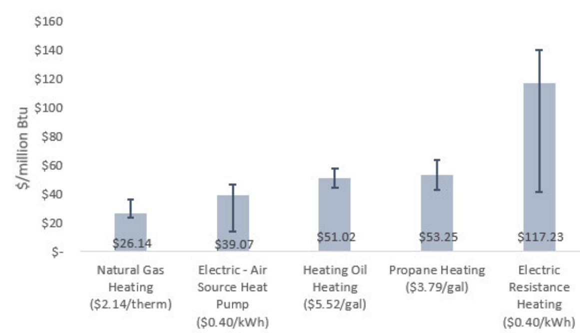
Securing the energy future of the New England by enhancing the direct connection to clean and abundant regional supplies of natural gas

Open Season

Due to input from the New England market and in response to recent FERC technical conferences held in the region, Enbridge's Algonquin Gas Transmission, LLC ("Algonquin"), a leading provider of natural gas transportation to New England, is announcing an open season ("Open Season") for its Project Maple. Project Maple will provide much needed supply reliability during peak daily demand, while stabilizing energy prices in the region and supporting New England's continued journey to Net Zero. Through this Open Season, Algonquin seeks to identify parties desiring to obtain firm transportation service from receipt points on the west end of Algonquin's system ("Ramapo Receipt Point") and on the east end of Algonquin's system ("Salem Receipt Point"). The Ramapo Receipt Point path is scalable with expansion capacity up to 500,000 Dth/d, depending on market commitments. The Salem Receipt Point path has an anticipated capacity of 250,000 Dth/d opening up more access to in-region LNG services to meet end users peak demand. Algonquin anticipates that Project Maple will have a target in-service date as early as November 2029.

Existing pipeline infrastructure has played a critical role in the emissions reduction success New England has achieved to date; however, natural gas demand in New England continues to grow and additional pipeline capacity will be required to maintain a reliable and affordable supply of energy. According to ISO New England's 2022 annual markets report "Natural gas generation continued to account for the largest share (52%) of native electricity generation…"[1]. Although over 60 percent of New England's natural gas-fired generation fleet is directly connected to Algonquin and Maritimes & Northeast Pipeline, L.L.C., these generators hold only approximately six percent of the primary firm natural gas transportation quantities on a contractual basis needed to support their peak demand requirements.[2] This untenable disconnect drives New England's energy prices higher, limits economic competitiveness and growth, strains the region's bulk power system to the detriment of public safety, reliability and security during times of winter peak energy demand, and often necessitates that the electric system resort to using less-environmentally-friendly fuel oil for generation.

LDCs continue to see growth as natural gas remains the lowest cost delivered energy making it the first choice for business and industry. According to an analysis by the MA Department of Energy Resources for the 2022/23 winter Natural Gas heating was 30% less expensive than the next least costly heating alternative, and almost 80% less than the most costly heating alternative for residential consumers, shown in the chart below[3]. Overall, annual demand on a peak day basis on Algonquin continues to increase and LDC growth alone is estimated at an additional 6.5% over the next five years.[4]



Source: DOER Analysis

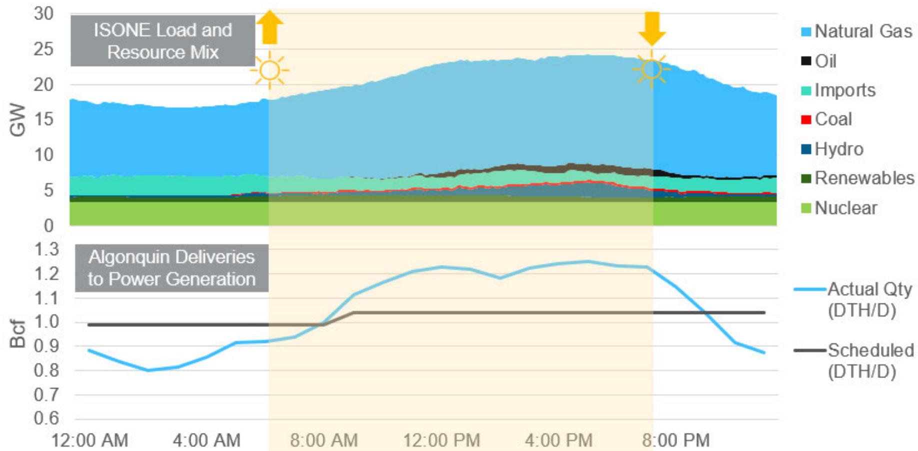
[1] ISO NE Internal Markets Monitor, 2023, ISO NE, *https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf*

[2] ISO-NE's 2023 CELT report indicates the Winter Nameplate Capacity interconnected with Algonquin and M&N systems of 9,495 MW and 1,755 MW respectively. Approximately 2.2 Bcf/day of firm capacity would be required to serve this load at an assumed aggregate heat rate of 8 Dth/MW. 136,000 Dth of Firm capacity is held by power generators on the Algonquin and M&N systems. 2023 CELT Report at 2 3 (May 1, 2023), available at https://www.iso-ne com/system-planning/system-plans-studies/celt.

[3] Massachusetts Household Heating Costs, November 30 2022, https://www.mass gov/info-details/massachusetts-household-heating-costs#comparison-of-heating-fuel-cost-effectiveness-

4 Natural Gas Demand Forecast through 2032 and Natural Gas Topology Tool, ICF (March 2023), available at: a13_b_rca_daily_gas_pipeline_forecast.pdf (iso-ne.com)

ISO New England Resource Graph Mix and Gas Generator Load on Algonquin



Additional pipeline capacity dedicated to gas-fired power generation is also essential to providing rapid ramping capability as they are increasingly called upon to offset the supply gaps that occur as solar production wanes coincident with the peak day demand in the evening. With further proliferation of solar and wind resources, in combination with increased electrification of the economy, this phenomenon will become even more prevalent in winter months when considerably less natural gas pipeline capacity is available to meet demand similar to what is experienced on the peak summer days, as illustrated above from August 8, 2022. Project Maple offers an opportunity for this gap to be closed with dedicated capacity right sized for gas-fired generators needs.

Project Maple will provide New England with an opportunity to secure a cost effective, regionally produced, environmentally responsible source of clean-burning natural gas to support the current and future demand for energy.

The Algonquin system is experiencing near full utilization on an annual average basis relative to its available west-end capacity. In addition, a lack of pipeline capacity to satisfy growing peak day needs in the region results in Algonquin city gate prices substantially higher than the production area in periods of moderate-to-peak demand, such as in 2021/22 where the region saw prices 9 times higher than prices in Western Pennsylvania. This has led to a reliance on globally supplied Liquefied Natural Gas, coal, and oil, all of which have a higher carbon footprint than domestically produced natural gas. Pipeline infrastructure is needed to ensure reliability of the energy systems New England consumers depend on, especially as the projected LDC growth coupled with increased electric demand and variable resources is realized over the next several years.

With most of the construction expected to occur within or adjacent to existing rights-of-way and at company-owned facilities, Project Maple can be developed with minimal impacts to landowners, local communities, and the environment. Project scope will be comprised of a combination of replacing existing smaller diameter pipe with larger diameter pipe, extending pipeline loops in parallel to existing pipeline facilities, and adding compression at existing compressor stations, depending on subscribed volumes.

Through this Open Season, Algonquin invites parties interested in being a part of Project Maple to submit a Service Request Form.

Project Service

Project Maple will provide firm transportation service to subscribing shippers via two potential receipt points: the Ramapo Receipt Point interconnect with Millennium Pipeline and the Salem Receipt Point interconnect with the Maritimes and Northeast Pipeline. Both receipt points will offer delivery to existing meters on the Algonquin mainline and/or lateral systems.

Algonquin may consider offering service enhancements or other flexibility based on requests made by interested shippers on the Service Request Form.

Project Rates

The illustrative rates for each receipt point may be updated based on the subscribed volume at the conclusion of the Open Season.

Salem receipt with service to meters on the J and G systems and in path meters $1.05 Dth/day.[5]

Ramapo receipt with service to head of G and J system and in path meters $2.75 Dth/day.[6]

Shippers will have the option of paying the applicable recourse rates of Algonquin for service on Project Maple facilities or mutually agreed-upon negotiated rates for such service, if available, plus any applicable fuel and applicable charges and surcharges.

Nomination Process

During the Open Season period (4:00 p.m., EST, Tuesday, September 12th, 2023, to 5:00 p.m., EST, on Friday, November 17th, 2023), interested parties must submit a Service Request Form, which specifies the Maximum Daily Transportation Quantity (MDTQ), contract term, and desired primary receipt and delivery points. The Service Request Form is included in this package. The completed Service Request Form must be executed by a duly authorized representative and mailed or emailed in pdf format to Algonquin's office at:

890 Winter Street, Suite 320, Waltham, MA 02451
Attn: Blair Hastey, Business Development
Blair.Hastey@enbridge.com

[5] Rates Expressed in 2023 dollars.

[6] Rates Expressed in 2023 dollars.

Algonquin reserves the right to reject any Service Request Form that is not received by 5:00 p.m. EST, on Friday, November 17th , 2023.

Contracting for Service

Once determined, Algonquin representatives will contact all parties who submitted valid requests and were awarded capacity for the Project.

By submitting a Service Request Form in this Open Season bidding period, a bidder is committing to execute a binding precedent agreement that incorporates the terms set forth in the bidder's Service Request Form with Algonquin within 90 days of the conclusion of the Open Season bidding period.

Capacity Allocation Process

In the event Algonquin receives valid requests for service that exceed the quantity of pipeline, point or segment capacity that Algonquin is willing to propose for Project Maple, then Algonquin will allocate such capacity on a not unduly discriminatory basis to shippers that have executed binding precedent agreements. Algonquin will allocate capacity on a net present value basis among such other shippers based on rate, contract term and MDTQ nominated, with Algonquin having the discretion to grant capacity to any bid or combination of bids that provides the highest net present value.

Limitations and Reservations

Algonquin reserves the right, in its sole discretion, to decline to proceed with Project Maple, or any portion thereof. Algonquin also reserves the right to proceed with one or more projects that will be defined through the contracting process and to develop alternative projects from the requests received during this Open Season that may be more representative of the timing and the points requested and markets served. Algonquin also may request a nominating party to modify its proposed point(s), to the extent Algonquin determines that the nominated point(s) will unduly increase the cost of the overall Project or otherwise adversely affect the scope of the Project. Algonquin reserves the right to negotiate with only those parties that submit valid bids as part of this Open Season.

Without limiting the foregoing, Algonquin may, but is not required to, reject any request for service in which the Service Request Form is incomplete, is inconsistent with the terms and conditions outlined in this Open Season Notice, contains additional or modified terms, or is otherwise deficient in any respect. Algonquin reserves the right to reject any bid requesting an in-service date that is later than November 1, 2031. Algonquin also may reject requests for service in the event requesting parties are unable to meet the pipelines' creditworthiness requirements. No request for service shall be binding on Algonquin unless and until duly authorized representatives of a requesting party and Algonquin have executed a binding precedent agreement. Algonquin reserves the right to reject any party's valid Service Request Form, in the event a duly authorized representative of such party has not executed a binding Precedent Agreement on or before the date that is 90 days after the last day of the Open Season.

Communications

At any time during the Open Season, interested parties are encouraged to contact their Algonquin account manager or Blair Hastey at (617) 560-1436 to discuss any questions or to seek additional information.

About Enbridge Inc.

At Enbridge, we safely connect millions of people to the energy they rely on every day, fueling quality of life through our North American natural gas, oil or renewable power networks and our growing European offshore wind portfolio. We're investing in modern energy delivery infrastructure to sustain access to secure, affordable energy and building on two decades of experience in renewable energy to advance new technologies including wind and solar power, hydrogen, renewable natural gas and carbon capture and storage. We're committed to reducing the carbon footprint of the energy we deliver, and to achieving net zero greenhouse gas emissions by 2050. Headquartered in Calgary, Alberta, Enbridge's common shares trade under the symbol ENB on the Toronto (TSX) and New York (NYSE) stock exchanges. To learn more, visit us at enbridge.com.

Project Maple
Service Request Form

Shipper Information

Company ______________________________

Contact ______________________________

Title ______________________________

Address ______________________________

Telephone ____________________ Fax ____________________

Email ______________________________

Contract Requirements

Maximum Daily Transportation Quantity (dekatherms): ____________________

Receipt Point(s)	Quantity (Dth/d)	Delivery Point(s) [1]	Quantity (Dth/d)

Service Commencement Date: ____________________

Contract Term: ____________________

Other: ______________________________

Please specify other service enhancements or flexibility that may be of interest. This information will not affect the validity of the service request. The incorporation of any such service enhancement or flexibility into this Project will be at the sole discretion of Algonquin and, further, will be dependent upon Project economics, timing, and requests for service received during this Open Season.

Signature of Requester/Customer: ____________________ Date: ____________

Please mail or email a pdf of the completed Service Request Form to:

Blair Hastey, Business Development
Blair.Hastey@enbridge.com
890 Winter Street
Suite 320
Waltham, MA 02451
617-560-1436 *office*

[1] *The sum of multiple Maximum Daily Delivery Obligation quantities may not exceed the Maximum Daily Transportation Quantity.*

Maine Division Statistical Model Results

Variable Nomenclature

Variable	Description	Type
HH(-3)	Total Households Lagged by 3	Actual/Forecast
HH_SIZE	Houshehold Size (i.e. Population/Households)	Actual/Forecast
GMP(-3)	Gross Metro Product Lagged by 3	Actual/Forecast
UNEMP_RT(-1)	Unemployment Rate Percentage Lagged by 1	Actual/Forecast
C	Constant	Intercept Value
TREND	Linear Trend	Linear Count (e.g. i=i+1)
JAN	January	Boolean
FEB	February	Boolean
MAR	March	Boolean
APR	April	Boolean
MAY	May	Boolean
JUN	June	Boolean
JUL	July	Boolean
AUG	August	Boolean
SEP	September	Boolean
OCT	October	Boolean
NOV	November	Boolean
DEC	December	Boolean
BC_EDD	Billing Cycle EDDs	Actual/Forecast
BC_JAN	January Bill Cycle EDD	Actual/Forecast
BC_FEB	February Bill Cycle EDD	Actual/Forecast
BC MAR	March Bill Cycle EDD	Actual/Forecast
BC_APR	April Bill Cycle EDD	Actual/Forecast
BC_MAY	May Bill Cycle EDD	Actual/Forecast
BC_JUN	June Bill Cycle EDD	Actual/Forecast
BC_JUL	July Bill Cycle EDD	Actual/Forecast
BC_AUG	August Bill Cycle EDD	Actual/Forecast
BC_SEP	September Bill Cycle EDD	Actual/Forecast
BC_OCT	October Bill Cycle EDD	Actual/Forecast
BC_NOV	November Bill Cycle EDD	Actual/Forecast
BC_DEC	December Bill Cycle EDD	Actual/Forecast
ME_EDD	Maine Calendar EDD	Actual
ME_EDD(-1)	Maine Calendar EDD Lagged by 1	Actual
ME_EDD_50	Maine Calendar EDD Base 15	Actual
@WEEKDAY=X	Xth Day of Week (i.e. X=1 is Sunday)	Boolean
Q4_to_Q2	October to June	Boolean
AR(X)	Autoregressive Term at Lag X (where X is a real integer)	ARMA
MA(X)	Moving Average Term at Lag X (where X is a real integer)	ARMA
D_*YearMx*	Dummy Variable for *Year* and *Month x*	Boolean
D_*YearMx_f*	Dummy Variable for *Year* and *Month x* and all future months	Boolean
D_*Year1Mx_Year2My*	Dummy Variable for time between *Year 1-Month x and Year 2-Month y*	Boolean

Residential Customer Segment – Customer Model

Dependent Variable: RES_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 02/26/23 Time: 11:35
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Failure to improve likelihood (non-zero gradients) after 17 iterations
Coefficient covariance computed using outer product of gradients
MA Backcast: 2015M01 2015M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HH(-3)*TREND	0.118592	0.030147	3.933744	0.0002
AUG	-762.7841	67.19731	-11.35141	0.0000
SEP	-641.8783	61.78035	-10.38968	0.0000
OCT	-251.1848	48.11117	-5.220926	0.0000
MAY	-424.2753	47.62273	-8.909093	0.0000
JUN	-596.0700	61.39381	-9.708960	0.0000
JUL	-690.2223	67.18205	-10.27391	0.0000
D_2021M11_F	195.5350	54.35576	3.597319	0.0006
C	21957.43	649.4600	33.80875	0.0000
AR(1)	0.928198	0.045037	20.60951	0.0000
MA(12)	0.924969	0.023194	39.88002	0.0000

R-squared	0.995453	Mean dependent var	23519.15
Adjusted R-squared	0.994830	S.D. dependent var	959.1573
S.E. of regression	68.96271	Akaike info criterion	11.42656
Sum squared resid	347177.4	Schwarz criterion	11.74488
Log likelihood	-468.9154	Hannan-Quinn criter.	11.55452
F-statistic	1598.270	Durbin-Watson stat	2.106341
Prob(F-statistic)	0.000000		

Inverted AR Roots	.93			
Inverted MA Roots	.96+.26i	.96-.26i	.70-.70i	.70+.70i
	.26-.96i	.26+.96i	-.26+.96i	-.26-.96i
	-.70-.70i	-.70-.70i	-.96+.26i	-.96-.26i

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.095229	Prob. F(11,72)	0.3776
Obs*R-squared	12.04071	Prob. Chi-Square(11)	0.3606
Scaled explained SS	17.75638	Prob. Chi-Square(11)	0.0874

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/22/23 Time: 16:38
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	3672.762	1815.950	2.022502	0.0468
GRADF_01^2	-0.004341	0.003778	-1.148863	0.2544
GRADF_02^2	-19336.74	14327.88	-1.349588	0.1814
GRADF_03^2	18369.73	15150.33	1.212497	0.2293
GRADF_04^2	-7261.355	13635.98	-0.532514	0.5960
GRADF_05^2	9545.504	10138.29	0.941530	0.3496
GRADF_06^2	-6758.646	12048.92	-0.560934	0.5766
GRADF_07^2	14830.58	13831.23	1.072254	0.2872
GRADF_08^2	33195.98	19757.80	1.680146	0.0973
GRADF_09^2	180180.0	1934140.	0.093158	0.9260
GRADF_10^2	0.021438	0.012250	1.750030	0.0844
GRADF_11^2	0.001684	0.005271	0.319400	0.7503

R-squared	0.143342	Mean dependent var	4269.495
Adjusted R-squared	0.012463	S.D. dependent var	8216.663
S.E. of regression	8165.298	Akaike info criterion	20.98474
Sum squared resid	4.80E+09	Schwarz criterion	21.33200
Log likelihood	-869.3590	Hannan-Quinn criter.	21.12433
F-statistic	1.095229	Durbin-Watson stat	2.281413
Prob(F-statistic)	0.377559		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>22476.0</td><td>22478.2</td><td>-2.2</td><td>| . * . |</td></tr>
<tr><td>2016M02</td><td>22502.0</td><td>22477.0</td><td>25.0</td><td>| . |* . |</td></tr>
<tr><td>2016M03</td><td>22527.0</td><td>22547.3</td><td>-20.3</td><td>| . *| . |</td></tr>
<tr><td>2016M04</td><td>22435.0</td><td>22536.7</td><td>-101.7</td><td>| * . | . |</td></tr>
<tr><td>2016M05</td><td>22040.0</td><td>22060.3</td><td>-20.3</td><td>| . *| . |</td></tr>
<tr><td>2016M06</td><td>21770.0</td><td>21813.4</td><td>-43.4</td><td>| .* | . |</td></tr>
<tr><td>2016M07</td><td>21685.0</td><td>21663.7</td><td>21.3</td><td>| . |* . |</td></tr>
<tr><td>2016M08</td><td>21618.0</td><td>21609.3</td><td>8.7</td><td>| . * . |</td></tr>
<tr><td>2016M09</td><td>21908.0</td><td>22013.3</td><td>-105.3</td><td>| * . | . |</td></tr>
<tr><td>2016M10</td><td>22379.0</td><td>22470.3</td><td>-91.3</td><td>| *. | . |</td></tr>
<tr><td>2016M11</td><td>22628.0</td><td>22455.9</td><td>172.1</td><td>| . | . * |</td></tr>
<tr><td>2016M12</td><td>22813.0</td><td>22774.0</td><td>39.0</td><td>| . | *. |</td></tr>
<tr><td>2017M01</td><td>22865.0</td><td>22848.5</td><td>16.5</td><td>| . |* . |</td></tr>
<tr><td>2017M02</td><td>22891.0</td><td>22924.0</td><td>-33.0</td><td>| .* | . |</td></tr>
<tr><td>2017M03</td><td>22888.0</td><td>22908.3</td><td>-20.3</td><td>| . *| . |</td></tr>
<tr><td>2017M04</td><td>22706.0</td><td>22832.0</td><td>-126.0</td><td>| * . | . |</td></tr>
<tr><td>2017M05</td><td>22263.0</td><td>22315.8</td><td>-52.8</td><td>| * | . |</td></tr>
<tr><td>2017M06</td><td>22064.0</td><td>22106.9</td><td>-42.9</td><td>| .* | . |</td></tr>
<tr><td>2017M07</td><td>22073.0</td><td>22049.1</td><td>23.9</td><td>| . |* . |</td></tr>
<tr><td>2017M08</td><td>22046.0</td><td>22062.8</td><td>-16.8</td><td>| . *| . |</td></tr>
<tr><td>2017M09</td><td>22156.0</td><td>22123.0</td><td>33.0</td><td>| . | *. |</td></tr>
<tr><td>2017M10</td><td>22539.0</td><td>22518.8</td><td>20.2</td><td>| . |* . |</td></tr>
<tr><td>2017M11</td><td>23008.0</td><td>23008.4</td><td>-0.4</td><td>| . * . |</td></tr>
<tr><td>2017M12</td><td>23144.0</td><td>23089.2</td><td>54.8</td><td>| . | * |</td></tr>
<tr><td>2018M01</td><td>23223.0</td><td>23196.3</td><td>26.7</td><td>| . |* . |</td></tr>
<tr><td>2018M02</td><td>23234.0</td><td>23225.8</td><td>8.2</td><td>| . * . |</td></tr>
<tr><td>2018M03</td><td>23246.0</td><td>23249.9</td><td>-3.9</td><td>| . * . |</td></tr>
<tr><td>2018M04</td><td>23099.0</td><td>23165.4</td><td>-66.4</td><td>| * | . |</td></tr>
<tr><td>2018M05</td><td>22665.0</td><td>22674.2</td><td>-9.2</td><td>| . * . |</td></tr>
<tr><td>2018M06</td><td>22527.0</td><td>22504.4</td><td>22.6</td><td>| . |* . |</td></tr>
<tr><td>2018M07</td><td>22339.0</td><td>22505.4</td><td>-166.4</td><td>| * . | . |</td></tr>
<tr><td>2018M08</td><td>22338.0</td><td>22310.0</td><td>28.0</td><td>| . |* . |</td></tr>
<tr><td>2018M09</td><td>22513.0</td><td>22545.3</td><td>-32.3</td><td>| .* | . |</td></tr>
<tr><td>2018M10</td><td>23193.0</td><td>22976.7</td><td>216.3</td><td>| . | . *</td></tr>
<tr><td>2018M11</td><td>23511.0</td><td>23479.6</td><td>31.4</td><td>| . | *. |</td></tr>
<tr><td>2018M12</td><td>23636.0</td><td>23595.0</td><td>41.0</td><td>| . | *. |</td></tr>
<tr><td>2019M01</td><td>23696.0</td><td>23687.3</td><td>8.7</td><td>| . * . |</td></tr>
<tr><td>2019M02</td><td>23753.0</td><td>23727.7</td><td>25.3</td><td>| . |* . |</td></tr>
<tr><td>2019M03</td><td>23755.0</td><td>23771.0</td><td>-16.0</td><td>| . *| . |</td></tr>
</table>

<table>
<tr><td>2019M04</td><td>23658.0</td><td>23716.8</td><td>-58.8</td><td>| * | . |</td></tr>
<tr><td>2019M05</td><td>23339.0</td><td>23257.4</td><td>81.6</td><td>| . | .* |</td></tr>
<tr><td>2019M06</td><td>23296.0</td><td>23215.0</td><td>81.0</td><td>| . | .* |</td></tr>
<tr><td>2019M07</td><td>23155.0</td><td>23067.7</td><td>87.3</td><td>| . | .* |</td></tr>
<tr><td>2019M08</td><td>23141.0</td><td>23132.8</td><td>8.2</td><td>| . * . |</td></tr>
<tr><td>2019M09</td><td>23292.0</td><td>23253.3</td><td>38.7</td><td>| . |*. |</td></tr>
<tr><td>2019M10</td><td>23795.0</td><td>23903.0</td><td>-108.0</td><td>| * . | . |</td></tr>
<tr><td>2019M11</td><td>24183.0</td><td>24088.9</td><td>94.1</td><td>| . | . * |</td></tr>
<tr><td>2019M12</td><td>24286.0</td><td>24226.8</td><td>59.2</td><td>| . | * |</td></tr>
<tr><td>2020M01</td><td>24325.0</td><td>24294.6</td><td>30.4</td><td>| . |* . |</td></tr>
<tr><td>2020M02</td><td>24370.0</td><td>24348.1</td><td>21.9</td><td>| . |* . |</td></tr>
<tr><td>2020M03</td><td>24384.0</td><td>24353.5</td><td>30.5</td><td>| . |* . |</td></tr>
<tr><td>2020M04</td><td>24337.0</td><td>24328.1</td><td>8.9</td><td>| . * . |</td></tr>
<tr><td>2020M05</td><td>24131.0</td><td>23990.2</td><td>140.8</td><td>| . | . * |</td></tr>
<tr><td>2020M06</td><td>23962.0</td><td>24020.2</td><td>-58.2</td><td>| * | . |</td></tr>
<tr><td>2020M07</td><td>23940.0</td><td>23934.9</td><td>5.1</td><td>| . * . |</td></tr>
<tr><td>2020M08</td><td>23871.0</td><td>23857.9</td><td>13.1</td><td>| . |* . |</td></tr>
<tr><td>2020M09</td><td>24025.0</td><td>24013.3</td><td>11.7</td><td>| . |* . |</td></tr>
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<tr><td>2020M11</td><td>24555.0</td><td>24741.7</td><td>-186.7</td><td>| * . | . |</td></tr>
<tr><td>2020M12</td><td>24646.0</td><td>24608.3</td><td>37.7</td><td>| . |*. |</td></tr>
<tr><td>2021M01</td><td>24687.0</td><td>24668.1</td><td>18.9</td><td>| . |* . |</td></tr>
<tr><td>2021M02</td><td>24725.0</td><td>24700.1</td><td>24.9</td><td>| . |* . |</td></tr>
<tr><td>2021M03</td><td>24721.0</td><td>24745.4</td><td>-24.4</td><td>| . *| . |</td></tr>
<tr><td>2021M04</td><td>24619.0</td><td>24724.3</td><td>-105.3</td><td>| * . | . |</td></tr>
<tr><td>2021M05</td><td>24266.0</td><td>24330.8</td><td>-64.8</td><td>| * | . |</td></tr>
<tr><td>2021M06</td><td>24061.0</td><td>24045.0</td><td>16.0</td><td>| . |* . |</td></tr>
<tr><td>2021M07</td><td>23936.0</td><td>23982.4</td><td>-46.4</td><td>| .* | . |</td></tr>
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<tr><td>2021M09</td><td>23995.0</td><td>24051.7</td><td>-56.7</td><td>| * | . |</td></tr>
<tr><td>2021M10</td><td>24503.0</td><td>24509.7</td><td>-6.7</td><td>| . * . |</td></tr>
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<tr><td>2021M12</td><td>24871.0</td><td>24816.9</td><td>54.1</td><td>| . | * |</td></tr>
<tr><td>2022M01</td><td>24914.0</td><td>24911.1</td><td>2.9</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>24938.0</td><td>24958.2</td><td>-20.2</td><td>| . *| . |</td></tr>
<tr><td>2022M03</td><td>24927.0</td><td>24936.5</td><td>-9.5</td><td>| . * . |</td></tr>
<tr><td>2022M04</td><td>24826</td><td>24853</td><td>-27.319</td><td>| . *| . |</td></tr>
<tr><td>2022M05</td><td>24351</td><td>24375</td><td>-23.694</td><td>| . *| . |</td></tr>
<tr><td>2022M06</td><td>24228</td><td>24233</td><td>-4.5337</td><td>| . * . |</td></tr>
<tr><td>2022M07</td><td>24150</td><td>24128</td><td>21.8845</td><td>| . |* . |</td></tr>
<tr><td>2022M08</td><td>24101</td><td>24128</td><td>-26.533</td><td>| . *| . |</td></tr>
<tr><td>2022M09</td><td>24298</td><td>24206</td><td>91.5345</td><td>| . | .* |</td></tr>
<tr><td>2022M10</td><td>24691</td><td>24716</td><td>-24.551</td><td>| . *| . |</td></tr>
</table>

2022M11	24880	24943	-62.602	| * | . |
2022M12	25005	24971	33.6802	| . | *. |

Date: 03/22/23 Time: 16:53
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.056	-0.056	0.2770	
. | . |	. | . |	2	0.057	0.054	0.5654	
.*| . |	.*| . |	3	-0.123	-0.117	1.9071	0.167
. | . |	. | . |	4	0.026	0.011	1.9662	0.374
. |*. |	. |*. |	5	0.089	0.105	2.6878	0.442
. | . |	. | . |	6	-0.016	-0.024	2.7114	0.607
.*| . |	.*| . |	7	-0.081	-0.092	3.3225	0.650
. |*. |	. |*. |	8	0.075	0.097	3.8563	0.696
. |*. |	. |*. |	9	0.085	0.099	4.5475	0.715
. |*. |	. | . |	10	0.097	0.066	5.4683	0.707
. | . |	. | . |	11	0.042	0.069	5.6399	0.775
.*| . |	. | . |	12	-0.077	-0.048	6.2395	0.795

*Probabilities may not be valid for this equation specification.

Residential Customer Segment - Use Per Customer Model

Dependent Variable: RES_UPC
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 02/23/23 Time: 10:51
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 11 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HH_SIZE	5.337191	0.403572	13.22488	0.0000
BC_APR	0.071850	0.001712	41.97937	0.0000
BC_DEC	0.081650	0.001402	58.23022	0.0000
BC_FEB	0.086877	0.001185	73.30187	0.0000
BC_JAN	0.088753	0.001172	75.76030	0.0000
BC_JUN	0.038721	0.005110	7.577560	0.0000
BC_MAR	0.085500	0.001429	59.84032	0.0000
BC_NOV	0.058883	0.002275	25.88355	0.0000
BC_MAY	0.059969	0.002490	24.08049	0.0000
BC_OCT	0.034515	0.004017	8.592851	0.0000
D_2021M3	11.83394	2.807497	4.215120	0.0001
D_2021M4	-5.817365	2.747138	-2.117610	0.0378
D_2018M11	5.276086	2.628966	2.006905	0.0486
AR(1)	0.567888	0.107711	5.272312	0.0000

R-squared	0.996641	Mean dependent var	57.64206
Adjusted R-squared	0.996018	S.D. dependent var	42.27987
S.E. of regression	2.668100	Akaike info criterion	4.956257
Sum squared resid	498.3132	Schwarz criterion	5.361393
Log likelihood	-194.1628	Hannan-Quinn criter.	5.119119
Durbin-Watson stat	2.058827		

Inverted AR Roots	.57

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	2.275954	Prob. F(14,69)	0.0127
Obs*R-squared	26.53612	Prob. Chi-Square(14)	0.0221
Scaled explained SS	22.10192	Prob. Chi-Square(14)	0.0765

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/22/23 Time: 16:55
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.698692	4.143939	-0.168606	0.8666
GRADF_01^2	18.10580	18.74193	0.966058	0.3374
GRADF_02^2	8.14E-05	3.15E-05	2.587529	0.0118
GRADF_03^2	7.86E-05	2.15E-05	3.646306	0.0005
GRADF_04^2	7.68E-07	1.49E-05	0.051480	0.9591
GRADF_05^2	2.70E-05	1.43E-05	1.882856	0.0639
GRADF_06^2	-2.05E-06	0.000451	-0.004546	0.9964
GRADF_07^2	2.66E-05	2.02E-05	1.316318	0.1924
GRADF_08^2	6.15E-06	6.31E-05	0.097514	0.9226
GRADF_09^2	-1.65E-05	7.60E-05	-0.217164	0.8287
GRADF_10^2	3.90E-05	0.000279	0.139641	0.8894
GRADF_11^2	-44.39519	54.09261	-0.820726	0.4146
GRADF_12^2	-61.66869	52.35317	-1.177936	0.2429
GRADF_13^2	56.37988	57.56912	0.979342	0.3308
GRADF_14^2	-0.366355	0.541187	-0.676947	0.5007

R-squared	0.315906	Mean dependent var	5.932300
Adjusted R-squared	0.177104	S.D. dependent var	9.243069
S.E. of regression	8.384720	Akaike info criterion	7.251132
Sum squared resid	4850.943	Schwarz criterion	7.685206
Log likelihood	-289.5475	Hannan-Quinn criter.	7.425626
F-statistic	2.275954	Durbin-Watson stat	2.138243
Prob(F-statistic)	0.012733		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>104.9</td><td>108.7</td><td>-3.8</td><td>| * . | . |</td></tr>
<tr><td>2016M02</td><td>116.1</td><td>113.0</td><td>3.1</td><td>| . | .* |</td></tr>
<tr><td>2016M03</td><td>95.9</td><td>100.9</td><td>-5.0</td><td>| *   . | . |</td></tr>
<tr><td>2016M04</td><td>69.4</td><td>68.9</td><td>0.5</td><td>| . |* . |</td></tr>
<tr><td>2016M05</td><td>41.8</td><td>44.8</td><td>-3.0</td><td>| *. | . |</td></tr>
<tr><td>2016M06</td><td>19.9</td><td>17.5</td><td>2.4</td><td>| . | * |</td></tr>
<tr><td>2016M07</td><td>13.3</td><td>12.7</td><td>0.6</td><td>| . |* . |</td></tr>
<tr><td>2016M08</td><td>13.8</td><td>13.0</td><td>0.8</td><td>| . |* . |</td></tr>
<tr><td>2016M09</td><td>13.4</td><td>13.3</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2016M10</td><td>22.2</td><td>22.8</td><td>-0.6</td><td>| . *| . |</td></tr>
<tr><td>2016M11</td><td>50.9</td><td>49.0</td><td>1.9</td><td>| . | *. |</td></tr>
<tr><td>2016M12</td><td>89.3</td><td>94.6</td><td>-5.3</td><td>| *   . | . |</td></tr>
<tr><td>2017M01</td><td>116.3</td><td>117.5</td><td>-1.1</td><td>| . *| . |</td></tr>
<tr><td>2017M02</td><td>112.5</td><td>113.6</td><td>-1.1</td><td>| . *| . |</td></tr>
<tr><td>2017M03</td><td>103.9</td><td>105.6</td><td>-1.6</td><td>| .* | . |</td></tr>
<tr><td>2017M04</td><td>81.1</td><td>77.2</td><td>3.9</td><td>| . | . * |</td></tr>
<tr><td>2017M05</td><td>46.5</td><td>43.9</td><td>2.6</td><td>| . | * |</td></tr>
<tr><td>2017M06</td><td>27.1</td><td>25.1</td><td>2.0</td><td>| . | *. |</td></tr>
<tr><td>2017M07</td><td>15.4</td><td>15.0</td><td>0.4</td><td>| . |* . |</td></tr>
<tr><td>2017M08</td><td>13.7</td><td>14.2</td><td>-0.6</td><td>| . *| . |</td></tr>
<tr><td>2017M09</td><td>14.6</td><td>13.2</td><td>1.3</td><td>| . | * . |</td></tr>
<tr><td>2017M10</td><td>17.5</td><td>19.4</td><td>-2.0</td><td>| .* | . |</td></tr>
<tr><td>2017M11</td><td>40.4</td><td>43.6</td><td>-3.3</td><td>| *. | . |</td></tr>
<tr><td>2017M12</td><td>100.3</td><td>95.6</td><td>4.6</td><td>| . | .   * |</td></tr>
<tr><td>2018M01</td><td>155.0</td><td>151.2</td><td>3.8</td><td>| . | . * |</td></tr>
<tr><td>2018M02</td><td>116.5</td><td>120.1</td><td>-3.6</td><td>| * . | . |</td></tr>
<tr><td>2018M03</td><td>96.4</td><td>95.6</td><td>0.8</td><td>| . |* . |</td></tr>
<tr><td>2018M04</td><td>82.6</td><td>80.8</td><td>1.8</td><td>| . | *. |</td></tr>
<tr><td>2018M05</td><td>42.1</td><td>43.4</td><td>-1.4</td><td>| . *| . |</td></tr>
<tr><td>2018M06</td><td>21.1</td><td>20.1</td><td>1.0</td><td>| . | * . |</td></tr>
<tr><td>2018M07</td><td>13.7</td><td>13.2</td><td>0.5</td><td>| . |* . |</td></tr>
<tr><td>2018M08</td><td>12.7</td><td>13.3</td><td>-0.5</td><td>| . *| . |</td></tr>
<tr><td>2018M09</td><td>12.7</td><td>12.7</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2018M10</td><td>25.2</td><td>23.3</td><td>1.9</td><td>| . | *. |</td></tr>
<tr><td>2018M11</td><td>67.1</td><td>64.0</td><td>3.1</td><td>| . | .* |</td></tr>
<tr><td>2018M12</td><td>110.5</td><td>105.0</td><td>5.5</td><td>| . | .   *|</td></tr>
<tr><td>2019M01</td><td>125.5</td><td>126.7</td><td>-1.2</td><td>| . *| . |</td></tr>
<tr><td>2019M02</td><td>128.6</td><td>129.7</td><td>-1.1</td><td>| . *| . |</td></tr>
<tr><td>2019M03</td><td>114.3</td><td>113.0</td><td>1.2</td><td>| . | * . |</td></tr>
<tr><td>2019M04</td><td>79.2</td><td>75.4</td><td>3.8</td><td>| . | . * |</td></tr>
</table>

<table>
<tr><td>2019M05</td><td>47.6</td><td>47.7</td><td>-0.1</td><td>| . * . |</td></tr>
<tr><td>2019M06</td><td>23.9</td><td>24.3</td><td>-0.4</td><td>| . *| . |</td></tr>
<tr><td>2019M07</td><td>15.1</td><td>13.3</td><td>1.7</td><td>| . | *. |</td></tr>
<tr><td>2019M08</td><td>12.3</td><td>14.1</td><td>-1.7</td><td>| .* | . |</td></tr>
<tr><td>2019M09</td><td>12.7</td><td>12.5</td><td>0.2</td><td>| . * . |</td></tr>
<tr><td>2019M10</td><td>24.9</td><td>22.4</td><td>2.6</td><td>| . | * |</td></tr>
<tr><td>2019M11</td><td>53.5</td><td>52.9</td><td>0.5</td><td>| . |* . |</td></tr>
<tr><td>2019M12</td><td>100.6</td><td>99.8</td><td>0.9</td><td>| . |* . |</td></tr>
<tr><td>2020M01</td><td>117.9</td><td>112.2</td><td>5.6</td><td>| . | . *|</td></tr>
<tr><td>2020M02</td><td>115.9</td><td>114.2</td><td>1.8</td><td>| . | *. |</td></tr>
<tr><td>2020M03</td><td>102.7</td><td>99.6</td><td>3.1</td><td>| . | .* |</td></tr>
<tr><td>2020M04</td><td>70.2</td><td>73.8</td><td>-3.5</td><td>| * . | . |</td></tr>
<tr><td>2020M05</td><td>50.5</td><td>47.9</td><td>2.6</td><td>| . | * |</td></tr>
<tr><td>2020M06</td><td>22.2</td><td>21.9</td><td>0.3</td><td>| . * . |</td></tr>
<tr><td>2020M07</td><td>13.8</td><td>13.9</td><td>-0.1</td><td>| . * . |</td></tr>
<tr><td>2020M08</td><td>11.7</td><td>13.5</td><td>-1.8</td><td>| .* | . |</td></tr>
<tr><td>2020M09</td><td>15.2</td><td>12.2</td><td>3.0</td><td>| . | .* |</td></tr>
<tr><td>2020M10</td><td>22.6</td><td>23.5</td><td>-0.9</td><td>| . * | . |</td></tr>
<tr><td>2020M11</td><td>50.2</td><td>50.1</td><td>0.2</td><td>| . * . |</td></tr>
<tr><td>2020M12</td><td>88.4</td><td>88.9</td><td>-0.5</td><td>| . *| . |</td></tr>
<tr><td>2021M01</td><td>108.5</td><td>114.5</td><td>-6.0</td><td>| * . | . |</td></tr>
<tr><td>2021M02</td><td>120.7</td><td>120.3</td><td>0.4</td><td>| . |* . |</td></tr>
<tr><td>2021M03</td><td>117.1</td><td>117.2</td><td>-0.1</td><td>| . * . |</td></tr>
<tr><td>2021M04</td><td>61.5</td><td>61.7</td><td>-0.2</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>40.5</td><td>40.7</td><td>-0.3</td><td>| . * . |</td></tr>
<tr><td>2021M06</td><td>18.4</td><td>18.6</td><td>-0.3</td><td>| . * . |</td></tr>
<tr><td>2021M07</td><td>13.3</td><td>12.6</td><td>0.7</td><td>| . |* . |</td></tr>
<tr><td>2021M08</td><td>12.5</td><td>13.2</td><td>-0.7</td><td>| . *| . |</td></tr>
<tr><td>2021M09</td><td>12.4</td><td>12.7</td><td>-0.3</td><td>| . *| . |</td></tr>
<tr><td>2021M10</td><td>17.4</td><td>19.8</td><td>-2.4</td><td>| * | . |</td></tr>
<tr><td>2021M11</td><td>46.1</td><td>45.6</td><td>0.6</td><td>| . |* . |</td></tr>
<tr><td>2021M12</td><td>90.8</td><td>90.7</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2022M01</td><td>123.5</td><td>123.3</td><td>0.2</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>131.8</td><td>130.9</td><td>0.9</td><td>| . |* . |</td></tr>
<tr><td>2022M03</td><td>106.7</td><td>104.9</td><td>1.8</td><td>| . | *. |</td></tr>
<tr><td>2022M04</td><td>65.143</td><td>71.652</td><td>-6.5094</td><td>|* . | . |</td></tr>
<tr><td>2022M05</td><td>42.629</td><td>41.462</td><td>1.16715</td><td>| . | * . |</td></tr>
<tr><td>2022M06</td><td>17.268</td><td>19.311</td><td>-2.0438</td><td>| .* | . |</td></tr>
<tr><td>2022M07</td><td>12.895</td><td>11.194</td><td>1.70174</td><td>| . | *. |</td></tr>
<tr><td>2022M08</td><td>11.413</td><td>12.911</td><td>-1.4984</td><td>| . * | . |</td></tr>
<tr><td>2022M09</td><td>12.423</td><td>12.068</td><td>0.35458</td><td>| . |* . |</td></tr>
<tr><td>2022M10</td><td>23.795</td><td>24.065</td><td>-0.2697</td><td>| . * . |</td></tr>
<tr><td>2022M11</td><td>38.381</td><td>42.287</td><td>-3.906</td><td>| * . | . |</td></tr>
</table>

2022M12	81.464	86.788	-5.3245	| * . | . |

Date: 03/22/23 Time: 16:56
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
.*| . |	.*| . |	1	-0.074	-0.074	0.4713	
. | . |	. | . |	2	0.062	0.057	0.8080	0.369
. | . |	. | . |	3	-0.002	0.007	0.8082	0.668
. | . |	. | . |	4	0.062	0.060	1.1577	0.763
.*| . |	.*| . |	5	-0.085	-0.078	1.8204	0.769
. | . |	. | . |	6	0.043	0.026	1.9953	0.850
. |*. |	. |*. |	7	0.085	0.100	2.6749	0.848
. |*. |	. |*. |	8	0.122	0.132	4.0983	0.768
. |*. |	. |*. |	9	0.106	0.128	5.1823	0.738
. | . |	. | . |	10	0.004	-0.003	5.1837	0.818
. |*. |	. |*. |	11	0.127	0.115	6.7917	0.745
.*| . |	. | . |	12	-0.073	-0.057	7.3331	0.772

*Probabilities may not be valid for this equation specification.

LLF Customer Segment – Customer Model

Dependent Variable: LLF_CUST
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/15/23 Time: 15:47
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 27 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GMP(-3)	49.21921	4.630230	10.62997	0.0000
SEP	36.87870	10.60025	3.479042	0.0009
OCT	177.4436	21.64816	8.196706	0.0000
NOV	250.2749	31.43497	7.961670	0.0000
DEC	268.8000	37.99549	7.074524	0.0000
JAN	272.4971	40.16800	6.783934	0.0000
FEB	267.6736	37.73925	7.092710	0.0000
MAR	251.9503	31.21293	8.071985	0.0000
APR	190.6793	21.63935	8.811693	0.0000
MAY	72.11797	11.16290	6.460506	0.0000
C	6338.707	143.6450	44.12757	0.0000
D_2019M7_F	-120.8420	33.81450	-3.573675	0.0007
D_2019M6	-123.8904	21.75894	-5.693769	0.0000
D_2018M5	-37.93431	13.17609	-2.879026	0.0053
AR(1)	1.502714	0.089907	16.71411	0.0000
AR(2)	-0.702501	0.093575	-7.507348	0.0000

R-squared	0.989984	Mean dependent var	8056.417
Adjusted R-squared	0.987774	S.D. dependent var	211.3534
S.E. of regression	23.36929	Akaike info criterion	9.344538
Sum squared resid	37136.43	Schwarz criterion	9.807551
Log likelihood	-376.4706	Hannan-Quinn criter.	9.530665
F-statistic	448.0663	Durbin-Watson stat	1.852223
Prob(F-statistic)	0.000000		

Inverted AR Roots	.75-.37i	.75+.37i

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.497744	Prob. F(16,67)	0.1269
Obs*R-squared	22.12931	Prob. Chi-Square(16)	0.1391
Scaled explained SS	13.62877	Prob. Chi-Square(16)	0.6263

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 08:55
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	802.4543	394.0999	2.036170	0.0457
GRADF_01^2	-6565.721	2823.870	-2.325079	0.0231
GRADF_02^2	-105563.2	64229.40	-1.643534	0.1050
GRADF_03^2	154224.3	64572.80	2.388378	0.0197
GRADF_04^2	-51171.98	72283.01	-0.707939	0.4814
GRADF_05^2	-12444.37	71120.49	-0.174976	0.8616
GRADF_06^2	-45532.45	72903.37	-0.624559	0.5344
GRADF_07^2	-7357.906	67491.60	-0.109020	0.9135
GRADF_08^2	-81046.72	69002.59	-1.174546	0.2443
GRADF_09^2	66121.76	61785.93	1.070175	0.2884
GRADF_10^2	15642.44	67982.16	0.230096	0.8187
GRADF_11^2	3934210.	3855226.	1.020487	0.3112
GRADF_12^2	45158.82	652625.7	0.069196	0.9450
GRADF_13^2	-105174.6	274776.6	-0.382764	0.7031
GRADF_14^2	-26507.65	115027.8	-0.230446	0.8184
GRADF_15^2	-8.459338	11.34664	-0.745537	0.4586
GRADF_16^2	8.619244	11.86824	0.726245	0.4702

R-squared	0.263444	Mean dependent var	442.1003
Adjusted R-squared	0.087550	S.D. dependent var	609.7491
S.E. of regression	582.4460	Akaike info criterion	15.75099
Sum squared resid	22729303	Schwarz criterion	16.24294
Log likelihood	-644.5415	Hannan-Quinn criter.	15.94875
F-statistic	1.497744	Durbin-Watson stat	2.277469
Prob(F-statistic)	0.126917		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>7928.0</td><td>7942.3</td><td>-14.3</td><td>| . * | . |</td></tr>
<tr><td>2016M02</td><td>7939.0</td><td>7932.4</td><td>6.6</td><td>| . |* . |</td></tr>
<tr><td>2016M03</td><td>7926.0</td><td>7943.9</td><td>-17.9</td><td>| .* | . |</td></tr>
<tr><td>2016M04</td><td>7857.0</td><td>7876.7</td><td>-19.7</td><td>| .* | . |</td></tr>
<tr><td>2016M05</td><td>7740.0</td><td>7744.8</td><td>-4.8</td><td>| . *| . |</td></tr>
<tr><td>2016M06</td><td>7655.0</td><td>7681.2</td><td>-26.2</td><td>| * | . |</td></tr>
<tr><td>2016M07</td><td>7622.0</td><td>7661.6</td><td>-39.6</td><td>| * . | . |</td></tr>
<tr><td>2016M08</td><td>7633.0</td><td>7622.0</td><td>11.0</td><td>| . | * . |</td></tr>
<tr><td>2016M09</td><td>7682.0</td><td>7699.9</td><td>-17.9</td><td>| .* | . |</td></tr>
<tr><td>2016M10</td><td>7856.0</td><td>7851.8</td><td>4.2</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>7930.0</td><td>7967.1</td><td>-37.1</td><td>| * . | . |</td></tr>
<tr><td>2016M12</td><td>7979.0</td><td>7965.0</td><td>14.0</td><td>| . | * . |</td></tr>
<tr><td>2017M01</td><td>7999.0</td><td>8015.0</td><td>-16.0</td><td>| .* | . |</td></tr>
<tr><td>2017M02</td><td>8002.0</td><td>8014.3</td><td>-12.3</td><td>| . * | . |</td></tr>
<tr><td>2017M03</td><td>7998.0</td><td>7999.5</td><td>-1.5</td><td>| . * . |</td></tr>
<tr><td>2017M04</td><td>7925.0</td><td>7951.3</td><td>-26.3</td><td>| * | . |</td></tr>
<tr><td>2017M05</td><td>7833.0</td><td>7806.4</td><td>26.6</td><td>| . | * |</td></tr>
<tr><td>2017M06</td><td>7783.0</td><td>7782.7</td><td>0.3</td><td>| . * . |</td></tr>
<tr><td>2017M07</td><td>7753.0</td><td>7798.7</td><td>-45.7</td><td>| * . | . |</td></tr>
<tr><td>2017M08</td><td>7764.0</td><td>7740.4</td><td>23.6</td><td>| . | * |</td></tr>
<tr><td>2017M09</td><td>7798.0</td><td>7818.3</td><td>-20.3</td><td>| .* | . |</td></tr>
<tr><td>2017M10</td><td>7939.0</td><td>7948.0</td><td>-9.0</td><td>| . * | . |</td></tr>
<tr><td>2017M11</td><td>8089.0</td><td>8025.4</td><td>63.6</td><td>| . | . *</td></tr>
<tr><td>2017M12</td><td>8160.0</td><td>8159.9</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2018M01</td><td>8172.0</td><td>8189.6</td><td>-17.6</td><td>| .* | . |</td></tr>
<tr><td>2018M02</td><td>8182.0</td><td>8160.8</td><td>21.2</td><td>| . | * |</td></tr>
<tr><td>2018M03</td><td>8184.0</td><td>8161.7</td><td>22.3</td><td>| . | * |</td></tr>
<tr><td>2018M04</td><td>8131.0</td><td>8119.0</td><td>12.0</td><td>| . | * . |</td></tr>
<tr><td>2018M05</td><td>7930.0</td><td>7964.5</td><td>-34.5</td><td>| * . | . |</td></tr>
<tr><td>2018M06</td><td>7835.0</td><td>7860.8</td><td>-25.8</td><td>| * | . |</td></tr>
<tr><td>2018M07</td><td>7796.0</td><td>7802.0</td><td>-6.0</td><td>| . *| . |</td></tr>
<tr><td>2018M08</td><td>7804.0</td><td>7786.2</td><td>17.8</td><td>| . | *. |</td></tr>
<tr><td>2018M09</td><td>7876.0</td><td>7862.6</td><td>13.4</td><td>| . | * . |</td></tr>
<tr><td>2018M10</td><td>8085.0</td><td>8051.1</td><td>33.9</td><td>| . | . * |</td></tr>
<tr><td>2018M11</td><td>8192.0</td><td>8204.0</td><td>-12.0</td><td>| . * | . |</td></tr>
<tr><td>2018M12</td><td>8238.0</td><td>8227.0</td><td>11.0</td><td>| . | * . |</td></tr>
<tr><td>2019M01</td><td>8264.0</td><td>8249.4</td><td>14.6</td><td>| . | * . |</td></tr>
<tr><td>2019M02</td><td>8281.0</td><td>8259.9</td><td>21.1</td><td>| . | * |</td></tr>
<tr><td>2019M03</td><td>8283.0</td><td>8262.5</td><td>20.5</td><td>| . | *. |</td></tr>
<tr><td>2019M04</td><td>8225.0</td><td>8213.9</td><td>11.1</td><td>| . | * . |</td></tr>
<tr><td>2019M05</td><td>8068.0</td><td>8087.7</td><td>-19.7</td><td>| .* | . |</td></tr>
<tr><td>2019M06</td><td>7805.0</td><td>7832.9</td><td>-27.9</td><td>| *. | . |</td></tr>
</table>

<table>
<tr><td>2019M07</td><td>7758.0</td><td>7764.6</td><td>-6.6</td><td>| . *| . |</td></tr>
<tr><td>2019M08</td><td>7766.0</td><td>7740.4</td><td>25.6</td><td>| . | * |</td></tr>
<tr><td>2019M09</td><td>7830.0</td><td>7828.4</td><td>1.6</td><td>| . * . |</td></tr>
<tr><td>2019M10</td><td>8022.0</td><td>8005.2</td><td>16.8</td><td>| . | *. |</td></tr>
<tr><td>2019M11</td><td>8162.0</td><td>8135.8</td><td>26.2</td><td>| . | * |</td></tr>
<tr><td>2019M12</td><td>8193.0</td><td>8219.0</td><td>-26.0</td><td>| * | . |</td></tr>
<tr><td>2020M01</td><td>8213.0</td><td>8202.0</td><td>11.0</td><td>| . |* . |</td></tr>
<tr><td>2020M02</td><td>8219.0</td><td>8224.4</td><td>-5.4</td><td>| . *| . |</td></tr>
<tr><td>2020M03</td><td>8205.0</td><td>8222.4</td><td>-17.4</td><td>| .* | . |</td></tr>
<tr><td>2020M04</td><td>8153.0</td><td>8143.1</td><td>9.9</td><td>| . |* . |</td></tr>
<tr><td>2020M05</td><td>8051.0</td><td>8006.6</td><td>44.4</td><td>| . | . * |</td></tr>
<tr><td>2020M06</td><td>7963.0</td><td>7923.7</td><td>39.3</td><td>| . | . * |</td></tr>
<tr><td>2020M07</td><td>7924.0</td><td>7896.0</td><td>28.0</td><td>| . | .* |</td></tr>
<tr><td>2020M08</td><td>7900.0</td><td>7887.5</td><td>12.5</td><td>| . |* . |</td></tr>
<tr><td>2020M09</td><td>7972.0</td><td>7956.6</td><td>15.4</td><td>| . | *. |</td></tr>
<tr><td>2020M10</td><td>8154.0</td><td>8167.0</td><td>-13.0</td><td>| . * | . |</td></tr>
<tr><td>2020M11</td><td>8222.0</td><td>8255.8</td><td>-33.8</td><td>| * . | . |</td></tr>
<tr><td>2020M12</td><td>8252.0</td><td>8211.8</td><td>40.2</td><td>| . | . * |</td></tr>
<tr><td>2021M01</td><td>8261.0</td><td>8241.6</td><td>19.4</td><td>| . | *. |</td></tr>
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<tr><td>2021M04</td><td>8211.0</td><td>8211.9</td><td>-0.9</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>8084.0</td><td>8109.8</td><td>-25.8</td><td>| * | . |</td></tr>
<tr><td>2021M06</td><td>7991.0</td><td>8013.7</td><td>-22.7</td><td>| * | . |</td></tr>
<tr><td>2021M07</td><td>7987.0</td><td>7988.9</td><td>-1.9</td><td>| . * . |</td></tr>
<tr><td>2021M08</td><td>8000.0</td><td>7997.7</td><td>2.3</td><td>| . * . |</td></tr>
<tr><td>2021M09</td><td>8050.0</td><td>8057.5</td><td>-7.5</td><td>| . *| . |</td></tr>
<tr><td>2021M10</td><td>8210.0</td><td>8209.6</td><td>0.4</td><td>| . * . |</td></tr>
<tr><td>2021M11</td><td>8323.0</td><td>8306.7</td><td>16.3</td><td>| . | *. |</td></tr>
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<tr><td>2022M04</td><td>8359</td><td>8356.6</td><td>2.39551</td><td>| . * . |</td></tr>
<tr><td>2022M05</td><td>8216</td><td>8242.4</td><td>-26.353</td><td>| * | . |</td></tr>
<tr><td>2022M06</td><td>8125</td><td>8131.5</td><td>-6.5391</td><td>| . *| . |</td></tr>
<tr><td>2022M07</td><td>8103</td><td>8122.7</td><td>-19.741</td><td>| .* | . |</td></tr>
<tr><td>2022M08</td><td>8099</td><td>8105.7</td><td>-6.6988</td><td>| . *| . |</td></tr>
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<tr><td>2022M11</td><td>8459</td><td>8454.9</td><td>4.0553</td><td>| . |* . |</td></tr>
<tr><td>2022M12</td><td>8513</td><td>8510.2</td><td>2.79299</td><td>| . * . |</td></tr>
</table>

Date: 03/23/23 Time: 08:58
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.071	0.071	0.4380	
. | . |	. | . |	2	-0.012	-0.018	0.4516	
. |*. |	. |*. |	3	0.109	0.112	1.5157	0.218
.*| . |	.*| . |	4	-0.156	-0.176	3.7209	0.156
. | . |	. | . |	5	0.016	0.051	3.7456	0.290
. |*. |	. |*. |	6	0.101	0.078	4.6921	0.320
. | . |	. |*. |	7	0.050	0.078	4.9305	0.424
. |*. |	. |*. |	8	0.141	0.105	6.8320	0.337
. | . |	.*| . |	9	-0.042	-0.078	7.0050	0.428
. |*. |	. |*. |	10	0.111	0.154	8.2128	0.413
. | . |	. | . |	11	0.071	0.031	8.7061	0.465
.*| . |	.*| . |	12	-0.130	-0.097	10.389	0.407

*Probabilities may not be valid for this equation specification.

LLF Customer Segment - Use Per Customer Model

Dependent Variable: LLF_UPC
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/15/23 Time: 15:58
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 37 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GMP(-3)*Q4_TO_Q2	5.768885	0.350578	16.45534	0.0000
BC_OCT	0.656343	0.049796	13.18068	0.0000
BC_NOV	0.777321	0.021105	36.83191	0.0000
BC_DEC	0.862919	0.013049	66.13121	0.0000
BC_JAN	0.851006	0.010050	84.67489	0.0000
BC_FEB	0.795727	0.010808	73.62164	0.0000
BC_MAR	0.845921	0.012130	69.73958	0.0000
BC_APR	0.705366	0.015123	46.64289	0.0000
BC_MAY	0.576968	0.025034	23.04736	0.0000
BC_JUN	0.414042	0.059806	6.923118	0.0000
D_2020M11	-49.83477	20.15067	-2.473107	0.0161
D_2021M1	-140.2356	31.61630	-4.435547	0.0000
D_2021M3	185.4522	21.06101	8.805475	0.0000
JAN*D_2019M7_F*TREND	1.714488	0.238028	7.202874	0.0000
FEB*D_2019M7_F*TREND	1.400399	0.153369	9.130924	0.0000
JUL	230.5824	5.838559	39.49304	0.0000
AUG	223.4388	5.818609	38.40072	0.0000
SEP	238.3795	5.806183	41.05615	0.0000
AR(4)	0.405994	0.120794	3.361050	0.0013
AR(12)	-0.569236	0.116028	-4.906018	0.0000
MA(1)	-0.310136	0.119261	-2.600475	0.0116

R-squared	0.997998	Mean dependent var	661.2274
Adjusted R-squared	0.997363	S.D. dependent var	402.3675
S.E. of regression	20.66231	Akaike info criterion	9.186360
Sum squared resid	26896.66	Schwarz criterion	9.794064
Log likelihood	-364.8271	Hannan-Quinn criter.	9.430652
Durbin-Watson stat	1.930293		

Inverted AR Roots	.95-.22i	.95+.22i	.65-.65i	.65-.65i
	.22+.95i	.22-.95i	-.22-.95i	-.22+.95i
	-.65+.65i	-.65+.65i	-.95+.22i	-.95-.22i
Inverted MA Roots	.31			

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.091819	Prob. F(21,62)	0.3801
Obs*R-squared	22.67761	Prob. Chi-Square(21)	0.3614
Scaled explained SS	13.91161	Prob. Chi-Square(21)	0.8734

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 09:00
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	413.0482	196.0643	2.106697	0.0392
GRADF_01^2	3.092344	22.45101	0.137737	0.8909
GRADF_02^2	-0.238647	0.480606	-0.496555	0.6213
GRADF_03^2	-0.091821	0.120521	-0.761872	0.4490
GRADF_04^2	-0.005049	0.051168	-0.098680	0.9217
GRADF_05^2	0.035031	0.029211	1.199217	0.2350
GRADF_06^2	0.021681	0.029949	0.723924	0.4718
GRADF_07^2	-0.021412	0.035282	-0.606892	0.5461
GRADF_08^2	-0.026211	0.050847	-0.515475	0.6081
GRADF_09^2	-0.101647	0.137395	-0.739814	0.4622
GRADF_10^2	-0.642370	0.789536	-0.813604	0.4190
GRADF_11^2	-40374.88	167244.2	-0.241413	0.8100
GRADF_12^2	-19525.84	234764.9	-0.083172	0.9340
GRADF_13^2	125314.4	170573.5	0.734665	0.4653
GRADF_14^2	-17.01009	13.71272	-1.240460	0.2195
GRADF_15^2	-7.541975	9.976487	-0.755975	0.4525
GRADF_16^2	-20594.57	34243.90	-0.601409	0.5498
GRADF_17^2	-32718.50	32696.47	-1.000674	0.3209
GRADF_18^2	78234.98	32463.09	2.409967	0.0189
GRADF_19^2	-19.13194	32.72570	-0.584615	0.5609
GRADF_20^2	-22.03407	28.24707	-0.780048	0.4383
GRADF_21^2	-0.115592	35.73657	-0.003235	0.9974

R-squared	0.269971	Mean dependent var	320.1984
Adjusted R-squared	0.022704	S.D. dependent var	475.7333
S.E. of regression	470.3018	Akaike info criterion	15.36475
Sum squared resid	13713397	Schwarz criterion	16.00140
Log likelihood	-623.3197	Hannan-Quinn criter.	15.62068
F-statistic	1.091819	Durbin-Watson stat	1.771135
Prob(F-statistic)	0.380138		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>1125.4</td><td>1100.6</td><td>24.8</td><td>| . | .* |</td></tr>
<tr><td>2016M02</td><td>1154.9</td><td>1111.5</td><td>43.4</td><td>| . | . *|</td></tr>
<tr><td>2016M03</td><td>998.3</td><td>1006.6</td><td>-8.3</td><td>| . * | . |</td></tr>
<tr><td>2016M04</td><td>743.3</td><td>738.2</td><td>5.1</td><td>| . |* . |</td></tr>
<tr><td>2016M05</td><td>465.1</td><td>490.0</td><td>-24.9</td><td>| *. | . |</td></tr>
<tr><td>2016M06</td><td>271.4</td><td>272.8</td><td>-1.4</td><td>| . * . |</td></tr>
<tr><td>2016M07</td><td>204.5</td><td>214.2</td><td>-9.7</td><td>| . * | . |</td></tr>
<tr><td>2016M08</td><td>215.2</td><td>230.6</td><td>-15.4</td><td>| .* | . |</td></tr>
<tr><td>2016M09</td><td>217.1</td><td>219.8</td><td>-2.8</td><td>| . *| . |</td></tr>
<tr><td>2016M10</td><td>356.9</td><td>353.2</td><td>3.7</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>643.0</td><td>641.0</td><td>2.0</td><td>| . * . |</td></tr>
<tr><td>2016M12</td><td>987.4</td><td>1017.2</td><td>-29.8</td><td>| * . | . |</td></tr>
<tr><td>2017M01</td><td>1190.4</td><td>1172.6</td><td>17.8</td><td>| . | * |</td></tr>
<tr><td>2017M02</td><td>1109.7</td><td>1077.6</td><td>32.2</td><td>| . | . * |</td></tr>
<tr><td>2017M03</td><td>1104.9</td><td>1110.6</td><td>-5.7</td><td>| . *| . |</td></tr>
<tr><td>2017M04</td><td>814.3</td><td>806.6</td><td>7.7</td><td>| . | * . |</td></tr>
<tr><td>2017M05</td><td>482.1</td><td>464.3</td><td>17.7</td><td>| . | * |</td></tr>
<tr><td>2017M06</td><td>271.6</td><td>255.9</td><td>15.7</td><td>| . | *. |</td></tr>
<tr><td>2017M07</td><td>244.0</td><td>240.8</td><td>3.2</td><td>| . |* . |</td></tr>
<tr><td>2017M08</td><td>211.0</td><td>224.5</td><td>-13.5</td><td>| .* | . |</td></tr>
<tr><td>2017M09</td><td>221.9</td><td>264.3</td><td>-42.3</td><td>| * . | . |</td></tr>
<tr><td>2017M10</td><td>292.2</td><td>285.7</td><td>6.5</td><td>| . |* . |</td></tr>
<tr><td>2017M11</td><td>588.4</td><td>593.9</td><td>-5.5</td><td>| . *| . |</td></tr>
<tr><td>2017M12</td><td>1100.4</td><td>1089.6</td><td>10.8</td><td>| . | * . |</td></tr>
<tr><td>2018M01</td><td>1441.0</td><td>1482.0</td><td>-41.0</td><td>| * . | . |</td></tr>
<tr><td>2018M02</td><td>1118.0</td><td>1151.0</td><td>-33.0</td><td>| * . | . |</td></tr>
<tr><td>2018M03</td><td>1016.3</td><td>1010.7</td><td>5.6</td><td>| . |* . |</td></tr>
<tr><td>2018M04</td><td>835.0</td><td>856.0</td><td>-21.0</td><td>| * | . |</td></tr>
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<tr><td>2018M07</td><td>219.3</td><td>224.9</td><td>-5.6</td><td>| . *| . |</td></tr>
<tr><td>2018M08</td><td>221.0</td><td>229.0</td><td>-7.9</td><td>| . * | . |</td></tr>
<tr><td>2018M09</td><td>221.5</td><td>242.9</td><td>-21.4</td><td>| * | . |</td></tr>
<tr><td>2018M10</td><td>403.4</td><td>387.1</td><td>16.4</td><td>| . | *. |</td></tr>
<tr><td>2018M11</td><td>780.9</td><td>766.1</td><td>14.8</td><td>| . | *. |</td></tr>
<tr><td>2018M12</td><td>1110.7</td><td>1112.5</td><td>-1.8</td><td>| . * . |</td></tr>
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<tr><td>2019M02</td><td>1246.9</td><td>1248.2</td><td>-1.2</td><td>| . * . |</td></tr>
<tr><td>2019M03</td><td>1146.9</td><td>1166.8</td><td>-19.9</td><td>| * | . |</td></tr>
<tr><td>2019M04</td><td>796.5</td><td>793.4</td><td>3.1</td><td>| . |* . |</td></tr>
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<tr><td>2019M09</td><td>232.6</td><td>252.3</td><td>-19.7</td><td>| * | . |</td></tr>
<tr><td>2019M10</td><td>382.7</td><td>373.6</td><td>9.2</td><td>| . | * . |</td></tr>
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<tr><td>2020M01</td><td>1217.6</td><td>1225.7</td><td>-8.2</td><td>| . * | . |</td></tr>
<tr><td>2020M02</td><td>1175.3</td><td>1182.8</td><td>-7.5</td><td>| . * | . |</td></tr>
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<tr><td>2021M03</td><td>1283.6</td><td>1299.2</td><td>-15.6</td><td>| .* | . |</td></tr>
<tr><td>2021M04</td><td>794.1</td><td>781.4</td><td>12.7</td><td>| . | *. |</td></tr>
<tr><td>2021M05</td><td>504.4</td><td>495.9</td><td>8.5</td><td>| . | * . |</td></tr>
<tr><td>2021M06</td><td>276.1</td><td>295.7</td><td>-19.6</td><td>| * | . |</td></tr>
<tr><td>2021M07</td><td>247.7</td><td>223.7</td><td>23.9</td><td>| . | .* |</td></tr>
<tr><td>2021M08</td><td>241.5</td><td>233.0</td><td>8.5</td><td>| . | * . |</td></tr>
<tr><td>2021M09</td><td>244.8</td><td>233.3</td><td>11.4</td><td>| . | * . |</td></tr>
<tr><td>2021M10</td><td>330.3</td><td>350.1</td><td>-19.8</td><td>| * | . |</td></tr>
<tr><td>2021M11</td><td>687.1</td><td>692.7</td><td>-5.5</td><td>| . *| . |</td></tr>
<tr><td>2021M12</td><td>1085.2</td><td>1048.2</td><td>37.0</td><td>| . | . * |</td></tr>
<tr><td>2022M01</td><td>1419.9</td><td>1409.9</td><td>10.0</td><td>| . | * . |</td></tr>
<tr><td>2022M02</td><td>1381.8</td><td>1403.1</td><td>-21.3</td><td>| * | . |</td></tr>
<tr><td>2022M03</td><td>1198.8</td><td>1165.2</td><td>33.6</td><td>| . | . * |</td></tr>
<tr><td>2022M04</td><td>788.05</td><td>771.29</td><td>16.7589</td><td>| . | * |</td></tr>
<tr><td>2022M05</td><td>510.46</td><td>509.39</td><td>1.06406</td><td>| . * . |</td></tr>
<tr><td>2022M06</td><td>289.03</td><td>291.28</td><td>-2.2543</td><td>| . * . |</td></tr>
<tr><td>2022M07</td><td>251.05</td><td>250.35</td><td>0.69725</td><td>| . * . |</td></tr>
<tr><td>2022M08</td><td>229.8</td><td>212.95</td><td>16.8508</td><td>| . | * |</td></tr>
<tr><td>2022M09</td><td>272.52</td><td>222.05</td><td>50.4721</td><td>| . | . *</td></tr>
<tr><td>2022M10</td><td>413.2</td><td>441.92</td><td>-28.721</td><td>| * . | . |</td></tr>
<tr><td>2022M11</td><td>619.93</td><td>633.89</td><td>-13.958</td><td>| .* | . |</td></tr>
<tr><td>2022M12</td><td>1024.1</td><td>1027.4</td><td>-3.2869</td><td>| . *| . |</td></tr>
</table>

Date: 03/23/23 Time: 09:01
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 3 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.023	0.023	0.0470	
.*| . |	.*| . |	2	-0.148	-0.149	1.9745	
. | . |	. | . |	3	0.025	0.034	2.0320	
. | . |	. | . |	4	0.059	0.036	2.3458	0.126
. |*. |	. |*. |	5	0.101	0.109	3.2722	0.195
.*| . |	.*| . |	6	-0.080	-0.075	3.8591	0.277
. | . |	. | . |	7	-0.035	-0.003	3.9754	0.409
. | . |	. | . |	8	0.030	-0.001	4.0604	0.541
.*| . |	.*| . |	9	-0.078	-0.092	4.6529	0.589
.*| . |	.*| . |	10	-0.136	-0.136	6.4497	0.488
. | . |	. | . |	11	-0.023	-0.026	6.5034	0.591
. | . |	. | . |	12	-0.008	-0.044	6.5104	0.688

*Probabilities may not be valid for this equation specification.

HLF Customer Segment – Customer Model

Dependent Variable: HLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/01/23 Time: 14:40
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Failure to improve likelihood (non-zero gradients) after 6 iterations
Coefficient covariance computed using outer product of gradients
MA Backcast: 2015M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GMP(-3)*D_2021M11_F	0.416276	0.187631	2.218592	0.0294
D_2018M5_2019M6	48.21605	4.956835	9.727186	0.0000
C	1147.672	23.69634	48.43244	0.0000
AR(2)	0.925010	0.047803	19.35032	0.0000
MA(1)	0.887361	0.061507	14.42699	0.0000

R-squared	0.961960	Mean dependent var	1139.595
Adjusted R-squared	0.960034	S.D. dependent var	35.12323
S.E. of regression	7.021644	Akaike info criterion	6.793551
Sum squared resid	3894.976	Schwarz criterion	6.938242
Log likelihood	-280.3291	Hannan-Quinn criter.	6.851715
F-statistic	499.4437	Durbin-Watson stat	2.118708
Prob(F-statistic)	0.000000		

Inverted AR Roots	.96	-.96
Inverted MA Roots	-.89	

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.926651	Prob. F(5,78)	0.0993
Obs*R-squared	9.233861	Prob. Chi-Square(5)	0.1001
Scaled explained SS	24.04808	Prob. Chi-Square(5)	0.0002

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 09:02
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	104.4041	255.0703	0.409315	0.6834
GRADF_01^2	-0.002528	0.081696	-0.030942	0.9754
GRADF_02^2	223.2042	81.43100	2.741022	0.0076
GRADF_03^2	-31805.69	160310.3	-0.198401	0.8432
GRADF_04^2	-0.006336	0.019829	-0.319542	0.7502
GRADF_05^2	-0.053236	0.048869	-1.089365	0.2793

R-squared	0.109927	Mean dependent var	46.36876
Adjusted R-squared	0.052871	S.D. dependent var	113.1988
S.E. of regression	110.1657	Akaike info criterion	12.31060
Sum squared resid	946645.6	Schwarz criterion	12.48423
Log likelihood	-511.0451	Hannan-Quinn criter.	12.38040
F-statistic	1.926651	Durbin-Watson stat	1.830369
Prob(F-statistic)	0.099318		

obs	Actual	Fitted	Residual	Residual Plot
2016M01	2135.6	1968.4	167.2	| . | . * |
2016M02	2004.6	1961.2	43.4	| . |* . |
2016M03	2000.3	2012.3	-12.0	| . * . |
2016M04	1978.3	1872.7	105.6	| . | .* |
2016M05	1968.0	1892.4	75.6	| . | * |
2016M06	1963.7	1929.9	33.9	| . |* . |
2016M07	1766.5	1923.6	-157.1	| * . | . |
2016M08	1975.5	1861.3	114.2	| . | .* |
2016M09	1815.5	1835.9	-20.4	| . *| . |
2016M10	2014.6	1986.1	28.5	| . |* . |
2016M11	2035.3	2040.3	-5.0	| . * . |
2016M12	2044.5	1940.8	103.7	| . | * |
2017M01	2017.3	2059.7	-42.4	| . *| . |
2017M02	1976.7	1980.3	-3.6	| . * . |
2017M03	2057.8	1957.0	100.8	| . | * |
2017M04	1867.5	1879.4	-12.0	| . * . |
2017M05	2025.6	1883.3	142.3	| . | . * |
2017M06	1581.3	1898.3	-317.0	|* . | . |
2017M07	2014.4	1834.3	180.1	| . | . * |
2017M08	1850.9	1764.9	86.0	| . | * |
2017M09	1772.7	1922.3	-149.7	| * . | . |
2017M10	1978.1	1902.0	76.0	| . | * |
2017M11	2222.1	2080.3	141.8	| . | . * |
2017M12	2244.6	2158.9	85.8	| . | * |
2018M01	2351.7	2445.4	-93.7	| * | . |
2018M02	2001.2	1977.8	23.4	| . |* . |
2018M03	2150.2	2130.1	20.1	| . |* . |
2018M04	2081.5	2042.9	38.6	| . |* . |
2018M05	1792.5	1957.0	-164.5	| * . | . |
2018M06	1740.3	1859.8	-119.5	| *. | . |
2018M07	1660.9	1736.5	-75.6	| * | . |
2018M08	1728.5	1714.1	14.4	| . * . |
2018M09	1668.2	1719.7	-51.5	| .* | . |
2018M10	2011.5	1892.1	119.4	| . | .* |
2018M11	2091.0	2132.1	-41.2	| . *| . |
2018M12	2038.8	2076.7	-37.9	| . *| . |
2019M01	2237.0	2165.3	71.7	| . | *. |
2019M02	2060.3	2137.2	-76.9	| * | . |
2019M03	2118.4	2126.8	-8.4	| . * . |
2019M04	2021.9	1919.6	102.3	| . | * |
2019M05	1977.6	1918.5	59.0	| . | *. |
2019M06	1845.5	1912.6	-67.1	| .* | . |

<table>
<tr><td>2019M07</td><td>1885.9</td><td>1855.7</td><td>30.2</td><td>| . |* . |</td></tr>
<tr><td>2019M08</td><td>1906.6</td><td>1835.0</td><td>71.6</td><td>| . | *. |</td></tr>
<tr><td>2019M09</td><td>1919.0</td><td>1882.2</td><td>36.8</td><td>| . |* . |</td></tr>
<tr><td>2019M10</td><td>2058.1</td><td>2018.6</td><td>39.5</td><td>| . |* . |</td></tr>
<tr><td>2019M11</td><td>2196.2</td><td>2191.7</td><td>4.5</td><td>| . * . |</td></tr>
<tr><td>2019M12</td><td>2263.5</td><td>2140.5</td><td>123.0</td><td>| . | .* |</td></tr>
<tr><td>2020M01</td><td>2337.5</td><td>2300.0</td><td>37.6</td><td>| . |* . |</td></tr>
<tr><td>2020M02</td><td>2303.4</td><td>2278.5</td><td>24.9</td><td>| . |* . |</td></tr>
<tr><td>2020M03</td><td>2229.8</td><td>2219.7</td><td>10.1</td><td>| . * . |</td></tr>
<tr><td>2020M04</td><td>1809.8</td><td>1983.3</td><td>-173.5</td><td>| * . | . |</td></tr>
<tr><td>2020M05</td><td>1689.1</td><td>1750.0</td><td>-60.9</td><td>| .* | . |</td></tr>
<tr><td>2020M06</td><td>1680.1</td><td>1536.1</td><td>144.0</td><td>| . | . * |</td></tr>
<tr><td>2020M07</td><td>1619.1</td><td>1583.1</td><td>36.0</td><td>| . |* . |</td></tr>
<tr><td>2020M08</td><td>1634.2</td><td>1707.9</td><td>-73.7</td><td>| .* | . |</td></tr>
<tr><td>2020M09</td><td>1716.0</td><td>1757.2</td><td>-41.2</td><td>| . *| . |</td></tr>
<tr><td>2020M10</td><td>1877.5</td><td>1900.4</td><td>-22.9</td><td>| . *| . |</td></tr>
<tr><td>2020M11</td><td>2115.2</td><td>2059.7</td><td>55.5</td><td>| . | *. |</td></tr>
<tr><td>2020M12</td><td>2050.8</td><td>1985.8</td><td>65.0</td><td>| . | *. |</td></tr>
<tr><td>2021M01</td><td>2075.8</td><td>2161.0</td><td>-85.2</td><td>| * | . |</td></tr>
<tr><td>2021M02</td><td>2018.0</td><td>2078.2</td><td>-60.2</td><td>| .* | . |</td></tr>
<tr><td>2021M03</td><td>2138.2</td><td>2010.3</td><td>127.9</td><td>| . | .* |</td></tr>
<tr><td>2021M04</td><td>1879.9</td><td>1874.7</td><td>5.1</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>1888.8</td><td>1858.9</td><td>29.9</td><td>| . |* . |</td></tr>
<tr><td>2021M06</td><td>1745.7</td><td>1787.4</td><td>-41.7</td><td>| . *| . |</td></tr>
<tr><td>2021M07</td><td>1742.6</td><td>1774.1</td><td>-31.5</td><td>| . *| . |</td></tr>
<tr><td>2021M08</td><td>1766.7</td><td>1738.1</td><td>28.6</td><td>| . |* . |</td></tr>
<tr><td>2021M09</td><td>1788.6</td><td>1760.5</td><td>28.1</td><td>| . |* . |</td></tr>
<tr><td>2021M10</td><td>1830.5</td><td>1889.9</td><td>-59.4</td><td>| .* | . |</td></tr>
<tr><td>2021M11</td><td>2051.4</td><td>2054.2</td><td>-2.8</td><td>| . * . |</td></tr>
<tr><td>2021M12</td><td>1988.4</td><td>1991.9</td><td>-3.5</td><td>| . * . |</td></tr>
<tr><td>2022M01</td><td>2161.0</td><td>2176.5</td><td>-15.5</td><td>| . *| . |</td></tr>
<tr><td>2022M02</td><td>2029.1</td><td>2100.4</td><td>-71.3</td><td>| .* | . |</td></tr>
<tr><td>2022M03</td><td>1887.5</td><td>2039.7</td><td>-152.2</td><td>| * . | . |</td></tr>
<tr><td>2022M04</td><td>1772.5</td><td>1826.2</td><td>-53.675</td><td>| .* | . |</td></tr>
<tr><td>2022M05</td><td>1828.8</td><td>1756</td><td>72.7797</td><td>| . | *. |</td></tr>
<tr><td>2022M06</td><td>1688.3</td><td>1753.9</td><td>-65.625</td><td>| .* | . |</td></tr>
<tr><td>2022M07</td><td>1622</td><td>1747.8</td><td>-125.81</td><td>| *. | . |</td></tr>
<tr><td>2022M08</td><td>1724.9</td><td>1688.7</td><td>36.1949</td><td>| . |* . |</td></tr>
<tr><td>2022M09</td><td>1720.2</td><td>1708.2</td><td>11.9693</td><td>| . * . |</td></tr>
<tr><td>2022M10</td><td>1796.9</td><td>1912.7</td><td>-115.74</td><td>| *. | . |</td></tr>
<tr><td>2022M11</td><td>1888.9</td><td>1943.9</td><td>-55.085</td><td>| .* | . |</td></tr>
<tr><td>2022M12</td><td>1709.5</td><td>1895.8</td><td>-186.3</td><td>| * . | . |</td></tr>
</table>

Date: 03/23/23 Time: 09:04
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
.*| . |	.*| . |	1	-0.077	-0.077	0.5132	
. | . |	. | . |	2	0.048	0.042	0.7142	
. |*. |	. |*. |	3	0.102	0.110	1.6429	0.200
. | . |	. | . |	4	-0.028	-0.014	1.7133	0.425
. | . |	. | . |	5	-0.027	-0.041	1.7799	0.619
. | . |	.*| . |	6	-0.063	-0.079	2.1466	0.709
. | . |	. | . |	7	-0.051	-0.055	2.3900	0.793
.*| . |	.*| . |	8	-0.098	-0.095	3.3081	0.769
. | . |	. | . |	9	0.049	0.055	3.5424	0.831
. | . |	. | . |	10	-0.025	0.002	3.6011	0.891
.*| . |	.*| . |	11	-0.079	-0.075	4.2250	0.896
. | . |	. | . |	12	0.042	0.008	4.4038	0.927

*Probabilities may not be valid for this equation specification.

HLF Customer Segment - Use Per Customer Model

Dependent Variable: HLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/01/23 Time: 14:43
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Convergence achieved after 9 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
UNEMP_RT(-1)	-38.92861	12.16159	-3.200949	0.0020
BC_DEC+BC_FEB	0.082400	0.037778	2.181186	0.0324
BC_JAN	0.160811	0.041997	3.829057	0.0003
BC_MAR	0.108100	0.039050	2.768211	0.0071
BC_NOV	0.326041	0.065012	5.015113	0.0000
BC_OCT	0.370237	0.130697	2.832779	0.0060
D_2017M09_F*BC_EDD	0.173506	0.047100	3.683750	0.0004
D_2018_M02	-225.1990	88.33268	-2.549441	0.0129
C	1909.704	63.35549	30.14268	0.0000
AR(1)	0.301170	0.112975	2.665810	0.0095
AR(2)	0.448404	0.114953	3.900740	0.0002

R-squared	0.762541	Mean dependent var	1939.575
Adjusted R-squared	0.730012	S.D. dependent var	185.2815
S.E. of regression	96.27292	Akaike info criterion	12.09380
Sum squared resid	676598.7	Schwarz criterion	12.41212
Log likelihood	-496.9395	Hannan-Quinn criter.	12.22176
F-statistic	23.44213	Durbin-Watson stat	2.111396
Prob(F-statistic)	0.000000		

Inverted AR Roots	.84	-.54

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.089450	Prob. F(10,73)	0.3816
Obs*R-squared	10.90820	Prob. Chi-Square(10)	0.3647
Scaled explained SS	11.23007	Prob. Chi-Square(10)	0.3399

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 09:08
Sample: 2016M01 2022M12
Included observations: 84
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4224.363	3078.661	1.372143	0.1742
GRADF_01^2	309.5210	340.6919	0.908507	0.3666
GRADF_02^2	-0.000455	0.006339	-0.071710	0.9430
GRADF_03^2	-0.001777	0.004336	-0.409837	0.6831
GRADF_04^2	0.000123	0.004917	0.024994	0.9801
GRADF_05^2	-0.010428	0.015735	-0.662705	0.5096
GRADF_06^2	0.003512	0.071358	0.049215	0.9609
GRADF_07^2	0.001939	0.013079	0.148242	0.8826
GRADF_08^2	-4920.476	13766.29	-0.357429	0.7218
GRADF_10^2	0.337597	0.121971	2.767854	0.0071
GRADF_11^2	0.005587	0.122979	0.045431	0.9639

R-squared	0.129859	Mean dependent var	8054.746
Adjusted R-squared	0.010662	S.D. dependent var	13379.46
S.E. of regression	13307.94	Akaike info criterion	21.95166
Sum squared resid	1.29E+10	Schwarz criterion	22.26998
Log likelihood	-910.9696	Hannan-Quinn criter.	22.07962
F-statistic	1.089450	Durbin-Watson stat	1.857778
Prob(F-statistic)	0.381601		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>2135.6</td><td>1968.4</td><td>167.2</td><td>| . | . * |</td></tr>
<tr><td>2016M02</td><td>2004.6</td><td>1961.2</td><td>43.4</td><td>| . |* . |</td></tr>
<tr><td>2016M03</td><td>2000.3</td><td>2012.3</td><td>-12.0</td><td>| . * . |</td></tr>
<tr><td>2016M04</td><td>1978.3</td><td>1872.7</td><td>105.6</td><td>| . | .* |</td></tr>
<tr><td>2016M05</td><td>1968.0</td><td>1892.4</td><td>75.6</td><td>| . | * |</td></tr>
<tr><td>2016M06</td><td>1963.7</td><td>1929.9</td><td>33.9</td><td>| . |* . |</td></tr>
<tr><td>2016M07</td><td>1766.5</td><td>1923.6</td><td>-157.1</td><td>| * . | . |</td></tr>
<tr><td>2016M08</td><td>1975.5</td><td>1861.3</td><td>114.2</td><td>| . | .* |</td></tr>
<tr><td>2016M09</td><td>1815.5</td><td>1835.9</td><td>-20.4</td><td>| .*| . |</td></tr>
<tr><td>2016M10</td><td>2014.6</td><td>1986.1</td><td>28.5</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>2035.3</td><td>2040.3</td><td>-5.0</td><td>| . * . |</td></tr>
<tr><td>2016M12</td><td>2044.5</td><td>1940.8</td><td>103.7</td><td>| . | * |</td></tr>
<tr><td>2017M01</td><td>2017.3</td><td>2059.7</td><td>-42.4</td><td>| .*| . |</td></tr>
<tr><td>2017M02</td><td>1976.7</td><td>1980.3</td><td>-3.6</td><td>| . * . |</td></tr>
<tr><td>2017M03</td><td>2057.8</td><td>1957.0</td><td>100.8</td><td>| . | * |</td></tr>
<tr><td>2017M04</td><td>1867.5</td><td>1879.4</td><td>-12.0</td><td>| . * . |</td></tr>
<tr><td>2017M05</td><td>2025.6</td><td>1883.3</td><td>142.3</td><td>| . | . * |</td></tr>
<tr><td>2017M06</td><td>1581.3</td><td>1898.3</td><td>-317.0</td><td>|* . | . |</td></tr>
<tr><td>2017M07</td><td>2014.4</td><td>1834.3</td><td>180.1</td><td>| . | . * |</td></tr>
<tr><td>2017M08</td><td>1850.9</td><td>1764.9</td><td>86.0</td><td>| . | * |</td></tr>
<tr><td>2017M09</td><td>1772.7</td><td>1922.3</td><td>-149.7</td><td>| * . | . |</td></tr>
<tr><td>2017M10</td><td>1978.1</td><td>1902.0</td><td>76.0</td><td>| . | * |</td></tr>
<tr><td>2017M11</td><td>2222.1</td><td>2080.3</td><td>141.8</td><td>| . | . * |</td></tr>
<tr><td>2017M12</td><td>2244.6</td><td>2158.9</td><td>85.8</td><td>| . | * |</td></tr>
<tr><td>2018M01</td><td>2351.7</td><td>2445.4</td><td>-93.7</td><td>| * | . |</td></tr>
<tr><td>2018M02</td><td>2001.2</td><td>1977.8</td><td>23.4</td><td>| . |* . |</td></tr>
<tr><td>2018M03</td><td>2150.2</td><td>2130.1</td><td>20.1</td><td>| . |* . |</td></tr>
<tr><td>2018M04</td><td>2081.5</td><td>2042.9</td><td>38.6</td><td>| . |* . |</td></tr>
<tr><td>2018M05</td><td>1792.5</td><td>1957.0</td><td>-164.5</td><td>| * . | . |</td></tr>
<tr><td>2018M06</td><td>1740.3</td><td>1859.8</td><td>-119.5</td><td>| *. | . |</td></tr>
<tr><td>2018M07</td><td>1660.9</td><td>1736.5</td><td>-75.6</td><td>| * | . |</td></tr>
<tr><td>2018M08</td><td>1728.5</td><td>1714.1</td><td>14.4</td><td>| . * . |</td></tr>
<tr><td>2018M09</td><td>1668.2</td><td>1719.7</td><td>-51.5</td><td>| .* | . |</td></tr>
<tr><td>2018M10</td><td>2011.5</td><td>1892.1</td><td>119.4</td><td>| . | .* |</td></tr>
<tr><td>2018M11</td><td>2091.0</td><td>2132.1</td><td>-41.2</td><td>| .*| . |</td></tr>
<tr><td>2018M12</td><td>2038.8</td><td>2076.7</td><td>-37.9</td><td>| .*| . |</td></tr>
<tr><td>2019M01</td><td>2237.0</td><td>2165.3</td><td>71.7</td><td>| . | *. |</td></tr>
<tr><td>2019M02</td><td>2060.3</td><td>2137.2</td><td>-76.9</td><td>| * | . |</td></tr>
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<tr><td>2019M04</td><td>2021.9</td><td>1919.6</td><td>102.3</td><td>| . | * |</td></tr>
<tr><td>2019M05</td><td>1977.6</td><td>1918.5</td><td>59.0</td><td>| . | *. |</td></tr>
<tr><td>2019M06</td><td>1845.5</td><td>1912.6</td><td>-67.1</td><td>| .* | . |</td></tr>
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<tr><td>2019M08</td><td>1906.6</td><td>1835.0</td><td>71.6</td><td>| . | *. |</td></tr>
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<tr><td>2019M10</td><td>2058.1</td><td>2018.6</td><td>39.5</td><td>| . |* . |</td></tr>
<tr><td>2019M11</td><td>2196.2</td><td>2191.7</td><td>4.5</td><td>| . * . |</td></tr>
<tr><td>2019M12</td><td>2263.5</td><td>2140.5</td><td>123.0</td><td>| . | .* |</td></tr>
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<tr><td>2020M02</td><td>2303.4</td><td>2278.5</td><td>24.9</td><td>| . |* . |</td></tr>
<tr><td>2020M03</td><td>2229.8</td><td>2219.7</td><td>10.1</td><td>| . * . |</td></tr>
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<tr><td>2021M01</td><td>2075.8</td><td>2161.0</td><td>-85.2</td><td>| * | . |</td></tr>
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<tr><td>2021M04</td><td>1879.9</td><td>1874.7</td><td>5.1</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>1888.8</td><td>1858.9</td><td>29.9</td><td>| . |* . |</td></tr>
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<tr><td>2021M12</td><td>1988.4</td><td>1991.9</td><td>-3.5</td><td>| . * . |</td></tr>
<tr><td>2022M01</td><td>2161.0</td><td>2176.5</td><td>-15.5</td><td>| . *| . |</td></tr>
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<tr><td>2022M03</td><td>1887.5</td><td>2039.7</td><td>-152.2</td><td>| * . | . |</td></tr>
<tr><td>2022M04</td><td>1772.5</td><td>1826.2</td><td>-53.675</td><td>| .* | . |</td></tr>
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<tr><td>2022M07</td><td>1622</td><td>1747.8</td><td>-125.81</td><td>| *. | . |</td></tr>
<tr><td>2022M08</td><td>1724.9</td><td>1688.7</td><td>36.1949</td><td>| . |* . |</td></tr>
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<tr><td>2022M12</td><td>1709.5</td><td>1895.8</td><td>-186.3</td><td>| * . | . |</td></tr>
</table>

Date: 03/23/23 Time: 09:11
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
.*| . |	.*| . |	1	-0.102	-0.102	0.9055	
.*| . |	.*| . |	2	-0.138	-0.150	2.5830	
. |*. |	. | . |	3	0.100	0.071	3.4812	0.062
. |*. |	. |*. |	4	0.170	0.175	6.1039	0.047
. | . |	. |*. |	5	0.059	0.130	6.4225	0.093
.*| . |	. | . |	6	-0.106	-0.051	7.4618	0.113
. | . |	. | . |	7	0.029	-0.004	7.5415	0.183
. | . |	. | . |	8	0.012	-0.060	7.5543	0.273
. |*. |	. |*. |	9	0.166	0.163	10.221	0.176
.*| . |	.*| . |	10	-0.122	-0.075	11.673	0.166
. |*. |	. |*. |	11	0.154	0.209	14.022	0.122
.*| . |	.*| . |	12	-0.073	-0.124	14.562	0.149

*Probabilities may not be valid for this equation specification.

Capacity Exempt Customer Demand Segment Model

Dependent Variable: CE_PERCENT
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/10/23 Time: 12:43
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 20 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
D_2020M5	-0.046242	0.013971	-3.309849	0.0015
D_2020M9	-0.044298	0.013920	-3.182377	0.0022
MONTH=1	0.197440	0.013748	14.36111	0.0000
MONTH=2	0.182214	0.013949	13.06332	0.0000
MONTH=3	0.203593	0.014081	14.45875	0.0000
MONTH=4	0.235430	0.014180	16.60265	0.0000
MONTH=5	0.297393	0.014357	20.71460	0.0000
MONTH=6	0.355445	0.014253	24.93880	0.0000
MONTH=7	0.379183	0.014239	26.62939	0.0000
MONTH=8	0.392417	0.014211	27.61449	0.0000
MONTH=9	0.390960	0.014291	27.35700	0.0000
MONTH=10	0.353627	0.014052	25.16515	0.0000
MONTH=11	0.275833	0.013923	19.81165	0.0000
MONTH=12	0.216350	0.013717	15.77207	0.0000
AR(2)	0.719591	0.118503	6.072335	0.0000
MA(1)	0.923104	0.075228	12.27083	0.0000

R-squared	0.964207	Mean dependent var	0.290357
Adjusted R-squared	0.956311	S.D. dependent var	0.082454
S.E. of regression	0.017234	Akaike info criterion	-5.096660
Sum squared resid	0.020198	Schwarz criterion	-4.633648
Log likelihood	230.0597	Hannan-Quinn criter.	-4.910533
Durbin-Watson stat	2.101461		

Inverted AR Roots	.85	-.85
Inverted MA Roots	-.92	

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	0.647694	Prob. F(16,67)	0.8329
Obs*R-squared	11.25215	Prob. Chi-Square(16)	0.7937
Scaled explained SS	11.34213	Prob. Chi-Square(16)	0.7879

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 11:57
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.000229	0.000371	0.618418	0.5384
GRADF_01^2	-3.09E-08	8.90E-08	-0.347457	0.7293
GRADF_02^2	-3.54E-08	8.87E-08	-0.399290	0.6909
GRADF_03^2	-7.70E-09	8.53E-08	-0.090228	0.9284
GRADF_04^2	-1.68E-08	7.91E-08	-0.211997	0.8328
GRADF_05^2	-1.55E-08	8.31E-08	-0.186273	0.8528
GRADF_06^2	-4.82E-09	7.86E-08	-0.061356	0.9513
GRADF_07^2	-1.85E-08	8.34E-08	-0.221909	0.8251
GRADF_08^2	4.93E-08	7.85E-08	0.627538	0.5324
GRADF_09^2	3.74E-08	8.27E-08	0.452515	0.6524
GRADF_10^2	-1.96E-08	7.89E-08	-0.248515	0.8045
GRADF_11^2	-2.13E-08	8.40E-08	-0.253237	0.8009
GRADF_12^2	4.54E-09	7.95E-08	0.057073	0.9547
GRADF_13^2	-2.20E-08	8.43E-08	-0.260614	0.7952
GRADF_14^2	6.85E-09	7.93E-08	0.086394	0.9314
GRADF_15^2	1.33E-05	1.59E-05	0.832098	0.4083
GRADF_16^2	3.20E-06	7.21E-06	0.443754	0.6587

R-squared	0.133954	Mean dependent var	0.000240
Adjusted R-squared	-0.072863	S.D. dependent var	0.000424
S.E. of regression	0.000439	Akaike info criterion	-12.44344
Sum squared resid	1.29E-05	Schwarz criterion	-11.95149
Log likelihood	539.6245	Hannan-Quinn criter.	-12.24568
F-statistic	0.647694	Durbin-Watson stat	1.895080
Prob(F-statistic)	0.832896		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2016M02</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2016M03</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2016M04</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2016M05</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2016M06</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2016M07</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2016M08</td><td>0.5</td><td>0.4</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2016M09</td><td>0.5</td><td>0.4</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2016M10</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
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<tr><td>2016M12</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2017M01</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| * | . |</td></tr>
<tr><td>2017M02</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . | *. |</td></tr>
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<tr><td>2017M08</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | . * |</td></tr>
<tr><td>2017M09</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2017M10</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2017M11</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2017M12</td><td>0.2</td><td>0.3</td><td>0.0</td><td>| * . | . |</td></tr>
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<tr><td>2019M04</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * . |</td></tr>
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<tr><td>2019M11</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2019M12</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2020M01</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2020M02</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2020M03</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2020M04</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2020M05</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2020M06</td><td>0.3</td><td>0.4</td><td>0.0</td><td>| * | . |</td></tr>
<tr><td>2020M07</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2020M08</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2020M09</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2020M10</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2020M11</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2020M12</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2021M01</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2021M02</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| * | . |</td></tr>
<tr><td>2021M03</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| *. | . |</td></tr>
<tr><td>2021M04</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2021M06</td><td>0.4</td><td>0.3</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2021M07</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2021M08</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| * | . |</td></tr>
<tr><td>2021M09</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2021M10</td><td>0.4</td><td>0.3</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2021M11</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2021M12</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2022M01</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2022M03</td><td>0.2</td><td>0.2</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2022M04</td><td>0.23</td><td>0.22</td><td>0.01</td><td>| . |* . |</td></tr>
<tr><td>2022M05</td><td>0.28</td><td>0.29</td><td>-0.01</td><td>| * | . |</td></tr>
<tr><td>2022M06</td><td>0.36</td><td>0.34</td><td>0.02</td><td>| . | .* |</td></tr>
<tr><td>2022M07</td><td>0.33</td><td>0.39</td><td>-0.06</td><td>|* . | . |</td></tr>
<tr><td>2022M08</td><td>0.32</td><td>0.34</td><td>-0.02</td><td>| * . | . |</td></tr>
<tr><td>2022M09</td><td>0.31</td><td>0.33</td><td>-0.02</td><td>| *. | . |</td></tr>
<tr><td>2022M10</td><td>0.26</td><td>0.28</td><td>-0.02</td><td>| *. | . |</td></tr>
<tr><td>2022M11</td><td>0.2</td><td>0.20</td><td>0.00</td><td>| . * . |</td></tr>
<tr><td>2022M12</td><td>0.17</td><td>0.15</td><td>0.02</td><td>| . | .* |</td></tr>
</table>

Date: 03/23/23 Time: 12:01
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.065	-0.065	0.3713	
. | . |	. | . |	2	-0.024	-0.028	0.4206	
. |*. |	. |*. |	3	0.124	0.121	1.7846	0.182
.*| . |	.*| . |	4	-0.142	-0.129	3.6109	0.164
. | . |	. | . |	5	-0.019	-0.030	3.6432	0.303
. |*. |	. |*. |	6	0.120	0.101	4.9798	0.289
. | . |	. | . |	7	-0.051	-0.009	5.2208	0.390
. |*. |	. |*. |	8	0.103	0.094	6.2293	0.398
.*| . |	.*| . |	9	-0.117	-0.147	7.5590	0.373
. | . |	. | . |	10	0.011	0.041	7.5705	0.477
. | . |	. | . |	11	0.053	0.029	7.8456	0.550
.*| . |	. | . |	12	-0.102	-0.063	8.8862	0.543

*Probabilities may not be valid for this equation specification.

COMPANY USE MODEL

Dependent Variable: CO_USE_ME
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/22/23 Time: 16:03
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 26 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_NOV	0.061746	0.020182	3.059385	0.0031
BC_DEC	0.095223	0.012820	7.427792	0.0000
BC_JAN	0.139963	0.010506	13.32189	0.0000
BC_FEB	0.152549	0.010384	14.69089	0.0000
BC_MAR	0.152373	0.011861	12.84642	0.0000
BC_APR	0.116614	0.014843	7.856502	0.0000
C	18.31669	4.377402	4.184374	0.0001
AR(4)	-0.262271	0.118772	-2.208194	0.0303
MA(12)	0.637245	0.137102	4.647954	0.0000

R-squared	0.939778	Mean dependent var	80.94750
Adjusted R-squared	0.933354	S.D. dependent var	75.70202
S.E. of regression	19.54311	Akaike info criterion	8.960696
Sum squared resid	28644.99	Schwarz criterion	9.221141
Log likelihood	-367.3492	Hannan-Quinn criter.	9.065392
F-statistic	146.2988	Durbin-Watson stat	2.105252
Prob(F-statistic)	0.000000		

Inverted AR Roots	.51-.51i	.51+.51i	-.51+.51i	-.51-.51i
Inverted MA Roots	.93-.25i	.93+.25i	.68-.68i	.68+.68i
	.25-.93i	.25+.93i	-.25+.93i	-.25-.93i
	-.68+.68i	-.68+.68i	-.93-.25i	-.93+.25i

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	2.083602	Prob. F(9,74)	0.0417
Obs*R-squared	16.98288	Prob. Chi-Square(9)	0.0490
Scaled explained SS	23.81504	Prob. Chi-Square(9)	0.0046

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 12:04
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	180.6188	244.0094	0.740212	0.4615
GRADF_01^2	-0.252728	0.427628	-0.590998	0.5563
GRADF_02^2	-0.100872	0.197651	-0.510353	0.6113
GRADF_03^2	0.082207	0.132333	0.621211	0.5364
GRADF_04^2	0.302401	0.130478	2.317634	0.0232
GRADF_05^2	0.293994	0.174963	1.680319	0.0971
GRADF_06^2	-0.115615	0.282665	-0.409017	0.6837
GRADF_07^2	17933.61	115055.7	0.155869	0.8766
GRADF_08^2	-4.425325	36.39240	-0.121600	0.9035
GRADF_09^2	82.26489	39.83053	2.065373	0.0424

R-squared	0.202177	Mean dependent var	341.0118
Adjusted R-squared	0.105145	S.D. dependent var	643.4620
S.E. of regression	608.6944	Akaike info criterion	15.77185
Sum squared resid	27417660	Schwarz criterion	16.06124
Log likelihood	-652.4178	Hannan-Quinn criter.	15.88818
F-statistic	2.083602	Durbin-Watson stat	2.310832
Prob(F-statistic)	0.041701		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>143.5</td><td>166.1</td><td>-22.6</td><td>| *. | . |</td></tr>
<tr><td>2016M02</td><td>183.6</td><td>196.3</td><td>-12.7</td><td>| .* | . |</td></tr>
<tr><td>2016M03</td><td>155.8</td><td>171.5</td><td>-15.7</td><td>| * | . |</td></tr>
<tr><td>2016M04</td><td>127.0</td><td>116.3</td><td>10.7</td><td>| . | *. |</td></tr>
<tr><td>2016M05</td><td>57.4</td><td>29.8</td><td>27.6</td><td>| . | .* |</td></tr>
<tr><td>2016M06</td><td>7.1</td><td>19.6</td><td>-12.5</td><td>| .* | . |</td></tr>
<tr><td>2016M07</td><td>2.8</td><td>19.6</td><td>-16.9</td><td>| * | . |</td></tr>
<tr><td>2016M08</td><td>2.6</td><td>13.3</td><td>-10.7</td><td>| .* | . |</td></tr>
<tr><td>2016M09</td><td>2.9</td><td>10.0</td><td>-7.2</td><td>| . *| . |</td></tr>
<tr><td>2016M10</td><td>19.8</td><td>22.5</td><td>-2.7</td><td>| . * . |</td></tr>
<tr><td>2016M11</td><td>71.8</td><td>64.1</td><td>7.8</td><td>| . |* . |</td></tr>
<tr><td>2016M12</td><td>119.2</td><td>115.9</td><td>3.3</td><td>| . |* . |</td></tr>
<tr><td>2017M01</td><td>160.1</td><td>177.7</td><td>-17.6</td><td>| * | . |</td></tr>
<tr><td>2017M02</td><td>158.0</td><td>190.1</td><td>-32.1</td><td>| * . | . |</td></tr>
<tr><td>2017M03</td><td>152.8</td><td>174.2</td><td>-21.4</td><td>| * | . |</td></tr>
<tr><td>2017M04</td><td>121.2</td><td>129.9</td><td>-8.7</td><td>| . *| . |</td></tr>
<tr><td>2017M05</td><td>64.0</td><td>41.5</td><td>22.5</td><td>| . | .* |</td></tr>
<tr><td>2017M06</td><td>38.0</td><td>23.0</td><td>15.1</td><td>| . | *. |</td></tr>
<tr><td>2017M07</td><td>2.7</td><td>17.2</td><td>-14.5</td><td>| .* | . |</td></tr>
<tr><td>2017M08</td><td>2.7</td><td>13.2</td><td>-10.6</td><td>| .* | . |</td></tr>
<tr><td>2017M09</td><td>3.9</td><td>3.1</td><td>0.8</td><td>| . * . |</td></tr>
<tr><td>2017M10</td><td>14.1</td><td>12.8</td><td>1.4</td><td>| . * . |</td></tr>
<tr><td>2017M11</td><td>65.7</td><td>60.5</td><td>5.1</td><td>| . |* . |</td></tr>
<tr><td>2017M12</td><td>118.2</td><td>123.4</td><td>-5.2</td><td>| . *| . |</td></tr>
<tr><td>2018M01</td><td>255.9</td><td>228.2</td><td>27.7</td><td>| . | .* |</td></tr>
<tr><td>2018M02</td><td>197.4</td><td>183.8</td><td>13.6</td><td>| . | *. |</td></tr>
<tr><td>2018M03</td><td>167.7</td><td>150.7</td><td>17.0</td><td>| . | * |</td></tr>
<tr><td>2018M04</td><td>123.4</td><td>123.0</td><td>0.4</td><td>| . * . |</td></tr>
<tr><td>2018M05</td><td>75.2</td><td>27.4</td><td>47.8</td><td>| . | . * |</td></tr>
<tr><td>2018M06</td><td>11.8</td><td>28.2</td><td>-16.4</td><td>| * | . |</td></tr>
<tr><td>2018M07</td><td>1.9</td><td>9.2</td><td>-7.3</td><td>| . *| . |</td></tr>
<tr><td>2018M08</td><td>1.9</td><td>13.0</td><td>-11.1</td><td>| .* | . |</td></tr>
<tr><td>2018M09</td><td>2.0</td><td>3.6</td><td>-1.6</td><td>| . * . |</td></tr>
<tr><td>2018M10</td><td>18.6</td><td>20.7</td><td>-2.1</td><td>| . * . |</td></tr>
<tr><td>2018M11</td><td>68.8</td><td>72.6</td><td>-3.8</td><td>| . *| . |</td></tr>
<tr><td>2018M12</td><td>140.4</td><td>124.6</td><td>15.8</td><td>| . | * |</td></tr>
<tr><td>2019M01</td><td>182.2</td><td>212.2</td><td>-30.0</td><td>| * . | . |</td></tr>
<tr><td>2019M02</td><td>226.0</td><td>228.8</td><td>-2.8</td><td>| . * . |</td></tr>
<tr><td>2019M03</td><td>191.1</td><td>205.9</td><td>-14.8</td><td>| .* | . |</td></tr>
<tr><td>2019M04</td><td>142.5</td><td>114.6</td><td>27.9</td><td>| . | . * |</td></tr>
<tr><td>2019M05</td><td>66.9</td><td>50.6</td><td>16.3</td><td>| . | * |</td></tr>
<tr><td>2019M06</td><td>11.6</td><td>6.6</td><td>5.0</td><td>| . |* . |</td></tr>
</table>

<table>
<tr><td>2019M07</td><td>3.8</td><td>15.0</td><td>-11.2</td><td>| .* | . |</td></tr>
<tr><td>2019M08</td><td>2.6</td><td>5.1</td><td>-2.5</td><td>| . * . |</td></tr>
<tr><td>2019M09</td><td>5.5</td><td>4.7</td><td>0.8</td><td>| . * . |</td></tr>
<tr><td>2019M10</td><td>16.9</td><td>18.8</td><td>-1.9</td><td>| . * . |</td></tr>
<tr><td>2019M11</td><td>45.6</td><td>60.3</td><td>-14.7</td><td>| .* | . |</td></tr>
<tr><td>2019M12</td><td>130.0</td><td>132.3</td><td>-2.3</td><td>| . * . |</td></tr>
<tr><td>2020M01</td><td>172.0</td><td>157.8</td><td>14.2</td><td>| . | *. |</td></tr>
<tr><td>2020M02</td><td>189.4</td><td>188.2</td><td>1.2</td><td>| . * . |</td></tr>
<tr><td>2020M03</td><td>195.3</td><td>161.6</td><td>33.7</td><td>| . | . * |</td></tr>
<tr><td>2020M04</td><td>120.1</td><td>125.9</td><td>-5.8</td><td>| . *| . |</td></tr>
<tr><td>2020M05</td><td>66.7</td><td>29.1</td><td>37.6</td><td>| . | . * |</td></tr>
<tr><td>2020M06</td><td>26.9</td><td>21.5</td><td>5.4</td><td>| . |* . |</td></tr>
<tr><td>2020M07</td><td>4.0</td><td>3.9</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2020M08</td><td>3.2</td><td>14.4</td><td>-11.2</td><td>| .* | . |</td></tr>
<tr><td>2020M09</td><td>8.1</td><td>6.1</td><td>2.0</td><td>| . * . |</td></tr>
<tr><td>2020M10</td><td>27.0</td><td>14.9</td><td>12.1</td><td>| . | *. |</td></tr>
<tr><td>2020M11</td><td>44.5</td><td>51.3</td><td>-6.8</td><td>| . *| . |</td></tr>
<tr><td>2020M12</td><td>117.7</td><td>109.1</td><td>8.6</td><td>| . |* . |</td></tr>
<tr><td>2021M01</td><td>146.0</td><td>190.2</td><td>-44.2</td><td>| * . | . |</td></tr>
<tr><td>2021M02</td><td>181.6</td><td>211.3</td><td>-29.7</td><td>| * . | . |</td></tr>
<tr><td>2021M03</td><td>259.2</td><td>210.7</td><td>48.5</td><td>| . | . * |</td></tr>
<tr><td>2021M04</td><td>95.4</td><td>101.7</td><td>-6.3</td><td>| . *| . |</td></tr>
<tr><td>2021M05</td><td>73.4</td><td>50.8</td><td>22.6</td><td>| . | .* |</td></tr>
<tr><td>2021M06</td><td>26.5</td><td>29.9</td><td>-3.4</td><td>| . *| . |</td></tr>
<tr><td>2021M07</td><td>11.0</td><td>-0.8</td><td>11.8</td><td>| . | *. |</td></tr>
<tr><td>2021M08</td><td>4.4</td><td>14.6</td><td>-10.2</td><td>| .* | . |</td></tr>
<tr><td>2021M09</td><td>3.0</td><td>5.2</td><td>-2.2</td><td>| . * . |</td></tr>
<tr><td>2021M10</td><td>9.8</td><td>23.9</td><td>-14.1</td><td>| .* | . |</td></tr>
<tr><td>2021M11</td><td>63.0</td><td>51.7</td><td>11.3</td><td>| . | *. |</td></tr>
<tr><td>2021M12</td><td>104.9</td><td>118.7</td><td>-13.8</td><td>| .* | . |</td></tr>
<tr><td>2022M01</td><td>162.3</td><td>168.6</td><td>-6.3</td><td>| . *| . |</td></tr>
<tr><td>2022M02</td><td>274.3</td><td>208.9</td><td>65.4</td><td>| . | . *</td></tr>
<tr><td>2022M03</td><td>179.9</td><td>209.9</td><td>-30.0</td><td>| * . | . |</td></tr>
<tr><td>2022M04</td><td>105.5</td><td>108.7</td><td>-3.2</td><td>| . *| . |</td></tr>
<tr><td>2022M05</td><td>63.8</td><td>40.7</td><td>23.1</td><td>| . | .* |</td></tr>
<tr><td>2022M06</td><td>6.7</td><td>3.3</td><td>3.4</td><td>| . |* . |</td></tr>
<tr><td>2022M07</td><td>3.8</td><td>26.2</td><td>-22.4</td><td>| *. | . |</td></tr>
<tr><td>2022M08</td><td>2.2</td><td>13.4</td><td>-11.2</td><td>| .* | . |</td></tr>
<tr><td>2022M09</td><td>3</td><td>5.0</td><td>-2.0</td><td>| . * . |</td></tr>
<tr><td>2022M10</td><td>15.9</td><td>12.4</td><td>3.5</td><td>| . |* . |</td></tr>
<tr><td>2022M11</td><td>56.9</td><td>60.4</td><td>-3.5</td><td>| . *| . |</td></tr>
<tr><td>2022M12</td><td>87.8</td><td>102.7</td><td>-14.9</td><td>| .* | . |</td></tr>
</table>

Date: 03/23/23 Time: 12:05
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.065	-0.065	0.3714	
. | . |	. | . |	2	-0.038	-0.042	0.4979	
.*| . |	.*| . |	3	-0.088	-0.094	1.1848	0.276
. | . |	. | . |	4	-0.025	-0.040	1.2400	0.538
. | . |	. | . |	5	-0.009	-0.022	1.2472	0.742
. | . |	. | . |	6	-0.004	-0.018	1.2487	0.870
. |*. |	. | . |	7	0.077	0.069	1.8002	0.876
.*| . |	.*| . |	8	-0.089	-0.085	2.5614	0.862
. | . |	. | . |	9	0.015	0.007	2.5841	0.921
.*| . |	.*| . |	10	-0.182	-0.181	5.8024	0.669
. |*. |	. |*. |	11	0.161	0.134	8.3816	0.496
. | . |	. | . |	12	-0.006	-0.012	8.3847	0.591

*Probabilities may not be valid for this equation specification.

Design Day – Total Throughput Model

Dependent Variable: ME
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/07/23 Time: 14:24
Sample: 11/01/2021 10/31/2022
Included observations: 365
Convergence achieved after 10 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
ME_EDD	761.7274	15.27650	49.86269	0.0000
ME_EDD_50	133.0725	50.16445	2.652725	0.0084
ME_EDD(-1)	127.5060	13.30992	9.579773	0.0000
NOV	1933.355	860.7461	2.246138	0.0253
DEC	4927.538	960.1441	5.132082	0.0000
JAN	7922.300	1058.078	7.487446	0.0000
FEB	7287.685	1023.136	7.122887	0.0000
MAR	3282.115	887.7268	3.697212	0.0003
@WEEKDAY=1	12602.27	446.4029	28.23071	0.0000
@WEEKDAY=2	13019.12	449.1675	28.98500	0.0000
@WEEKDAY=3	13058.48	444.7703	29.36006	0.0000
@WEEKDAY=4	12680.14	440.9532	28.75620	0.0000
@WEEKDAY=5	11110.72	443.3921	25.05844	0.0000
@WEEKDAY=6	9549.785	450.0271	21.22047	0.0000
@WEEKDAY=7	10930.01	452.5882	24.15002	0.0000
AR(1)	0.688932	0.053372	12.90808	0.0000
AR(2)	-0.113640	0.053622	-2.119278	0.0348
AR(7)	0.113334	0.042574	2.662044	0.0081

R-squared	0.992316	Mean dependent var	31481.15
Adjusted R-squared	0.991939	S.D. dependent var	17922.52
S.E. of regression	1609.102	Akaike info criterion	17.65280
Sum squared resid	8.98E+08	Schwarz criterion	17.84512
Log likelihood	-3203.636	Hannan-Quinn criter.	17.72923
Durbin-Watson stat	1.981212		

Inverted AR Roots	.85	.57+.56i	.57-.56i	-.07-.70i
	-.07+.70i	-.58+.31i	-.58-.31i	

Design Day – Planning Load Model

Dependent Variable: ME_PL
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/07/23 Time: 14:27
Sample: 11/01/2021 10/31/2022
Included observations: 365
Convergence achieved after 15 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
ME_EDD	673.2066	14.47470	46.50921	0.0000
ME_EDD_50	138.0786	46.37837	2.977219	0.0031
ME_EDD(-1)	119.2066	12.64109	9.430085	0.0000
DEC	3987.129	1137.438	3.505359	0.0005
JAN	5956.069	1245.314	4.782783	0.0000
FEB	5197.835	1189.036	4.371469	0.0000
NOV+MAR	1584.345	781.3198	2.027780	0.0433
@WEEKDAY=1	8742.846	615.8627	14.19610	0.0000
@WEEKDAY=2	9023.326	615.8424	14.65200	0.0000
@WEEKDAY=3	9099.289	613.6828	14.82735	0.0000
@WEEKDAY=4	8866.792	610.3431	14.52755	0.0000
@WEEKDAY=5	7834.077	610.1823	12.83891	0.0000
@WEEKDAY=6	6614.848	616.7908	10.72462	0.0000
@WEEKDAY=7	7614.231	619.2793	12.29531	0.0000
AR(1)	0.754368	0.053333	14.14440	0.0000
AR(2)	-0.109478	0.053290	-2.054401	0.0407
AR(7)	0.172346	0.039643	4.347416	0.0000

R-squared	0.991052	Mean dependent var	25417.32
Adjusted R-squared	0.990640	S.D. dependent var	15935.13
S.E. of regression	1541.648	Akaike info criterion	17.56455
Sum squared resid	8.27E+08	Schwarz criterion	17.74619
Log likelihood	-3188.530	Hannan-Quinn criter.	17.63673
Durbin-Watson stat	1.992085		

Inverted AR Roots	.92	.60-.58i	.60+.58i	-.08+.74i
	-.08-.74i	-.61+.33i	-.61-.33i	

NH Division Statistical Model Results

Variable Nomenclature

Variable	Description	Type
HH	Total Households	Actual/Forecast
INC_HH	Average Household Income	Actual/Forecast
GMP(-3)	Gross Metro Product Lagged by 3	Actual/Forecast
EMP_MAN	Empoyment in Manufacturing	Actual/Forecast
C	Constant	Intercept Value
TREND	Linear Trend	Linear Count (e.g. i=i+1)
JAN	January	Boolean
FEB	February	Boolean
MAR	March	Boolean
APR	April	Boolean
MAY	May	Boolean
JUN	June	Boolean
JUL	July	Boolean
AUG	August	Boolean
SEP	September	Boolean
OCT	October	Boolean
NOV	November	Boolean
DEC	December	Boolean
Winter	December through March	Boolean
BC_EDD	Billing Cycle EDDs	Actual/Forecast
BC_JAN	January Bill Cycle EDD	Actual/Forecast
BC FEB	February Bill Cycle EDD	Actual/Forecast
BC_MAR	March Bill Cycle EDD	Actual/Forecast
BC_APR	April Bill Cycle EDD	Actual/Forecast
BC_MAY	May Bill Cycle EDD	Actual/Forecast
BC_JUN	June Bill Cycle EDD	Actual/Forecast
BC_JUL	July Bill Cycle EDD	Actual/Forecast
BC_AUG	August Bill Cycle EDD	Actual/Forecast
BC_SEP	September Bill Cycle EDD	Actual/Forecast
BC_OCT	October Bill Cycle EDD	Actual/Forecast
BC_NOV	November Bill Cycle EDD	Actual/Forecast
BC_DEC	December Bill Cycle EDD	Actual/Forecast
NH_EDD	New Hampshire Calendar EDD	Actual
NH_EDD(-1)	New Hampshire Calendar EDD Lagged by 1	Actual
NH_EDD_50	New Hampshire Calendar EDD Base 15	Actual
@WEEKDAY=X	Xth Day of Week (i.e. X=1 is Sunday)	Boolean
AR(X)	Autoregressive Term at Lag X (where X is a real integer)	ARMA
MA(X)	Moving Average Term at Lag X (where X is a real integer)	ARMA
D_*YearMx*	Dummy Variable for *Year* and *Month x*	Boolean
D_*YearMx_f*	Dummy Variable for *Year* and *Month x* and all future months	Boolean
D_*Year1Mx_Year2My*	Dummy Variable for time between *Year 1-Month x and Year 2-Month y*	Boolean

Residential Customer Segment – Customer Model

Dependent Variable: RES_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/01/23 Time: 16:37
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Convergence achieved after 4 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HH*TREND	0.314898	0.014534	21.66690	0.0000
NOV	239.1119	30.48741	7.842971	0.0000
OCT	122.5238	22.95183	5.338303	0.0000
DEC	294.8019	34.89187	8.449013	0.0000
JAN	321.2978	37.07813	8.665426	0.0000
FEB	309.9434	37.82896	8.193283	0.0000
MAR	285.0016	37.12897	7.675991	0.0000
APR	293.2273	34.82543	8.419918	0.0000
MAY	210.2675	30.50249	6.893452	0.0000
JUN	105.6103	22.97249	4.597252	0.0000
C	23653.23	173.5852	136.2630	0.0000
AR(1)	0.891131	0.056927	15.65395	0.0000

R-squared	0.998292	Mean dependent var	26958.83
Adjusted R-squared	0.998032	S.D. dependent var	1371.574
S.E. of regression	60.85307	Akaike info criterion	11.18637
Sum squared resid	266622.9	Schwarz criterion	11.53362
Log likelihood	-457.8273	Hannan-Quinn criter.	11.32596
F-statistic	3826.633	Durbin-Watson stat	2.026558
Prob(F-statistic)	0.000000		

Inverted AR Roots	.89

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	2.600332	Prob. F(11,72)	0.0076
Obs*R-squared	23.88290	Prob. Chi-Square(11)	0.0132
Scaled explained SS	36.46099	Prob. Chi-Square(11)	0.0001

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:20
Sample: 2016M01 2022M12
Included observations: 84
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	9964.434	1863.785	5.346342	0.0000
GRADF_01^2	0.000403	0.000567	0.711156	0.4793
GRADF_02^2	-2212.793	2846.045	-0.777498	0.4394
GRADF_03^2	-8710.723	2734.388	-3.185620	0.0021
GRADF_04^2	-5928.386	3437.216	-1.724764	0.0889
GRADF_05^2	-3831.358	3313.790	-1.156186	0.2514
GRADF_06^2	-6952.676	3595.784	-1.933563	0.0571
GRADF_07^2	-3862.953	3304.595	-1.168964	0.2463
GRADF_08^2	-5247.397	3437.823	-1.526372	0.1313
GRADF_09^2	-3737.354	2844.790	-1.313754	0.1931
GRADF_10^2	-5910.662	2732.749	-2.162900	0.0339
GRADF_12^2	-0.036534	0.032492	-1.124392	0.2646

R-squared	0.284320	Mean dependent var	3174.082
Adjusted R-squared	0.174980	S.D. dependent var	6509.554
S.E. of regression	5912.667	Akaike info criterion	20.33915
Sum squared resid	2.52E+09	Schwarz criterion	20.68640
Log likelihood	-842.2441	Hannan-Quinn criter.	20.47874
F-statistic	2.600332	Durbin-Watson stat	2.310094
Prob(F-statistic)	0.007625		

obs	Actual	Fitted	Residual	Residual Plot
2016M01	24888.0	24896.0	-8.0	| . * . |
2016M02	24935.0	24919.7	15.3	| . |* . |
2016M03	25000.0	24952.9	47.1	| . | *. |
2016M04	25039.0	25047.4	-8.4	| . * . |
2016M05	25005.0	24997.9	7.1	| . * . |
2016M06	25005.0	24942.8	62.2	| . | * |
2016M07	24846.0	24936.4	-90.4	| *. | . |
2016M08	24774.0	24895.0	-121.0	| * . | . |
2016M09	24928.0	24837.1	90.9	| . | .* |
2016M10	25086.0	25103.0	-17.0	| . *| . |
2016M11	25233.0	25257.6	-24.6	| . *| . |
2016M12	25342.0	25346.5	-4.5	| . * . |
2017M01	25395.0	25426.6	-31.6	| . *| . |
2017M02	25432.0	25444.7	-12.7	| . *| . |
2017M03	25440.0	25468.3	-28.3	| . *| . |
2017M04	25500.0	25511.8	-11.8	| . *| . |
2017M05	25425.0	25481.2	-56.2	| * | . |
2017M06	25390.0	25390.2	-0.2	| . * . |
2017M07	25399.0	25353.1	45.9	| . | *. |
2017M08	25559.0	25461.1	97.9	| . | . * |
2017M09	25706.0	25609.2	96.8	| . | . * |
2017M10	25822.0	25868.4	-46.4	| .* | . |
2017M11	26029.0	25985.0	44.0	| . | *. |
2017M12	26110.0	26127.4	-17.4	| . *| . |
2018M01	26135.0	26182.5	-47.5	| .* | . |
2018M02	26155.0	26175.5	-20.5	| . *| . |
2018M03	26173.0	26184.2	-11.2	| . *| . |
2018M04	26225.0	26236.2	-11.2	| . *| . |
2018M05	26178.0	26198.4	-20.4	| . *| . |
2018M06	26103.0	26132.1	-29.1	| . *| . |
2018M07	26047.0	26059.4	-12.4	| . *| . |
2018M08	26041.0	26110.5	-69.5	| * | . |
2018M09	26169.0	26111.9	57.1	| . | * |
2018M10	26406.0	26354.9	51.1	| . | *. |
2018M11	26592.0	26579.1	12.9	| . |* . |
2018M12	26699.0	26701.9	-2.9	| . * . |
2019M01	26828.0	26779.8	48.2	| . | *. |
2019M02	26888.0	26866.5	21.5	| . |* . |
2019M03	26896.0	26912.4	-16.4	| . *| . |

<table>
<tr><td>2019M04</td><td>26907.0</td><td>26957.2</td><td>-50.2</td><td>| .* | . |</td></tr>
<tr><td>2019M05</td><td>26870.0</td><td>26882.1</td><td>-12.1</td><td>| . *| . |</td></tr>
<tr><td>2019M06</td><td>26752.0</td><td>26822.9</td><td>-70.9</td><td>| * | . |</td></tr>
<tr><td>2019M07</td><td>26587.0</td><td>26710.0</td><td>-123.0</td><td>| * . | . |</td></tr>
<tr><td>2019M08</td><td>26589.0</td><td>26662.4</td><td>-73.4</td><td>| * | . |</td></tr>
<tr><td>2019M09</td><td>26731.0</td><td>26670.4</td><td>60.6</td><td>| . | * |</td></tr>
<tr><td>2019M10</td><td>26949.0</td><td>26925.7</td><td>23.3</td><td>| . |* . |</td></tr>
<tr><td>2019M11</td><td>27162.0</td><td>27133.6</td><td>28.4</td><td>| . |* . |</td></tr>
<tr><td>2019M12</td><td>27206.0</td><td>27281.0</td><td>-75.0</td><td>| *. | . |</td></tr>
<tr><td>2020M01</td><td>27345.0</td><td>27301.8</td><td>43.2</td><td>| . | *. |</td></tr>
<tr><td>2020M02</td><td>27387.0</td><td>27394.0</td><td>-7.0</td><td>| . * . |</td></tr>
<tr><td>2020M03</td><td>27395.0</td><td>27418.9</td><td>-23.9</td><td>| . *| . |</td></tr>
<tr><td>2020M04</td><td>27454.0</td><td>27459.4</td><td>-5.4</td><td>| . * . |</td></tr>
<tr><td>2020M05</td><td>27510.0</td><td>27427.1</td><td>82.9</td><td>| . | .* |</td></tr>
<tr><td>2020M06</td><td>27460.0</td><td>27453.1</td><td>6.9</td><td>| . * . |</td></tr>
<tr><td>2020M07</td><td>27480.0</td><td>27403.6</td><td>76.4</td><td>| . | .* |</td></tr>
<tr><td>2020M08</td><td>27502.0</td><td>27522.2</td><td>-20.2</td><td>| . *| . |</td></tr>
<tr><td>2020M09</td><td>27773.0</td><td>27547.9</td><td>225.1</td><td>| . | . *</td></tr>
<tr><td>2020M10</td><td>27924.0</td><td>27917.9</td><td>6.1</td><td>| . * . |</td></tr>
<tr><td>2020M11</td><td>28077.0</td><td>28065.9</td><td>11.1</td><td>| . |* . |</td></tr>
<tr><td>2020M12</td><td>28217.0</td><td>28159.7</td><td>57.3</td><td>| . | * |</td></tr>
<tr><td>2021M01</td><td>28278.0</td><td>28268.4</td><td>9.6</td><td>| . * . |</td></tr>
<tr><td>2021M02</td><td>28301.0</td><td>28295.8</td><td>5.2</td><td>| . * . |</td></tr>
<tr><td>2021M03</td><td>28316.0</td><td>28310.7</td><td>5.3</td><td>| . * . |</td></tr>
<tr><td>2021M04</td><td>28466.0</td><td>28363.5</td><td>102.5</td><td>| . | . * |</td></tr>
<tr><td>2021M05</td><td>28435.0</td><td>28415.0</td><td>20.0</td><td>| . |* . |</td></tr>
<tr><td>2021M06</td><td>28342.0</td><td>28364.3</td><td>-22.3</td><td>| . *| . |</td></tr>
<tr><td>2021M07</td><td>28299.0</td><td>28276.2</td><td>22.8</td><td>| . |* . |</td></tr>
<tr><td>2021M08</td><td>28243.0</td><td>28339.2</td><td>-96.2</td><td>| * . | . |</td></tr>
<tr><td>2021M09</td><td>28309.0</td><td>28295.7</td><td>13.3</td><td>| . |* . |</td></tr>
<tr><td>2021M10</td><td>28513.0</td><td>28483.7</td><td>29.3</td><td>| . |* . |</td></tr>
<tr><td>2021M11</td><td>28635.0</td><td>28678.9</td><td>-43.9</td><td>| .* | . |</td></tr>
<tr><td>2021M12</td><td>28829.0</td><td>28745.6</td><td>83.4</td><td>| . | .* |</td></tr>
<tr><td>2022M01</td><td>28874.0</td><td>28901.4</td><td>-27.4</td><td>| . *| . |</td></tr>
<tr><td>2022M02</td><td>28896.0</td><td>28913.0</td><td>-17.0</td><td>| . *| . |</td></tr>
<tr><td>2022M03</td><td>28935.0</td><td>28924.6</td><td>10.4</td><td>| . * . |</td></tr>
<tr><td>2022M04</td><td>28962</td><td>28997</td><td>-34.6</td><td>| .* | . |</td></tr>
<tr><td>2022M05</td><td>28893</td><td>28936</td><td>-42.742</td><td>| .* | . |</td></tr>
<tr><td>2022M06</td><td>28878</td><td>28849</td><td>29.2935</td><td>| . |* . |</td></tr>
<tr><td>2022M07</td><td>28882</td><td>28828</td><td>53.7266</td><td>| . | * |</td></tr>
<tr><td>2022M08</td><td>28787</td><td>28932</td><td>-145.26</td><td>| * . | . |</td></tr>
<tr><td>2022M09</td><td>28907</td><td>28854</td><td>53.3869</td><td>| . | * |</td></tr>
<tr><td>2022M10</td><td>29034</td><td>29090</td><td>-55.955</td><td>| * | . |</td></tr>
</table>

2022M11	29178	29217	-38.587	| .* | . |
2022M12	29250	29303	-53.031	| .* | . |

Date: 03/23/23 Time: 10:23
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.019	-0.019	0.0303	
. | . |	. | . |	2	0.061	0.061	0.3626	0.547
. |*. |	. |*. |	3	0.131	0.134	1.9014	0.386
. | . |	. | . |	4	0.039	0.042	2.0402	0.564
.*| . |	.*| . |	5	-0.090	-0.107	2.7785	0.596
. | . |	.*| . |	6	-0.043	-0.074	2.9522	0.707
. | . |	. | . |	7	0.066	0.068	3.3612	0.762
. | . |	. |*. |	8	0.035	0.077	3.4772	0.838
.*| . |	. | . |	9	-0.069	-0.054	3.9350	0.863
. | . |	. | . |	10	-0.018	-0.060	3.9678	0.914
.*| . |	.*| . |	11	-0.104	-0.135	5.0347	0.889
. |*. |	. |*. |	12	0.092	0.125	5.8793	0.881

*Probabilities may not be valid for this equation specification.

Residential Customer Segment - Use Per Customer Model

Dependent Variable: RES_UPC
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/01/23 Time: 16:36
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 8 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_EDD*WINTER	0.089362	0.001121	79.71743	0.0000
BC_JUN	0.046447	0.007007	6.628348	0.0000
BC_MAY	0.061968	0.002974	20.83464	0.0000
BC_NOV	0.062902	0.002358	26.67220	0.0000
BC_OCT	0.032853	0.005221	6.292172	0.0000
BC_APR	0.075890	0.001837	41.31016	0.0000
D_2018M01	10.47930	2.891172	3.624586	0.0005
D_2021M3	9.450857	3.038427	3.110444	0.0027
D_2021M4	-7.993735	3.164518	-2.526051	0.0137
C	12.98196	0.888218	14.61575	0.0000
AR(1)	0.393934	0.111405	3.536065	0.0007

R-squared	0.995509	Mean dependent var	57.08762
Adjusted R-squared	0.994894	S.D. dependent var	42.30665
S.E. of regression	3.023112	Akaike info criterion	5.174006
Sum squared resid	667.1621	Schwarz criterion	5.492327
Log likelihood	-206.3082	Hannan-Quinn criter.	5.301968
F-statistic	1618.199	Durbin-Watson stat	2.002945
Prob(F-statistic)	0.000000		

Inverted AR Roots	.39

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	2.176712	Prob. F(11,72)	0.0251
Obs*R-squared	20.96312	Prob. Chi-Square(11)	0.0338
Scaled explained SS	23.80686	Prob. Chi-Square(11)	0.0136

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:35
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	18.05556	10.83058	1.667091	0.0998
GRADF_01^2	0.000126	4.65E-05	2.711056	0.0084
GRADF_02^2	3.95E-06	0.001239	0.003186	0.9975
GRADF_03^2	-6.82E-05	0.000193	-0.353564	0.7247
GRADF_04^2	0.000300	0.000120	2.496032	0.0149
GRADF_05^2	-0.000213	0.000708	-0.301541	0.7639
GRADF_06^2	0.000181	6.71E-05	2.698129	0.0087
GRADF_07^2	-155.4881	112.7174	-1.379451	0.1720
GRADF_08^2	-63.15435	103.4773	-0.610321	0.5436
GRADF_09^2	-133.5674	106.9352	-1.249050	0.2157
GRADF_10^2	-304.4358	227.7623	-1.336638	0.1855
GRADF_11^2	-0.820953	0.829737	-0.989413	0.3258

R-squared	0.249561	Mean dependent var	7.942406
Adjusted R-squared	0.134911	S.D. dependent var	13.85630
S.E. of regression	12.88777	Akaike info criterion	8.081998
Sum squared resid	11958.81	Schwarz criterion	8.429258
Log likelihood	-327.4439	Hannan-Quinn criter.	8.221594
F-statistic	2.176712	Durbin-Watson stat	2.062716
Prob(F-statistic)	0.025050		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>105.3</td><td>105.5</td><td>-0.2</td><td>| . * . |</td></tr>
<tr><td>2016M02</td><td>121.0</td><td>115.1</td><td>5.9</td><td>| . | . * |</td></tr>
<tr><td>2016M03</td><td>98.7</td><td>102.0</td><td>-3.2</td><td>| * | . |</td></tr>
<tr><td>2016M04</td><td>68.1</td><td>70.4</td><td>-2.3</td><td>| .* | . |</td></tr>
<tr><td>2016M05</td><td>42.0</td><td>43.2</td><td>-1.1</td><td>| . *| . |</td></tr>
<tr><td>2016M06</td><td>19.5</td><td>19.2</td><td>0.2</td><td>| . * . |</td></tr>
<tr><td>2016M07</td><td>13.4</td><td>12.7</td><td>0.6</td><td>| . |* . |</td></tr>
<tr><td>2016M08</td><td>14.1</td><td>13.1</td><td>0.9</td><td>| . |* . |</td></tr>
<tr><td>2016M09</td><td>13.5</td><td>13.4</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2016M10</td><td>22.7</td><td>21.7</td><td>1.0</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>48.9</td><td>49.9</td><td>-1.0</td><td>| . *| . |</td></tr>
<tr><td>2016M12</td><td>91.4</td><td>96.9</td><td>-5.5</td><td>| * . | . |</td></tr>
<tr><td>2017M01</td><td>118.5</td><td>112.8</td><td>5.7</td><td>| . | . * |</td></tr>
<tr><td>2017M02</td><td>111.6</td><td>114.3</td><td>-2.7</td><td>| .* | . |</td></tr>
<tr><td>2017M03</td><td>103.9</td><td>104.5</td><td>-0.6</td><td>| . *| . |</td></tr>
<tr><td>2017M04</td><td>85.5</td><td>78.6</td><td>6.9</td><td>| . | . *|</td></tr>
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<tr><td>2017M08</td><td>13.8</td><td>14.1</td><td>-0.4</td><td>| . * . |</td></tr>
<tr><td>2017M09</td><td>14.8</td><td>13.3</td><td>1.5</td><td>| . | * . |</td></tr>
<tr><td>2017M10</td><td>17.3</td><td>18.3</td><td>-1.0</td><td>| . *| . |</td></tr>
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<tr><td>2018M01</td><td>157.8</td><td>156.3</td><td>1.5</td><td>| . | * . |</td></tr>
<tr><td>2018M02</td><td>119.7</td><td>116.0</td><td>3.8</td><td>| . | .* |</td></tr>
<tr><td>2018M03</td><td>97.8</td><td>97.6</td><td>0.2</td><td>| . * . |</td></tr>
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<tr><td>2018M05</td><td>42.2</td><td>42.2</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2018M06</td><td>20.9</td><td>21.2</td><td>-0.2</td><td>| . * . |</td></tr>
<tr><td>2018M07</td><td>14.0</td><td>13.1</td><td>0.8</td><td>| . |* . |</td></tr>
<tr><td>2018M08</td><td>12.1</td><td>13.4</td><td>-1.2</td><td>| . * | . |</td></tr>
<tr><td>2018M09</td><td>12.5</td><td>12.6</td><td>-0.2</td><td>| . * . |</td></tr>
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<tr><td>2018M11</td><td>61.5</td><td>59.0</td><td>2.5</td><td>| . | *. |</td></tr>
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<tr><td>2019M02</td><td>132.1</td><td>128.1</td><td>4.0</td><td>| . | .* |</td></tr>
<tr><td>2019M03</td><td>115.3</td><td>115.4</td><td>-0.1</td><td>| . * . |</td></tr>
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<tr><td>2019M06</td><td>21.6</td><td>23.3</td><td>-1.7</td><td>| . * | . |</td></tr>
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<tr><td>2020M02</td><td>114.8</td><td>112.0</td><td>2.8</td><td>| . | * |</td></tr>
<tr><td>2020M03</td><td>97.8</td><td>99.3</td><td>-1.5</td><td>| . * | . |</td></tr>
<tr><td>2020M04</td><td>68.2</td><td>71.8</td><td>-3.7</td><td>| *. | . |</td></tr>
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<tr><td>2021M02</td><td>121.1</td><td>122.9</td><td>-1.7</td><td>| . * | . |</td></tr>
<tr><td>2021M03</td><td>114.9</td><td>115.0</td><td>-0.1</td><td>| .   *   . |</td></tr>
<tr><td>2021M04</td><td>57.9</td><td>58.1</td><td>-0.2</td><td>| .   *   . |</td></tr>
<tr><td>2021M05</td><td>38.3</td><td>38.8</td><td>-0.5</td><td>| . *| . |</td></tr>
<tr><td>2021M06</td><td>18.1</td><td>18.9</td><td>-0.8</td><td>| . *| . |</td></tr>
<tr><td>2021M07</td><td>13.3</td><td>12.6</td><td>0.7</td><td>| . |* . |</td></tr>
<tr><td>2021M08</td><td>12.5</td><td>13.1</td><td>-0.6</td><td>| . *| . |</td></tr>
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<tr><td>2022M02</td><td>124.8</td><td>126.9</td><td>-2.1</td><td>| .* | . |</td></tr>
<tr><td>2022M03</td><td>101.6</td><td>101.7</td><td>-0.1</td><td>| .   *   . |</td></tr>
<tr><td>2022M04</td><td>60.82</td><td>68.11529169</td><td>-7.295291689</td><td>| *   . | . |</td></tr>
<tr><td>2022M05</td><td>37.56</td><td>38.63437548</td><td>-1.074375484</td><td>| . *| . |</td></tr>
<tr><td>2022M06</td><td>22.55</td><td>18.23585333</td><td>4.314146668</td><td>| . | . * |</td></tr>
<tr><td>2022M07</td><td>13.13</td><td>14.04317563</td><td>-0.91317563</td><td>| . *| . |</td></tr>
<tr><td>2022M08</td><td>13.13</td><td>13.04027966</td><td>0.089720341</td><td>| .   *   . |</td></tr>
<tr><td>2022M09</td><td>13.13</td><td>13.04027966</td><td>0.089720341</td><td>| .   *   . |</td></tr>
<tr><td>2022M10</td><td>22.9</td><td>22.4033121</td><td>0.4966879</td><td>| . |* . |</td></tr>
</table>

2022M11	50.05	41.75813159	8.291868411	| . | . *
2022M12	96.18	95.33041388	0.849586125	| . |* . |

Date: 03/23/23 Time: 10:36
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.002	-0.002	0.0004	
. | . |	. | . |	2	-0.027	-0.027	0.0627	0.802
. | . |	. | . |	3	0.059	0.059	0.3770	0.828
. | . |	. | . |	4	0.029	0.028	0.4518	0.929
. |*. |	. |*. |	5	0.082	0.086	1.0669	0.899
. | . |	. | . |	6	0.005	0.004	1.0694	0.957
.*| . |	.*| . |	7	-0.171	-0.171	3.7971	0.704
. |*. |	. |*. |	8	0.139	0.132	5.6402	0.582
. | . |	. | . |	9	0.030	0.016	5.7256	0.678
. | . |	. | . |	10	0.017	0.037	5.7531	0.764
. |*. |	. |*. |	11	0.112	0.112	6.9839	0.727
. | . |	. | . |	12	0.050	0.068	7.2378	0.780

*Probabilities may not be valid for this equation specification.

LLF Customer Segment – Customer Model

Dependent Variable: LLF_CUST
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 02/28/23 Time: 16:34
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Failure to improve likelihood (non-zero gradients) after 11 iterations
Coefficient covariance computed using outer product of gradients
MA Backcast: 2015M01 2015M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
INC_HH	0.004256	0.000657	6.481474	0.0000
C	4885.498	122.0650	40.02374	0.0000
OCT	134.9704	19.85551	6.797628	0.0000
NOV	217.3649	26.77860	8.117112	0.0000
DEC	255.4447	29.09260	8.780401	0.0000
JAN	256.3956	29.81657	8.599096	0.0000
FEB	246.1860	28.98291	8.494175	0.0000
MAR	215.4283	26.72703	8.060316	0.0000
APR	122.8948	19.75750	6.220162	0.0000
AR(1)	0.523342	0.112513	4.651391	0.0000
MA(1)	0.437739	0.091709	4.773112	0.0000
MA(12)	0.532122	0.078479	6.780431	0.0000

R-squared	0.962837	Mean dependent var	5782.214
Adjusted R-squared	0.957159	S.D. dependent var	159.5827
S.E. of regression	33.03042	Akaike info criterion	9.964298
Sum squared resid	78552.60	Schwarz criterion	10.31156
Log likelihood	-406.5005	Hannan-Quinn criter.	10.10389
F-statistic	169.5827	Durbin-Watson stat	1.990634
Prob(F-statistic)	0.000000		

Inverted AR Roots	.52			
Inverted MA Roots	.89+.24i	.89-.24i	.64-.67i	.64+.67i
	.21+.91i	.21-.91i	-.28-.91i	-.28+.91i
	-.71+.66i	-.71-.66i	-.96-.24i	-.96+.24i

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	2.484055	Prob. F(12,71)	0.0089
Obs*R-squared	24.83842	Prob. Chi-Square(12)	0.0156
Scaled explained SS	17.34936	Prob. Chi-Square(12)	0.1369

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:41
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	130.6459	718.6242	0.181800	0.8563
GRADF_01^2	1.52E-07	3.37E-07	0.450198	0.6539
GRADF_02^2	10933.89	13011.56	0.840321	0.4035
GRADF_03^2	-2725.584	1300.201	-2.096278	0.0396
GRADF_04^2	-148.3618	1249.391	-0.118747	0.9058
GRADF_05^2	-1280.051	1297.428	-0.986606	0.3272
GRADF_06^2	-906.6791	1294.497	-0.700411	0.4860
GRADF_07^2	-1644.571	1358.923	-1.210201	0.2302
GRADF_08^2	-269.3192	1256.585	-0.214326	0.8309
GRADF_09^2	-1195.871	1170.206	-1.021932	0.3103
GRADF_10^2	0.197884	0.074409	2.659415	0.0097
GRADF_11^2	0.019649	0.013345	1.472348	0.1453
GRADF_12^2	-0.012084	0.009443	-1.279701	0.2048

R-squared	0.295695	Mean dependent var	935.1500
Adjusted R-squared	0.176658	S.D. dependent var	1297.249
S.E. of regression	1177.101	Akaike info criterion	17.12088
Sum squared resid	98375188	Schwarz criterion	17.49708
Log likelihood	-706.0771	Hannan-Quinn criter.	17.27211
F-statistic	2.484055	Durbin-Watson stat	1.996995
Prob(F-statistic)	0.008926		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>5764.0</td><td>5768.8</td><td>-4.8</td><td>| . *| . |</td></tr>
<tr><td>2016M02</td><td>5779.0</td><td>5773.6</td><td>5.4</td><td>| . |* . |</td></tr>
<tr><td>2016M03</td><td>5756.0</td><td>5737.2</td><td>18.8</td><td>| . | * . |</td></tr>
<tr><td>2016M04</td><td>5681.0</td><td>5691.3</td><td>-10.3</td><td>| . *| . |</td></tr>
<tr><td>2016M05</td><td>5574.0</td><td>5529.8</td><td>44.2</td><td>| . | . * |</td></tr>
<tr><td>2016M06</td><td>5574.0</td><td>5610.2</td><td>-36.2</td><td>| *. | . |</td></tr>
<tr><td>2016M07</td><td>5477.0</td><td>5514.9</td><td>-37.9</td><td>| *. | . |</td></tr>
<tr><td>2016M08</td><td>5430.0</td><td>5495.6</td><td>-65.6</td><td>| * . | . |</td></tr>
<tr><td>2016M09</td><td>5540.0</td><td>5459.2</td><td>80.8</td><td>| . | . *</td></tr>
<tr><td>2016M10</td><td>5695.0</td><td>5732.4</td><td>-37.4</td><td>| *. | . |</td></tr>
<tr><td>2016M11</td><td>5766.0</td><td>5739.2</td><td>26.8</td><td>| . | * |</td></tr>
<tr><td>2016M12</td><td>5831.0</td><td>5829.8</td><td>1.2</td><td>| . * . |</td></tr>
<tr><td>2017M01</td><td>5820.0</td><td>5824.3</td><td>-4.3</td><td>| . *| . |</td></tr>
<tr><td>2017M02</td><td>5824.0</td><td>5812.5</td><td>11.5</td><td>| . | * . |</td></tr>
<tr><td>2017M03</td><td>5815.0</td><td>5803.3</td><td>11.7</td><td>| . | * . |</td></tr>
<tr><td>2017M04</td><td>5722.0</td><td>5706.9</td><td>15.1</td><td>| . | * . |</td></tr>
<tr><td>2017M05</td><td>5613.0</td><td>5615.9</td><td>-2.9</td><td>| . * . |</td></tr>
<tr><td>2017M06</td><td>5526.0</td><td>5575.9</td><td>-49.9</td><td>| * . | . |</td></tr>
<tr><td>2017M07</td><td>5513.0</td><td>5511.8</td><td>1.2</td><td>| . * . |</td></tr>
<tr><td>2017M08</td><td>5496.0</td><td>5513.5</td><td>-17.5</td><td>| . * | . |</td></tr>
<tr><td>2017M09</td><td>5523.0</td><td>5573.0</td><td>-50.0</td><td>| * . | . |</td></tr>
<tr><td>2017M10</td><td>5657.0</td><td>5644.1</td><td>12.9</td><td>| . | * . |</td></tr>
<tr><td>2017M11</td><td>5805.0</td><td>5788.9</td><td>16.1</td><td>| . | * . |</td></tr>
<tr><td>2017M12</td><td>5851.0</td><td>5852.6</td><td>-1.6</td><td>| . * . |</td></tr>
<tr><td>2018M01</td><td>5876.0</td><td>5850.5</td><td>25.5</td><td>| . | *. |</td></tr>
<tr><td>2018M02</td><td>5883.0</td><td>5874.4</td><td>8.6</td><td>| . |* . |</td></tr>
<tr><td>2018M03</td><td>5891.0</td><td>5844.6</td><td>46.4</td><td>| . | . * |</td></tr>
<tr><td>2018M04</td><td>5847.0</td><td>5790.1</td><td>56.9</td><td>| . | . * |</td></tr>
<tr><td>2018M05</td><td>5703.0</td><td>5689.1</td><td>13.9</td><td>| . | * . |</td></tr>
<tr><td>2018M06</td><td>5613.0</td><td>5637.8</td><td>-24.8</td><td>| .* | . |</td></tr>
<tr><td>2018M07</td><td>5567.0</td><td>5604.1</td><td>-37.1</td><td>| *. | . |</td></tr>
<tr><td>2018M08</td><td>5561.0</td><td>5565.4</td><td>-4.4</td><td>| . *| . |</td></tr>
<tr><td>2018M09</td><td>5595.0</td><td>5557.7</td><td>37.3</td><td>| . | .* |</td></tr>
<tr><td>2018M10</td><td>5770.0</td><td>5762.4</td><td>7.6</td><td>| . |* . |</td></tr>
<tr><td>2018M11</td><td>5862.0</td><td>5859.3</td><td>2.7</td><td>| . * . |</td></tr>
<tr><td>2018M12</td><td>5885.0</td><td>5900.4</td><td>-15.4</td><td>| . * | . |</td></tr>
<tr><td>2019M01</td><td>5899.0</td><td>5908.9</td><td>-9.9</td><td>| . *| . |</td></tr>
<tr><td>2019M02</td><td>5908.0</td><td>5902.2</td><td>5.8</td><td>| . |* . |</td></tr>
<tr><td>2019M03</td><td>5898.0</td><td>5906.4</td><td>-8.4</td><td>| . *| . |</td></tr>
<tr><td>2019M04</td><td>5830.0</td><td>5820.7</td><td>9.3</td><td>| . |* . |</td></tr>
</table>

<table>
<tr><td>2019M05</td><td>5717.0</td><td>5694.0</td><td>23.0</td><td>| . | *. |</td></tr>
<tr><td>2019M06</td><td>5606.0</td><td>5686.0</td><td>-80.0</td><td>| *   . | . |</td></tr>
<tr><td>2019M07</td><td>5559.0</td><td>5578.5</td><td>-19.5</td><td>| .* | . |</td></tr>
<tr><td>2019M08</td><td>5540.0</td><td>5599.1</td><td>-59.1</td><td>| *   . | . |</td></tr>
<tr><td>2019M09</td><td>5559.0</td><td>5594.2</td><td>-35.2</td><td>| *. | . |</td></tr>
<tr><td>2019M10</td><td>5727.0</td><td>5733.9</td><td>-6.9</td><td>| . *| . |</td></tr>
<tr><td>2019M11</td><td>5848.0</td><td>5844.2</td><td>3.8</td><td>| . |* . |</td></tr>
<tr><td>2019M12</td><td>5891.0</td><td>5899.5</td><td>-8.5</td><td>| . *| . |</td></tr>
<tr><td>2020M01</td><td>5892.0</td><td>5904.4</td><td>-12.4</td><td>| . * | . |</td></tr>
<tr><td>2020M02</td><td>5899.0</td><td>5906.9</td><td>-7.9</td><td>| . *| . |</td></tr>
<tr><td>2020M03</td><td>5879.0</td><td>5887.6</td><td>-8.6</td><td>| . *| . |</td></tr>
<tr><td>2020M04</td><td>5847.0</td><td>5816.5</td><td>30.5</td><td>| . | * |</td></tr>
<tr><td>2020M05</td><td>5737.0</td><td>5752.0</td><td>-15.0</td><td>| . * | . |</td></tr>
<tr><td>2020M06</td><td>5656.0</td><td>5681.5</td><td>-25.5</td><td>| .* | . |</td></tr>
<tr><td>2020M07</td><td>5666.0</td><td>5662.3</td><td>3.7</td><td>| . * . |</td></tr>
<tr><td>2020M08</td><td>5688.0</td><td>5655.2</td><td>32.8</td><td>| . | * |</td></tr>
<tr><td>2020M09</td><td>5748.0</td><td>5690.6</td><td>57.4</td><td>| . | .   * |</td></tr>
<tr><td>2020M10</td><td>5930.0</td><td>5886.3</td><td>43.7</td><td>| . | . * |</td></tr>
<tr><td>2020M11</td><td>5960.0</td><td>6004.3</td><td>-44.3</td><td>| * . | . |</td></tr>
<tr><td>2020M12</td><td>6003.0</td><td>5987.8</td><td>15.2</td><td>| . | * . |</td></tr>
<tr><td>2021M01</td><td>6015.0</td><td>6029.8</td><td>-14.8</td><td>| . * | . |</td></tr>
<tr><td>2021M02</td><td>6038.0</td><td>6016.5</td><td>21.5</td><td>| . | *. |</td></tr>
<tr><td>2021M03</td><td>6031.0</td><td>6008.9</td><td>22.1</td><td>| . | *. |</td></tr>
<tr><td>2021M04</td><td>5966.0</td><td>5937.6</td><td>28.4</td><td>| . | * |</td></tr>
<tr><td>2021M05</td><td>5853.0</td><td>5800.5</td><td>52.5</td><td>| . | . * |</td></tr>
<tr><td>2021M06</td><td>5761.0</td><td>5811.6</td><td>-50.6</td><td>| * . | . |</td></tr>
<tr><td>2021M07</td><td>5718.0</td><td>5738.6</td><td>-20.6</td><td>| .* | . |</td></tr>
<tr><td>2021M08</td><td>5724.0</td><td>5750.8</td><td>-26.8</td><td>| * | . |</td></tr>
<tr><td>2021M09</td><td>5750.0</td><td>5769.9</td><td>-19.9</td><td>| .* | . |</td></tr>
<tr><td>2021M10</td><td>5876.0</td><td>5917.2</td><td>-41.2</td><td>| *. | . |</td></tr>
<tr><td>2021M11</td><td>5980.0</td><td>5937.5</td><td>42.5</td><td>| . | . * |</td></tr>
<tr><td>2021M12</td><td>6027.0</td><td>6049.6</td><td>-22.6</td><td>| .* | . |</td></tr>
<tr><td>2022M01</td><td>6047.0</td><td>6005.6</td><td>41.4</td><td>| . | .* |</td></tr>
<tr><td>2022M02</td><td>6053.0</td><td>6051.9</td><td>1.1</td><td>| . * . |</td></tr>
<tr><td>2022M03</td><td>6014.0</td><td>6016.1</td><td>-2.1</td><td>| . * . |</td></tr>
<tr><td>2022M04</td><td>5961</td><td>5926.3</td><td>34.7</td><td>| . | .* |</td></tr>
<tr><td>2022M05</td><td>5854</td><td>5856.6</td><td>-2.6</td><td>| . * . |</td></tr>
<tr><td>2022M06</td><td>5772</td><td>5794.9</td><td>-22.9</td><td>| .* | . |</td></tr>
<tr><td>2022M07</td><td>5758</td><td>5759.3</td><td>-1.3</td><td>| . * . |</td></tr>
<tr><td>2022M08</td><td>5742</td><td>5758.6</td><td>-16.6</td><td>| . * | . |</td></tr>
<tr><td>2022M09</td><td>5786</td><td>5748.0</td><td>38.0</td><td>| . | .* |</td></tr>
<tr><td>2022M10</td><td>5939</td><td>5919.5</td><td>19.5</td><td>| . | *. |</td></tr>
<tr><td>2022M11</td><td>6011</td><td>6048.8</td><td>-37.8</td><td>| *. | . |</td></tr>
</table>

2022M12	6058	6022.7	35.3	| . | .* |

Date: 03/23/23 Time: 10:42
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 3 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.004	-0.004	0.0011	
. |*. |	. |*. |	2	0.092	0.092	0.7516	
.*| . |	.*| . |	3	-0.108	-0.109	1.8010	
.*| . |	.*| . |	4	-0.104	-0.114	2.7712	0.096
. | . |	. | . |	5	-0.010	0.011	2.7797	0.249
. | . |	. |*. |	6	0.072	0.084	3.2552	0.354
.*| . |	.*| . |	7	-0.086	-0.114	3.9560	0.412
. | . |	. | . |	8	0.059	0.032	4.2855	0.509
.*| . |	.*| . |	9	-0.126	-0.093	5.8218	0.443
.*| . |	.*| . |	10	-0.068	-0.086	6.2771	0.508
. |*. |	. |*. |	11	0.116	0.135	7.6066	0.473
.*| . |	.*| . |	12	-0.099	-0.113	8.5966	0.475

*Probabilities may not be valid for this equation specification.

LLF Customer Segment - Use Per Customer Model

Dependent Variable: LLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/01/23 Time: 16:39
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Convergence achieved after 4 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_APR	0.512579	0.012877	39.80641	0.0000
BC_DEC	0.627852	0.010786	58.21156	0.0000
BC_FEB	0.644884	0.008848	72.88302	0.0000
BC_JAN	0.672333	0.008812	76.29469	0.0000
BC_MAR	0.650791	0.010375	62.72448	0.0000
BC_JUN	0.262052	0.047871	5.474143	0.0000
BC_MAY	0.407200	0.020589	19.77739	0.0000
BC_NOV	0.504947	0.017154	29.43526	0.0000
BC_OCT	0.335837	0.036147	9.290974	0.0000
C	103.0396	8.660396	11.89779	0.0000
TREND*D_2017M11_F	0.142555	0.117558	1.212642	0.2292
AR(1)	0.424663	0.110428	3.845602	0.0003

R-squared	0.995950	Mean dependent var	428.0715
Adjusted R-squared	0.995331	S.D. dependent var	303.2711
S.E. of regression	20.72207	Akaike info criterion	9.031839
Sum squared resid	30917.10	Schwarz criterion	9.379099
Log likelihood	-367.3373	Hannan-Quinn criter.	9.171435
F-statistic	1609.603	Durbin-Watson stat	2.026622
Prob(F-statistic)	0.000000		

Inverted AR Roots	.42

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.580393	Prob. F(11,72)	0.1231
Obs*R-squared	16.33713	Prob. Chi-Square(11)	0.1291
Scaled explained SS	24.30089	Prob. Chi-Square(11)	0.0115

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:43
Sample: 2016M01 2022M12
Included observations: 84
Collinear test regressors dropped from specification

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	37.09083	187.9646	0.197329	0.8441
GRADF_01^2	0.001018	0.000470	2.164905	0.0337
GRADF_02^2	-0.000143	0.000335	-0.427059	0.6706
GRADF_03^2	-0.000133	0.000221	-0.602272	0.5489
GRADF_04^2	0.000383	0.000211	1.814142	0.0738
GRADF_05^2	0.000382	0.000296	1.290557	0.2010
GRADF_06^2	-0.000592	0.008894	-0.066528	0.9471
GRADF_07^2	-0.001173	0.001324	-0.885490	0.3788
GRADF_08^2	0.000867	0.000865	1.002662	0.3194
GRADF_09^2	-0.002158	0.005044	-0.427849	0.6700
GRADF_11^2	0.194774	0.081604	2.386831	0.0196
GRADF_12^2	-0.044484	0.111536	-0.398830	0.6912

R-squared	0.194490	Mean dependent var	368.0608
Adjusted R-squared	0.071426	S.D. dependent var	745.0839
S.E. of regression	717.9820	Akaike info criterion	16.12233
Sum squared resid	37115865	Schwarz criterion	16.46959
Log likelihood	-665.1378	Hannan-Quinn criter.	16.26193
F-statistic	1.580393	Durbin-Watson stat	1.866098
Prob(F-statistic)	0.123095		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>778.9</td><td>782.1</td><td>-3.2</td><td>| . *| . |</td></tr>
<tr><td>2016M02</td><td>847.0</td><td>832.3</td><td>14.8</td><td>| . | *. |</td></tr>
<tr><td>2016M03</td><td>694.4</td><td>737.0</td><td>-42.6</td><td>| * . | . |</td></tr>
<tr><td>2016M04</td><td>491.6</td><td>476.2</td><td>15.4</td><td>| . | *. |</td></tr>
<tr><td>2016M05</td><td>294.7</td><td>307.6</td><td>-12.9</td><td>| .* | . |</td></tr>
<tr><td>2016M06</td><td>141.5</td><td>137.4</td><td>4.1</td><td>| . |* . |</td></tr>
<tr><td>2016M07</td><td>95.2</td><td>102.3</td><td>-7.2</td><td>| . *| . |</td></tr>
<tr><td>2016M08</td><td>102.5</td><td>99.7</td><td>2.8</td><td>| . * . |</td></tr>
<tr><td>2016M09</td><td>110.7</td><td>102.8</td><td>7.9</td><td>| . |* . |</td></tr>
<tr><td>2016M10</td><td>198.3</td><td>193.3</td><td>5.0</td><td>| . |* . |</td></tr>
<tr><td>2016M11</td><td>381.0</td><td>398.9</td><td>-18.0</td><td>| * | . |</td></tr>
<tr><td>2016M12</td><td>667.9</td><td>687.7</td><td>-19.8</td><td>| * | . |</td></tr>
<tr><td>2017M01</td><td>839.6</td><td>859.8</td><td>-20.3</td><td>| * | . |</td></tr>
<tr><td>2017M02</td><td>798.2</td><td>811.4</td><td>-13.2</td><td>| .* | . |</td></tr>
<tr><td>2017M03</td><td>770.4</td><td>762.1</td><td>8.3</td><td>| . |* . |</td></tr>
<tr><td>2017M04</td><td>580.8</td><td>547.7</td><td>33.0</td><td>| . | . * |</td></tr>
<tr><td>2017M05</td><td>302.4</td><td>296.5</td><td>5.9</td><td>| . |* . |</td></tr>
<tr><td>2017M06</td><td>171.5</td><td>173.9</td><td>-2.5</td><td>| . * . |</td></tr>
<tr><td>2017M07</td><td>114.6</td><td>105.5</td><td>9.1</td><td>| . |* . |</td></tr>
<tr><td>2017M08</td><td>109.8</td><td>107.9</td><td>1.8</td><td>| . * . |</td></tr>
<tr><td>2017M09</td><td>126.3</td><td>105.9</td><td>20.4</td><td>| . | * |</td></tr>
<tr><td>2017M10</td><td>164.5</td><td>159.9</td><td>4.5</td><td>| . |* . |</td></tr>
<tr><td>2017M11</td><td>336.8</td><td>362.4</td><td>-25.6</td><td>| *. | . |</td></tr>
<tr><td>2017M12</td><td>745.4</td><td>723.0</td><td>22.4</td><td>| . | .* |</td></tr>
<tr><td>2018M01</td><td>1140.2</td><td>1115.7</td><td>24.5</td><td>| . | .* |</td></tr>
<tr><td>2018M02</td><td>855.1</td><td>861.4</td><td>-6.3</td><td>| . *| . |</td></tr>
<tr><td>2018M03</td><td>730.6</td><td>715.7</td><td>14.9</td><td>| . | *. |</td></tr>
<tr><td>2018M04</td><td>614.5</td><td>590.2</td><td>24.3</td><td>| . | .* |</td></tr>
<tr><td>2018M05</td><td>308.6</td><td>304.3</td><td>4.3</td><td>| . |* . |</td></tr>
<tr><td>2018M06</td><td>162.3</td><td>159.6</td><td>2.7</td><td>| . * . |</td></tr>
<tr><td>2018M07</td><td>110.1</td><td>113.8</td><td>-3.7</td><td>| . *| . |</td></tr>
<tr><td>2018M08</td><td>106.7</td><td>109.9</td><td>-3.2</td><td>| . *| . |</td></tr>
<tr><td>2018M09</td><td>113.1</td><td>108.5</td><td>4.6</td><td>| . |* . |</td></tr>
<tr><td>2018M10</td><td>213.1</td><td>204.0</td><td>9.1</td><td>| . |* . |</td></tr>
<tr><td>2018M11</td><td>485.8</td><td>483.6</td><td>2.2</td><td>| . * . |</td></tr>
<tr><td>2018M12</td><td>782.0</td><td>782.3</td><td>-0.3</td><td>| . * . |</td></tr>
<tr><td>2019M01</td><td>895.2</td><td>910.1</td><td>-14.9</td><td>| .* | . |</td></tr>
<tr><td>2019M02</td><td>916.2</td><td>928.7</td><td>-12.6</td><td>| .* | . |</td></tr>
<tr><td>2019M03</td><td>832.3</td><td>834.9</td><td>-2.6</td><td>| . * . |</td></tr>
</table>

2019M04	537.5	517.4	20.1	| . | * |
2019M05	320.2	318.7	1.5	| . * . |
2019M06	160.4	170.6	-10.1	| .* | . |
2019M07	111.9	108.3	3.5	| . |* . |
2019M08	103.2	111.6	-8.4	| . *| . |
2019M09	117.2	108.0	9.2	| . |* . |
2019M10	204.2	199.3	4.8	| . |* . |
2019M11	438.8	435.0	3.8	| . |* . |
2019M12	765.7	773.4	-7.7	| . *| . |
2020M01	874.4	844.2	30.3	| . | . * |
2020M02	849.5	832.2	17.3	| . | * |
2020M03	724.5	743.0	-18.5	| * | . |
2020M04	479.0	507.6	-28.6	| * . | . |
2020M05	326.6	326.2	0.5	| . * . |
2020M06	146.2	152.9	-6.7	| . *| . |
2020M07	98.9	107.7	-8.8	| . *| . |
2020M08	77.7	107.1	-29.4	| * . | . |
2020M09	124.8	98.2	26.7	| . | .* |
2020M10	189.8	201.2	-11.4	| .* | . |
2020M11	397.0	396.5	0.5	| . * . |
2020M12	646.5	658.3	-11.7	| .* | . |
2021M01	797.3	849.3	-52.0	| * . | . |
2021M02	894.8	891.7	3.1	| . * . |
2021M03	827.7	787.7	40.0	| . | . * |
2021M04	426.9	489.2	-62.3	|* . | . |
2021M05	276.8	264.9	11.9	| . | *. |
2021M06	126.4	145.8	-19.4	| * | . |
2021M07	96.6	104.7	-8.1	| . *| . |
2021M08	92.1	107.1	-15.0	| .* | . |
2021M09	100.5	105.3	-4.8	| . *| . |
2021M10	147.7	162.6	-14.9	| .* | . |
2021M11	353.1	378.9	-25.8	| *. | . |
2021M12	662.0	660.0	2.1	| . * . |
2022M01	921.1	896.0	25.1	| . | .* |
2022M02	944.5	948.1	-3.6	| . *| . |
2022M03	762.0	770.5	-8.6	| . *| . |
2022M04	472.78	488.3	-15.5	| .* | . |
2022M05	289.1	296.8	-7.7	| . *| . |
2022M06	182.44	148.4	34.1	| . | . * |
2022M07	131.03	128.0	3.1	| . * . |
2022M08	131.31	122.7	8.6	| . |* . |
2022M09	131.6	122.9	8.7	| . |* . |
2022M10	229.78	218.8	11.0	| . | *. |

2022M11	420.35	353.5	66.9	| . | . *
2022M12	716.58	703.6	13.0	| . |*. |

Date: 03/23/23 Time: 10:44
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.016	-0.016	0.0229	
. | . |	. | . |	2	-0.031	-0.031	0.1072	0.743
. |*. |	. |*. |	3	0.084	0.083	0.7311	0.694
. | . |	. | . |	4	0.051	0.053	0.9637	0.810
. |*. |	. |*. |	5	0.133	0.141	2.5768	0.631
. |*. |	. |*. |	6	0.115	0.120	3.7927	0.580
.*| . |	.*| . |	7	-0.122	-0.119	5.1983	0.519
. |*. |	. | . |	8	0.080	0.058	5.8026	0.563
. | . |	. | . |	9	0.042	0.003	5.9763	0.650
. |*. |	. |*. |	10	0.188	0.193	9.4112	0.400
.*| . |	.*| . |	11	-0.091	-0.121	10.239	0.420
.*| . |	.*| . |	12	-0.099	-0.089	11.224	0.425

*Probabilities may not be valid for this equation specification.

HLF Customer Segment – Customer Model

Dependent Variable: HLF_CUST
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/01/23 Time: 16:57
Sample: 2016M01 2022M12
Included observations: 84
Convergence achieved after 7 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GMP(-3)*D_2018M10_F	1.651933	0.112163	14.72801	0.0000
OCT	-18.05317	2.697196	-6.693310	0.0000
NOV	-27.83772	3.233165	-8.610053	0.0000
DEC	-28.47943	3.405677	-8.362341	0.0000
JAN	-26.74723	3.428057	-7.802448	0.0000
FEB	-28.10918	3.388798	-8.294734	0.0000
MAR	-23.09065	3.182269	-7.256032	0.0000
APR	-10.20767	2.640882	-3.865250	0.0002
C	1112.908	2.835638	392.4719	0.0000
AR(1)	0.579640	0.098358	5.893154	0.0000

R-squared	0.945592	Mean dependent var	1128.560
Adjusted R-squared	0.938975	S.D. dependent var	26.69748
S.E. of regression	6.595166	Akaike info criterion	6.726769
Sum squared resid	3218.720	Schwarz criterion	7.016152
Log likelihood	-272.5243	Hannan-Quinn criter.	6.843098
F-statistic	142.8987	Durbin-Watson stat	1.998958
Prob(F-statistic)	0.000000		

Inverted AR Roots	.58

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	0.870918	Prob. F(10,73)	0.5638
Obs*R-squared	8.953351	Prob. Chi-Square(10)	0.5365
Scaled explained SS	29.78060	Prob. Chi-Square(10)	0.0009

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:46
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	66.29393	53.05915	1.249435	0.2155
GRADF_01^2	-3.399809	5.076663	-0.669694	0.5052
GRADF_02^2	610.0929	1900.058	0.321092	0.7491
GRADF_03^2	-1534.095	1814.488	-0.845470	0.4006
GRADF_04^2	-504.7691	1866.479	-0.270439	0.7876
GRADF_05^2	-1648.072	1958.109	-0.841665	0.4027
GRADF_06^2	-1276.184	1869.542	-0.682619	0.4970
GRADF_07^2	-1244.399	1815.998	-0.685242	0.4954
GRADF_08^2	-1503.561	1832.583	-0.820460	0.4146
GRADF_09^2	-1868.685	9405.081	-0.198689	0.8431
GRADF_10^2	6.998729	3.653221	1.915769	0.0593

R-squared	0.106588	Mean dependent var	38.31810
Adjusted R-squared	-0.015798	S.D. dependent var	112.8602
S.E. of regression	113.7482	Akaike info criterion	12.42740
Sum squared resid	944522.1	Schwarz criterion	12.74572
Log likelihood	-510.9508	Hannan-Quinn criter.	12.55536
F-statistic	0.870918	Durbin-Watson stat	2.031925
Prob(F-statistic)	0.563842		

obs	Actual	Fitted	Residual	Residual Plot
2016M01	1089.0	1086.7	2.3	| . |*. |
2016M02	1085.0	1086.4	-1.4	| . * . |
2016M03	1097.0	1089.9	7.1	| . | * |
2016M04	1113.0	1106.9	6.1	| . | * |
2016M05	1127.0	1118.9	8.1	| . | .* |
2016M06	1127.0	1121.1	5.9	| . | * |
2016M07	1118.0	1121.1	-3.1	| .*| . |
2016M08	1147.0	1115.9	31.1	| . | . *
2016M09	1115.0	1132.7	-17.7	| * . | . |
2016M10	1085.0	1096.1	-11.1	| * . | . |
2016M11	1084.0	1079.4	4.6	| . | * |
2016M12	1090.0	1083.8	6.2	| . | * |
2017M01	1094.0	1089.4	4.6	| . | * |
2017M02	1092.0	1089.3	2.7	| . |*. |
2017M03	1097.0	1094.0	3.0	| . |*. |
2017M04	1105.0	1106.9	-1.9	| .*| . |
2017M05	1113.0	1114.2	-1.2	| . * . |
2017M06	1115.0	1113.0	2.0	| . |*. |
2017M07	1116.0	1114.1	1.9	| . |*. |
2017M08	1113.0	1114.7	-1.7	| .*| . |
2017M09	1107.0	1113.0	-6.0	| * | . |
2017M10	1096.0	1091.4	4.6	| . | * |
2017M11	1075.0	1085.7	-10.7	| * . | . |
2017M12	1076.0	1078.6	-2.6	| .*| . |
2018M01	1077.0	1081.3	-4.3	| .*| . |
2018M02	1074.0	1079.5	-5.5	| * | . |
2018M03	1082.0	1083.6	-1.6	| .*| . |
2018M04	1097.0	1098.2	-1.2	| . * . |
2018M05	1109.0	1109.6	-0.6	| . * . |
2018M06	1110.0	1110.6	-0.6	| . * . |
2018M07	1099.0	1111.2	-12.2	| * . | . |
2018M08	1096.0	1104.8	-8.8	| *. | . |
2018M09	1114.0	1103.1	10.9	| . | . * |
2018M10	1151.0	1138.7	12.3	| . | . * |
2018M11	1131.0	1135.9	-4.9	| * | . |
2018M12	1131.0	1129.3	1.7	| . |*. |
2019M01	1133.0	1131.3	1.7	| . |*. |

<table>
<tr><td>2019M02</td><td>1130.0</td><td>1130.2</td><td>-0.2</td><td>| . * . |</td></tr>
<tr><td>2019M03</td><td>1134.0</td><td>1134.4</td><td>-0.4</td><td>| . * . |</td></tr>
<tr><td>2019M04</td><td>1145.0</td><td>1146.8</td><td>-1.8</td><td>| .*| . |</td></tr>
<tr><td>2019M05</td><td>1156.0</td><td>1155.9</td><td>0.1</td><td>| . * . |</td></tr>
<tr><td>2019M06</td><td>1151.0</td><td>1156.4</td><td>-5.4</td><td>| * | . |</td></tr>
<tr><td>2019M07</td><td>1150.0</td><td>1153.5</td><td>-3.5</td><td>| .*| . |</td></tr>
<tr><td>2019M08</td><td>1148.0</td><td>1153.1</td><td>-5.1</td><td>| * | . |</td></tr>
<tr><td>2019M09</td><td>1155.0</td><td>1152.2</td><td>2.8</td><td>| . |*. |</td></tr>
<tr><td>2019M10</td><td>1143.0</td><td>1138.4</td><td>4.6</td><td>| . | * |</td></tr>
<tr><td>2019M11</td><td>1135.0</td><td>1132.1</td><td>2.9</td><td>| . |*. |</td></tr>
<tr><td>2019M12</td><td>1138.0</td><td>1132.4</td><td>5.6</td><td>| . | * |</td></tr>
<tr><td>2020M01</td><td>1137.0</td><td>1136.3</td><td>0.7</td><td>| . * . |</td></tr>
<tr><td>2020M02</td><td>1139.0</td><td>1133.8</td><td>5.2</td><td>| . | * |</td></tr>
<tr><td>2020M03</td><td>1141.0</td><td>1141.5</td><td>-0.5</td><td>| . * . |</td></tr>
<tr><td>2020M04</td><td>1148.0</td><td>1152.7</td><td>-4.7</td><td>| * | . |</td></tr>
<tr><td>2020M05</td><td>1161.0</td><td>1158.4</td><td>2.6</td><td>| . |*. |</td></tr>
<tr><td>2020M06</td><td>1166.0</td><td>1157.9</td><td>8.1</td><td>| . | .* |</td></tr>
<tr><td>2020M07</td><td>1160.0</td><td>1159.4</td><td>0.6</td><td>| . * . |</td></tr>
<tr><td>2020M08</td><td>1153.0</td><td>1156.3</td><td>-3.3</td><td>| .*| . |</td></tr>
<tr><td>2020M09</td><td>1149.0</td><td>1154.5</td><td>-5.5</td><td>| * | . |</td></tr>
<tr><td>2020M10</td><td>1133.0</td><td>1136.4</td><td>-3.4</td><td>| .*| . |</td></tr>
<tr><td>2020M11</td><td>1129.0</td><td>1128.8</td><td>0.2</td><td>| . * . |</td></tr>
<tr><td>2020M12</td><td>1126.0</td><td>1130.8</td><td>-4.8</td><td>| * | . |</td></tr>
<tr><td>2021M01</td><td>1127.0</td><td>1130.2</td><td>-3.2</td><td>| .*| . |</td></tr>
<tr><td>2021M02</td><td>1127.0</td><td>1128.0</td><td>-1.0</td><td>| . * . |</td></tr>
<tr><td>2021M03</td><td>1132.0</td><td>1134.3</td><td>-2.3</td><td>| .*| . |</td></tr>
<tr><td>2021M04</td><td>1151.0</td><td>1147.8</td><td>3.2</td><td>| . |*. |</td></tr>
<tr><td>2021M05</td><td>1161.0</td><td>1162.0</td><td>-1.0</td><td>| . * . |</td></tr>
<tr><td>2021M06</td><td>1160.0</td><td>1162.1</td><td>-2.1</td><td>| .*| . |</td></tr>
<tr><td>2021M07</td><td>1163.0</td><td>1161.7</td><td>1.3</td><td>| . * . |</td></tr>
<tr><td>2021M08</td><td>1164.0</td><td>1163.5</td><td>0.5</td><td>| . * . |</td></tr>
<tr><td>2021M09</td><td>1166.0</td><td>1164.1</td><td>1.9</td><td>| . |*. |</td></tr>
<tr><td>2021M10</td><td>1150.0</td><td>1147.3</td><td>2.7</td><td>| . |*. |</td></tr>
<tr><td>2021M11</td><td>1142.0</td><td>1139.0</td><td>3.0</td><td>| . |*. |</td></tr>
<tr><td>2021M12</td><td>1142.0</td><td>1139.9</td><td>2.1</td><td>| . |*. |</td></tr>
<tr><td>2022M01</td><td>1142.0</td><td>1142.3</td><td>-0.3</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>1142.0</td><td>1139.9</td><td>2.1</td><td>| . |*. |</td></tr>
<tr><td>2022M03</td><td>1143.0</td><td>1145.3</td><td>-2.3</td><td>| .*| . |</td></tr>
<tr><td>2022M04</td><td>1161</td><td>1155.4</td><td>5.56509</td><td>| . | * |</td></tr>
<tr><td>2022M05</td><td>1170</td><td>1168.6</td><td>1.39886</td><td>| . * . |</td></tr>
<tr><td>2022M06</td><td>1169</td><td>1168.2</td><td>0.75175</td><td>| . * . |</td></tr>
<tr><td>2022M07</td><td>1167</td><td>1168.1</td><td>-1.1015</td><td>| . * . |</td></tr>
<tr><td>2022M08</td><td>1161</td><td>1167.2</td><td>-6.214</td><td>| * | . |</td></tr>
</table>

2022M09	1156	1163.8	-7.814	| *. | . |
2022M10	1133	1142.9	-9.8875	| *. | . |
2022M11	1135	1130.3	4.65329	| . | * |
2022M12	1128	1136.7	-8.746	| *. | . |

Date: 03/23/23 Time: 10:47
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	-0.012	-0.012	0.0129	
. | . |	. | . |	2	-0.049	-0.050	0.2281	0.633
. |*. |	. |*. |	3	0.081	0.080	0.8205	0.663
. | . |	. | . |	4	0.045	0.045	1.0048	0.800
. | . |	. | . |	5	0.053	0.063	1.2623	0.868
.*| . |	.*| . |	6	-0.068	-0.070	1.6918	0.890
. | . |	. | . |	7	0.072	0.070	2.1795	0.902
. | . |	. | . |	8	-0.035	-0.054	2.2968	0.942
. | . |	. | . |	9	-0.045	-0.032	2.4876	0.962
.*| . |	.*| . |	10	-0.092	-0.110	3.3078	0.951
. | . |	. | . |	11	-0.018	-0.014	3.3416	0.972
. | . |	. | . |	12	-0.021	-0.037	3.3846	0.985

*Probabilities may not be valid for this equation specification.

HLF Customer Segment - Use Per Customer Model

Dependent Variable: HLF_UPC
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/01/23 Time: 16:52
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Convergence achieved after 10 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
EMP_MAN	117.1330	1.296859	90.32054	0.0000
BC_APR	0.229463	0.064422	3.561847	0.0006
BC_DEC	0.274235	0.053433	5.132346	0.0000
BC_FEB	0.257756	0.043542	5.919776	0.0000
BC_JAN	0.383185	0.046608	8.221471	0.0000
BC_MAR	0.515305	0.050454	10.21333	0.0000
BC_NOV	0.416274	0.088170	4.721266	0.0000
BC_OCT	0.794346	0.215811	3.680753	0.0004
D_2020M03_2020M12	-117.0448	56.67702	-2.065119	0.0424
AR(3)	0.314714	0.118335	2.659521	0.0096

R-squared	0.748788	Mean dependent var	2612.165
Adjusted R-squared	0.718235	S.D. dependent var	243.0022
S.E. of regression	128.9894	Akaike info criterion	12.66868
Sum squared resid	1231231.	Schwarz criterion	12.95806
Log likelihood	-522.0846	Hannan-Quinn criter.	12.78501
Durbin-Watson stat	1.718469		

Inverted AR Roots	.68	-.34+.59i	-.34-.59i

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	0.595111	Prob. F(10,73)	0.8129
Obs*R-squared	6.331684	Prob. Chi-Square(10)	0.7867
Scaled explained SS	8.623504	Prob. Chi-Square(10)	0.5682

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 10:47
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	60394.32	65280.10	0.925157	0.3579
GRADF_01^2	-197.6579	315.0902	-0.627306	0.5324
GRADF_02^2	-0.011943	0.018128	-0.658791	0.5121
GRADF_03^2	0.008911	0.012820	0.695112	0.4892
GRADF_04^2	-0.001083	0.008390	-0.129091	0.8976
GRADF_05^2	0.002942	0.008148	0.360989	0.7192
GRADF_06^2	-0.013745	0.011552	-1.189872	0.2380
GRADF_07^2	-0.042251	0.034075	-1.239940	0.2190
GRADF_08^2	-0.208026	0.193484	-1.075163	0.2858
GRADF_09^2	-8133.780	17435.05	-0.466519	0.6422
GRADF_10^2	-0.066516	0.106283	-0.625839	0.5334

R-squared	0.075377	Mean dependent var	14657.51
Adjusted R-squared	-0.051283	S.D. dependent var	27625.21
S.E. of regression	28324.71	Akaike info criterion	23.46240
Sum squared resid	5.86E+10	Schwarz criterion	23.78073
Log likelihood	-974.4210	Hannan-Quinn criter.	23.59037
F-statistic	0.595111	Durbin-Watson stat	1.708186
Prob(F-statistic)	0.812878		

obs	Actual	Fitted	Residual	Residual Plot
2016M01	3062.6	2792.1	270.4	| . | . * |
2016M02	2963.9	2678.9	284.9	| . | . * |
2016M03	2917.2	2916.9	0.3	| . * . |
2016M04	2665.5	2642.6	22.9	| . |* . |
2016M05	2458.8	2469.7	-10.9	| . * . |
2016M06	2316.8	2393.7	-76.9	| .* | . |
2016M07	2190.6	2421.2	-230.6	| * . | . |
2016M08	2367.4	2418.9	-51.5	| . *| . |
2016M09	2398.8	2383.6	15.1	| . * . |
2016M10	2591.5	2559.9	31.6	| . |* . |
2016M11	2670.5	2657.6	12.9	| . * . |
2016M12	2687.4	2687.1	0.4	| . * . |
2017M01	2802.9	2861.2	-58.2	| . *| . |
2017M02	2587.8	2720.4	-132.7	| * | . |
2017M03	2912.7	2957.4	-44.7	| . *| . |
2017M04	2572.1	2600.7	-28.6	| . *| . |
2017M05	2586.5	2381.0	205.4	| . | . * |
2017M06	1989.8	2412.8	-423.0	|* . | . |
2017M07	2546.0	2416.0	130.0	| . | * |
2017M08	2431.2	2484.5	-53.3	| . *| . |
2017M09	2249.6	2289.4	-39.8	| . *| . |
2017M10	2646.3	2567.1	79.1	| . | *. |
2017M11	2682.3	2621.5	60.8	| . | *. |
2017M12	2820.7	2642.0	178.6	| . | .* |
2018M01	2981.2	3046.7	-65.4	| .* | . |
2018M02	2735.8	2766.2	-30.4	| . *| . |
2018M03	2882.2	2974.3	-92.1	| .* | . |
2018M04	2752.6	2661.5	91.1	| . | *. |
2018M05	2598.4	2460.9	137.5	| . | * |
2018M06	2374.8	2458.2	-83.4	| .* | . |
2018M07	2320.9	2513.7	-192.8	| * . | . |
2018M08	2544.8	2535.9	8.9	| . * . |
2018M09	2463.0	2458.7	4.3	| . * . |
2018M10	2641.0	2649.9	-8.9	| . * . |
2018M11	2807.8	2803.6	4.2	| . * . |
2018M12	2734.9	2781.0	-46.2	| . *| . |
2019M01	3057.0	2951.9	105.1	| . | * |

<table>
<tr><td>2019M02</td><td>2951.9</td><td>2865.9</td><td>86.0</td><td>| . |*. |</td></tr>
<tr><td>2019M03</td><td>3057.7</td><td>3096.1</td><td>-38.4</td><td>| . *| . |</td></tr>
<tr><td>2019M04</td><td>2839.3</td><td>2739.9</td><td>99.4</td><td>| . |*. |</td></tr>
<tr><td>2019M05</td><td>2849.8</td><td>2553.3</td><td>296.5</td><td>| . | . * |</td></tr>
<tr><td>2019M06</td><td>2456.7</td><td>2506.7</td><td>-50.0</td><td>| . *| . |</td></tr>
<tr><td>2019M07</td><td>2518.9</td><td>2565.2</td><td>-46.2</td><td>| . *| . |</td></tr>
<tr><td>2019M08</td><td>2526.6</td><td>2624.3</td><td>-97.7</td><td>| .* | . |</td></tr>
<tr><td>2019M09</td><td>2393.5</td><td>2488.9</td><td>-95.4</td><td>| .* | . |</td></tr>
<tr><td>2019M10</td><td>2689.9</td><td>2701.7</td><td>-11.8</td><td>| . * . |</td></tr>
<tr><td>2019M11</td><td>2680.5</td><td>2777.9</td><td>-97.4</td><td>| .* | . |</td></tr>
<tr><td>2019M12</td><td>2546.8</td><td>2793.9</td><td>-247.1</td><td>| * . | . |</td></tr>
<tr><td>2020M01</td><td>2692.7</td><td>2980.5</td><td>-287.8</td><td>| * . | . |</td></tr>
<tr><td>2020M02</td><td>2794.8</td><td>2795.8</td><td>-1.0</td><td>| . * . |</td></tr>
<tr><td>2020M03</td><td>2731.1</td><td>2737.1</td><td>-6.0</td><td>| . * . |</td></tr>
<tr><td>2020M04</td><td>2089.1</td><td>2308.2</td><td>-219.1</td><td>| * . | . |</td></tr>
<tr><td>2020M05</td><td>2103.2</td><td>2135.0</td><td>-31.8</td><td>| . *| . |</td></tr>
<tr><td>2020M06</td><td>2194.9</td><td>2117.1</td><td>77.8</td><td>| . |*. |</td></tr>
<tr><td>2020M07</td><td>2185.4</td><td>2104.3</td><td>81.1</td><td>| . |*. |</td></tr>
<tr><td>2020M08</td><td>2212.2</td><td>2247.7</td><td>-35.5</td><td>| . *| . |</td></tr>
<tr><td>2020M09</td><td>2390.1</td><td>2299.2</td><td>90.9</td><td>| . |*. |</td></tr>
<tr><td>2020M10</td><td>2499.8</td><td>2475.1</td><td>24.7</td><td>| . |* . |</td></tr>
<tr><td>2020M11</td><td>2516.2</td><td>2502.2</td><td>14.0</td><td>| . * . |</td></tr>
<tr><td>2020M12</td><td>2727.1</td><td>2562.8</td><td>164.3</td><td>| . | .* |</td></tr>
<tr><td>2021M01</td><td>2934.0</td><td>2853.0</td><td>81.0</td><td>| . |*. |</td></tr>
<tr><td>2021M02</td><td>2796.0</td><td>2754.3</td><td>41.8</td><td>| . |* . |</td></tr>
<tr><td>2021M03</td><td>3000.7</td><td>3032.1</td><td>-31.4</td><td>| . *| . |</td></tr>
<tr><td>2021M04</td><td>2616.1</td><td>2605.9</td><td>10.2</td><td>| . * . |</td></tr>
<tr><td>2021M05</td><td>2617.9</td><td>2417.8</td><td>200.2</td><td>| . | . * |</td></tr>
<tr><td>2021M06</td><td>2343.9</td><td>2410.9</td><td>-67.0</td><td>| .* | . |</td></tr>
<tr><td>2021M07</td><td>2636.7</td><td>2417.7</td><td>219.0</td><td>| . | . * |</td></tr>
<tr><td>2021M08</td><td>2388.1</td><td>2481.2</td><td>-93.1</td><td>| .* | . |</td></tr>
<tr><td>2021M09</td><td>2351.6</td><td>2401.9</td><td>-50.3</td><td>| . *| . |</td></tr>
<tr><td>2021M10</td><td>2468.4</td><td>2625.6</td><td>-157.2</td><td>| *. | . |</td></tr>
<tr><td>2021M11</td><td>2651.0</td><td>2650.6</td><td>0.4</td><td>| . * . |</td></tr>
<tr><td>2021M12</td><td>2461.5</td><td>2668.6</td><td>-207.0</td><td>| * . | . |</td></tr>
<tr><td>2022M01</td><td>2870.6</td><td>2881.1</td><td>-10.5</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>2791.9</td><td>2799.6</td><td>-7.7</td><td>| . * . |</td></tr>
<tr><td>2022M03</td><td>2955.3</td><td>2928.1</td><td>27.1</td><td>| . |* . |</td></tr>
<tr><td>2022M04</td><td>2643.8</td><td>2648.9</td><td>-5.0231</td><td>| . * . |</td></tr>
<tr><td>2022M05</td><td>2468.8</td><td>2497.6</td><td>-28.805</td><td>| . *| . |</td></tr>
<tr><td>2022M06</td><td>2544.6</td><td>2493.7</td><td>50.8291</td><td>| . |* . |</td></tr>
<tr><td>2022M07</td><td>2546.9</td><td>2508.4</td><td>38.5275</td><td>| . |* . |</td></tr>
<tr><td>2022M08</td><td>2549.3</td><td>2508.3</td><td>41.0549</td><td>| . |* . |</td></tr>
</table>

2022M09	2551.7	2534.6	17.1255	| . * . |
2022M10	2810.2	2762.2	47.9852	| . |* . |
2022M11	2853.8	2725.3	128.494	| . | * |
2022M12	2907.8	2778	129.82	| . | * |

Date: 03/23/23 Time: 10:49
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. |*. |	. |*. |	1	0.104	0.104	0.9467	
. |*. |	. |*. |	2	0.100	0.090	1.8324	0.176
. | . |	. | . |	3	0.030	0.011	1.9118	0.384
. |*. |	. |*. |	4	0.115	0.104	3.0965	0.377
. | . |	. | . |	5	-0.022	-0.047	3.1392	0.535
.*| . |	.*| . |	6	-0.126	-0.144	4.6105	0.465
. | . |	. | . |	7	-0.050	-0.024	4.8494	0.563
.*| . |	.*| . |	8	-0.150	-0.137	6.9883	0.430
. | . |	. | . |	9	-0.060	-0.018	7.3318	0.501
.*| . |	.*| . |	10	-0.180	-0.125	10.491	0.312
.*| . |	.*| . |	11	-0.171	-0.147	13.380	0.203
.*| . |	.*| . |	12	-0.130	-0.076	15.066	0.180

*Probabilities may not be valid for this equation specification.

Capacity Exempt Customer Demand Segment Model

Dependent Variable: CE_PERCENT
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/10/23 Time: 12:51
Sample (adjusted): 2016M01 2022M12
Included observations: 84 after adjustments
Failure to improve likelihood (non-zero gradients) after 24 iterations
Coefficient covariance computed using outer product of gradients
MA Backcast: 2015M01 2015M12

Variable	Coefficient	Std. Error	t-Statistic	Prob.
@MONTH=1	0.267397	0.003732	71.64662	0.0000
@MONTH=2	0.269585	0.003714	72.58119	0.0000
@MONTH=3	0.288824	0.003811	75.78498	0.0000
@MONTH=4	0.351915	0.003708	94.91660	0.0000
@MONTH=5	0.431266	0.003705	116.4004	0.0000
@MONTH=6	0.519825	0.003711	140.0756	0.0000
@MONTH=7	0.540047	0.003702	145.8814	0.0000
@MONTH=8	0.554889	0.003712	149.4883	0.0000
@MONTH=9	0.540804	0.003720	145.3582	0.0000
@MONTH=10	0.496756	0.003720	133.5425	0.0000
@MONTH=11	0.399130	0.003778	105.6413	0.0000
@MONTH=12	0.299116	0.003733	80.13196	0.0000
AR(1)	0.279852	0.108494	2.579438	0.0120
MA(12)	-0.914370	0.031862	-28.69779	0.0000

R-squared	0.973396	Mean dependent var	0.417738
Adjusted R-squared	0.968455	S.D. dependent var	0.111953
S.E. of regression	0.019884	Akaike info criterion	-4.846813
Sum squared resid	0.027676	Schwarz criterion	-4.441677
Log likelihood	217.5662	Hannan-Quinn criter.	-4.683952
Durbin-Watson stat	2.158062		

Inverted AR Roots	.28			
Inverted MA Roots	.99	.86+.50i	.86-.50i	.50+.86i
	.50-.86i	.00+.99i	-.00-.99i	-.50+.86i
	-.50-.86i	-.86+.50i	-.86-.50i	-.99

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	1.352967	Prob. F(14,69)	0.2006
Obs*R-squared	18.09258	Prob. Chi-Square(14)	0.2026
Scaled explained SS	12.18586	Prob. Chi-Square(14)	0.5914

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 12:15
Sample: 2016M01 2022M12
Included observations: 84

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.000242	9.74E-05	2.486547	0.0153
GRADF_01^2	-2.43E-05	2.94E-05	-0.826571	0.4113
GRADF_02^2	-4.06E-05	3.03E-05	-1.338832	0.1850
GRADF_03^2	-5.43E-05	3.01E-05	-1.803305	0.0757
GRADF_04^2	-1.98E-05	2.96E-05	-0.671009	0.5045
GRADF_05^2	-4.00E-05	2.95E-05	-1.356728	0.1793
GRADF_06^2	1.84E-05	2.98E-05	0.618518	0.5383
GRADF_07^2	-7.89E-06	2.91E-05	-0.271599	0.7867
GRADF_08^2	4.61E-06	3.02E-05	0.152757	0.8790
GRADF_09^2	-4.42E-06	2.92E-05	-0.151354	0.8801
GRADF_10^2	4.96E-06	2.91E-05	0.170096	0.8654
GRADF_11^2	-4.31E-05	3.84E-05	-1.121331	0.2660
GRADF_12^2	-3.62E-05	2.95E-05	-1.226518	0.2242
GRADF_13^2	0.083930	0.097444	0.861311	0.3921
GRADF_14^2	0.027868	0.010025	2.779892	0.0070

R-squared	0.215388	Mean dependent var	0.000329
Adjusted R-squared	0.056191	S.D. dependent var	0.000462
S.E. of regression	0.000448	Akaike info criterion	-12.42103
Sum squared resid	1.39E-05	Schwarz criterion	-11.98695
Log likelihood	536.6832	Hannan-Quinn criter.	-12.24653
F-statistic	1.352967	Durbin-Watson stat	2.020956
Prob(F-statistic)	0.200607		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2016M02</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2016M03</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2016M04</td><td>0.4</td><td>0.3</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2016M05</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2016M06</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| *. | . |</td></tr>
<tr><td>2016M07</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2016M08</td><td>0.6</td><td>0.6</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2016M09</td><td>0.5</td><td>0.6</td><td>0.0</td><td>| * | . |</td></tr>
<tr><td>2016M10</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2016M11</td><td>0.4</td><td>0.5</td><td>0.0</td><td>| *. | . |</td></tr>
<tr><td>2016M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2017M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | *. |</td></tr>
<tr><td>2017M02</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2017M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * . |</td></tr>
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<tr><td>2017M05</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2017M06</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2017M07</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| * . | . |</td></tr>
<tr><td>2017M08</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . | . * |</td></tr>
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<tr><td>2017M11</td><td>0.5</td><td>0.4</td><td>0.0</td><td>| . | . *|</td></tr>
<tr><td>2017M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2018M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2018M02</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2018M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | . * |</td></tr>
<tr><td>2018M04</td><td>0.3</td><td>0.4</td><td>0.0</td><td>| * . | . |</td></tr>
<tr><td>2018M05</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2018M06</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | .* |</td></tr>
<tr><td>2018M07</td><td>0.6</td><td>0.6</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2018M08</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2018M09</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . | . * |</td></tr>
<tr><td>2018M10</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2018M11</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2018M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2019M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2019M02</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2019M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2019M04</td><td>0.3</td><td>0.4</td><td>0.0</td><td>| * . | . |</td></tr>
<tr><td>2019M05</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2019M06</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . * . |</td></tr>
</table>

<table>
<tr><td>2019M07</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2019M08</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2019M09</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2019M10</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2019M11</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2019M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2020M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2020M02</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . | . * |</td></tr>
<tr><td>2020M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * |</td></tr>
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<tr><td>2020M05</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| .* | . |</td></tr>
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<tr><td>2020M09</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2020M10</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2020M11</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2020M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * |</td></tr>
<tr><td>2021M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . | * . |</td></tr>
<tr><td>2021M02</td><td>0.3</td><td>0.2</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2021M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2021M04</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2021M05</td><td>0.4</td><td>0.5</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2021M06</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . *| . |</td></tr>
<tr><td>2021M07</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2021M08</td><td>0.6</td><td>0.5</td><td>0.0</td><td>| . | . *</td></tr>
<tr><td>2021M09</td><td>0.5</td><td>0.6</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2021M10</td><td>0.5</td><td>0.5</td><td>0.0</td><td>| . | . * |</td></tr>
<tr><td>2021M11</td><td>0.4</td><td>0.4</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2021M12</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * | . |</td></tr>
<tr><td>2022M01</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . * . |</td></tr>
<tr><td>2022M02</td><td>0.2</td><td>0.3</td><td>0.0</td><td>| .* | . |</td></tr>
<tr><td>2022M03</td><td>0.3</td><td>0.3</td><td>0.0</td><td>| . |* . |</td></tr>
<tr><td>2022M04</td><td>0.35</td><td>0.34</td><td>0.01</td><td>| . |* . |</td></tr>
<tr><td>2022M05</td><td>0.45</td><td>0.44</td><td>0.01</td><td>| . | * . |</td></tr>
<tr><td>2022M06</td><td>0.53</td><td>0.53</td><td>0.00</td><td>| . * . |</td></tr>
<tr><td>2022M07</td><td>0.57</td><td>0.56</td><td>0.01</td><td>| . | * . |</td></tr>
<tr><td>2022M08</td><td>0.5</td><td>0.52</td><td>-0.02</td><td>| * | . |</td></tr>
<tr><td>2022M09</td><td>0.54</td><td>0.54</td><td>0.00</td><td>| . |* . |</td></tr>
<tr><td>2022M10</td><td>0.45</td><td>0.47</td><td>-0.02</td><td>| .* | . |</td></tr>
<tr><td>2022M11</td><td>0.41</td><td>0.39</td><td>0.02</td><td>| . | *. |</td></tr>
<tr><td>2022M12</td><td>0.32</td><td>0.31</td><td>0.01</td><td>| . |* . |</td></tr>
</table>

Date: 03/23/23 Time: 12:16
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 2 ARMA terms

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
.*| . |	.*| . |	1	-0.138	-0.138	1.6620	
. | . |	. | . |	2	0.021	0.001	1.6992	
. | . |	. | . |	3	0.012	0.015	1.7115	0.191
. | . |	. | . |	4	-0.005	-0.001	1.7137	0.424
. | . |	. | . |	5	0.052	0.052	1.9646	0.580
. | . |	. |*. |	6	0.074	0.090	2.4665	0.651
. | . |	. | . |	7	-0.008	0.014	2.4722	0.781
. |*. |	. |*. |	8	0.081	0.081	3.0966	0.797
. | . |	. | . |	9	0.047	0.071	3.3114	0.855
. | . |	. | . |	10	-0.003	0.010	3.3124	0.913
.*| . |	.*| . |	11	-0.082	-0.097	3.9808	0.913
. |*. |	. | . |	12	0.085	0.053	4.7089	0.910

*Probabilities may not be valid for this equation specification.

COMPANY USE MODEL

Dependent Variable: CO_USE_NH
Method: ARMA Generalized Least Squares (Gauss-Newton)
Date: 03/08/23 Time: 11:00
Sample: 2016M01 2022M12
Included observations: 81
Convergence achieved after 10 iterations
Coefficient covariance computed using outer product of gradients
d.f. adjustment for standard errors & covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
BC_DEC	0.130743	0.013288	9.839400	0.0000
BC_JAN	0.181744	0.011373	15.98071	0.0000
BC_FEB	0.177857	0.012171	14.61275	0.0000
BC_MAR	0.175852	0.013992	12.56798	0.0000
BC_APR	0.138580	0.016168	8.571159	0.0000
BC_MAY+BC_NOV	0.049929	0.016026	3.115567	0.0026
C	76.04524	7.362864	10.32822	0.0000
AR(1)	0.443080	0.108180	4.095746	0.0001

R-squared	0.905262	Mean dependent var	146.5062
Adjusted R-squared	0.896177	S.D. dependent var	86.60718
S.E. of regression	27.90619	Akaike info criterion	9.594493
Sum squared resid	56849.14	Schwarz criterion	9.830982
Log likelihood	-380.5770	Hannan-Quinn criter.	9.689376
F-statistic	99.64895	Durbin-Watson stat	1.908732
Prob(F-statistic)	0.000000		

Inverted AR Roots	.44

Heteroskedasticity Test: White
Null hypothesis: Homoskedasticity

F-statistic	0.212466	Prob. F(8,72)	0.9878
Obs*R-squared	1.868091	Prob. Chi-Square(8)	0.9848
Scaled explained SS	1.196739	Prob. Chi-Square(8)	0.9967

Test Equation:
Dependent Variable: RESID^2
Method: Least Squares
Date: 03/23/23 Time: 12:18
Sample: 2016M01 2022M12
Included observations: 81

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	668.4616	508.4039	1.314824	0.1927
GRADF_01^2	-0.130876	0.282146	-0.463861	0.6441
GRADF_02^2	0.130250	0.189419	0.687628	0.4939
GRADF_03^2	0.049855	0.207486	0.240278	0.8108
GRADF_04^2	0.149771	0.280017	0.534865	0.5944
GRADF_05^2	0.153548	0.423091	0.362918	0.7177
GRADF_06^2	-0.286218	0.693016	-0.413003	0.6808
GRADF_07^2	38952.79	1019513.	0.038207	0.9696
GRADF_08^2	-8.246553	70.50046	-0.116972	0.9072

R-squared	0.023063	Mean dependent var	701.8413
Adjusted R-squared	-0.085486	S.D. dependent var	886.9810
S.E. of regression	924.1157	Akaike info criterion	16.59999
Sum squared resid	61487269	Schwarz criterion	16.86604
Log likelihood	-663.2996	Hannan-Quinn criter.	16.70673
F-statistic	0.212466	Durbin-Watson stat	1.552815
Prob(F-statistic)	0.987762		

<table>
<tr><th>obs</th><th>Actual</th><th>Fitted</th><th>Residual</th><th>Residual Plot</th></tr>
<tr><td>2016M01</td><td>305.0</td><td>268.4</td><td>36.6</td><td>| . | .* |</td></tr>
<tr><td>2016M02</td><td>332.0</td><td>297.6</td><td>34.4</td><td>| . | .* |</td></tr>
<tr><td>2016M03</td><td>226.0</td><td>269.9</td><td>-43.9</td><td>| * . | . |</td></tr>
<tr><td>2016M04</td><td>236.0</td><td>172.4</td><td>63.6</td><td>| . | . *</td></tr>
<tr><td>2016M05</td><td>83.0</td><td>125.4</td><td>-42.4</td><td>| * . | . |</td></tr>
<tr><td>2016M06</td><td>46.0</td><td>68.0</td><td>-22.0</td><td>| .* | . |</td></tr>
<tr><td>2016M07</td><td>48.0</td><td>62.7</td><td>-14.7</td><td>| . * | . |</td></tr>
<tr><td>2016M08</td><td>77.0</td><td>63.6</td><td>13.4</td><td>| . | * . |</td></tr>
<tr><td>2016M09</td><td>85.0</td><td>76.5</td><td>8.5</td><td>| . |* . |</td></tr>
<tr><td>2016M10</td><td>76.0</td><td>80.0</td><td>-4.0</td><td>| . *| . |</td></tr>
<tr><td>2016M11</td><td>109.0</td><td>104.9</td><td>4.1</td><td>| . |* . |</td></tr>
<tr><td>2016M12</td><td>180.0</td><td>200.9</td><td>-20.9</td><td>| . * | . |</td></tr>
<tr><td>2017M01</td><td>219.0</td><td>275.1</td><td>-56.1</td><td>| * . | . |</td></tr>
<tr><td>2017M02</td><td>218.0</td><td>246.4</td><td>-28.4</td><td>| * | . |</td></tr>
<tr><td>2017M03</td><td>211.0</td><td>231.9</td><td>-20.9</td><td>| . * | . |</td></tr>
<tr><td>2017M04</td><td>162.0</td><td>176.2</td><td>-14.2</td><td>| . * | . |</td></tr>
<tr><td>2017M05</td><td>74.0</td><td>82.8</td><td>-8.8</td><td>| . *| . |</td></tr>
<tr><td>2017M06</td><td>56.0</td><td>65.4</td><td>-9.4</td><td>| . * | . |</td></tr>
<tr><td>2017M07</td><td>59.0</td><td>67.2</td><td>-8.2</td><td>| . *| . |</td></tr>
<tr><td>2017M08</td><td>62.0</td><td>68.5</td><td>-6.5</td><td>| . *| . |</td></tr>
<tr><td>2017M09</td><td>56.0</td><td>69.8</td><td>-13.8</td><td>| . * | . |</td></tr>
<tr><td>2017M10</td><td>32.0</td><td>67.2</td><td>-35.2</td><td>| *. | . |</td></tr>
<tr><td>2017M11</td><td>71.0</td><td>81.0</td><td>-10.0</td><td>| . * | . |</td></tr>
<tr><td>2017M12</td><td>209.0</td><td>192.6</td><td>16.4</td><td>| . | * . |</td></tr>
<tr><td>2018M01</td><td>373.0</td><td>348.1</td><td>24.9</td><td>| . | *. |</td></tr>
<tr><td>2018M02</td><td>270.0</td><td>291.7</td><td>-21.7</td><td>| .* | . |</td></tr>
<tr><td>2018M03</td><td>239.0</td><td>234.8</td><td>4.2</td><td>| . |* . |</td></tr>
<tr><td>2018M04</td><td>211.0</td><td>204.0</td><td>7.0</td><td>| . |* . |</td></tr>
<tr><td>2018M05</td><td>108.0</td><td>101.4</td><td>6.6</td><td>| . |* . |</td></tr>
<tr><td>2018M06</td><td>40.0</td><td>80.3</td><td>-40.3</td><td>| * . | . |</td></tr>
<tr><td>2018M07</td><td>92.0</td><td>60.1</td><td>31.9</td><td>| . | * |</td></tr>
<tr><td>2018M08</td><td>131.0</td><td>83.1</td><td>47.9</td><td>| . | . * |</td></tr>
<tr><td>2018M09</td><td>131.0</td><td>100.4</td><td>30.6</td><td>| . | * |</td></tr>
<tr><td>2018M10</td><td>100.0</td><td>100.4</td><td>-0.4</td><td>| . * . |</td></tr>
<tr><td>2018M11</td><td>142.0</td><td>123.2</td><td>18.8</td><td>| . | * . |</td></tr>
<tr><td>2018M12</td><td>207.0</td><td>228.5</td><td>-21.5</td><td>| .* | . |</td></tr>
<tr><td>2019M01</td><td>254.0</td><td>288.2</td><td>-34.2</td><td>| *. | . |</td></tr>
<tr><td>2019M02</td><td>257.0</td><td>286.5</td><td>-29.5</td><td>| * | . |</td></tr>
<tr><td>2019M03</td><td>251.0</td><td>253.3</td><td>-2.3</td><td>| . * . |</td></tr>
<tr><td>2019M04</td><td>173.0</td><td>177.0</td><td>-4.0</td><td>| . *| . |</td></tr>
<tr><td>2019M05</td><td>100.0</td><td>94.4</td><td>5.6</td><td>| . |* . |</td></tr>
<tr><td>2019M06</td><td>58.0</td><td>75.7</td><td>-17.7</td><td>| . * | . |</td></tr>
</table>

<table>
<tr><td>2019M07</td><td>83.0</td><td>68.0</td><td>15.0</td><td>| . |* . |</td></tr>
<tr><td>2019M08</td><td>140.0</td><td>79.1</td><td>60.9</td><td>| . | . *|</td></tr>
<tr><td>2019M09</td><td>100.0</td><td>104.4</td><td>-4.4</td><td>| . *| . |</td></tr>
<tr><td>2019M10</td><td>89.0</td><td>86.7</td><td>2.3</td><td>| . * . |</td></tr>
<tr><td>2019M11</td><td>84.0</td><td>113.4</td><td>-29.4</td><td>| * | . |</td></tr>
<tr><td>2019M12</td><td>240.0</td><td>202.7</td><td>37.3</td><td>| . | .* |</td></tr>
<tr><td>2020M01</td><td>294.0</td><td>286.4</td><td>7.6</td><td>| . |* . |</td></tr>
<tr><td>2020M02</td><td>289.0</td><td>280.0</td><td>9.0</td><td>| . | * . |</td></tr>
<tr><td>2020M03</td><td>257.0</td><td>250.9</td><td>6.1</td><td>| . |* . |</td></tr>
<tr><td>2020M04</td><td>180.0</td><td>189.7</td><td>-9.7</td><td>| . * | . |</td></tr>
<tr><td>2020M05</td><td>141.0</td><td>102.3</td><td>38.7</td><td>| . | .* |</td></tr>
<tr><td>2020M06</td><td>60.0</td><td>92.5</td><td>-32.5</td><td>| * | . |</td></tr>
<tr><td>2020M07</td><td>64.0</td><td>68.9</td><td>-4.9</td><td>| . *| . |</td></tr>
<tr><td>2020M08</td><td>89.0</td><td>70.7</td><td>18.3</td><td>| . | *. |</td></tr>
<tr><td>2020M09</td><td>118.0</td><td>81.8</td><td>36.2</td><td>| . | .* |</td></tr>
<tr><td>2020M10</td><td>61.0</td><td>94.6</td><td>-33.6</td><td>| *. | . |</td></tr>
<tr><td>2020M11</td><td>98.0</td><td>97.6</td><td>0.4</td><td>| . * . |</td></tr>
<tr><td>2020M12</td><td>171.0</td><td>186.9</td><td>-15.9</td><td>| .* | . |</td></tr>
<tr><td>2021M01</td><td>263.0</td><td>268.1</td><td>-5.1</td><td>| . *| . |</td></tr>
<tr><td>2021M02</td><td>328.0</td><td>291.4</td><td>36.6</td><td>| . | .* |</td></tr>
<tr><td>2021M03</td><td>327.0</td><td>274.1</td><td>52.9</td><td>| . | . *|</td></tr>
<tr><td>2021M04</td><td>162.0</td><td>203.3</td><td>-41.3</td><td>| * . | . |</td></tr>
<tr><td>2021M05</td><td>99.0</td><td>91.8</td><td>7.2</td><td>| . |* . |</td></tr>
<tr><td>2021M06</td><td>78.0</td><td>76.9</td><td>1.1</td><td>| . * . |</td></tr>
<tr><td>2021M07</td><td>99.0</td><td>76.9</td><td>22.1</td><td>| . | *. |</td></tr>
<tr><td>2021M08</td><td>106.0</td><td>86.2</td><td>19.8</td><td>| . | *. |</td></tr>
<tr><td>2021M09</td><td>116.0</td><td>89.3</td><td>26.7</td><td>| . | *. |</td></tr>
<tr><td>2021M10</td><td>83.0</td><td>93.7</td><td>-10.7</td><td>| . * | . |</td></tr>
<tr><td>2021M11</td><td>64.0</td><td>106.1</td><td>-42.1</td><td>| * . | . |</td></tr>
<tr><td>2021M12</td><td>167.0</td><td>175.3</td><td>-8.3</td><td>| . *| . |</td></tr>
<tr><td>2022M01</td><td>298.0</td><td>277.2</td><td>20.8</td><td>| . | *. |</td></tr>
<tr><td>2022M05</td><td>88.0</td><td>98.3</td><td>-10.3</td><td>| . * | . |</td></tr>
<tr><td>2022M06</td><td>39.0</td><td>71.1</td><td>-32.1</td><td>| * | . |</td></tr>
<tr><td>2022M07</td><td>92</td><td>59.6</td><td>32.4</td><td>| . | * |</td></tr>
<tr><td>2022M08</td><td>136</td><td>83.1</td><td>52.9</td><td>| . | . *|</td></tr>
<tr><td>2022M09</td><td>95</td><td>102.6</td><td>-7.6</td><td>| . *| . |</td></tr>
<tr><td>2022M10</td><td>63</td><td>84.4</td><td>-21.4</td><td>| .* | . |</td></tr>
<tr><td>2022M11</td><td>70</td><td>92.9</td><td>-22.9</td><td>| .* | . |</td></tr>
<tr><td>2022M12</td><td>167</td><td>178.9</td><td>-11.9</td><td>| . * | . |</td></tr>
<tr><td>2022M10</td><td>15.9</td><td>12.4</td><td>3.5</td><td>| . |* . |</td></tr>
<tr><td>2022M11</td><td>56.9</td><td>60.4</td><td>-3.5</td><td>| . *| . |</td></tr>
<tr><td>2022M12</td><td>87.8</td><td>102.7</td><td>-14.9</td><td>| .* | . |</td></tr>
</table>

Date: 03/23/23 Time: 12:19
Sample (adjusted): 2016M01 2022M12
Q-statistic probabilities adjusted for 1 ARMA term

Autocorrelation	Partial Correlation		AC	PAC	Q-Stat	Prob*
. | . |	. | . |	1	0.039	0.039	0.1307	
.*| . |	.*| . |	2	-0.083	-0.085	0.7160	0.397
.*| . |	.*| . |	3	-0.109	-0.103	1.7378	0.419
. | . |	. | . |	4	0.042	0.044	1.8886	0.596
.*| . |	.*| . |	5	-0.073	-0.095	2.3611	0.670
. | . |	. |*. |	6	0.071	0.075	2.8081	0.730
. |*. |	. |*. |	7	0.144	0.137	4.6798	0.585
. | . |	. | . |	8	-0.012	-0.034	4.6937	0.697
.*| . |	. | . |	9	-0.072	-0.025	5.1713	0.739
. | . |	. | . |	10	-0.002	0.016	5.1719	0.819
. | . |	. | . |	11	-0.043	-0.064	5.3533	0.866
. | . |	. |*. |	12	0.062	0.082	5.7301	0.891

*Probabilities may not be valid for this equation specification.

Design Day – Total Throughput Model

Dependent Variable: NH
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/07/23 Time: 14:47
Sample: 11/01/2021 10/31/2022
Included observations: 365
Convergence achieved after 10 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
NH_EDD	368.4487	20.53407	17.94329	0.0000
NH_EDD(-1)	102.0463	8.645163	11.80386	0.0000
NH_EDD*NOV	203.9453	23.17855	8.798880	0.0000
NH_EDD*DEC	228.9558	22.29822	10.26789	0.0000
NH_EDD*JAN	292.7508	21.00954	13.93418	0.0000
NH_EDD*FEB	293.4200	21.43986	13.68572	0.0000
NH_EDD*MAR	244.9859	22.64311	10.81944	0.0000
NH_EDD*APR	139.5325	25.39865	5.493696	0.0000
@WEEKDAY=1	11495.23	255.5063	44.98999	0.0000
@WEEKDAY=2	12187.84	258.0902	47.22319	0.0000
@WEEKDAY=3	11799.37	256.3309	46.03178	0.0000
@WEEKDAY=4	11533.67	252.4055	45.69499	0.0000
@WEEKDAY=5	10434.27	255.1180	40.89979	0.0000
@WEEKDAY=6	9052.847	262.3008	34.51322	0.0000
@WEEKDAY=7	9418.392	261.8009	35.97540	0.0000
AR(1)	0.415772	0.051170	8.125294	0.0000
AR(7)	0.105840	0.049166	2.152683	0.0320

R-squared	0.991125	Mean dependent var	23189.38
Adjusted R-squared	0.990717	S.D. dependent var	12298.16
S.E. of regression	1184.905	Akaike info criterion	17.03817
Sum squared resid	4.89E+08	Schwarz criterion	17.21981
Log likelihood	-3092.466	Hannan-Quinn criter.	17.11035
Durbin-Watson stat	1.959584		

Inverted AR Roots	.80	.52-.55i	.52+.55i	-.11-.70i
	-.11+.70i	-.61+.31i	-.61-.31i	

Design Day – Planning Load Model

Dependent Variable: NH_PL
Method: ARMA Conditional Least Squares (Gauss-Newton / Marquardt steps)
Date: 03/07/23 Time: 14:49
Sample: 11/01/2021 10/31/2022
Included observations: 365
Convergence achieved after 7 iterations
Coefficient covariance computed using outer product of gradients

Variable	Coefficient	Std. Error	t-Statistic	Prob.
NH_EDD	321.2646	15.45785	20.78326	0.0000
NH_EDD(-1)	92.31004	7.806648	11.82454	0.0000
NH_EDD*NOV	182.7073	19.38970	9.422909	0.0000
NH_EDD*DEC	251.1275	17.95045	13.99004	0.0000
NH_EDD*JAN	299.1885	16.23630	18.42714	0.0000
NH_EDD*FEB	281.8939	16.81651	16.76293	0.0000
NH_EDD*MAR	223.9156	18.19069	12.30935	0.0000
@WEEKDAY=1	6197.783	230.1394	26.93057	0.0000
@WEEKDAY=2	6603.130	232.5413	28.39552	0.0000
@WEEKDAY=3	6423.367	230.9847	27.80862	0.0000
@WEEKDAY=4	6280.504	226.6640	27.70843	0.0000
@WEEKDAY=5	5583.160	229.2346	24.35566	0.0000
@WEEKDAY=6	4876.089	236.4445	20.62255	0.0000
@WEEKDAY=7	5365.038	235.9145	22.74145	0.0000
AR(1)	0.523165	0.047850	10.93341	0.0000

R-squared	0.990795	Mean dependent var	16951.13
Adjusted R-squared	0.990427	S.D. dependent var	11380.48
S.E. of regression	1113.507	Akaike info criterion	16.90864
Sum squared resid	4.34E+08	Schwarz criterion	17.06891
Log likelihood	-3070.828	Hannan-Quinn criter.	16.97234
Durbin-Watson stat	2.063164		

Inverted AR Roots	.52

Federal Energy Regulatory Commission

Date: June 20, 2023
Volume:

Case: 2023 New England Winter Gas-Electric Forum

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Internet: www.acefederal.com

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

2023 NEW ENGLAND WINTER GAS-ELECTRIC FORUM — Docket No. AD22-9-000

DoubleTree by Hilton
363 Maine Mall Road
Portland, ME 04106

Tuesday, June 20, 2023
8:30 a.m.

Chairman Willie L. Phillips
Commissioner James P. Danly
Commissioner Allison Clements
Commissioner Mark C. Christie

Welcome and Opening Remarks from the Chairman and Commissioners

Opening Presentations: Winters 2023/2024 and 2024/2025 in New England and the Role of Everett

Panelists:

Stephen George, Director, Operational Performance, Training and Integration, ISO New England

Richard Levitan, President, Levitan & Associates

Panel 1: Should Everett be Retained and, if so, how?

Panelists:

Carrie H. Allen, SVP and DGC, Regulatory Policy, Constellation Energy Generation

Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO New England

Charles Dickerson, President and CEO, Northeast Power Coordinating Council (NPCC)

Dan Dolan, President, New England Power Generators Association

James Holodak, Jr., Vice President, Energy Supply, National Grid

Richard Levitan, President, Levitan & Associates

Robert Neustaedter, Director of Regulatory Affairs, Repsol

Ernesto Ochoa, Vice President of Commercial, Kinder Morgan

Third Presentation: Extreme Weather Risks to ISO-NE, Presentation of the EPRI Study by ISO-NE and EPRI

Panelists:

Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO New England

Stephen George, Director, Operational Performance, Training and Integration, ISO New England

Eamonn Lannoye, Senior Program Manager, Electric Power Research Institute Europe (virtual presenter)

Panel 2: Reactions to the EPRI Study

Panelists:

Phil Bartlett, Chair, Maine Public Utilities Commission

Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO New England

James Daly, Vice President Energy Supply, Eversource Energy

Ronald T. Gerwatowski, Chairman, Rhode Island Public Utilities Commission

Stephen George, Director, Operational Performance, Training and Integration, ISO New England

Ben Griffiths, Senior Director of New England Regulatory Policy, LS Power

Mark Lauby, Senior Vice President and Chief Engineer, North American Electric Reliability Corporation

Rob Perkins, Vice President of Pipeline Management, Kinder Morgan

Panel 3: Path to Sustainable Solutions - Infrastructure
Panelists:
David Cavanaugh, Senior Vice President Regulatory & Market Affairs, Energy New England
Patricia DiOrio, Head of Americas Project Development, Orsted North America
Vandan Divatia, Vice President, Transmission Policy, Compliance, and Interconnections, Eversource Energy
Katie Dykes, Commissioner, Connecticut Department of Energy and Environmental Protection
Bob Ethier, Vice President, System Planning, ISO New England
Richard Paglia, Vice President, Marketing & Business Development, Enbridge
Rebecca Tepper, Secretary, Massachusetts Executive Office of Energy and Environmental Affairs

Panel 4: Path to Sustainable Solutions - Market Design
Panelists:
Riley Allen, Commissioner, Vermont Public Utilities Commission
Michelle Gardner, Executive Director Regulatory Affairs - Northeast, NextEra Energy Resources

Mark Karl, Vice President, Market Development and Settlements, ISO New England

Donald Kreis, Consumer Advocate, New Hampshire Office of the Consumer Advocate

Pallas LeeVanSchaick, Vice President, Potomac Economics

Aleks Mitreski, Senior Director, Regulatory Affairs, Brookfield Renewables

Christie Prescott, Director, Energy Supply, United Illuminating

Andrew Weinstein, Vice President, FERC Market Policy, Vistra

Closing Roundtable

Panelists:

Jim Robb, President and CEO, North American Electric Reliability Corporation (NERC)

Gordon van Welie, President and CEO, ISO New England

State Representatives:

Phil Bartlett, Chair, Maine Public Utilities Commission

Katie Dykes, Commissioner, Connecticut Department of Energy and Environmental Protection

Ronald T. Gerwatowski, Chairman, Rhode Island Public Utilities Commission

Carleton Simpson, Commissioner, New Hampshire Public Utilities Commission

Rebecca Tepper, Secretary, Massachusetts Executive Office of Energy and Environmental Affairs

June Tierney, Commissioner, Vermont Department of Public Service

P R O C E E D I N G S

MR. LINNEMAN: If you could find your seats. If we could find our seats. Good morning, everybody. Please find your seats. If we could please find our seats. Good morning once again and welcome. My name is Jared Linneman I'm with FERC Security and Safety team. Just want to do a little briefing on some security items before we get started.

First of all, most importantly, restrooms out the doors you came in just around to the left. If there is a need for an evacuation, we will go out the door that you came in through the glass double doors over to the Tru hotel.

If that route is blocked, our secondary route will be through these wood double doors and through a set of steel doors right after those, we will take a right, go out and be by the Cracker Barrel. If we do have an evacuation, please go to those assembly areas and do not leave. We are going to use our registration checklists to make sure that we have everybody as much as possible. Once again, thank you and welcome.

MR. BURNS: Good morning, everyone. My name is David Burns. I am with the Commission's Office of Energy Policy and Innovation. We're happy to be joined by all of you here today in New England. Before I turn it over to Chairman Phillips for his opening remarks, I just want to provide a brief roadmap for the day. We'll have three presentations, four panels and a closing roundtable with a break after the second and third panels. During these, only the Chairman, Commissioners, panelists, presenters, state representatives and a small group of Commission staff will have speaking roles. This conference is being webcast and transcribed and a recording will be available for future viewing. The goal and purpose of this conference is to discuss possible solutions to the electricity and natural gas challenges facing the New England region.

Just a reminder regarding our rules on ex parte communications, we will not discuss the specific details of any pending contested proceedings before the Commission, including those listed on the Supplemental Notice issued on June 13th. We ask that all participants similarly refrain from such discussion. If anyone engages in these kinds of discussions, one of my colleagues at this table will interrupt the discussion to ask the speaker to avoid the topic. With that out of the way, I turn it over to Chairman Phillips for his opening remarks.

CHAIRMAN PHILLIPS: Thank you. Hello, everybody, and good morning and welcome to the second New England Winter Gas-Electric Forum in beautiful Portland, Maine. I want to thank the many panelists appearing here today for their time and contributions to this forum and also want to thank my colleagues for their interest in and dedication to addressing critical issues regarding New England resource adequacy. And a special thanks to David Burns, who has led our great staff's effort to conduct outreach with New England states and stakeholders. These are not new issues. Winter after winter, we are warned about the reliability risk to New England and the potential for life threatening blackouts when natural gas pipelines are constrained and energy demand is high.

We also know that New England has some of the highest electricity rates in the country. And with the ripple effects of the Russian invasion of Ukraine impacting global LNG and natural gas prices, we brace ourselves for utility bills which are already high to soar even higher.

And while FERC is resource neutral, I also want to acknowledge that states have their own policy objectives and are working toward achieving their clean energy goals. But for the near term, it is clear that New England remains reliant on natural gas and needs LNG as well as oil during extreme weather. And the gas system is constrained when the gas system is constrained. This infrastructure problem only gets more difficult as demand increases on both the electric and gas systems.

So, we know that infrastructure is needed now and more will be needed in the coming years. To this end, FERC is focused on interconnection reform, transmission reform and expediting permitting processes. But we can and must explore what other options we can collectively pursue in the near term and how to overcome any barriers to implementing these solutions. Additionally, our markets needs to provide the correct incentives and price signals for all types of resources. I know these challenges are complicated and solutions are difficult, that the problems are cross product, both gas and electric, and cross jurisdictional, both state and federal.

And to be clear, no one entity can solve these issues alone. And there is no singular solution to winter reliability. And so it is critical that we coordinate closely with all relevant stakeholders to address the challenges ahead. To put it another way, we must come together, state officials and regulators, utilities, ISO, if we have any hope to put this region on a reliable, affordable and sustainable path forward. That means today, we stop talking as if we are disconnected entities and start collectively identifying actionable next steps and solutions both in the near term and for the future. People are counting on us. Let's not let them down. With that, I turn to my colleagues for their opening statements. Commissioner Danly.

COMMISSIONER DANLY: Thank you, Mr. Chairman. I don't have anything as an opening statement other than to say I'll be interested to hear what people have to present to us today. And I'm rather skeptical. Thanks.

COMMISSIONER CLEMENTS: Just in general?

COMMISSIONER DANLY: In general. Yes.

COMMISSIONER CLEMENTS: Good morning. It's nice to see you all. Thank you for taking the time out of your busy schedules to be here, especially our state colleagues. It's nice to see you all. And thanks to staff for putting this together. This is a lot of work, especially when we're not at home. I agree with everything the Chairman said. I will just add a little bit from some more specifics relative to the studies we've been engaging in. I'm encouraged that between our last meeting and this meeting that the ISO has engaged in analysis around the winter 2024-2025 and I think it's important to get some clarity around this electric system risk. We now have probabilities and sensitivities to evaluate.

And I hope today's discussion will be based in the consideration of next steps, will be based in the fact that we have that data out there. I think this morning with all of this information we've had to digest, not only the near term study, but also the February 2027 studies and the impending steps there.

It's really important that we get panelists' perspectives on what concerns remain, if any, related to these studies. And I think from an electric system perspective, sorry, I'm trying to talk in the coffee. It's just not kicked in yet this morning. But from an electric system perspective, I think that every ISO study is really comprehensive and provides key parameters to consider, and the resulting low odds of load shedding are encouraging.

The ISO, however notes itself that it is not equipped to assess the gas system effects without Everett because only the pipelines and the LDCs can speak to that. And Mr. Levitan, perhaps you know, it said the study assumes the operational performance of the regional pipeline system is not impacted. So I want to hear -- I hope we all want to hear this morning, are there other concerns related to that side of the coin that will have impact for the reliability of the bulk electric system? This is the morning to have that conversation.

Let's get any specific concerns out there and try and work through them so that we can go forward with a consensus across stakeholders and jurisdictions.

For this afternoon, we have time to think longer term. And I have three things that have come to mind. One is, I've talked about the need to consider a prompt and/or seasonal auction structure. The ISO has put forward this idea. Perhaps it can bring benefits based on the market changes, based on lessons learned and operating the markets over the last decade. So, tell me more about the value proposition there. You know, the gas fleet is going to remain integral for the foreseeable future, but I'm increasingly hearing about the challenges related to the gas-electric coordination.

The Chairman mentioned and how it will grow as the gas fleet is asked to perform differently as the system needs change. And so how do we get out in front of this challenge? What's the next step on this region's gas-electric coordination challenges? And then finally, what is the untapped potential for flexibility? We have a more sophisticated commitment and dispatch of limited. May we have a more sophisticated dispatch of limited duration resources.

Do these studies give us better information to inform demand response and energy efficiency decisions and programs that the states are responsible for? And what else do we need there to try and optimize system flexibility? So those are the lots of things I'm thinking about today, and I really look forward to the conversation. Thanks.

CHAIRMAN PHILLIPS: Commissioner.

COMMISSIONER CHRISTIE: Well, good morning, everybody. I'm always glad to be back in Maine. Frustrating thing. I'm close to Belfast, but not going to be there for the next week, which I'd like to be my favorite place on the East Coast. I want to thank everybody for coming out and in particular, thank everybody for all the prep that you did. Getting ready for these things is not easy. It's not something that people just walk in and start doing.

So, I know there's a lot of work, really appreciate all the effort from all the speakers we're going to hear today getting ready as well as staff, getting the logistics of this event. Great to see some state regulators here today. Phil Bartlett, Chair of the Maine Commission, Riley Allen, good friend from Vermont. I've said many, many times, at the end of the day, it's the states who decide what generating units get built and which ones get retired. Reconciling those policies with the engineering realities of keeping the lights on is the big challenge that not only New England, but really across the country we have.

So I look forward to hearing today from speakers about how we're going to reconcile those challenges and fulfill the state's legitimate desires to have the mix that they want. So with that, I'll sit back and I want to listen to all the great speakers that we have lined up today, and thank you all again for all the prep work, all the hard work, getting ready for this and for coming out and taking a whole day to give us the benefit of your views. Thank you.

CHAIRMAN PHILIPS: And thank you, Commissioners, for your opening remarks. We are now ready to move to our opening presentations.

MR. BURNS: We'll now begin with the opening presentations. The first presentation will be given by Stephen George from ISO New England, discussing winters 2023-2024 and 2024-2025 and the role of Everett. Following Stephen's presentation, the second presentation will be given by Richard Levitan of Levitan & Associates, explaining Everett's physical capabilities and its impact on the electric and natural gas systems in New England. Each presentations will be 15 minutes. Following these presentations, we will begin with Panel 1: Should Evertt be Retained, and, if so, how? Mr. George.

MR. GEORGE: Thank you and good morning. Good morning, Mr. Chairman, Commissioners, state commissioners, New England stakeholders, FERC staff. Mr. Levitan, to my left here. Good morning to everyone. Appreciate the opportunity to be here today, to have a chance to share our views on these important discussions and be part of the conversation. I'd like to get started today by giving a review of our assessment of the upcoming winters of 2023-2024 as well as 2024-2025 and conclude with some thoughts on the Everett Marine Terminal facility. I'd like to start with a review of four key takeaways and then I'll cover these in a little bit more detail as we go.

I think it's clear as the system evolves, both on the generation side, the demand side, and at the same time as the weather continues to change and become more extreme, we see that the region's risk profile in terms of energy adequacy also evolves along with that, with all those things that are changing simultaneously. ISO's assessment of the next two winters shows limited exposure to energy shortfalls in the context of this evolving system. This does not mean that the risk is gone. This means in the context of the evolving system, that we actually need to be more vigilant and continue to enhance our ability to assess energy adequacy as the system evolves. We know that has been the case in the past, the region continues to be reliant on stored fuels in the near term, both LNG and fuel oil. And it's really replenishment of those stored fuels that's going to get us through the really cold times this winter. And I think you'll see that in our presentation this morning and the presentation in a little bit.

Finally, in terms of Everett, though, our near term assessment of the next two winters does not show the need to retain Everett for electric system reliability. We all know that there's several qualitative or resilience type factors that need to be part of the discussion in determining the long term plans for the Everett facility. And I'll touch on that more as we go on. I'll note that I'm not going to cover every slide in the deck, but only just a few in the interest of keeping to my 15-minute time limit.

In terms of the evolving resource mix, I think most notable is the change with respect to behind the meter or even in front of the meter solar in New England. From starting in January of 2010, when we had roughly close to zero behind the meter PV to the end of last year, where we had roughly 5,500 MW of PV. And looking ahead to a projection of adding 700MW per year of PV through 2032, we start to think about the impact of that PV on our energy adequacy situation. Our assessment is that over a typical winter season, 700 MW of PV that we're adding each year is roughly the energy equivalent of 7 to 10 million gallons of oil or 1 to 1.5 BCF of natural gas.

So, the impact is clear. Along with our near-term inspection or expectations for PV and the expectation for offshore wind growth beginning later this year and into next year, combined with expectations for a limited demand growth in the near term, all these things come together to inform our analysis of the next two winters. As I mentioned at the outset, the region remains reliant on natural gas, as the Chairman mentioned in his opening remarks. We know that when natural gas pipelines become constrained in the cold weather, we turn to fuel oil and we turn to LNG. LNG from our facilities in the east and fuel oil from our vast fuel oil generating capability that exists throughout New England.

We know that when we get into conditions where these stored fuels are rapidly depleted, that's when the system is at its most risk. We saw this in the winter of 2017/2018. And it's in that context that we think about how our energy adequacy risk is going to evolve over time. As I mentioned, it's replenishment that becomes critical not just of LNG but of fuel oil. And that's what's going to get us through the severe cold weather snaps.

Before I turn to results of the 2023-2024 and 2024-2025 winter assessments, I'd like to spend a minute speaking about our expectations for the next two winters and preparation and activities that take place throughout the region, really every winter. Looking ahead to the upcoming winter, we know that the cost of service agreement for Mystic 8&9 continues for one more year through June 1st of next year. We also know that the Inventoried Energy Program goes into effect this year for the next two winters, which we expect to bring an incremental amount of BCF excuse me, 3 BCF of LNG and about 10 million gallons of fuel oil.

In addition to those two programs, we know that starting this winter, we anticipate roughly 500 MW of additional dual fuel generating capability in the region, which provides significant backup to the generation fleet when we come upon constrained natural gas pipelines. In terms of preparation, we have one bullet here on the slide that generally speaks to the robust communication protocols, which really doesn't provide a full picture of what goes on in New England to get ready for a winter. Winter preparations in New England are actually ongoing all year, as we all know.

As we've come to learn over the past few years. It's a 24/7, 365 job getting ready for cold weather in New England and we take that seriously. Just this past week, we got an update from the FERC-NERC team that's working on the joint investigation of Winter Storm Elliot. And we're once again reminded of the recommendations from previous reports that are still to be implemented in some regions. In New England, our experience is that we take these recommendations seriously. We act on them, and they're an important facet of our preparation for the winter. A couple of things I'd like to highlight in that regard. One is our natural gas-electric coordination in New England. It's second to none.

We really invented it in New England only by necessity. And that's not to boast, and that was done in close coordination with the natural gas pipelines in the region. And that work is ongoing year-round and is immensely critical to our success in the winter. I'd also like to highlight ISO's 21-day energy forecast, which should not be forgotten in terms of how we see and react and prepare for potential energy emergencies.

This tool put into place after 2017-2018's winter that we all remember is what we're going to rely on to alert the region, to alert FERC and NERC, the states of a potential energy shortfall, which is going to be the prompt for us all to take the actions we need to take to minimize the potential for any energy shortfall to ever occur.

So, we can't underestimate the power of that tool and the reports that we put out every week throughout the winter and more frequently as needed. So those preparation activities and our expectations for the next winters give some context to our winter scenario analysis. You may recall that in for a number of years, actually, we've discussed our winter preparations and expectations in terms of a mild, moderate and severe winter. Mild is your typical winter. Think of it like the last couple of winters that were relatively warm, and we don't highlight any results from a mild winter scenario this year.

But we look at moderate, which is modeled after our winter 2017-2018's winter, which overall was a mild winter but featured a two-week-long cold stretch that we all remember and really was the genesis for a lot of the activities we're discussing today. The severe winter we model after the 2013-2014, which overall was below normal in terms of temperature, but consisted of six cold snaps of four or more days in duration. And it has really been what we think about as sort of the worst case scenario winter from years past.

For 2023-2024, our deterministic winter scenario analysis shows that under a moderate winter we expect to have sufficient capacity and energy to meet peak loads and energy demands. And in the severe winter scenario, we expect capacity deficiency actions could be possible across just a few days with energy shortfalls very unlikely. Turning to the ISO's 2024-2025 winter analysis.

It's important to think about this in context a year and a half or so from now. In this context, we have Mystic 8 & 9 retired. We're still operating under an IEP paradigm for one more year. We've added an additional at least 700 MW of PV. We expect to have some operational offshore wind. And in terms of demand, we expect minimal growth between now and then. So in that context, in a moderate winter, we expect no energy shortfall in cases with Everett and in cases without Everett, we expect that any shortfall will be fully mitigated with increased amounts of fuel oil inventory.

Looking at a severe winter, similar to the moderate winter, we expect no energy shortfall in cases with

Everett and in cases without Everett. We expect that any potential energy shortfall would be mostly mitigated with increased fuel inventories, which I'll highlight on this chart. And to put this in context, given that on a cold day in New England, the winter energy demand for that day is roughly 400,000 MWh.

We expect our estimated energy shortfall in a lower fuel oil inventory scenario to be roughly 0.6% to 1.8% of the daily energy across the 9 to 13 days where we'd expect to be at most risk. With regard to the Everett Marine Terminal, as we just described the assessment for the winter of 2024-2025, it shows no need to retain Everett for electric system reliability.

We are relying on the gas pipeline operators and LDCs to speak to the operation of the gas system and identify any operational concerns that would put generating stations at risk. Generally speaking, we've shared our concerns about the retirement of infrastructure, including Everett, before new infrastructure is in service. And given the variety of uncertainties that I discussed in the beginning of this presentation, including the uncertainties around the resource mix, potential for retirements and significant load growth in the mid to long term, we believe that the region would be prudent to retain its limited gas infrastructure in that mid-term time frame. That concludes my presentation this morning. Turn it over to Mr. Levitan.

MR. LEVITAN: Good morning, Mr. Chairman, fellow Commissioners. Thank you very much for having me and my firm here today to share with you our perspective on a variety of strategic issues. I want to thank FERC's staff for outstanding guidance and the continued heavy lift to make today possible. I'm here as an independent consultant. You may know that we do work for ISO New England, a variety of workstreams.

We've worked for other state commissions and trade associations throughout the region. But my comments today and my perspective is as an independent consultant. My job today is to help you visualize the world with and without the Everett Marine Terminal. So I want to talk about the imperfect substitutability of alternative LNG import facilities and help you calibrate the risks associated with the potential loss of the facility. So I would like to start with the main points so that you can understand what the historic role of the facility has been and its strategic operational impact across the region. As I'm sure you know, that the Mystic facility, which will retire next May, has the equivalent of firm transportation. Most, if not the supermajority of other gas-fired generators throughout the region, are non firm shippers. They're relying on that which is left over after the LDCs have fulfilled their daily obligations. That means they're not firm. And to the extent that the Mystic facility is gone, there is, at least in theory, more deliverability from the Everett Terminal to displace traditional flows from Marcellus or from Canada. That displacement capability is key operationally to help schedule gas-fired generation that is non firm in nature.

The Marine Terminal is a critical source of displacement services on Tennessee and Algonquin. There are roughly 12,000 MW of direct connected gas-fired generation on those two pipelines in southern New England. The Everett Terminal is also a primary source of LNG to the myriad satellite tanks throughout the region. There are 30 some odd facilities, some of which many of which actually don't turn throughout the heating season. But there are a myriad satellite tanks smaller in nature that turn multiple times. They need to be replenished and the Everett facility is within spitting distance, you might say, to many of these locations. Alternative supplies from Quebec, Pennsylvania. Not so much. It's important to recognize that the Everett Marine Terminal is a key source of supply. It's instantaneous, it's non-tradable, it comes in the back end of the system, so that instantaneity provides the pipelines with a source of ancillary services. I like to think of the import facility as being an ancillary service machine.

In electric terms, it's providing AGC, automatic generation control or ten minute spin. There aren't any other alternatives for that in the region. So that instantaneity and non-ratable supply is critical in terms of the generators ability to ramp in the morning during the cold snap or during the heating season and also in the evening. We have been surprised to observe that many of these generators are not actually taking ratably 1/24 of their daily quantity each day, and that is made possible by the operation of the import facility providing back end services.

Another key point is that global procurement, logistics and tight markets as a result of the war require supply arrangements a year or a large portion of that year in advance. There is no Amazon.com, you know, providing overnight services. There is no way to get LNG from Trinidad or Africa to the import facilities, whether it's Saint John or the buoy submersible system or Everett, without scheduling it in advance and committing to a schedule that requires on time delivery.

I have mentioned previously that the loss of Mystic, which is 75% or 80% of the annual volumes that are imported, will leave the LDCs and the generators with the fixed cost of operating the import facility. Let's round that to $60 million. Also, part of a standalone import facility would be the cost of bringing the vessels in at

Dutch transfer prices, which reflect worldwide global willingness to pay.

So that is another very big cost at $20 or $30 a million BTUs. Let's just use $20 as an example with each vessel being approximately 3 BCF. You can do the math. It's something like $60 million per tanker. Four tankers per season would be $240 million.

And then on top of that, we need to recognize that a standalone import facility where the fixed costs are applicable to the benefited counterparties would involve tank management charges. There are times if there aren't heating degree days that are large, that there has to be a mechanism to bring the next vessel in. So those tank management charges are not insignificant and need to be recognized if there is to be deals cut to keep a standalone import facility viable.

Lastly, I want to mention that from my perspective, my firm's perspective, we don't see existing wholesale power prices and the market paradigm on the electric side providing an orderly mechanism to incent generators to enter into the types of arrangements that would anchor a standalone facility. So those are the main points. I want to reinforce some of those. I'm going to skip over a lot of these panels, but I want to provide a satellite image of what the facility is capable of doing.

I've already mentioned the precious support on Algonquin and Tennessee, it being instantaneous and non-ratable. I've mentioned the liquids to the satellite tanks. What you see here is what you get: 3.4 BCF of total storage capacity. This is New England's Lady Ellisburg Oakford.

We don't have any underground storage, so this is the import facility that energizes the 30 some odd tanks, at least those that don't have on-site liquefaction capability. There is a tremendous lot that can be got through vaporization services, and it's important to recognize that on top of service to Mystic, Algonquin, Tennessee, there is, of course, service to the local utility National Grid. In looking at liquids and the presentation does provide some emphasis on liquids.

You'll see on the right-hand side of this graph that there's in mild years with moderate heating degree days, something like 2 BCF, in annual send out to the satellite tanks. But if you look on the left-hand side, there have been years where it's like 10 BCF or greater.

So I don't think we can underestimate the critical importance in terms of gas resilience that the Everett facility plays in providing quick, orderly refill to the satellite tanks. It's also important to recognize that those satellite tanks are earmarked for gas resilience at the local level. It has nothing to do or little to do with electric system resilience. The inventories that are maintained at the myriad satellite tanks are for local system pressure during cold snaps to bolster the deliverability from Algonquin, Tennessee, Iroquois and the like. I apologize for the use of sharpies here. The triangles are the, you know, many satellite tanks.

The pipelines are shown here as well. And what you don't see is the fact that we go into the heating season really strained to begin with. These pipelines in terms of the orderly flow from Marcellus, from the Gulf Coast, from Canada, they're all tight.

We go into the season with critical notices and with flow day alerts, a majority of the 141 days during the heating season. So it's tight and that's with the import facility, providing that critical, instantaneous back-end flow, which provides displacement services that course through Massachusetts, Rhode Island and Connecticut. So it's tight as a starting point. I don't want to spend too much time on trucking operations. It is featured here. Point is that that the import facility is close, like 30 minutes to a couple of hours to all of the facilities throughout the region. Yes, there are alternate ways to truck LNG from Quebec or from Harrisburg, Pennsylvania, but that's 5 to 7 hours under relatively ideal driving conditions. And we all know here in New England that that's not necessarily the case during the middle of the heating season.

So hazardous conditions or problems at the border crossing could add time. It could be staged, it can be replenished through staging and phasing a convoy of trucks that are parked to replenish. But from my perspective, it's a bit of a wild card. We don't know how hard that alternative supply chain is. With the Assistance of Energir, a Gas Met Affiliate in Quebec, there are some dots here that show the location of all the tanks, and the large ones in black are the ones that are 1 Bcf holders or larger that basically don't get replenished. They zealously manage their inventory, so in the event Mother Nature throws a hissy fit in early March, there's enough spare inventory to safeguard local protection at the system level, the LDC system level. Again, none of this is particularly useful for electric system resilience, but you can see many other tanks here. We've identified the location in terms of the mileage from the alternative supply chains to the satellite tanks. I won't dwell on this. I want to move to history here. There's a lot of information, too much to get into. I'm sure your staff has studied this. Please don't squint to identify the amount of gas from the import facility that's going into Algonquin and Tennessee during cold snaps. But if you look on the left-hand side, you can see that the volumes have been relatively trivial during the last couple of heating seasons. And on the right- hand side is a more historic perspective.

So we sorted that in this graph, which I think is the more important one. It shows the quantity into the two pipelines that matter most in southern New England. And you can see that when you're looking at HDDs 55 or greater, and 55 HDDs is like an average of 10 degrees Fahrenheit, there have been 22 days since 2014 and there have been substantial deliveries into both pipelines on those days. The numbers speak for themselves. The max send out has been for 65 MDTH, including send out to Mystic. But during the Polar Vortex there was like 1.5 BCF during that five day period that was sent out to the pipelines and to Mystic. And during the Arctic outbreak in late December and early 2017 or early 2018, there was over 4 BCF.

So, this is basically the insurance that is helping to safeguard both gas and electric resilience on extremely cold days. So is it time for decision or is a non-decision a decision? Surely there are significant costs for reliability-must-run type arrangements for a standalone Everett facility. Can we reasonably bank on imperfect substitutes from Saint John and from the buoy submersible system in a world without district gas? I don't know. Saint John has to compete in world markets as well. They are not philanthropic.

Therefore, there must be contract formation to backstop their willingness to commit in northern New England. Repsol has obligations in Europe and in South America. Europe, of course, for obvious reasons, is a can't miss market.

If they were delivering in a world without district gas, it is likely but not certain that the fleet of generators in northern New England would be siphoning off flow and pressure along the way, meeting ISO's call in the day-ahead and the real-time market so the quantities that flow south to the terminus at Beverley and Dracut would not be necessarily close to the 0.8 BCF that represents the Saint John entitlement flowing south to the Maritimes and northeast. Another quick comment on that.

It does sound that Saint John is a bit of a hike. You know, it's 400 miles away, but not really because they're perfectly capable being so smart with the risk desk and reading the meteorological outlook, packing the pipe so that the gas is basically there at the terminus of the system the next morning when gas scheduling is completed.

Dracut is 30 miles from southern New England, not 430 miles. So I think that it's important to recognize that they're capable of providing a seasonal service. But on those days when they would be delivering at max quantity at the terminus of the system, those would be the very same days that Everett is -- would otherwise be dispatching. So as far as incrementality, it's hard to say that there would be any additional flow. The buoy submersible system that Excelerate operates and owns is a bit of a wild card. We've only, after all, had five shipments over the last 15 years.

They too would require contract formation. Thus far, not much evidence that both Genco and LDC are willing to step up under the type of remunerative arrangements that would put those call options in the black. So we don't really know. In regard to mitigation on the electric side, as Stephen has said, it would appear that oil inventory is the answer. DFO, not so much residual fuel oil. On the gas side, the alternatives turn on Saint John and the buoy submersible system.

So in closing, because you've asked the question, do we need the Everett Marine Terminal or not? I hate to disappoint you, but I think the answer is. I don't know and I would say that we don't need it, probably don't need it if we get mild temperatures winter season after winter season.

If we don't get back to back cold snaps or a particularly long cold snap, which would impair the ability of dual fuel capable generators to scramble to refill their distillate fuel oil inventory. It's one thing to have a cold snap for 3 or 4 days and then wait two weeks for the next one. It's another thing if it's an extended one or back to back. I'm not worried about the first cold snap. It's the back to back, the second one that triggers jeopardy. If nothing breaks in terms of both gas infrastructure into the region or within the region. Loss of a compressor station, a pipeline that is constrained, a segment of critical significance into the region.

If we don't see a breakdown in electric infrastructure, in particular the loss of hydro from Quebec, the potential constraint or trip of a nuclear power plant. There are three that typically operate reliably during the critical heating season. If the Saint John facility and/or the Excelerate buoy submersible system operate reliably and there are contracts that are formed to welcome timely arrival. And finally, if the trucks on the region's highway system emanating from Quebec and/or Pennsylvania arrive on time. It's a lot of ifs. At the end of the day, the question is, what's the price of the insurance and how much does this region want to pay? Thank you for your attention.

MR. BURNS: Thank you, Stephen and Richard. We will now begin Panel 1. Welcome our panelists to join us. Panelists include Carrie Allen, Senior Vice President and Deputy General Counsel, Regulatory Policy, Constellation. Vamsi Chadalavada, Executive Vice President and Chief

Operating Officer, ISO New England. Charles Dickerson, President and CEO, Northeast Power Coordinating Council. Dan Dolan, President, New England Power Generators Association. James Holodak, Jr., Vice President, Energy Supply, National Grid. Richard Levitan, President, Levitan & Associates. Robert Neustaedter, Director of Regulatory Affairs, Repsol and Ernesto Ochoa, Vice President of Commercial, Kinder Morgan. As a reminder to our panelists regarding ex parte communications, we will not discuss the specific details of any pending contested proceedings before the Commission. We ask that all participants refrain from such discussion. If anyone engages in these kinds of discussions, we will interrupt the conversation. We have a timer here to limit responses to three minutes. The goal is to not hear it beep. Mr. Chairman.

CHAIRMAN PHILLIPS: Thank you, David, and welcome to our new panelists. So my first question goes to ISO New England, Vamsi. So we were here last August and the message was slightly different. Some would say almost dramatically different that in the problem statement it was. We got some confusion in the front. We're all good. So the problem statement last August, it was sort of laid out that we must retain Everett in order to maintain the reliability of the system here in New England. Today with some big ifs, we see that there's potentially a different path. Can you unpack for us a little bit more, in your view, what has changed in the past ten months?

MR. CHADALAVADA: Thank you, Chairman, and good morning, Commissioners. Glad to be here today. So the ISO since last September has undertaken this extensive work to try to model the analytics and the quantitative side. When we expressed our concerns, they were based on the qualitative assessments that we had made for a period of time now about how retirements, the pace of new entry and the demand growth may not be well aligned. And so it could lead to choppy waters if, for example, the pace of retirements and demand growth offsets the pace of new entry.

And so it was from that context that we're talking about the need for Everett and really the need for infrastructure that's somewhat constrained and limited in New England. But as we went through our analytics, what really surprised us was to see the impact of the PV installation on reducing the energy requirements for New England over a period of time. It's not a spot analysis of maybe a single day, but over a 21-day or a 90-day time frame, there's a substantial reduction in what the energy that needs to be served has been. We've also seen some additional supply side increases that have come along and we've seen the demand really be flat and the retirements have not sort of been what we thought they could be. So it's the totality of those factors that really have sort of led us to evolve a little bit.

And lastly, also a recognition that forward price signals in a market are critical. And so the more the ISO intervenes and impacts those forward price signals, it's to the detriment of the aggregate performance of the market. And then equally importantly, the logistics. We have an increased confidence level in the logistics because of the assessments that we've done over the past several months, the sophistication that we've built into our analytics and into our platform. We are confident now that not only is the ISO better positioned to respond to these sorts of contingencies, but also equally importantly to give the market the signal that it needs and to be able to work with the federal and state agencies. And the last point, which is to emphasize this is not sort of an expectation that this risk is going to be static over the next period of time. This is a new look for the next 4 to 5 years.

The uncertainties beyond the five-year time frame could show up in much the wrong way. And so we would therefore recommend that it's prudent from a resilience standpoint for the retention of Everett as an example. But at this point in time, if the question is can the ISO make a clear and convincing need for Everett in the near term, the answer is we cannot.

CHAIRMAN PHILLIPS: So just -- you mentioned this briefly in your discussion, but in your answer, I want to drill down a little bit. What I'm hearing and help me out is that you're saying that you're confident in the assumptions in the study that from the supply side and the demand side, that means on the supply side, LNG is going to be able to fill the gap if there's an issue. And on the demand side, that growth that you're confident that growth will remain flat? Is that what I'm hearing?

MR. CHADALAVADA: Chairman. Yes. And I know our panelists will have differing opinions. And at some point I'd like to be able to respond. But yes, we are confident in the assumptions that we've made. There is no guarantee. But our assumptions are based on actual facts and observations and experience.

CHAIRMAN PHILLIPS: You're not going to have to wait long to find out whether --

MR. CHADALAVADA: That is true. I'm looking forward to that.

CHAIRMAN PHILLIPS: I'm going to start with Constellation Ms. Allen.

MS. ALLEN: Here we go. Thank you for the opportunity to be here again and to speak about the value of the Marine Terminal. Our view, based on our experience, what we see as operator of the facility is that Everett is needed. But you don't need to take Mystic's or Constellation's word for it. You can talk to and hear from and I imagine you will, the LDCs who operate in the area, who are the true experts as to the reliability of the system and the pipelines as well. What I'm hearing is less confidence than what my neighbor, Vamsi, has with respect to that. And I think even ISO New England will say that their study was predicated on the assumption of a reliable gas system. So the question really is what to do with the facility? And I'll just make one other comment while I have the mic, which is as I read through the comments for this, pre-filed comments for this proceeding, there were a lot of comments that talked about the need to avoid out of market solutions to retain the facility and based on the mystic experience. To be very clear, that is a straw dog that Constellation is not advocating for. We are not advocating for an out of market solution. We are looking to see whether there is sufficient bilateral contract support for the facility.

CHAIRMAN PHILLIPS: Thank you. Mr. Dickerson, it's good to see you outside of the airport for once. Usually we're passing each other in the airport. I'd like to hear your comments.

MR. DICKERSON: Good morning, Mr. Chairman and members of the commission. I'll try to be brief. I was going to give the kind of overview of NPCC, but you have that in the documents that we filed. I will say that all of my comments are going to be provided through a very narrow lens because my organization is responsible for ensuring the reliability and energy security of the northeast part of the continent. I have perspectives around price and environmental, having worked in various areas of the utility space, but I was restricted to reliability. You've already heard from two panelists. You're going to hear from a number of others with different views.

I will say very simplistically that it is -- it would take magnitudes more time to build something than it will to tear it down. And almost all the analysis that any of these organizations will do will take past events and kind of project them forward. If those analysis miss the mark and we're in a position in some of the ifs that Richard Levitan talked about come to fruition, it's going to take a long time to kind of close that gap.

One of the things that Richard talked about that I think we need to think of, which is a very good analogy, is kind of the construct of ancillary services or ten minute spinning reserve. I'm certain I'm not the only one, but I think I've been in the unique position of having worked in utilities in the Northeast and mid-Atlantic and the South, having been an operator of utilities in those areas, having been in constructing generating plants, having been a designer and having been an executive over market operations. Ten minute reserve is very important.

You can't be a supplier of energy on the market and hope to respond to load changes waiting for the line to get filled up with gas. You need to be able to respond very quickly. The reason why it's sitting spinning is because you want that big inertial unit to be able to move. I appreciate the notion of renewable sources coming on line and renewable sources working, and I think that's good. But I also have the unfortunate event of being a person who actually had it rain on my parade when I was a chief operating officer at Austin Energy. One hot summer day in August around 2017, I'm sorry, 2019, very high load, we have PVs out in western Texas and cloud cover covered the PV.

Some of them that Austin had. And it shifted the price because it put the region into an emergency alert so the sun doesn't always shine. And even when it does shine, you could get cloud cover. My assessment is that the region is in a better position from an energy security and reliability perspective to have Everett or a facility like it. And I don't know if we have any facilities like it.

So my vote I know we're not taking votes here would be that we're in a far better position with it than without it. I'm not going to speak to who pays for it and how it gets paid. I would say peripherally that those would benefit from it, should pay for it. But then that begs the question, who benefits from it? And smarter people than me will be able to or have to adjudicate that.

CHAIRMAN PHILLIPS: Thank you, Charles. We appreciate your perspective. Mr. Dolan.

MR. DOLAN: Great. Thank you, Mr. Chairman. Commissioners, welcome back to New England. Thank you for coming back the second time in nine months here. And I actually think to start with, that's a bit of what has changed since the last time we got together in Burlington, Vermont, which is I think your all's attention has helped sharpen the focus. Certainly the analysis that we've seen from ISO New England and others as well as a lot of the stakeholder conversations that have occurred. We've been pretty busy the last nine months under a lot of your leadership, Mr. Chairman, and in helping convene some of us as well. But we've been trying to work creatively and think constructively about how do we transition into the future and maximize what we do have.

To start with, certainly I think we always have to come back to the reliability question and the obligation that generators certainly face under the ISO New England tariff and the rules that you all have approved. And we're proud of the performance that we have had. And despite the fact that this past winter was a mild one, we did have two instances of pretty intense operations on the system. Certainly the second pay for performance event in ISO New England's history and a historic cold snap in the first weekend of February.

In both instances, New England did not have any supply driven outages or any need for public calls of conservation and generators met their obligations across the board. All that being said, we do have to be in the business of maximizing the infrastructure we do have. I agree with Mr. Dickerson that we have infrastructure constraints in this region. It's hard to build stuff. And so therefore, as we look forward, we need to look at that and maximize what we do have. But as we look at the history, the send out, the overall situation, we do believe the generators can continue to meet their obligations and do that. But we also recognize that to try and maximize the infrastructure we do have, we do have to think creatively.

In my Pre-filed statement, we put forward one such proposal as a path forward to try and get there, one that we've been working with stakeholders here and we think offers a potential path forward. But I want to make one thing very clear, and because it hasn't gotten a lot of airtime yet, and that is the fact that we do have a co-located power plant with the Everett Marine Terminal, the Mystic power station, as we've been pleased to see in the record, there is no evidentiary basis to continue or extend that cost of service contract.

And I want to emphasize that we should not use it as a politically expedient or regulatorily convenient mechanism to sustain the Everett Marine Terminal if there is a need determination on the gas or electric system overall. The price formation issues that Vamsi laid out are critical and become even more important as we think about sustaining the existing investments and driving the new investments that are going to be needed in this region. But again, appreciate your time and attention on all of this.

CHAIRMAN PHILLIPS: Thank you, Dan. We hear from National Grid now, James. Floor is yours.

MR. HOLODAK: Yes. Good morning, Commissioner. Commissioners, thank you for convening this forum and having this open and honest discussion. As Mr. Levitan has noted previously, the location of Everett on the east end of the pipeline systems provides needed supply and pressure support for our gas LDC and reliability for gas LDCs and interstate pipelines. National Grid uses Everett to provide both liquid for summer refill of our LNG tanks across our system and to top off those tanks in the winter for boil off and for usage of those tanks.

They're really important for our peak winter supply. As also noted we use Everett as vapor distributed directly into our gas LDC in Boston. So, it's really important for us to maintain that facility or to see that facility maintain an operation. We also see it providing needed reliability in the event of problems on the interstate pipeline systems that provide gas into the New England system. As noted also Repsol and Excelerate can provide needed LNG into the system as well. My understanding, though, is that they need secondary transportation capability to be able to get all that gas to market.

The gas LDCs for their firm gas customer requirements generally accommodate all of the firm transportation contracts on the pipelines. The only time we release that capacity to the secondary market is if we can decide or demonstrate that we do not need that transportation capability to provide firm transport to our firm retail customers. It's also noted that Repsol and Excelerate most likely need contracts to be able to make sure that that gas is there and available as needed and that it's difficult to get those supplies on an as needed basis.

I'm not sure even a 21 day forward view that those kind of contracts or that gas can be contracted for if it had not already been contracted for. Pipelines are becoming more and more constrained as gas demand continues to grow, and that leads to volatility in increased prices. We don't see any other near-term plausible solution in the event that Everett closes if gas demand is not decline as drastically as some may anticipate. The prudent decision would be to keep Everett open until electrification, clean energy resources, electric transmission and distribution systems are built substantially that can accommodate the increased electric load. Once gas demand drops on the system, then we could back off on some of our transportation contracts and supply considerations. It simply makes sense to keep existing infrastructure in place.

It has also noted how difficult it is to get anything built in New England. It's extremely frustrating to me on a personal basis that we can't get gas infrastructure built into the region that could relieve the constraints, help reduce prices and help support our customers bills on both the gas and electric side. The LDCs are meeting with Constellation to see if we can find a viable solution in order to keep Everett open. But as also noted it may not be enough supply from our systems to substantiate the need for Everett and others on the system that utilize the Everett facility from a beneficiary pay standpoint should be able to contribute to keeping the facility open. Thank you.

CHAIRMAN PHILLIPS: So, Mr. Levitan, we've heard that it's important. That it's prudent. Makes sense. Necessary. I want to give you an opportunity; do you have any reaction to what we've heard just so far, or do you want to add to or underscore anything in your presentation today?

MR. LEVITAN: Thank you, Mr. Chairman. I've probably said enough and should yield. But I can't resist the temptation to amend one thing that I neglected to address adequately, and that is in regard to the imperfect substitutability of both Repsol Saint John and the buoy submersible system. It's about contract formation. Arbitrage across the pond is not a bankable risk mitigation strategy. We shouldn't expect arbitrage to come to the salvation of the region's need for gas and/or electric resilience. Thank you.

CHAIRMAN PHILLIPS: Thank you. Repsol.

MR. NEUSTAEDTER: Yeah. Thank you for letting us all participate on this panel. There's been a lot of discussion regarding the capabilities of Everett, but I'd just like to take a second to discuss the capabilities of Saint John. Saint John has 10 BCF of storage capacity, three times the amount of Everett, and 1.2 BCF of regasification capacity. Since 2009, Saint John has reliably served New England markets through its firm capacity on Maritimes and Northeast Pipeline and its direct interconnects with Portland Natural Gas, Tennessee Gas Pipeline and Algonquin Gas Transmission. With the ability to receive the largest LNG tankers and its 10 BCF of storage capacity, Saint John has the flexibility to receive LNG from around the world.

The fact that Saint John is not located in Boston Harbor does not diminish its ability to reliably deliver natural gas when called upon into the eastern ends of Algonquin and Tennessee Gas pipelines and at pressures up to 1,100 pounds per square inch. In addition, except for Mystic, volumes from Saint John conserve all the electric generators that Everett can, plus generators, Everett cannot.

The focus of this panel is whether Everett should be retained. Repsol believes that the beneficiaries of Everett's services are in the best position to answer that question. And I'm happy to hear that Constellation is not thinking of an out of market solution, and it's in the retention of Everett. But other parties are. And that concerns Repsol. Repsol is concerned that retaining Everett through an out of market solution solely favoring Everett over other LNG suppliers in the region will have unintended consequences that will ripple through both electric and natural gas markets, distorting those markets and threaten the participation of existing electric and natural gas assets in those markets.

Thus, instead of increasing reliability, Repsol believes in an out-of-market solution favoring Everett will exasperate the reliability challenges facing New England as a result and result in significant costs.

CHAIRMAN PHILLIPS: Thank you. Kinder Morgan. Ernesto.

MR. OCHOA: Thank you, Chairman. Thank you, Commissioners, for having us here. We do value the opportunity to communicate our feelings here. I think first and foremost as a pipeline, I want to make sure that we all understand that we do not need the Everett facility to operate our system and/or to fulfill our firm commitments right. It does provide a very helpful insurance at times of peaking needs when there's over pulse in the system and they provide help as an operator, as many other operators across our systems do.

So we do rely on them from time to time as other pipelines rely on us from time to time. The grid helps each other. But our firm shippers and primarily the LDCs are firm shippers need this facility. They see a need for it. And so if they have a problem, we have a problem, right? And so as they as a customer service driven organization, we want to help them mitigate those concerns. It's no secret to you guys, it's no surprise that as a pipeline operator, we believe that more infrastructure is needed in the region, not less. And we're going to continue to say so forever.

More pipeline capacity, more storage capacity can help mitigate the impacts of high pricing.

As we saw during Yuri, where you had storage prices were not as high. Storage is important. This provides a storage option in the region. And so for that reason, taking away infrastructure that works today is not something that we want to see. Less supply, less flexibility to the system is not necessarily valuable. In addition, infrastructure as renewables continue to penetrate the market area here is going to be even more necessary. So perhaps a added molecule is not something that eventually we're going to need, but we're going to need more infrastructure because at times of -- sudden you don't have solar, you don't have wind, you're going to need natural gas to crank in a facility like this, as Mr. Levitan said, is needed for quick generation.

So because of all those reasons, we are fully committed to working with our customers and other stakeholders to develop creative solutions to get there. But those solutions need to be competitive and not impact the rest of the players in the region, like the gentleman sitting next to me. So pipeline services, again, a creative way of facilitating a commercial solution to maintaining this facility is what we believe needs to happen.

CHAIRMAN PHILLIPS: Thank you for that. I think that you have put up the perfect alley oop to my colleague, Commissioner Danly. So I will get out of the way and turn to him for any comments or questions he might have.

COMMISSIONER DANLY: So the Chairman began by asking about the change in assumptions. You responded that you were surprised by the value of the behind the meter PV, right? Is that the sole thing that surprised you? Because I have to admit -- I'm surprised to think that the hopes for winter reliability in New England hang entirely on one set of assumptions on one technology that is surprisingly being deployed at the rate that it is. So what other assumptions have changed? Because as the Chairman rightly said, the tenor of this discussion from, I assume New England is quite drastically different from the way that it was before.

MR. CHADALAVADA: Thank you, Commissioner, I think, you know, Stephen touched on it, but I want to emphasize that this study was about the electric system and about the near term. And so where the uncertainties are a bit more predictable for all the panelists that talked about the need for Everett, ISO is included in that list of where we think it's prudent to retain Everett, especially given the concerns that we heard from the LDCs about being able to serve gas customers reliably.

So my comments and my discussion focus on the electric system. So the installations that we've seen, and that was a good analogy that Stephen put up earlier this morning for each year of increment that we've seen, it's equivalent to about 1.5 BCF or 10 million gallons of oil.

And so while we look at it in the context of capacity or a single day, when you look at it as an aggregate energy reduction on the system, it's a substantial amount and there was never a quantification of that until the past several months as we started to embark on building this analytic platform to be able to put numbers and probabilities to the equation rather than having concerns about how some assets may or may not perform. That's one aspect of it.

We're also expecting in the next year one of our first offshore wind farms to come into service, which wasn't an expectation about a year ago. Things have progressed. Thankfully. That happens to be the case that it's in service by this time next year. The third, the retirements. We ran our auctions and through the middle of 2027, we have a high degree of confidence in the infrastructure that's going to be in place because the retirements have been announced and we have seen very limited amounts of retirements so far. And lastly, the demand growth, we were expecting to see some modest demand growth, but we haven't seen that. So it's the totality of it. When you put it into numbers and you put it into a sort of a tool and a platform, it gives you a result. Now, as some have commented, we certainly could stress the system further. We could assume the loss of a compressor station, or we could assume the loss of imports for 20 days. And those are legitimate contingencies to model. But when you do go down that path, I think we're going to see that it's not just Everett that's needed, but probably every piece of infrastructure. And so that's the slippery slope.

COMMISSIONER DANLY: You actually perfectly anticipated the got you follow up that I was planning. So you could probably see it in my eyes the exactly what you were saying. The problem is the assumptions -- first off, it is surprising to me, to use that word, surprising again, that all of a sudden we want to do this arithmetically, but I suppose better late than never. The second thing is the assumptions that are built in here. You either assume that everything is hunky dory up front and then just let the process play out and you have your ledger with columns and you say, hey, what do you know? The numbers work out or you do exactly what you suggest is, would you look at a bunch of potential contingencies, one of which is Everett going away and things start, I would think, to be a little bit scarier as you do that.

So it is perfectly acceptable to say these are the parameters of the study we're offering, but to then, I don't know, let that set the baseline for the discussion of what the likelihoods are of catastrophic failure is probably a little bit misguided and I just feel the need to reorient things. But thank you for getting my point out for me. So this is a contract formation problem, as was said. That means that it's a willing counterparty problem, presumably, which means that that is a money problem in the final analysis, which means it's probably a tariff problem.

And I would assume that given the -- despite your intentional equivocation, they're saying if in giving a series of conditionals, it sounds as though the value proposition of Everett being valuable to somebody at some point certainly is there, which means presumably we're simply not paying the people who would be the counterparties to the contract enough money, which means we either need to get a 205 to fix that or we have to 206 market.
That's all I have to say. Thank you.

CHAIRMAN PHILLIPS: Thank you. Commissioner Clements.

COMMISSIONER CLEMENTS: Thank you all for being here. I'm encouraged by Commissioner Danly's support for probabilistic planning. That's a good thing. It is really important to try and think through these issues. Mr. Levitan, one thing that I thought was left unsaid at the end of your presentation, so I'm going to follow up on it, although you lived -- the whole presentation lived in the nuance of this distinction, is the benefits of Everett to the bulk electric system versus the benefit of Everett to LDCs. And while both are really important functions, don't take this question the wrong way -- when you talk about the needed insurance policy, can you say a little bit more about for which purpose for both? Is it quantifiable in terms of the relative -- in terms of the relative benefit? And if it isn't, what's your intuition relative to the grid reliability piece and the LDCs' access to a reliable and resilient supply?

MR. LEVITAN: It is probable if the clients threatened to pay us that it would be quantifiable. That said, there are some hotspots in New England. Cambridge is one and Providence, Rhode Island is another, where the hydraulics are enabled and gas grid resilience are furthered through the existence of the import terminal and the supply pressure and flow wise.

The ancillary services I referenced are available instantaneously at the back-end of the system. So clearly, you know the gas utilities in Cambridge, in Massachusetts, in Rhode Island, are supported through the gas grid services ascribable to vapor into Algonquin and Tennessee and National Grid. Regarding electric reliability, we have looked at this before in a world without the facility. Then the pipelines have to maintain the pressures and flows through traditional west to east and north to south flows. That is clearly a tall challenge for electric resilience when the entitlement holders are taking 100% of what they need during cold snaps. Displacement services are part of the solution. So by scheduling gas at the back end of both pipelines, it emanates from east to west or from south to north. And that's a great thing for those generators that are scrambling for supply in the secondary market under restrictive scheduling conditions under the NAESB quadrant.

Therefore, those backend services are clearly improved for gas gen.co.scheduling on short notice in the intraday market. Now, to what extent can the Buoy and or Saint John supplant that? We don't really know exactly because we've not had the counterfactual case with Distrigas being gone. We have studied it previously hydraulically. But that said, I would recognize there's no question that gas from the Buoy submersible system, if it's entering the market, can zig and zag its way through the Algonquin system, the Ice system in southeast Massachusetts and make its way to the main line. The question is, how much? And how much is siphoned off by the Four River combined cycle plant?

How much in the case of Saint John would be siphoned off by the generators in northern New England? Thereby depleting the amount of leftover supply for redelivery on the Algonquin main line in southeast Mass. Lots of uncertainties there, but the intuition that I share with you today is that without question, electric system reliability because of the firming up of secondary transportation, is significantly improved as a result of products entering in the heart of the market in Boston.

COMMISSIONER CLEMENTS: Thank you. I have a follow up for Mr. Ochoa. But Mr. -- first, Mr. Neustaedter, did you have any reaction to that in terms of your perspective was that you shared was that you could --that there was a replaceable opportunity?

MR. NEUSTAEDTER: You know. Yeah, not to pass the buck, but I think in terms of determining Saint John's importance to the system, I think that is best answered by the pipelines themselves.

COMMISSIONER CLEMENTS: Mr. Ochoa, and in addition to that, can you say a little bit more in saying that your customers are saying they need it and therefore it affects you, but that your pipeline system would be okay without Everett. Can you say more about that?

MR. OCHOA: Sure. So one of the facts that has been said here is we're talking about firm systems, right? When we sell capacity, we sell it on reservation basis, and those firm requirements are going to be maintained. What you're going to see is a straining of the ability to flow secondary services, right, which is what mostly generators rely on. The other biggest issue for the generators, not so much for the LDCs. The LDCs have transportation that they have purchases many, many decades ago that they use and continue to use. In order for us to provide an even hourly services, we need a source of supply very close to where the generators are. And so that facility does provide that support. Again, at times on a secondary basis. We have firm services sold from the facility and they are used. And so the facility goes away, we're not going to sell those services anymore. But from a secondary perspective, that's where the facility provides some service and the ability for us to maintain our firm requirements doesn't go away.

So what you'll see the pipeline doing is you're going to see a more strained environment and that we're going to see more OFOs, forcing folks to stay under even hourly flows.

You're going to see, you know, more constrained environment from an operational perspective and in the case of a failure the pipeline is not going to necessarily have the support from a facility like that. Now, Repsol provides a lot of those same benefits through Dracut to Tennessee, and we get a lot of supply from Dracut every year. The question is whether it can replace whatever it provides Tennessee today, and that will require some analysis on our part. And it may require additional infrastructure in order to move all the molecules to the places wherever Everett goes today as a replacement, right.

So perhaps we would have to analyze that a little further. It may require a small project. And once again, infrastructure is going to be the key here and we can build more capacity from Everett and make it even more efficient as well if it stays. So all those things need to be taken into consideration.

COMMISSIONER CLEMENTS: Thank you. Mr. Holodak, it'd be great if you could say a little bit more about the operational risk that National Grid faces and also the cost risk. The price of addressing that risk. I think the EPRI study gets into operational risk on the grid side, doesn't get into cost questions. But for you on the on the LDC side, can you say more about that? And also, maybe I should have asked this part first. The 22 high demand days in Mr. Levitan's presentation, is that how you think about where the risk lives, or is it more consistent than that?

MR. HOLODAK: The risk, we think, is more consistent than that. We're concerned about the reliability on the interstate pipeline system as it feeds into New England and into our LDC. With Everett there that provides needed supply and reliability for the gas LDC. As I said earlier, it provides vapor right into the Boston gas system that helps support the pressures within that system. And as it releases capacity or as it releases vapor into the system, it naturally supports the pressures on the interstate pipeline systems as well. It helps bring those back up.

The concern about cost to me is that the firm transportation contracts that we hold, we've held those for a very long time. We cannot get new infrastructure built into the region that could be actually relatively inexpensive when compared to potentially the costs of keeping Everett open or the cost of other imported LNG.

As noted earlier, the LNG that's imported is from the world markets. And given the Russia-Ukraine War, the prices have increased drastically. They're extremely volatile and they had jumped up to nearly $70 to $100 a dekatherm, when we can get gas from Western supply regions at $2 to $3 a dekatherm. So the cost is inordinately expensive. It raises the cost to our guest customers. Sometimes it sets the margin for the electric system such that the electricity prices increase at the same time. So our customers are kind of getting a double whammy from the lack of infrastructure in the region.

When we talk about reliability and we're concerned about outages, the issue there is not so much on the electric side. When you have an outage, you flip a breaker and the power comes back on. And the gas LDC system, if you have an outage, you have to walk around and relight every home that doesn't have electronic ignition on a household by household basis, on a commercial by commercial basis. And that takes an inordinately long period of time. We're very concerned that in severe winter conditions that could lead to disaster for health of our residents.

So there's a number of issues. And all the solutions that we're talking about are fairly expensive relative to the potential for maybe a new pipeline into the area. We're looking at electrification and load declining over time. We don't see that necessarily happening until the mid 2030s. So we really need a solution that gets us from today to then. And as I mentioned earlier, once we see the demand for gas starting to decline, then we can start backing off and unwinding some of our infrastructure, some of our contracts on the pipelines. So it's a concern on a number of fronts.

COMMISSIONER CLEMENTS: Thank you. And one quick follow up on that. Is the -- your expectation is that the home heating natural gas will remain through the 2030s?

MR. HOLODAK: Yes.

COMMISSIONER CLEMENTS: Yeah. Okay, thanks. That's all. Thank you very much for being here.

MR. HOLODAK: Thank you.

CHAIRMAN PHILLIPS: Ms. Allen. I see your tent card. I want to go to Commissioner Christie, and then I promise to give you an opportunity at the end to close this out. Commissioner.

COMMISSIONER CHRISTIE: Are you going to let her go first or?

CHAIRMAN PHILLIPS: It's your time.

COMMISSIONER CHRISTIE: Okay. All righty. Well, just to make the allusion of Mr. Holodak, I mean, look, we all know we're here because over the last 20 years needed pipeline capacity was not built into New England. Constellation -- Constitution, USC. You can go down the list. You could be getting cheap gas from Pennsylvania below $3 and we wouldn't even be sitting here. But those pipelines were blocked. But we are where we are. So now we got to deal with it. Let me ask about two things, electric reliability, gas LDC reliability. And let me go on electric to Vamsi as I understood your presentation, and the first panel, Mr. Levitan. What you're saying is if you -- if the Mystics close and you've designated the Mystics as RMR. Ok -- RMR means reliability must-run units and you've been paying them out-of-market payments.

Now they're going to retire. And I just want to be clear what I heard from you and Mr. Levitan. Although Mr. Levitan was couched in about six ifs, which I took as basically the poker equivalent of drawing to an inside straight six times in a row. But what you're saying Vamsi is we can live without the Mystics from a reliability standpoint. Is that it?

MR. CHADALAVADA: It's a great question. It goes back to Commissioner Danly's phrasing. It's the baseline that we're measuring against. We can live without Mystic because the supply side has increased and the demand side hasn't grown. So we have the right balance today. We have the right balance for the next 3 to 4 years. It's not to say that balance continues through the end of the decade and therefore the note of caution and the prudency to retain Everett because it does provide an option value for the future uncertainties that we may face. But for the next 3 to 4 years, as we've studied with what we consider to be a reasonable set of assumptions with contingencies, with all of our experience to bear and we are the reliability coordinator, it is our primary mission to maintain reliability.

So recognizing that and sharing that burden amongst ourselves, we are confident that for the next 3 to 4 years we can maintain electric reliability. It's not to say there's no energy shortfall, but it's manageable. And that's where the risk profile starts to trend to potentially a greater degree. And that's where I feel that we need a bit more time to keep using this platform to provide the right way to assess risk so that actionable steps can be taken through markets versus out of market.

COMMISSIONER CHRISTIE: Let me take that as all a yes. You think you can live without the Mystics and keep and keep the lights on. Is that the way I'm taking that? I know you've got all the contingencies in there and the ifs and everything else, but you've designated those as RMR units. Now they're going to close and you're saying if these RMR units close, we can keep the lights on.

MR. CHADALAVADA: Yes, Commissioner but there's no guarantee.

COMMISSIONER CHRISTIE: I know there's no guarantee.

MR. CHADALAVADA: But yes.

COMMISSIONER CHRISTIE: But there are more -- but there's obviously safety margins.

MR. CHADALAVADA: Yes.

COMMISSIONER CHRISTIE: And the margins are going to be a lot tighter without the Mystics?

MR. CHADALAVADA: That is correct.

COMMISSIONER CHRISTIE: Okay. Now, if the Mystics close, that takes away the biggest source of revenue for Everett. But that is not a rate issue. That's just Everett's an LNG import facility. If they can't get revenue from the Mystics, then they don't get the revenue that they need to stay open. So let me move to the LDCs. We've heard a lot of comment about well, the LDCs need Everett. Whether or not the LDCs in Massachusetts have adequate supply to serve people who want to heat their homes with gas, who want to run their businesses with gas. That is not a FERC issue. That is really for the regulators in the state of Massachusetts. I used to regulate LDC. That's a state regulatory issue.

Whether Everett is essential to those LDCs is for the state of Massachusetts to step up and say, Everett is essential to our LDCs and then work on a funding mechanism to keep Everett open. If that's the only way to keep the LDC supplied. That's not a FERC issue. I have to say it's -- we can't order Everett stay open to serve LDCs. As important as that is, the state has to say we need Everett to serve our LDCs. Even if the Mystics close, we still need Everett. We being the state of Massachusetts. We need Everett for our LDCs.

Okay. Let's talk about how the state of Massachusetts wants to pay for Everett if it's essential to LDCs. But from the reliability standpoint, if ISO says close the Mystics Everett loses that revenue. The impact on the LDCs is something the state of Massachusetts needs to step up and say we want to keep it open. Here's how we're going to pay for it, here's how we're going to finance it. Any reaction to that?

MR. HOLODAK: No, Commissioner, I can completely agree with your assessment. The issue is if the LDCs step up and supply enough revenues to keep the facility open, and there are other people that still benefit from it, do we or don't we get compensated as a kind of credit back against that? But yes, if we can come to a solution with Constellation. I don't think it's just a Massachusetts issue. It's the LDCs and the New England region issue. Everyone that utilizes that facility now. So it's a little broader than just Massachusetts. But the long term contracts that we would require to keep it open. We would need to take to the DPU in Massachusetts to get approval.

MS. ALLEN: I think the other issue is timing. We're all talking about it like we've got all kinds of time in the world. And -- you know, I had the pleasure of appearing here back on September 8th to talk about the facility. We're nine months later. We've made some progress, but not the future of the facility is not insured. And let's say we are able to come to commercial arrangements with folks to support the facility. Then we have a nine month regulatory process right, to go through. And I just -- that is a huge issue that we're facing.

And anything that can be done to expedite an approval of agreements that we're able to reach, the negotiations are at arm's length. They are -- you know, there's every reason to believe that the deal -- that any deal that is struck is going to be arm's length and commercial and we need to get to a path where we can have the facility insured and procure the supply in a timely fashion. And we're just running out of time.

CHAIRMAN PHILLIPS: Commissioner Christie?

COMMISSIONER CHRISTIE: No, I just follow up. I mean, if ISO decides to let the Mystics -- you've designated the Mystics as RMR, if you've now decided that you don't need them anymore as RMR units and you're going to let them, if you decide you need them to continue it, then you'd have to come to us and say, are the rates just and reasonable? Are the out-of-market payments just and reasonable? But what would not enter into that equation would be whether the Mystics are needed to keep Everett open so the LDCs in Massachusetts have adequate supply.

MS. ALLEN: I think we've I mean, I think we talked about this last time, whether there are other mechanisms that can help defray the expense and would be just and reasonable. I think right now --

COMMISSIONER CHRISTIE: The Mystics or on Everett?

MS. ALLEN: On Everett, we did talk about whether there's a possibility of a pipeline surcharge or anything like that. I think that where we are from a timing perspective, because now we're nine months in, really the option that's in front of us is bilateral arrangements subject to hopefully expedited regulatory approval that are designed in such a way that if additional folks can come to the table and support, it will reduce the cost of those folks who stepped up to the plate. I think I don't see another way. My background is a regulatory attorney, 27 years. I just don't see how else we're going to get there at this point. I'm sorry.

CHAIRMAN PHILLIPS: One quick follow up, Ms. Allen. Do you have a drop-dead date?

MS. ALLEN: I get asked that a lot. And Norris Wright, who's with me, who's in charge of supply, will try to his last dying breath to make sure he gets adequate supply to fulfill the commitments. We wouldn't be here and we wouldn't be negotiating with the LDCs unless we thought we could pull off and get that supply if the contracts were approved. But there is no hard-and-fast drop-dead date. Normally I think we would have the supply procured at this point. You can look at the comments of Excelerate. They talk about the time horizon needed for bilateral contractual arrangements.

And while I have the mic, I just want to make one other point and maybe you can ask Mr. Ochoa about it. When he talked in his comments at page seven, he mentioned the fact that ISO New England assumes that Repsol and Excelerate will come to the table and kind of fill the supply that goes away with Everett. But he does mention that in order for the pipes to accommodate that additional supply, there may need to be additional infrastructure Buildout. And that's going to take time. That's just the truth of the matter here in New England. And so, I don't know if you want to ask him a little bit more about that, but for me, it was the first time I heard it so clearly expressed with respect to one of the key assumptions in the ISO New England study. Thank you.

CHAIRMAN PHILLIPS: We have about a minute left. I do want to give you an opportunity to respond since you were singled out.

MR. OCHOA: That's that alludes to what I said just a moment ago, that effectively to replace the amount of gas that we get from the Everett facility, from Dracut, which would effectively be Repsol, we don't -- we do not connect to the Bouy. So that's not an option for us. We would have to look at potentially expanding our system to be able to replace the same level of molecules where those molecules go today and we are reviewing that. So just because it's available for the grid doesn't mean it can get to the places that Everett can get today because the grid is complex, it's different. So that's a fair point that she brings up. And that put in our comments and I mentioned before.

CHAIRMAN PHILLIPS: Thank you. I don't want to prevent anybody from talking. 30 seconds.

MR. DICKERSON: Yes, Mr. Chairman. I'll be brief. We jumped quickly into a discussion around rates and who pays? And the whole nine yards. I'm still stuck on the physics. And it's not because I'm an engineering nerd. As CEO I look at the whole picture, but I heard at least three panelists reference the fact that the LDC heating customers are not the only beneficiaries of the molecules that come from Everett.

So, I think it's instructive upon us collectively, and I don't know who leads it per se, it would have to come from the gas pipelines to help facilitate it, for us to resolve the question of the physics is what happens if Everett isn't there with respect to pressures and the molecules that not only go to heating customers, but the molecules that go to generators that generate electricity otherwise we get into a death spiral. We get into a place where if the pressures drop, those generators can't produce electricity and people need it in the cold are going to suffer. It's going to put further strain on the system.

So, before we get to who pays for it, let's resolve is it physically possible to eliminate it and maintain the integrity of the system? And if not, is it physically possible to come up with a solution at some point that will? But we're not going to build anything in the next year or two years. So then it begs the question, what are we doing to gap? And I'll close with saying in the gap, I don't think we have many choices other than to keep it where it is. Thank you.

CHAIRMAN PHILLIPS: I think we're going to leave it there for this panel. Thank you, everyone, for your comments. Excellent, thoughtful comments to get us started. I'll turn it back over to Mr. Burns, tells us what to do next.

MR. BURNS: Thank you, everyone, on the first panel. We're going to move to the third presentation of the morning. This will be given by Stephen George and Vamsi Chadalavada, as well as Eamonn Lannoye, who will be joining us virtually from Ireland. This presentation is called Extreme Weather Risks to ISO New England, Presentation of the EPRI Study by ISO New England and EPRI. This presentation will be 30 minutes and following this presentation we'll begin the second panel the reaction to the EPRI Study.

(Recess)

Well, that's the --

(Recess)

We're just waiting to see -- make sure Eamonn's on the line and then we'll get going.

MR. LANNOYE: Yep. I'm here.

MR. BURNS: There's our answer. Stephen and Vamsi. Whenever you're ready.

MR. CHADALAVADA: So thank you. And I'm sorry that I'm going to be up here for at least another hour and a half. I really wish it wasn't the case, but delighted to be able to share some of our most innovative work that we've done over the past nine months. And I think the collaboration between ISO and EPRI for the first time, I'm proud to say that the ISO with EPRI has put together an innovative analytic platform that allows us to quantify the risk.

Every panelist up to this point in time has talked about risk in a way that is their best form of expression. And it's a qualitative expression, but those aren't easy to act on because you don't know what magnitude of risk exists and what the probability of such risk is and what are the costs associated with mitigating such risks. And all of it are important equations for policymakers to have at their disposal so that a very low probability event that may happen once in ten years or 12 years, which may be catastrophic, but if it requires an insurance product that is overly expensive, that's a calculation that we would expect to have the hand to the policymakers as they make their decisions.

So that's the first thing, the 2027 study that Stephen is going to walk through basically shows that when we study the system with and without Everett and it's the same continuing theme through the rest of this morning shows a manageable risk. And we'll get into some of the details for why that is the case. A critical takeaway of this platform is our ability now to continually monitor and assess the risk, not just for a multi-year outlook or the next year, but the next season and within the season.

And we expect that this risk is going to be dynamic. There are going to be years where we're going to have good results and there are going to be years where we're not going to have good results. It's critical for New England to have a baseline tolerance of its risk such that we understand expressed as energy what risk New England is willing to bear. And that's not a decision that's solely up to the ISO's discretion. That's a discussion that we'd love to have with our states and our participants and create that baseline metric. Where this baseline metric is going to be powerful is it now allows us for some years where we have a higher risk to design the necessary products that are dynamic and that the demand side of that product is appropriately reflected in the market products that we would otherwise build, so that the costs that are borne along with those products are reasonable expectations of what the future should bring.

Absent this sort of a platform, we would not have the ability to just design products and understand what amount of that product should be procured. And so that's where we see some really great value moving forward. We think this is extendable to every reliability coordinator because there's a non-uniform way of expressing energy adequacy risk. And we think the country and certainly every region in terms of neighboring collaboration would benefit from a uniform way of expressing energy adequacy risk in the form of energy with the associated probability.

So I'll just stop there and we'll try to get through this presentation a short period of time so that the panel can get back here. And the conversation is obviously a lot more productive than hearing from us on the details of this presentation.

MR. GEORGE: Thank you, Vamsi, and appreciate the opportunity to be back up here again this morning. And I do want to note that we have Eamonn Lannoye from EPRI on phone joining us this morning from Ireland. We appreciate his support and I want to just take the opportunity to thank EPRI, I think for their leadership in this project. This is a joint effort.

It's affectionately become known as the EPRI Study, but it's really been a collaborative project over the past 18 months between the ISO and EPRI and obviously we've leveraged EPRI's expertise in this area to help us, particularly on a couple of steps of the project that I'll outline this morning. I want to start just to give a couple of brief thoughts. When we talk about extreme weather, it's important as we get into the results to understand that what we're talking about here is weather that impacts the ability of generating resources to supply energy to the system. Doesn't necessarily mean things that we've historically thought of as extreme weather like hurricanes or blizzards or tornadoes.

We're talking about things that impact the ability of our growing renewable fleet, in addition to our more traditional fleet, to provide energy to the system. So that could be long periods of low wind combined with long periods of low solar combined with extreme heat or extreme cold. So I just want to give that context before we start.

So what I'll generally cover this morning is the framework. Framework is dense and there's a lot there, so I'll move through it quickly. I think the stakeholders in

New England have heard how the framework is built and they've helped us think about how to do that along the way. So we appreciate that. I'll also cover results. We'll talk about the 2027 winter in particular with a focus on one single event. The presentation we submitted provides all the results from all the events that we've studied from 2027. But in the interest of time this morning, we'll focus on one that we generally look at as being our worst-case scenario.

Then we'll touch on what we've learned from these initial round of studies. So let me start with the framework. On the screen in front of you, you see there's three steps: weather modeling, risk model development and scenario generation is step two, and step three is energy assessments that are done primarily by ISO New England. Let me give some brief information on step one. It was important for us to understand when thinking about the future weather and its impacts on the system. What -- how has the weather changed over the past time, over the past number of years? What are the trends? What are the extremes? How does it vary? Particularly in summer and winter conditions.

So we did a review of the past 72 years worth of historical weather to get a sense for how things are changing. Then with that context, EPRI's team leveraged global climate models five different models that cover a range of possible outcomes, along with two emissions pathways to help project how that past weather projects into the future. With a particular focus on our initial years of study: 2027 and 2032.

So what we ended up with for each year of study was really 720 different combinations of what the weather could look like in 2027 and 2032. And that was really the outcome of step one that we used sort of downstream in step two and step three. In step two, we had really two goals. One was to build a model that helped us identify the risky periods of that 72 years worth of weather projected to the future, and then to build scenarios that allowed us to assess the impacts of a variety of uncertainties, which I'll discuss in a little bit. To start, the risk screening model that we developed allowed us to search through that again, the 72 years worth of history to find what types of weather are riskiest to the system.

So through the use of technology-specific risk models, that allowed us to look at times when wind, solar, combined cycle, nuclear, batteries -- all types of resources. What are the times when they're in aggregate at the most risk in terms of their ability to provide energy to the system? In this risk reading model allowed us to do that. Ultimately, the risk screening model identified the top 4% of all possible events as being the riskiest. We took that top 4%. We grouped them into clusters of similar events. And then from those clusters, we selected events for study.

If we could, we'd study all 37,000 possible events. But in the interest of time and computing capabilities, we stuck with six events for the 2027 winter. And one of those we'll discuss in more detail today. Once we have the events selected, we then have to layer on a variety of uncertainties so that we know we're studying all a range of possibilities. Two potential uncertainties that we wanted to make sure we had some ability to assess as part of this study were the status of the Everett Marine Terminal, as we've been discussing this morning, as well as the status of the New England Clean Energy Connect, which is a new 1,200 MW tie from Quebec into New England. So we have scenarios built around different combinations of the status of those two key facilities. So four scenarios in total for each event that we selected.

Then given those four scenarios, we wanted to study a bunch of other uncertainties that we know factor into the region's energy adequacy during extreme weather. So we built in uncertainties related to LNG inventories fuel oil inventories, different interchange levels, a variety of forced outages as well as fuel prices. So at the end of the day, using a different combinations of those uncertainties, we study 720 different versions of each of the four scenarios for each event that we've selected. Following the selection of events and building the scenarios apprehends us that information and all the information that we need to do our energy assessment using our 21-day energy assessment tool. It's the same tool we use in our production winter -- weekly winter forecasts.

This is where we took those 720 cases for each scenario, for each event, and assessed what the energy adequacy profile looks like over the 21-day span. And this is where we get our magnitude of energy shortfall. And along with that, we get the probability of occurrence of each of those 720 cases. Looking at the screen. People in New England have seen this. This is our plot of energy surplus over time, we know that when the black line, which is energy surplus, dips into the red zone, that's when we're forecasting an energy shortfall. It doesn't necessarily mean that an energy shortfall will occur, but this is our indicator that there's the potential and we need to take action to reduce the likelihood that that shortfall ever occurs.

Let's talk a little bit about results. Before we do that. Want to give some context to this January 22nd, 1961 event. Which as I mentioned, is sort of our worst case event from energy adequacy perspective. So this event that started on January 22nd, 1961, again, we've projected the through climate modeling what the weather could look like in

2027. But what it looked like back in 1961, you see on the screen from a temperature perspective, which is I know it's tough to see the blue plot is a plot of the temperatures.

And so you can see over the first 12 days, we barely cracked 25 degrees. And this is an average New England temperature. So you would expect some places are much colder, some places are a little warmer. But on average, we barely got by past 25 Fahrenheit. So there's a lot of risk there in terms of operating the power system at that type of temperature for that duration of time. In addition to the temperatures, you can see in the figure that the wind speeds on average barely got up to about six meters per second on average offshore. That's just over the cut-in speed for an offshore wind turbine.

So they provide some energy, but definitely not at full output. But then again, that's the average speed over the course of the 21-day period. From an irradiance perspective that's supplying the fuel to our PV that we've talked about quite a bit this morning, about 120 W/m squared, which is roughly 8% capacity factor throughout this 21-day period.

So relatively low, but in total energy from renewables on average during this 21-day period was roughly 2,200 MW per hour. So that clearly notable contributions from renewables. From an energy demand perspective. This 21-day period was almost 8 TWh. We often talk about 400,000 MWh being the cold winter day in New England. During this event, it peaked out around 425,000 MWh, so about 6% higher than a pretty cold winter day. At least how we think about it. So in summary, just to put some context into the event, this was based on our analysis, the coldest 21-day period since 1950 and includes two of the top ten coldest five day stretches also since 1950. So. Very cold period of time.

What you see here on the screen is a summary of the results of that January 22nd, 1961, event. With the Everett facility in service and without the New England Clean Energy Connect facility in service. In the upper left hand part of the screen.

MR. GEORGE: The plot there that is, can be a little tough to read if you're far away. This is a summary of the energy shortfall or the energy surplus, I should say, for all 720 cases that we ran for this particular combination. I want to draw your attention to the red line that dips. The lowest of all the lines on the plot. This is representative of our worst-case energy shortfall for this scenario. And you can think of that as a combination of low oil inventories, low LNG inventories, low imports, high forced outages. So in all those factors come together to create our highest energy shortfall case, which comes out to be about 111,000 MWh of shortfall, roughly between days nine and 13 and this 21-day event.

MR. CHADALAVADA: Stephen, can I just jump in here --

MR. STEPHEN: Yep.

MR. CHADALAVADA: -- for just a second? I think this goes back to the earlier conversation we're having about the reasonableness of assumptions. I think the study. As we go through our contingency evaluation, the number that's reflected on screen, roughly the 100,000 MWh. We call that as a manageable energy shortfall, not because we are happy that, that's the volume of work that's left for us to do, but more because of the fact that we're going to know this on day one. When we do our simulation, we're going to do this every hour for the next 21 days. We're going to do it for the next 42 days, and we're going to do it for the next 90 days. So where New England has really improved upon its own sort of expectation and necessarily so is from a situational awareness. Logistics is the critical component of managing energy adequacy risk. So when you know on day one that you're exposed to this shortfall in days nine through 13, it gives us eight actionable days to work, which is to send the signal to our marketplace, send the signal to our policymakers and the states and the federal agencies, send the signal to our neighboring control areas and for the ISO to take the necessary actions, including, for example, relying more on its neighbors in the first eight days with an expectation that days nine through 13, we're not going to be able to rely on them.

It is sending a signal to dual fuel units to do what they can to replenish if they haven't. Same thing with the oil units and same thing with the LNG suppliers. So it is the totality of that market performance that we would expect where not one party is going to cure the shortfall, but everyone steps up to take a slice of it. And the conservation, which would be our last step, which is a very uncomfortable step, but a necessary step because it's the one thing that protects New England from involuntary load shed versus protecting it from the risks on the electric side.

So we take that very seriously and we leave that as the last margin if we have to go. But this analysis of 100,000 MWh is an important context to have because this is on the heels of a future where the supply side is more certain. But we're expecting a severe number of forced outages across all technologies. We expect underperformance from the photovoltaic installations. We expect underperformance from wind, we expect underperformance from oil units, from gas units and from imports. It is just that the demand hasn't taken off yet. And that's one of the biggest reasons for why we see this number result the way it is. And when we talk amongst the panelists later today that demand could skyrocket ten years from now, we could see a New England being a winter peaking system.

So we expect this risk will change its profile and might potentially show a much larger number. But the benefit of this tool is it gives New England the optionality to work towards it, either through market design or through infrastructure. And that is where we see the powerful sort of nature of this tool. And we're thrilled about having this with us right now.

MR. GEORGE: Thank you, Vamsi. I'll leave -- leave it at that for that slide. A couple additional points before we close out the presentation in terms of what the results are telling us. Well, you can see through these exhibits on this slide, particularly in the bottom left corner. Is that the region in times like these, remains reliant on stored fuels. And we touched on that this morning. You can see in the worst case scenario with the highest energy shortfall. In that chart. On the bottom left, we're burning roughly 60 million gallons of oil, 37,000 tons of coal. So this highlights the reliance on those stored fuels to get through these tough times. Also this slide, particularly in the upper left corner, highlights the sensitivity of the energy shortfall amounts to the starting LNG inventories. Given that we knew that this sensitivity existed, we ran the sensitivity case where we lowered the LNG starting inventory from 6.5 BCF to about 3.5 BCF to see how that would impact our projected energy shortfall amounts over the 21-day span.

As you can see, the worst case energy shortfall begins sooner and increases to as much as roughly 200,000 MWh or about 80% worse than starting with the higher LNG inventory of about 6.5 BCF. And I should note that results with and without Everett are similar in terms of magnitude and probability. So I'm going to conclude there. Unless Vamsi has any additional comments.

MR. BURNS: Thank you, Stephen and Vamsi. We'll start Panel 2 now. The panelists include Phil Bartlett, chair of the Maine Public Utilities Commission. Vamsi Chadalavada, Executive Vice President and Chief Operating Officer of ISO New England. James Daly, Vice President of Energy Supply, Eversource Energy. Ronald Gerwatowski, Chairman, Rhode Island Public Utilities Commission. Stephen George, Director, Operational Performance, Training and Integration, ISO New England. Ben Griffiths, Senior Director of New England Regulatory Policy, LS Power. Mark Lauby, Senior Vice President and Chief Engineer, NERC. And Rob Perkins, Vice President of Pipeline Management, Kinder Morgan. Before we begin, just a reminder to our panelists to avoid discussing any ex parte matters. Mr. Chairman, when everyone's ready.

CHAIRMAN PHILLIPS: Call them. We're good to go. Thank you, everybody. Thank you for joining us today. Are we good to go? All right. My first question is for ISO New England. Vamsi and Stephen, you guys weigh in. We have the study down. All right. What in your mind, can you say a little bit more about what you think the next steps have to be?

MR. CHADALAVADA: Great question, Chairman. For us, the next steps include sort of building upon this platform that we've built and continually using it to measure the risk profile in New England. We now have an assessment of the next four years. The next step is to assess the risk beyond for year 2032, and it's going to give us a different snapshot than what we see for 2027. And it's then working within our markets, which are our sort of jurisdiction and which you will which you regulate, where we need to see if we need to build new products, we need to understand what infrastructure options are being made available and we will be using those as inputs to our platform to have a dynamic assessment of this risk, which will be shared with the market and with our policy makers. And so those are, I think for us, the next steps.

We are sort of building a group within the ISO that's going to have the capability to expand on what we've built to date. We'll be working on this with our neighboring control areas. There's been some expression of interest in adopting some portions of it, of course, specific to their areas. And so hopefully over time we will be able to not only just establish this narrative of how energy adequacy risk is measured, but more importantly, work in New England to develop a metric.

It's too lofty for us to think of it as potentially being a national standard, but at least from a New England perspective, given where we've been and given where we are headed through this transition, it's critical that every step of this journey we understand the magnitude of risk that's faced, the probability of the risk and the way to cure that risk and the costs associated with that risk. So those are all the progression of steps that we intend to start right from the time that this conference is behind us.

CHAIRMAN PHILLIPS: I want to broaden the discussion then. All right. It seems that this is a study and the assumptions that we can use going forward to assess risk. Want to hear in particular from our state regulators. Do you share that? Do you believe that this study can be used going forward?

MR. BARTLETT: Yes. Thank you, Mr. Chairman. Absolutely. I think I share a lot of I agree with a lot of what Vamsi has said here today. I think this study is a valuable contribution to the region, helping us to understand both the likelihood and the magnitude of the risks that we face so that we can make informed decisions. Historically, we haven't had this rigorous analytical approach as we've been developing solutions. We've known we have a problem.

We've developed a number of both in-market and out-of-market fixes over the years, But we haven't really measured in advance just what the contribution was going to be to reliability or afterwards to really understand whether it's had the desired impact. So I think this is going to be incredibly useful as we move forward. And I think, as Vamsi is saying, trying to come up with what the right metric is that we can use to develop market based products that can help us identify and bring solutions to the table that are large and small.

I think one of the great surprises was the impact of solar PV and the contribution that's making to fuel security. I had never heard that talked about as a potential benefit of PV. So going forward, what contributions can you be made from demand response from battery storage, from all these things that in and of themselves can't solve the problem. But when you're looking at -- you understand sort of the duration of the outages you're facing, the magnitude of the risk you can make smart decisions and cost effective solutions on what group of options you can put together, ideally driven through the market so we get solid innovation that can help to address this problem longer term.

CHAIRMAN PHILLIPS: I just wanted to continue to go down the line, expound on whether or not you agree with the study, whether or not you think. What are your main takeaways from it?

MR. DALY: Thank you very much, Mr. Chairman, and thank you to the commissioners for putting on this forum. This, we think, is very valuable in terms of illuminating the issues before us. But we are hopeful that we will get solutions coming out of this, not just more, more talk. So reaction to the study itself. Well, as we all know, New England has very high and volatile electricity prices. We just came through an awful winter. And from a price perspective, our customers saw their energy rates double from an already high rate of $0.12 on the energy side to $0.024 or $0.27. This is averaged through the winter period and into the into the summer.

So the consequences of that for our region in terms of us responding to our customers, to our stakeholders, to our elected representatives, to the media, it's a major, major effort and it's one that is not crowned with success in terms of the story we have to tell. It's pretty bad. So the system itself is not working well at all. So we don't need models for that. We know we have the current system. We know exactly that the system is stressed and it's a fuel supply problem that's stressing it. You know, I will give credit to ISO and EPRI for putting this study together as a method to quantify what the risks are and what the view forward is, because now we can adjust those inputs and decide which ones are likely to come along and which ones are not.

So we would caution the use -- use so how do you use the study is really the question. We would caution do not use it to determine resource entry and an exit. It's too risky. It's just a model after all. And its output depends on your inputs. Some of the inputs we think overall the inputs are pretty optimistic. For example, the offshore wind is 1,600 MW.

We have 1,400 MW of storage that is really not under contract by anybody. I'm not sure how that's going to get financed at all. There's a lot of solar PV and we've heard questions -- how will that perform in terms of saving inventory? But another big assumption in this is that there's going to be a lot of LNG even with this with the EMT retiring, there's going to be a lot of LNG in the system and oil that will carry the day, if you like. And we question that significantly. It hasn't occurred in the past and we don't see the underlying market rules and compensation that would go to generators to generate that optimistic view.

So we think a better approach is let's yes, let's look at the inputs, but be critical about whether they are going to occur or not. We are a major contractor for these renewable resources that are coming online and we already see supply disruptions occurring.

We have three major offshore wind farms totaling 3,200 MW that have asked that their contracts be terminated because they're not financially viable. That is enormous. I mean, two years ago, that was not on the horizon at all when we put these under contracts and new infrastructure in New England continues to get significant challenges in terms of opposition, all sorts that delay all these projects. So the projects get delayed, the even fail get replaced by more expensive projects. So we say the way to use these kind of models is to -- yes, inform decision making, but do not let very significant resources exit like the Everett Marine Terminal that are impossible to replace.

Do not let them exit before these new resources come along. We're all supportive of getting new resources into the market. We're a major contractor for it to implement state policies. We work hard to make sure that they come on, they come online. But you're really rolling the dice if you're going to allow important facilities like the EMT to exit the market before you have those new resources in line. So we say we just need a more cautious approach to how you're going to use these studies and they're only models after all. Thanks for the opportunity to give you my view.

CHAIRMAN PHILLIPS: Thank you. Yes, sir.

MR. GERWATOWSKI: Thank you, Mr. Chairman. From my perspective, it's very easy to focus on the study's conclusion that we don't need the Everett Terminal for electric reliability. But when I look at it from the perspective of a state regulator whose state suffered a near catastrophic failure of the natural gas delivery system in Newport, Rhode Island, in January of 2019, I react with grave concern. Now, I'm not going to get into the details of what happened in 2019, but suffice it to say that we lost a large portion of the gas distribution system in Newport for a week in the middle of the winter, caused by events occurring at a significant distance upstream of the city from low pressure conditions on the interstate pipeline system, including as far north as Weymouth, Massachusetts.

For over a week, citizens of Newport did not have heat and we lucked out because the temperature warmed a bit after the outage. But unlike electric outages, you can't flip a switch to turn the gas back on. It was a painstakingly slow process to get the gas flowing safely and the heat back on as a virtual army of technicians went house to house twice, once to shut off every single meter, and then the gas would get filled into the low pressure system and then back again to every single meter and turn it back on.

So when I hear about low pressure risks on the system, I revisit that nightmare and I realized that we're talking about electric reliability risk at the conference. But I'm quite aware and supportive of the region-wide drive to transition our systems away from fossil fuels. I raised the specter of the Newport events as a reminder of how sensitive the gas delivery systems can be while we're relying upon on them for electricity and heat. Which brings me to the assumptions in the every study.

To be clear, I have no quibble with the study. It was well done and I commend the ISO New England for doing it. But there's the sentence on slide 16 that hasn't been alluded to. ISO does not have the expertise to assess the impacts of the of the retirement on the operational capability of the gas system. So it assumes the operability and I know others have referred to that.

We're all aware that there's negotiations going on between the LDCs and Constellation, and it's my hope that they work out some arrangement that keeps Everett on line, at least for the short term. I don't know where things stand at the moment, but it's my understanding that in the absence of Everett, the gas utilities serving the Cambridge and Boston area may face a low pressure condition on their system that could create a Newport on steroids type of event in those cities, if not adequately addressed.

And I think their options are very limited. But regardless of where those negotiations lead, I'm concerned that there is a conspicuous absence of studies of which I'm aware that address the operational capabilities of the gas delivery systems as they relate to all the winter risks that we've been talking about. We have substantial transparency on the electric side, but we've had almost nothing that I've heard in evaluating the gas side of the equation, and they link together.

So is there additional information that we need on to be -- to have conducted? Yes, I think unequivocally, yes. To the extent the electric and gas systems remain closely linked during this transition, I firmly believe that we should not be letting this facility close down without studies which link together the evaluation of the electric system with the evaluation of the gas system. Once Everett closes, I expect it to be permanent.

And it appears that Everett is needed for the gas delivery systems in the short term. But the continued existence of Everett represents a valuable insurance policy for the electric system during this transition. And it doesn't matter whether the winter risks we are insuring against is the loss of heating and the largest urban area in the region, or regional rolling outages because something tripped on the electric or gas system when the temperature is below ten degrees.

The probabilities of the risks may be low, but the severity of the risk is very high.

The design of integrated energy systems have always been included prudent redundancies. Should that not be a consideration now? The facility in Everett will eventually need to close as we move to a low carbon future. But we need a more comprehensive and coordinated evaluation of the electric and gas systems before it does. The gas utilities talk about adding new infrastructure, but I think that flies in the face of the state policies about reducing dependency on fossil fuels. In contrast, the Everett facility has been stated is not a new infrastructure. It's already exists.

So from my perspective, the question is not whether Everett should close, but when is it prudent to do so? And answering that question requires a comprehensive risk assessment. We need to look at the systems as one together, not the electric as this side. And somebody has a jurisdiction over that. The gas in this jurisdiction over here and the pipelines have jurisdiction over there, but it's not quite as strong as electric. The jurisdictional issues are not going to be important if we have one of these events. We're not going to sit back and say we had the event, but I'm glad we didn't use an out-of-market solution.

And I'm not trying to be sarcastic, but I'm really scared about where we are here in New England. We're running out of time and I know that there's these regulatory gaps, but at least at the very least, I think we need to call together interstate pipelines. And you have the ability to do that. You don't have to issue an order. I'll bet if you send them either a polite or strong letter, they'll be happily joined with ISO to do a study.

We in the state can do the same thing with the LDCs and have them join together. Well, they'll find a way to pay for the study, but let's join together and understand all the scenarios and how they link to the electric and the gas systems. The flows from north to south from Repsol as a as an option and the other things that can happen if something trips on the system. We -- I think there are great risks here. Low probabilities. But you heard the list of ifs and that's quite scary to me as well. But anyway, I think it's a good study. I think it's going to be very useful, but I think it's got a big missing part that we need to cover and it hasn't been covered yet, but thank you for the opportunity to go through that patiently.

CHAIRMAN PHILLIPS: No. I thank you. I think, you know, your passion is evident. As you were talking I think as a former state regulator, people tend to notice things like in January not having power for a week. And so I'm glad that you put that on the table. I think that's something that should be top of mind as we move through what the next steps are. And what our potential solutions are. Thank you. Thank you. We're going to go straight to LS Power.

MR. GRIFFITHS: Thanks, everybody, for having me. My name is Ben Griffiths. So there's this adage in modeling that all models are wrong, some models are useful, right? And I think the ISO to its credit, has developed an incredibly useful model. It speaks to a huge number of the ifs that Richard spoke of earlier. Right. What happens if the weather is bad? What happens if you have sustained cold weather? What happens if you have the loss of -- the forced outage of a major like a nuclear facility? We cover a lot of that looking across thousands of scenarios. That's a huge increase from the three that we spend most of our time historically. Right.

That's three orders of magnitude more possible things to go wrong. And I think the ISO deserves a lot of credit for doing that structure. I think also it's important to note when we look at this study, that we're able to finally put numbers to things. How likely are these scenarios to happen? And I think it's really telling when we look across thousands of scenarios, there's 20 where you have more than 10 GWh of shortfall. In ERCOT and -- ten gigawatt hours over 21 days, right, in ERCOT you were shedding 20 GW per hour at times. These are just such fundamentally different places.

And I think it's worth keeping that in mind. And I think from that we can make, you know, comments that are thoughtful about how Everett maybe is not needed for the power sector that gas -- that oil resources can largely fill that gap and that from those things we can say that this is a -- the ISO can -- that this study can reframe the problem as saying that New England has a fuel coordination problem rather than a fuel sufficiency problem.

You need to make sure that the molecules can get to resources. Not that there's maybe too few molecules overall, but the one thing I really do want to hit on is this a set of assumptions around gas sufficiency on the pipeline side. So the ISO, I think to their credit, took the

LDCs at their word in the various state forecast and supply plans. Right. The state dockets where the LDCs say how much gas do we need and how are we going to meet it. And they took those at their word that Everett doesn't seem to be a problem. Right.

The word Everett shows up once in those LDC dockets, one from National Grid, one from Eversource. And when the LDCs aren't talking about it, when they're not telling their state regulators about it. And then from that, the ISO takes those dockets at their word. I think it's reasonable to start from the premise like the ISO has that we don't have the pipeline issues, the LDC issues, because that's never in the record anywhere. And maybe that's wrong, certainly based on some of the testimony today, but I don't think we can hold that against the ISO, certainly for the study that they've done to date. So thanks.

CHAIRMAN PHILLIPS: Thank you for that. I think we're all excited to have NERC weigh in on what their thoughts are for the study. Mark.

MR. LAUBY: Thank you. I want to thank the chair and the rest of the commissioners for inviting me here today. And I'm asked to provide reactions to this system's assumptions, inputs and results, and I'm pleased to do so. The framework provided by the study is both useful and informative. I applaud the ISO New England for using new innovative novel tools to address the growing challenges of energy sufficiency. The study seeks to use probabilistic analysis augmented by five global climate models where deterministic assessments have been traditionally deployed. It provides keen insights for decision makers as they weigh complex factors of reliability, resilience, affordability and the environment. However, it's not a decisional study, but can be used to inform decision makers.

Widespread, long-duration, extreme weather affects the performance of all generating plants simultaneously, and we have to consider common mode effects, not just one right after the other. So that's something to consider when we do studies like this, depending on their fuel source and the weather impact on that fuel availability, the resulting impacts, as you know, can be catastrophic. And that's where it gets me on to discussion about what this real need for addressing the interconnectivity and the interdependency between gas and electric. You've heard NERC talk about this a number of times. Protocols are needed at that interface. It's very clear both sides need each other to succeed, very much like what happened in the 1965 blackout.

We are here today not with a gas electric as well. In addition to modeling impacts on gas and fuel availability, further model scenarios are also needed to look at wind and solar output, pipeline uncertainties, loss of large generators, as well as power transfer levels from neighboring organizations that are experiencing the same weather at the same time, further expanding the framework beyond one year and testing more extreme and stressful scenarios mentioned -- that I mentioned above would make for additional vital updates to the results. The analysis is helpful to provide direction but should not be considered decisional, as I said before.

As we learn more about an applied in these other areas, remember the probabilities are just an average of a distribution, right? You need to look at the whole distribution of forced outage rates and scenarios. In addition, like my colleague Mr. Dickerson indicated, before you retire or interconnect new facilities, it's important to understand the underlying reliability and resilience performance requirements of that system and the contributions of those facilities to that performance. And what's really missing here, and I think my colleague from ISO New England mentioned this before, which is a design criteria, right? What are we designing to? We always have the one day and ten and that was, you know, the life was wonderful, but we don't live that life anymore.

We have energy constrained facilities becoming coming on our system. So once we understand what the performance requirements are and what that design basis is for those -- for that system, then the reliability and resilience can be studied and maintained through a range of severe weather events and risky system scenarios and say, this is what I'm willing to accept as a risk I'm willing to accept, and this is a risk I'm not willing to accept.

And with that planning approach, the system could also be restored in an orderly fashion. When you go beyond that design basis. Developing this design basis is in the form of an expected unserved energy or other complementary metrics is really important here because right now we're just kind of throwing darts and trying to figure out where this thing fits in. And these are metrics beyond the one day and ten, which is now really waning. And the next important step, I think, is to bring these new innovative methods along with those design basis, to really kind of make some decisions down the road. I think FERC, NERC and the state provincial regulators and industry need to work together on that energy design basis number. So thank you again for inviting me to participate in this important conference.

I look forward to any additional questions.

CHAIRMAN PHILLIPS: Thank you, Mark. Kinder Morgan.

MR. PERKINS: Thank you, Mr. Chairman. So when I evaluated this study and the results, I think I think it is a good study. And I think some of the points have already been made in terms of it being decisional. You know, it's only as good as its assumptions. And there are a lot of assumptions. I didn't see a lot of detail on the pipeline side. I think I'd like to see, you know, a little more detail on the stack of generation to be able to opine on whether, you know, the pipelines agree with that. So some more involvement on other stakeholders in the assumptions in the study to be able to -- to really be able to vet the assumptions and I think run maybe run more sensitivities around it.

For Kinder Morgan, for Tennessee gas pipeline, when we look at this region, we can move a BCF, give or take, into the region. And on peak days we deliver one and a half BCF. So in the context of Everett and other downstream supplies in and LNG, 50% of our peak day demand in New England comes from downstream supply. It's effectively a pipeline into the region. It just comes in at the very end. And so, you know, I think that's very important. And so in the context of Everett and a five year study as a gas control guy who's conservative by nature, I would not use this decision, you know, as a decisional tool, as people have said. You know, it's got a lot of assumptions on solar, wind that's going to come into play. Northeast Clean Energy connect over the next five years. That from a prudency standpoint, it would be nice to see those develop and actually come to pass before a decision was made on Everett and have it be wrong. That -- so those are my thoughts on that study.

CHAIRMAN PHILLIPS: All right. With that, I'll turn to my colleagues for their comments and questions. We'll start this time with Commissioner Clements. Moving to Commissioner Christie and then Commissioner Danly.

COMMISSIONER CLEMENTS: Thank you, gentlemen. It's good to see you all. I want to congratulate the ISO on this study. I think it's a great tool and I think I've been hearing you talking about it as that as a tool and an evolving tool. So study is almost each production of it produces a study, right? And I think that's a great thing. And to your kind of meta point, Vamsi at the beginning of the presentation, as we are trying to be policy makers and making these decisions in the face of uncertainty, it's this kind of data driven tool that will assist us starts ratcheting away at the problem.

Certainly the design basis question is noted and heard. I think that's really, really important. But from the perspective of this tool, I'm really, really happy to see it. And I would ask you, you know, there's some questions about assumptions and I imagine some assumptions are optimistic and some are pessimistic. And depending on where you sit, you might have, you know, differing views on each of those questions. I understand that this is something where the assumptions can evolve over time. So I'm curious about that. And can you speak to how that would happen, how things would change as you see changes in the system and what things are outside of the ability of the of this study platform to take a look at?

MR. CHADALAVADA: Let's thank you, Commissioner, for your kind comments and we're excited about the tool also. With regards to assumptions, I think it's important for the ISO to first be transparent about the assumptions. All of them, not some of them, and to be reasonable about the assumptions that we're making. So, for example, the worst case that we saw assumes the coldest period that we've observed in New England in 72 years, and we assume up to 30% of our installed base is not going to perform. Now, we can assume 40% doesn't perform or 50% doesn't perform, but the number that is resulting in terms of forced outages is a function of the risk of the various technology types that are modeled. Granted, we could stress the system further, and that's a topic of conversation that we're willing to have with states and stakeholders.

So, for example, if we want to model gas contingencies as part of this study, we can do that. But we feel it's outside our scope to make that judgment and therefore to show an energy shortfall that may far exceed the limits of the ISO authority in what it can and can't do. So from where we sit, for what we've shared today for 2027, our assumptions are reasonable. They're based on either facts of what the infrastructure is. They're based on all of our known risks and some of the risks that we expect to manifest in the future.

We also expect our neighboring control areas are not going to be able to support us the way they could under unstressed times. So we have allowances for each of those. It's a question of to what degree, and the degree that we put into these models is again our best experience over the many cold periods that we've operated over the last decade. And in terms of what we could expect as our system evolves, but also as our neighboring system evolves. And lastly, these assumptions can be changed easily.

The benefit of having this platform is that it took us about 18 months to build it, but now we don't need to wait more than a day to see results of new scenarios we're going to offer to our stakeholders and states the opportunity to introduce scenarios that they prefer that they think may be a better manifestation of the future and we can turn results around. Bottom line, all of this to deliver for New England a baseline metric, an energy shortfall, tolerance that will act as a companion metric to resource adequacy, which is 1 in 10. They have to be two distinct products that we think we can then design markets because we have actionable data of what we're buying and to what extent the purchase that we're making will mitigate that risk. So that is really what's in our work plan looking ahead.

COMMISSIONER CLEMENTS: Thank you. And one other thing I meant to ask about it from the perspective of it being decisional, does that concern you? Can you say more about how it works together with your other tools?

MR. CHADALAVADA: The study absolutely agrees that it's not decisional in any particular scenario. It is going to be over tens of thousands of scenarios and expectation that we understand what the risk tolerance is in New England. And as we see the risk tolerance creep up, that baseline again is critical for us to always mitigate it back to that level.

So what's decisional in this would be for me, the information that we share with our stakeholders, with our states, looking at the totality of the spectrum of contingencies, highly stressed, low stress scenarios to pick a metric that allows New England to say that's our tolerance. And once the states can give us that information of what that tolerance is, it then is incumbent upon us to design the necessary market products. And one last comment on this. Going back to Panel 1, was a lot of discussion about infrastructure and commodity co-mingled. The ISO takes its responsibility very seriously of ensuring that markets induce the right sets of incentives for the commodity to be available, and that's clearly within our manifesto.

COMMISSIONER CLEMENTS: Thank you. And I just have one more question for Chair Bartlett and Chair Gerwatowski. How do you know, you mentioned putting some sort of value on the solar that came up in this study or maybe that was in the 2024-2025, I'm not sure. But how do you think about the usefulness of this study from the perspective of your own jurisdictional, whether it be, you know, the initiation or evolution of efficient -- energy efficiency programs or other demand side resource programs or otherwise?

MR. BARTLETT: You know, I think going back to the point of being decisional, I think where I think it's helpful is going to use to help us to really evaluate what are the risks and the costs and the value that we get out of various fixes. So from our perspective, you know, with this tool, we might be able to then think about demand response a little differently. What kind of retail demand response program could be set up, what kind of commercial retail demand response that could be set up and then have that evaluated to see whether it is providing enough of a benefit to justify the cost that would be putting onto ratepayers.

Similarly, as we're thinking about ways to incentivize storage or efficiency, to the extent we can run some of -- to analyze through the model the impact of those things, I think it makes it a lot easier to justify to ratepayers the expense and also just to make the decision whether any particular expense is really worth it based on what the return is. So to me it's really valuable in decision making, though obviously it doesn't dictate any particular answer.

MR. GERWATOWSKI: I'm just to echo what Barclay indicated. This is really excellent information for us to assess the value of renewables as they come in. One pleasant surprise that I had was I always knew that the offshore wind was going to be very useful during the winter to avoid burning down stored fuels. And I always had looked at solar as something that always helped in the summer, but really was not very helpful in the winter. And it was -- it surprised me. And I said, well, it shouldn't have been surprising.

So, I mean, the value of the solar has gone up quite a bit from my perspective, just from the basis of the study. I never thought it would be helpful in the context of winter reliability, and it is. So those are the kind of things we'll look at as a value proposition. I think as we evaluate programs that we go forward with.

COMMISSIONER CLEMENTS: Right. Thank you very much for participating.

CHAIRMAN PHILLIPS: Commissioner Christie.

COMMISSIONER CHRISTIE: Want to go to Commissioner Gerwatowski. I hope I got that right.

MR. GERWATOWSKI: I accept any reasonable approximation.

COMMISSIONER CHRISTIE: Well, I hope that was a just and reasonable. Your opening statement. I thought I agree with every single word. And he got to the very end. And I just want to clarify on the variant as a state regulator, former state regulator, I agree with you. And let's talk about your LDCs. So your LDCs, if you know, state regulators, we worry about whether our LDCs have sufficient supply and we make them tell us where they're getting it and where they're going to get it. And so every word you said, I obviously agree with you and Everett may be needed for longer term than a couple of years.

But the only thing is, at the very end you said, so somebody ought to do a study. It seems to me like that seems to be the default key up here is somebody ought to do a study. But you as a state regulator can call your LDCs in right now and say, where are you getting it from and where are you going to get it from? And if you're getting it from

Everett or and the same thing would apply in Massachusetts regulator. You don't need to study. I mean, they can tell you right now, your LDCs can tell you right now where they're getting it, where they're going to get it and where they're going to need to get it.

And so why can't we as state regulators just call them in and say, where are you getting it? And if they say we're getting it from Everett, we cannot afford Everett to close. You can say publicly we cannot afford Everett to close. Let's work on getting it financed. That'd be my only -- every word you said was true until I thought you said it at the end. We need another study. The reality is, know where they're getting it right now. You don't need another study, right?

MR. GERWATOWSKI: I think they. I probably conflated two things. Without question. You're right about the ability for us to bring in LDCs and learn a lot from them and demand that they do certain things. I think in part what I was doing was illustrating the sensitivities of the gas system that we have. We experienced this thing, this event for things that were occurring far away from Newport. And here we have the situation of the entire regional electric system. And we don't have evaluation where you need the pipelines -- the interstate pipelines and the LDCs and the ISO working together to develop the scenarios.

So when I said -- and that seems to be absent and actually that's not a criticism of the ISO study, it just seems to me that the assumption that, yes, the gas system will be operational and this is the basis that we're going forward with the conclusions just seems to be missing that piece.

And I don't think that, I've never felt that we've had the ability to tell the interstate pipelines to go and work on a on a on a on a study that does the hydraulic modeling along with the LDCs. I think that was the point that I was getting at. But I don't quibble with what you indicated in the beginning of your comment.

COMMISSIONER CHRISTIE: Okay. All right. That's my point.

CHAIRMAN PHILLIPS: Commissioner Danly.

COMMISSIONER DANLY: So I guess my question is what the ultimate conclusion we're supposed to draw from this thing is. It seems you don't believe that the weather conditions that had been alarming in the past are quite as severe or the consequences will be as severe as you thought before. And so what does that mean? Does it mean that we have been historically overpaying for reliability and I assume in England and there's a greater tolerance for it? Is that the point that the market has been over procuring for that? Last year I was informed that basically ISO New

England was unable to employee market mechanisms to ensure resource adequacy.

And now, nine months later, without presumably a whole lot of building of new things or some mass exodus from the region. Yeah, it looks like we're okay. I guess I'm having trouble understanding. And I've been coming back to this repeatedly, and you can see I'm really struggling with this. How is it possible or not how is it possible? How do we put this in actual terms? Right. Because we have limited jurisdiction. We're in charge of your tariff, or at least I shouldn't say that you're in charge of your tariff. We approve it when you file it. What has been the change that has occurred? And does this implicitly mean that we have had a poorly designed market historically that rather than what I thought last time we all were together, was underpaying people to ensure resource adequacy and reliability?

In fact, it's quite the opposite that you're saying, no, there's no problem here. And if anything, what we're going to do is potentially see the loss of this gas from Everett. That's okay, because even though our system relies upon a bunch of natural gas generators that don't -- you can't afford a firm fuel contracts in the main, but we'll take our chances with that. Good to go. Don't need to have the extra generation get rid of the Mystic perfectly fine. Which, by the way, I'm not saying anything on that.

I'm just giving a list of what appears to be what you're saying to us. I just -- I -- knowing that we have massive difficulties in building anything.

This isn't trying to build a pipeline in Oklahoma. It is very difficult to build infrastructure. You have a massive facility that is probably never going to come back once it goes. I'm just struggling to understand what was wrong before and how it is that things have changed. And sorry that I keep harping on this, but I am just not getting it.

MR. CHADALAVADA: The two things that I think are critical in the way that we've studied this. Up to this point in time, let's say roughly a year ago, we're looking at the equation in terms of capacity. Either you have enough capacity that can produce energy or not. We have started to shift our analytics to study about energy. And so all of the capacity that's in New England, what are the constraints on each of these technology types? What is the delivery of energy across all of these technology types and what is the need on the system from an energy standpoint?

So the capacity scarcity event and the sorts of events that have happened on December 20th may still happen, but we've now started to shift to an energy analysis and the tools that we've had to this point in time were limited. We are not able to take the same tools that studied capacity and use them for the purposes of understanding energy needs. What this platform has done for New England is start to appreciate the differences between the two models.

What is the equation when you have a capacity factor of 10% for solar versus what is the energy production when it's at 10% capacity factor across 21 days? And they're both necessary pieces of information, but we hadn't made them available side by side for the purposes of meeting our 1 in 10 standard, which is required from resource adequacy and separating it from what do we need for energy adequacy.

And so where maybe the message isn't going to be crisp because this is an evolution and it's necessary because of the changing system is we have to look at both. It's no longer sufficient to say we have enough installed capacity and for that matter, experience around the nation has shown more so than not that it's forced outages that have been the root cause of many of the concerns in terms of delivering energy.

So you have to look at those two dimensions. And this tool and what we've been discussing in the past are two different things. And so the sophistication of knowing energy adequacy, I think is for us, the key differentiator from all of the work and from the way that we've been expressing ourselves in the past. And so capacity accreditation, Commissioner, just to make it -- I know it's going to be later this afternoon, but the market is far from perfect. There's a lot of work.

We have the fundamental structures that we need, but in terms of incentives, we have substantially the right level of incentives. But there's still a lot of work for us to do in terms of getting capacity accreditation, right, in terms of getting the price formation in our energy and ancillary services, right. And in terms of designing the new products that we need to protect against the sorts of risks that we're talking about.

COMMISSIONER DANLY: Okay. That's really irritating because you did the same thing again, which was preempt the next question I was going to ask you. So -- I would like you to talk -- you said comes up later. Don't care. I want to hear about it now. You said there's still work to do in fixing the markets. My question remains, have we been overpaying for reliability? Is that the implicit lesson that we're to draw from this? Because if we're told the sky is falling nine months ago and then -- and really, I don't think that's an unfair characterization.

I don't it was it was pretty dire. And we're being told now. Now we actually got a whole new set of information. We bought a new laptop and we're running a new program on it now. And we can figure out these things we didn't know before. My question is, were all of the assumptions before faulty and were we overpaying for capacity or are you saying we just happened by a miracle without this information to have perfectly titrated the prices correctly? What are the capacity market reforms that you're envisioning or for that matter, any market reforms? I'm still -- I guess I'm just not convinced that this is as paradigm shifting as you're making it sound. So if you could try to persuade me, I would love that.

MR. CHADALAVADA: It's a tall order, Commissioner, and it isn't -- first question that you asked, have we been overpaying for reliability? Not at all. I think that we've been paying for reliability the way the markets have been structured based on the models and the product and the demand and the supply side. And it's really making sure that the supply and demand intersect at an installed capacity requirement on a curve that we are using the models that much of the nation uses. So on that basis now are the models perfect? Every panelist here has basically alluded to the fact that no single model is perfect. So those are the improvements that we're going to be making is in our model capacity.

Accreditation is at the forefront of what we want to work on, and it's a progress that's underway. They had ancillary services, which you'll hear is the next improvement that we want to make. But the journey doesn't stop. We know there's a need for ramping product. We know there's a need for other reserve products that will protect against the sorts of energy adequacy shortfall measures that we've just seen in the study.

So those are the steps that we need to take to improve our markets. And so in terms of a paradigm shift. It's not so much a paradigm shift as an assessment as we've improved our analytics of understanding where the weaknesses of the system are to a greater degree than we ever had before. So if you look at any of the areas PJM or Midwest, ISO or Texas, as they've gone through their experiences, they're starting to see that the models that they've used and the results and the experiences that they've had are different.

And so it's incumbent upon each of us to take the actual experience of the system and feed it back into our products and into our markets and into our tools and models. And that's the journey you're seeing. So it's less a paradigm shift rather than the ISO trying to improve itself at each step of the way, using the information that it has and knowing what its journey is going to be and struggling a bit along the way because there isn't --

COMMISSIONER DANLY: We can expect another iteration in nine months in which you then say actually we now have yet a new model and in fact we're completely facing the brink of disaster. It is a pretty dramatic shift that we're seeing in the story we're being told. I, I just I have to make that clear to everybody because it seems like it's being glossed over a little bit here.

MR. CHADALAVADA: I understand, Commissioner, in nine months, if we're doing a 2027 study, short of a catastrophic event on the system, I expect you will see similar results. But as we go out into the decade, for example, in 2032, the results may be much different than what you're seeing today because we're now studying a system nine years from now where the uncertainties are much greater. But again, many panelists have made the comment that the ISO should model the loss of a compressor station. We did that in 2017.

It shows a massive exposure of risk in New England, but that's not actionable from our standpoint because we are starting to model gas system contingencies. That's informational, but what would the ISO do with that? And so we didn't see the benefit of stressing the system to a point of saying what happens if there's a catastrophic black swan event? We're going to be in a world of hurt. There's almost a certainty that I won't be in my job probably the next day. But you know, those are the challenges that we need to prepare for, but we can't design markets for. And there is a limit to what we can accomplish. But that journey of discussion and information, as frustrating and tiring as it may be, is necessary because we are part of that conversation of trying to educate ourselves and bring the best information we have forward.

COMMISSIONER DANLY: I mean, if you're arguing for iteratively, I can't argue against that in return. It's just okay. I guess we have a couple of cards up. Go ahead.

MR. BARTLETT: Thank you, Commissioner. You know, I think for years and years, we've recognized that we have a fuel security risk in the region and have been putting one solution after another. Some of them are market based. Some of them are not trying to get a handle on this, but never really having sort of the robust probabilistic analysis to understand whether we were solving the problem or the magnitude of the problem continuing. So I look at this 2027. Every study is not so much a dramatic change in results, but it puts the risk into context. I think we often talk about the reliability risk.

As you get to a point, you can't serve all of the load and you hit tilt, right? Just the system breaks its tilt. And we don't really talk about, well, what's the magnitude? And I think what we see in the 2027 study is not that there's no risk but that ISOs assess that it is manageable, that it is of a magnitude of probability that they feel like they can handle it. And I think as we go forward to 2032, as we see the risk of more retirements, maybe the renewables aren't coming on as fast as we expected. I think we'll see more weak spots that we can plan to. But to me, this just goes to the power of having really good analysis so that you can make informed decisions and correct the actual problem, not sort of this tilt situation where, you know, the lights go off.

COMMISSIONER DANLY: And so correct the actual problem that is compensating people correctly through the market mechanisms or getting infrastructure built that's needed. Right. Are there any other solutions to the problem that you just alluded to?

MR. BARTLETT: And I think the discussion of the earlier panel sort of illuminated this, that whether you're talking about Everett or you're talking about the other LNG terminals, what's needed is the right contract incentives, you know, to get firm fuel delivered. And keeping everyone alone isn't going to solve that or any other infrastructure if you don't have the market mechanisms to work as well.

COMMISSIONER DANLY: And part of the problem, too, is because it's both LDCs and generators that are the beneficiaries of that gas. We only have jurisdiction over one of those two. And so there's a limit to the amount other than convening things. There's not a lot that can do directly there. Okay. Sorry. Do you have anything else Daly? Okay, go ahead.

MR. DALY: Thank you. So when we --when last we met, there was talk the problem was framed in terms of, well, power generators will not provide for those extreme cold events. They will procure fuel for what would be an expected winter type situation because it's very risky. Very cold weather doesn't show up once in ten years, 1 in 20 years, whatever. So nobody is willing to fill tanks to the degree to cover that type of scenario. But I just point out that in this in this study, a lot of LNG and oil is showing up supposedly, and questioning, questioning that. What changed? Well, is it the inventoried energy program? That's -- it's only a two year program, so it won't be in place in 2027.

So what's causing this optimistic view of what where the fuel is coming from? And you heard on an earlier panel what you need to do is to contract forward for those fuels to show up in the winter time. You can't decide on a 20 day forecast that you're going to you're going to now contract for ships of LNG and oil. It just the demand or the supply isn't really that immediate and that available and the cost recovery of it is not agreed. So, you know, I just question that we have the right market structure to produce the results that we're seeing in that study. And that's why

I say let's not dismantle stuff that we have and works today before we have these resources that are forecasted to be there, actually come into come into play.

I think it's a very risky strategy to go in and let resources you clearly need. And as I said, I started my comments and saying we have a high and volatile market. Volatility and high prices are synonymous with scarcity and we have precarious --

COMMISSIONER DANLY: Things are working correctly. Yeah. So I saw the look on your face there. I took that to be correct, that there were assumptions about the availability of both gas and oil. And so was that wrong because you shook your head?

MR. CHADALAVADA: No, not wrong. But the idea that those were optimistic, I wouldn't suggest that those were optimistic. Those were reasonable as informed by what we got post Ukraine chaos where post invasion of Ukraine, because that was a time where we were paralyzed in understanding how the world was going to behave in late fall, early winter of last year. And we saw the market perform beyond our expectation. We saw the volume of oil that came into New England probably higher than ever in the last ten years without any subsidization. We saw that the commodity, the LNG came into New England.

Now, yes, the weather was very mild and we're not going to take this for granted that the next time there's some global supply chain constraint that we should expect something similar. But we have downscaled our expectation of what we will have for LNG and for oil. And so I just quibble with the word optimistic. For example, the result that Steven mentioned assumes that at the start of a really cold snap, we have six BCF of LNG against an installed sort of infrastructure base of between 13 and 16 BCF. So we're assuming less than 50% of volume. I fully accept the need for a gas study because we are limited in our expertise.

And so I take to heart the concerns expressed by pipelines and LDCs about the gas system deliverability. If there are specific issues on the gas system that impact or impair the operation of the electric system, I have great confidence that they will give us that information, which we will reflect in the next iteration of this study. So it's not complete. I don't want anyone to think the study is incomplete. Neither do I want anyone to think that the study is either optimistic or conservative. It is our best expectation of the future based on our experience all the way through this past winter.

COMMISSIONER DANLY: For the next few years?

MR. CHADALAVADA: For the next three, four years. That's correct.

COMMISSIONER DANLY: Okay. So I should probably hand it back to you. I don't want to take up all the time here.

CHAIRMAN PHILLIPS: We can -- I see tent cards up at least one. No, we got two.

MR. GRIFFITH: Yes, sir. Just two really quick points on the topic of contracting. I don't disagree that some level of forward contracting is helpful. LS has, you know, dual fuel oil capability. We have a little bit of FTE for one of our units, but I think the magnitudes are still really important. When we look at what's coming out of this study, we're talking about needing 60 million gallons of oil for that worst week, the worst 21 days, and that's a lot of oil. But on the other hand, we have 240 million gallons of capability, so we need a quarter of it. That's and -- you know, we've gone through during things like the 2017, 2018, cold snap, similar amounts of oil, and we've replenished it immediately afterwards.

So we have a track record of managing through that kind of oil need and coming out the other side. Okay. So I guess I worry when I hear views expressed that say, you know, we need everything contracted super far forward because that's the only way we're going to ride through it. I think the study reflects reality and saying we have done it before, we can do it again, and the amount of oil we really need is real, but certainly within reach.

CHAIRMAN PHILLIPS: Mr. Lauby.

MR. LAUBY: Thank you. You know, I wish we had somebody who could regulate the fuel like wind and solar, along with, of course, the gas and coal. That's always been something that we've had to manage. And when it came to coal, it was in the back 40 or you had uranium or water. Now we're dealing with real life, you know, energy constraints and constraints systems which are just in time deliverable. And we need to understand what -- we're talking a lot about solutions here. We've got to start understanding what is -- what are we going to design to. Maybe the minus -- maybe 100,000 megawatt hours is the design parameter for 1961 and we never want to get there again. So we designed it to be able to overcome that. That might include fuel and the tanks, it might include other gas pipelines and might include a host of other facilities, energy efficiency, demand response, all sorts of different solutions to get us to what we want to design to.

And I think that's really missing in the conversation and something we need to start thinking about as we start wanting to get more decisional about our analysis. Realizing of course, again, a forced outage rate is just that. It's just a number which is represents a Poisson distribution and yada, yada, yada. And I can get pull up the covers on that and you don't want me to do that. But we have to understand really what is the acceptable level of risk, what are we willing to accept, build to that and then learn how to restore from those events that go beyond that. Thank you.

CHAIRMAN PHILLIPS: Mr. Danly, final thought?

COMMISSIONER DANLY: I was just going to say what we designed to is sort of the other side of my saying, are we overpaying? Right. We have that question is meaningless if you don't know what the thing is you're paying for. So it's the same. It's the same point fundamentally.

CHAIRMAN PHILLIPS: Any other final thoughts or comments from my colleagues? All right. We're going to stop right here with the first half of our day. I'm going to turn it over to Mr. Burns, who will instruct us on how we can get back here for an on time start after lunch.

MR. BURNS: We're starting at 12:55, not 1:00. 12:55. For those of you the -- excuse me, there is plenty of casual options around. So we'll see you back here five minutes before 1:00. Thank you.

CHAIRMAN PHILLIPS: Thank you, everybody.

(Whereupon, at 12:55 p.m., a luncheon recess was taken.)

AFTERNOON SESSION

MR. BURNS: Welcome back, everyone. We're going to get started before we start the third panel. I'm going to turn it over from -- to a colleague from PHMSA.

MS. GENTILI: Good afternoon, everybody. I hope you all had a good lunch. My name is Karen Gentili and I am with the Pipeline and Hazardous Materials Safety Administration, commonly referred to as PHMSA. PHMSA's mission is to protect people and the environment by advancing the safe transportation of energy and other hazardous materials throughout the United States and in support of National Safety Month.

I just wanted to give a safety minute to remind everybody to please notify 811 prior to disturbing any soil, whether it's to maintain or construct infrastructure or to perform a home improvement or landscaping project such as installing a fence or planting a tree, please notify 811 so that underground utilities can be marked. It's a free service and it's to protect you and the underground utilities. Thanks for the opportunity to deliver this message and be safe.

MR. BURNS: Thanks, Karen. We're ready for Panel 3, Paths to Sustainable Solutions Infrastructure. Panelists for this panel include David Cavanaugh, Senior Vice President, Regulatory and Market Affairs of Energy, New

England. Patricia Diorio, Head of Americas Project Development, Orsted, North America. Vandan Divatia Vice President, Transmission Policy, Compliance and Interconnections. Eversource Energy. Katie Dykes Commissioner, Connecticut Department of Energy and Environmental Protection. Bob Ethier Vice President, System Planning ISO New England. Richard Paglia Vice President, Marketing and Business Development, Enbridge, and Rebecca Tepper Secretary, Massachusetts Executive, Office of Energy and Environmental Affairs. Just a reminder to our panelists to please avoid any ex-parte discussions. We will interrupt if we need to. And, Mr. Chairman, we're ready to begin.

CHAIRMAN PHILLIPS: Thank you again. And thank you, everybody, for coming back. And thank you to all the panelists here today. And thanks, Karen, for that 811 reminder it is important that we call 811 before we dig. And I think that's a perfect segue to talk about what we're about to talk about, which is infrastructure. We've talked about Everett at length this morning.

And so what I would like to do with this panel is to transition into talking about other types of infrastructure. And it can mean many different things to different people. All right. It can mean transmission planning. It can mean development of new resources like onshore, offshore wind, oil, natural gas, traditional thermal resources. What I would like to start with, with this group is this. In your view what do you think? What is the key infrastructure needs for New England in order to sustain reliability beyond what we've talked about already today? And don't all start at once. Cavanaugh.

MR. CAVANAUGH: Thank you, Commissioner, and thank you again for having me on the panel this year. As I mentioned last September, for public power, it's certainly we have three objectives, right? It's reliability least cost power and decarbonizing our portfolios. But to your question, when I think about that transition we're making here to a cleaner grid, we have to also keep an eye on doing it safely. And you look at what's going on today in New England and we're right now going through qualifications for FC18 and we have in the news delayed offshore wind projects, but we also have reasonably quite a bit of retirement. You could see coming up of resources. We need to safely make that transition.

So when you think about infrastructure, immediately I think about what our main objective is. Reliability. And then of course, as I mentioned, our last is to decarbonize. And for us, we're starting to think about -- if I look into Q today and look at the publicly available data, there's a 742 megawatt resource in Connecticut that put a retirement bid in. If I back into that, there are about 28 million gallons of stored fuel there and it's a facility that's been around for a long time that will have impact as we think about the reliable transition to future, particularly with the delayed entry of wind.

And then if I look further at the publicly available data, there's a large storage facility in New Hampshire that's indicating its desire to probably start exiting the market before long. So as we think about where we are, it's also not only transmission that we'll need, but it's also maintaining the resources that provide those reliability services we need today and into the future.

CHAIRMAN PHILLIPS: So if we can add a twist to that question, what are the barriers? What are the obstacles to both keeping the resources that we need and bringing new resources online? Yes, sir.

MR. DIVATIA: Good afternoon, Vandan Divatia, Eversource. As I try to answer that question, I'd like to go back in the early days of my career, very similar timeframe where we as an industry, we evolved our planning process to start planning for multiple contingencies so we don't have a recurrence of what happened on August 14th, 2003. As we transform the New England system into potentially a winter peaking system, we have to start realizing that winter resource adequacy and winter reliability are inextricably connected and to our customers, they are indistinguishable.

So when you think about the obstacles, one of the obstacles is the lack of that type of a standard and that type of a planning attribute in the planning or grid. In addition to that, some of the comments made by the included in the FERC, NERP already point to a longer time, longer planning horizon, and we support that starting to look at multi-value solutions such as not just looking for reliability, but clean energy and an economically beneficial project. So when one of the obstacles is the planning process and I think the industry needs to start making strides into evolving that. And I would say the second key obstacle is clarity and cost recovery.

We've done numerous studies in New England to determine what kind of a system is needed to integrate the clean energy resources we need to maintain reliability, but we don't have the clarity in making decisions on those anticipatory solutions. And what I am encouraged by is the recent applications that were done by New England, by Massachusetts and by Connecticut for anticipatory transmission to interconnect offshore wind. So there are some positives in this direction, but I'll pause at the planning process as one of the key obstacles.

CHAIRMAN PHILLIPS: We go here, then come back down here.

MS. DiORIO: Thank you, Mr. Chairman. And I wanted to just express my appreciation to the FERC for holding this really important forum. Orsted, as you know, is a world leader in offshore wind energy. We also are engaged in onshore renewables here in the United States. We've got a five gigawatt awarded portfolio of offshore wind farms. And for New England, offshore is certainly our focus. So we own Block Island just for context, and we also have the 750 megawatt revolution wind farm, which has contracts with both Rhode Island and Connecticut.

So we'll serve the New England area. And I want to agree vehemently with my colleague from Eversource that transmission is the unlock for renewables of all stripes. And in New England, especially for offshore wind. I would say that taking the long view on this, it'll just get more challenging to connect offshore wind in particular in the future. And there are studies that show that we could have about 30GW of that resource, really super important resource by 2050. It does enhance reliability because of its seasonality in the wintertime. So it does have a role to play here.

But I would echo my colleague here that long term planning is super important. We've heard a lot of discussion about that. And then also cost allocation. I would encourage the Commission and the RTOs to take more of an expansive view of cost allocation and reliability benefits, as well as projects that will help states to meet their decarbonization goals.

CHAIRMAN PHILLIPS: So we have transmission planning, we have cost allocation. We want to add to the list or are we in agreement with the list?

MR. PAGLIA: Get that to work there. Thank you, Mr. Chairman. Thank you, Commissioners, for inviting me back. The short answer to your first question is infrastructure. We need infrastructure in this region. It -- we can study it as long as we want. We know we have constraints across all aspects of our energy systems in this region. And let me be clear. My comments today are largely going to focus on gas infrastructure, because that's what we -- what I do primarily at Enbridge. But please don't construe that as not being supportive of an all of the above approach if we want to move forward in this region. We need customer choice. We need affordability. We need reliability, resiliency and sustainability. We can't accomplish that with one silver bullet. I think that's a fair point.

So on the gas side, because again, that's my area of purview today. We have a problem, Commissioner Danly. You were poking at Vamsi. I did that similarly a couple of months ago when I first saw the report. Vamsi, I apologize to you because I got a little animated because it was a total 180 from where I thought the region collectively have been on the challenges between the gas electric interdependency. So I was obviously concerned as well.

We do have a problem. We provided comments on the record. I hope you all have had a chance to see them. If you haven't, I would encourage you to do so. And we're happy to speak to those at any time. We talk a lot about modeling and assumptions. The reality is our systems work in real time. Minute to minute, hour to hour. That's where the gremlins lie. They don't lie in -- oh, I hope we get X amount of supply over the period of the winter. We'll be fine. They lie in that minute to minute challenge of operating our energy systems, and that's where the vulnerabilities are really starting to show on the gas side. And as I said, we highlighted that in our comments.

So to move forward, we need more infrastructure. All of the above, again, as I said, and we can achieve the goals. And I think we all want to as a region, but without that common understanding of an all of the above approach, which includes additional gas infrastructure, we're going to be talking about this next year. I've been doing it for 27 years and I really hope that we can move that conversation forward today.

CHAIRMAN PHILLIPS: Quick follow up for you. Would you agree that additional gas and oil storage is included in that new infrastructure that we need?

MR. PAGLIA: Yes, I think we could largely reduce our reliance on the oil infrastructure if we focus on gas related solutions. And when I speak of gas related solutions, maybe if I may, just very quickly, two types that resonate for me in particularly as beneficial to this region. One would be on system LNG with liquefaction and storage capability that addresses that peak day reliability and resiliency concern that we're all focused on and we're scoping out several of those types of projects across our system and we're hopeful that we'll be able to move some of those forward.

The second would be expansions of our main lines. I'm not talking about greenfield pipeline development, I'm talking about lift and replace, adding horsepower compression to really tap into the supplies that are several hundred miles to our west. That really hits resiliency and affordability. So you get different results from different types of infrastructure. But if you broadly shape your thoughts around those two, we can really move the needle on where we are today in a timely fashion.

CHAIRMAN PHILLIPS: Thank you for that. I'm going to go to Ms. Dykes. Always good to see you.

MS. DYKES: Great to see you, Mr. Chairman, and thank you so much for again, traveling to the region to host this important conference. I'll just add to the list. I think one of the really important things that we need to address this long term challenge is better planning and analytical tools. And I am gratified or relieved that 11 months after the last forum where I joined some of my colleagues, I'm thinking of Chairman Bartlett's comments around calling for more proactive planning tools, more quantification and quantification of the performance characteristics of resources. We need to address the Winter Reliability challenge.

We now have this EPRI study moving forward, this tool. So I just want to, as someone who's been not shy about being, you know, vocal about the things that we need from the ISO to achieve our collective vision around reliability and affordability of our grid, I want to really recognize and appreciate how the conversation has been able to move forward because of the study.

I do think that we urgently need the results from the 2030 to run in order to answer the question of this panel and frankly, some of the questions in the earlier panels. So we're eagerly awaiting the results from those studies and particularly what it will say in terms of the amount of new offshore wind that might be needed to replace the oil units that we do. I share the concerns around the pace of retirements there, as well as what will be assumed in terms of the continuing operation of the nuclear facilities.

Keeping in mind that while we've been talking a lot about Everett over the last five years, there's a similar challenge that we faced and addressed -- Connecticut addressed in terms of retaining the Millstone nuclear facility. But I will say, beyond those planning tools, once we have those, it unlocks the ability for us to align our state procurements and things that we're doing to meet our climate and clean energy goals across the various states with the desire that we have as states to provide for affordability and reliability of the grid. And so that's really helpful for us to align those things.

I think that there's -- it's really very interesting looking at the 2027 study to recognize I see an implicit acknowledgment there that state clean energy policies are contributing to and not hindering the region's winter reliability. And so I think that the removal of some of the barriers in our market towards the participation of state public policy goals is really important.

It also opens up the possibility of cost allocation discussions that could seek to regionalize some of the costs of integrating those state public policy resources because of the reliability benefit that they're providing. And I'm thinking here in terms of transmission to integrate offshore wind. So there's lots more to say, but you have wonderful speakers here, so I'll reserve for another comment.

CHAIRMAN PHILLIPS: Thank you so much. And thank you for pointing out the attributes of your state policy choices and how it has benefited reliability. I appreciate you pointing that out. Ms. Tepper.

MS. TEPPER: Hi, Good afternoon. Thank you. Thank you for having us here today. Always appreciate you taking the time to come here and talk to us in New England. I did want to just start real quickly with a quick comment on, you know, last time you were here, I ended my remarks by encouraging the Commission to bring more people into this discussion and to think broadly about who's interested in these topics. And I noted that hearing from lots of voices gets us to the best answers. And I know your creation of the Office of Public Participation does exactly that. And I would just want to comment that I think this hearing would have been benefited from some additional voices today, particularly the environmental and the environmental justice communities and particularly the community of Everett.

I encourage the Commission to read the statements submitted by the people of Everett and by the 50 organizations that signed their comments and to pay attention to them. They live there with that facility. And I think it's important that their voices be heard. That being said, I also want to note not be surprised to hear from me that I will continue to say that the region's problem is over reliance on natural gas. And last year that really led to a pretty difficult winter for our customers.

Prices were extremely high and we can't continue to rely on sources of fuel to keep the lights on that are coming across the ocean and are vulnerable to supply disruptions and global market volatility. So our way out is to transition to a clean energy future, and we're doing that in Massachusetts with sort of our five point strategy, which is reduce, optimize, build, connect and partner and reduce is obvious. And I think, you know, this is a panel about infrastructure. But before you talk about infrastructure, the first thing you have to do is make sure that you're using energy efficiency and demand response and using your optimizing your system with grid enhancement technologies, with OPP, with all the different tools that we have now to make sure that we're using the current system that we have before, before we build. But number three is build.

And we are we are building here. Last week, the foundation of the nation's first commercial scale offshore wind farm was installed 15 miles off the coast of Massachusetts. And we also recently announced a draft RFP for 36,600MW, up to 3600MW of offshore wind. That's 25% of our state's annual load. I'll be quick. I know I don't want to talk much more.

But for this connect and that gets us to sort of one of our one of our barriers I think is interconnection. And I think as I don't remember who said it, but we just recently submitted an application for $250 Million to the Grid Innovation Program to upgrade and ready our onshore transmission system. And that would allow up to 3600MW of offshore wind and 300MW additional of solar. So, you know, I also along the same lines, we're looking into connecting with other regions. So yesterday -- all sometime this week, all the New England states a bipartisan letter and New Jersey and New York, all sent a letter to DOE asking to form a collaboration together, to be talking about connections between our states and regions.

And I know that's something you all have been interested in, is increasing that and really hoping that collaboration will get there. And lastly, partnering, and that's partnering with the people in the state, our low income and our environmental justice communities to ensure that they're part of the decision making and that they also receive the benefits of the clean energy transition. So we're on a path to clean energy, and I know the rest of the region is as well. And I think that's our way.

CHAIRMAN PHILLIPS: Thank you for your comments. I do want to pick up on the environmental justice comment that you made. I don't think I have to tell anyone here that you're preaching to the choir when it comes to putting first the voices of Everett communities. I'm sure you're aware that FERC held the first ever Environmental Justice Roundtable at FERC on infrastructure permitting in March. I've also made it a top priority of mine. And we also have the Office of Public Participation. Nicole Senarami, please stand. Here with us today. She's here in the room and is doing a fantastic job reaching out to community. So thank you for shining a light on this issue, and I appreciate your comments. ISO New England.

MR. ETHIER: Thanks for the opportunity to be here today. Thank you, Chairman Phillips. I just wanted to build on Vandan comments a little bit. First, I wanted to note that New England actually is having some success building new projects. We have two offshore wind farms that are currently under construction, two large wind farms. We have about 4700MW of offshore wind that has either completed their interconnection agreement process or are on the cusp of completing it. And that is going to largely use our existing infrastructure. We are not building large new lines to handle those, so we currently have some headroom to build and that is being used. So that's the good news in the near term, as a number of folks have pointed out, in the longer term, we clearly need infrastructure investment if we're going to accommodate the levels that many people throughout the region and on this panel have noted in terms of the region's public policy goals. And there's no doubt we need process improvements to do that, we need to look farther into the future and we need to figure out cost allocation.

The good news is we've made step progress on each of those already. We have more to do. But you all actually approved a change to our tariff in the last year or so that gave us the authority to do this longer term analysis. And we are doing that as we speak. And I think that's gone over quite well with the region. I think folks are appreciative of that and we're getting a lot of feedback about that. The fun part is now we are doing the cost estimates for those future projections.

So that'll be an interesting discussion with the region when we see what the price tag is on what we see as a need. So we're making progress on that. And we have a second phase of that whole tariff change process that will is seeking to build a process where we partner with the states and all of our stakeholders in identifying exactly which projects that we see we need in the future, which ones we're going to select to build now and how we're going to pay for those.

And what we're trying to also roll into that is asset condition projects. So what our study has identified is one of the -- I'm not going to say it's going to be cheap or easy, but one of the lower risk, lower disruption paths to getting more infrastructure is to upsize our current infrastructure. And a sensible way to do that is when current infrastructure needs to be upgraded anyway. Look at your models and say, oh, this path -- is this a path that gets overloaded in the future? If so, can we upsize it now for both cost savings and to prepare for the future? And we are looking to build that into our process as well.

So I think the good news I just want to follow up on Vandan's point about the good news is that we all collectively are already looking at that and I hope are trying to do it in a sensible and cost effective way. Thank you.

CHAIRMAN PHILLIPS: Thank you. And with that, we'll turn to my colleagues. Allow them to get in this discussion. Let's mix it up again. We'll start with Commissioner Christie, then we'll go to Commissioner Danly and Commissioner Clements. Commissioner Christie.

MRR. CHRISTIE: I'm just I'm going to ask Secretary Tepper. You're in the governor's cabinet, right?

MS. TEPPER: I am.

COMMISSIONER CHRISTIE: That's what I thought by the title. Let me just ask you, we've heard testimony today about Everett specifically, and you referenced Everett in your comments. Does the governor support keeping Everett open?

MS. TEPPER: I think right now we are interested in -- there's been a lot of -- as we talked about this morning, a lot of new information that has come in over the last few months on this issue. Our understanding is that the LDCs, the local distribution companies, the regional ones, are talking with Constellation about potential contracts. And, you know, it is their responsibility, as you know, to ensure that they serve their customers and, you know, they need to go to their regulator to ask for that.

COMMISSIONER CHRISTIE: Okay. Thanks.

CHAIRMAN PHILLIPS: Commissioner Daly.

So for -- we've had these discussions for a while. You said you've been doing it for decades, right? The. The hope, of course, is that there would be some practical outcome. I will admit that nine months ago I wasn't expecting to get the analysis back that we have. Nevertheless, it does seem that there has to be something practical done because there are still problems. And I'm curious from ISO New England what specific market reforms you have, accreditation. You still have to get the prices right. Even if you have an accreditation model that works correctly for the capacity. That's just one example. What specific market reforms do you think are necessary given the new information that we have apparently stumbled upon?

MR. ETHIER: That is a good question. Certainly, resource accreditation is an important one. I think the next the next step is the Daisy Project, which is turning real time reserve provision into a financial obligation. So it's not just we tote it up and we assume you'll deliver, but rather it be you have an obligation to deliver. And there are consequences if you fail to deliver. And then there's probably what I hope is the second phase of that project, which will look at a little more broadly at reserve provision and replacement reserves and also enshrine those in our rules so that you get resources that provide them, get paid for them, but also if they fail to deliver on their obligations, they face financial consequences.

So in my view, there's a lot to be done in that real time market and the reserve market to both quantify and identify the reserves that we rely on and make sure that they are appropriately compensated. It may be that in the short term. They're low cost because we have sufficient, but at times when we don't have a sufficient amount of reserves, we'll get positive pricing and lots of good downstream effects will come out of that.

COMMISSIONER DANLY: The reason I ask this is because the -- at the moment ISO New England. I don't concede that it's overreliant on gas, but let's just say for the sake of argument that it is. Regardless of whether there's an overreliance, it is reliant upon gas and there is obviously a lack of infrastructure to support the requirements because there are a lot of them. So we skated through a relatively mild winter this last winter after being concerned about what the future would hold.

COMMISSIONER DANLY: It seems now that we have a few years of a stay of execution, apparently based on current data. You can hear the uncertainty in my voice when I say that I'm still not convinced that this 180 degree turn is really based on analytics that I would trust. But let's just say that's true. But we still don't know what happens in the future. Right? And I alluded to this earlier, which is infrastructure is almost impossible to build in this region. You have a piece of infrastructure that by the ISO's own admission, you have not modeled far enough out to really know what the future holds. And if in 2027 we find, oh, oh, gosh, we really need that thing, you're kind of late to the game because even if you were to go through a process of permitting and construction as quickly as possible, it would be very challenging to get anything done on a broad enough scale, I would assume.

I'm happy to be disabused of this assumption, but I assume given that the challenge is that even those projects that apparently are both politically and publicly wanted, even if they have challenges being developed, then certainly the ones that are unpopular but necessary, are going to -- I would assume, run aground with an awful lot of difficulty. Right. So does the ISO, generally speaking, have as sanguine an attitude as it seems about that further period? Because I've heard we have to say about the next few years, but 27, 28, 29, 30, I haven't really heard anything other than we don't know yet.

And one would assume in the same way that one would have assumed you would have done this analysis before, that if you are making public documents that talk about the immediate future that are going to be used to make in part an informed decisions right now about infrastructure, that you would probably have an opinion about what's going to happen later. Thoughts.

MR. ETHIER: Well, certainly. I guess a couple thoughts. One is we do find ourselves in a position of if we see the load growth coming that we are anticipating, we are going to need more infrastructure. Now that infrastructure is in our queue right now some of it's under construction. If we get substantially more wind and solar, it's going to be a big plus. Our -- you know, to our credit, our vice president of operations has been saying for years, look, wind can help me in the winter because I have an energy problem, not a capacity problem. And he was saying this years and years ago. If those wind farms that we have studied and signed IAS with get built, that's a huge another.

COMMISSIONER DANLY: Another if though, yeah.

MR. ETHIER: It's an if. It certainly is an if. And I guess the other thing I would note is -- well, our projections of the future evolve, as we were talking about earlier today and which is, you know, understandably causing you consternation. I expect that to also be true going forward. Sometimes they evolve in negative ways. Sometimes they evolve in ways that are favorable and positive for the region.

So I think what you're hearing is partly a reluctance to state firm consequences the farther we get out into the future, because we've -- all of us here on the New England -- ISO New England team have sort of lived with those forecasts changing over time and the farther you get out, the more likely that is.

COMMISSIONER DANLY: Sure, I get that it's harder to predict things that are further off. It's also problematic to make decisions now for things that you haven't tried to make predictions for the consequences of down the road. That's the only point that I'm making. So given my little diatribe here, does anybody have another response before I hand it over to my colleagues here?

Anyone? The -- sure. Go ahead.

MR. PAGLIA: Thank you. I hate to sound like a broken record, but.

COMMISSIONER DANLY: Me too.

MR. PAGLIA: I guess that's. That's who I am. I'm a simple minded in this. And I think the studies, as have been mentioned, are very important. And they're very informative. But facts matter. And if we are even moderately successful in the build out of our offshore wind portfolio, solar, etc. We are going to find a day where. California is an example. Europe. Those resources aren't available. And what are we going to do? You got to turn the lights out?

We're going to shed load. To me, the glue that holds all this together are the gas plants that are highly dispatchable. And can solve that problem. But we don't have the supply to allow those plants to run when needed. That's my message to all of you today. It's been my message for a while. We can solve that and deal with all the other challenges fairly easily.

COMMISSIONER DANLY: So, understood. But what I'm putting to you guys, all of you, is we have limited powers at FERC, right? I mean, we're actually talking a lot about a non-jurisdictional asset. Right? That is kind of bewildering that we would convene to talk about an asset over which we have no power. I'm asking all of you what specific tariff provisions do you want to see in order to solve that problem? Because I agree that is a problem that needs solving, and that's either a 205 or we 206 them to say the dreaded three numbers again or there has to be, you know, more infrastructure development, which is something that FERC only partially. I mean, we have profound powers when it comes to Section seven, but we're not the only input to that. So what specific thing would you do to solve this problem that you rightfully identify?

MR. PAGLIA: Two comments. First is we need to have a common understanding that, that is a problem. Unfortunately agree to disagree with Rebecca Tepper, and they don't see that as a necessary pathway to solve for the energy transition, i.e. build out of additional gas infrastructure. And there are others in the region.

That's not a mystery. So that needs -- we need a common understanding because no sponsor is going to bring forward a project. No customer is going to bring forward a project without a common understanding of that need. So that's step one. Step two, there are multiple pathways, whether the LDCs contract for this, we put forward a very novel approach where the EDCs contract for new gas infrastructure. In the past, the merchant plants themselves with new tariff provisions at ISO, the list goes on. But first step is an understanding and support for that common need.

COMMISSIONER DANLY: Even the ISO has said that in the deep decarbonization scenario is more transmission capacity is required. So the ISO -- unless of course there's now been an evolution in that thinking too. But that has been the ISO's position for a while now. So. Okay, go ahead.

MR. CAVANAUGH: Yeah. Thanks. Mr. Danly. Probably not a fully satisfactory answer, but, you know, public power is kind of split on this as well. There's a part of me that a part of us that express an opinion really would like to see how you retain it. The current market design initiatives that ISO has underway, RCA and Daisy are future years, I think provide a lot more value, not so much in the immediate term as you can see from their studies. So I think where Daisy will provide some pressure to buy, you know, fuel in day ahead market, even if you're not dispatched to be ready to go.

Certainly that's an advantage in the RCA as it puts pressure down as. Electrification picks up when we start shifting the probable hours of loss of load towards the winter. That'll put pressure on resources, but we're a few years out from that. How do we solve that middle piece is a mystery to me right now. I think we certainly need to have, you know, EMT around for a while to help cover that. And how you get at it from your authority is a question for me. Certainly the ISO designs that are future years out will be helpful, but that's ways out before that resource would be retained.

DiORIO: Thank you, Commissioner Danly. I just wanted to make a comment about just offshore wind as a resource. The New England area is home to some of the best offshore wind resource on the planet and we do need to tap it. And I just wanted to make sure that it was well understood that actually it will add to reliability because it does operate at its strongest during the winter months when this region happens to need it the most. You also asked about what could the FERC do and just to put a plug in for one way that the FERC and the federal government can help offshore wind is maybe a little bit more coordination between the states, the FERC and BOEM who manage the NEPA process for offshore wind resources. These resources take a long time to develop. They're complex.

They need a thorough review, and we fully support that. Oftentimes, actually, all the time, we're going through the interconnection process at the same time as we're going through the BOEM, NEPA process. And sometimes there are changes that can come up. There are certainly in that length of time technological advances that come about that can benefit the resource and the region. We always run the risk that adopting some of those changes could result in material modification with the process. So a little bit of more flexibility and a little bit more working together I think will help smooth things and get the resources on stream faster. Thank you.

MR. DIVATIA: Thank you, Commissioner Danly. I have to admit, it is hard to not continue to think about the Everett Marine Terminal. But one of the things I did appreciate about this agenda and the way the staff planned this and the way it was planned is there's a focused conversation on long term infrastructure because there needs to be action now for us to start developing infrastructure.

That takes a long time. And if lack of doing so will put us in this doom loop of constantly thinking about what other short term measures can we deploy every year. I have two specific comments and one of them will address your question on what can FERC do? First comment is, I do think there is positive development in the quantification of the gap. I think the fact that the ISO has done this study up to 2027 is great.

We need it for '27, '28, '29, '30, '31, '32. We need it for every year. We need it to be quantified in megawatt hour terms so the electric sector can respond with solutions, whether it's how much solar or any other replacement resource. Offshore wind storage interregional capacity can replace not just the gap, but also keep in mind the New England states GHG goals. We have goals, so we have to go way beyond the gap that's being discussed today, practically speaking, in New England. The second point that I'd like to make is that, in addition to what Bob Ethier just said, is we are deploying solutions today.

We just had a groundbreaking on the Cape to start work to interconnect the next 800MW of offshore wind beyond the one that's expected this year. So from the onshore grid perspective, we are on the frontlines of starting to deploy resources and pursue development of the transmission solutions that will enable the next 800MW on the Cape.

And then there is plans in place to interconnect 12 more hundred megawatts on the Cape. Beyond that, these resources will help bridge some of the winter reliability gaps, but it also will help meet some carbon emission targets. Very helpful effort from the FERC was when we submitted the transmission support agreement, FERC approved it in a positive manner. It was one of the most an innovative way to allocate costs for a transmission proposal, where part of it was being paid for by reliability customers.

Part of it is being paid for by the interconnection customer. As we look into the remainder of this year, I hope we can look at tariff changes that allow us to rightsize projects and build some more anticipatory transmission proposals so we can continue to increase the hosting capacity of the grid and kind of do our part in this equation. So I think those efforts from FERC and that support on long term planning and cost recovery is very helpful. Thank you.

MS. DYKES: Thank you. I'll just say -- I share some of that frustration. I think that we if we don't have the 2032 study results to help inform the question about Everett, and they will arrive too late to really inform that question.

I am hopeful that they will not arrive too late to inform other decisions that are being taken over the next 6 to 12 months, 18 months that will be dispositive about other resources, that will be critical to maintaining reliability in the early 2030. And so I think some of those offshore wind discussions are very timely. The work on transmission, we know it's -- you know, New England has the reputation of being a place where it's difficult to build. But I think in reality, it just takes several years, right? It takes a long time to build and go through permitting and litigation and align on.

There's so many different stars that have to align in order to move big projects forward. So being sanguine about those timelines, we have to be really starting now. The urgency with which we've been having this discussion about Everett is also the same urgency that we have to have about the other set of resources that we're working hard to deploy in order to meet decarbonization and clean energy goals. That's going to be really dispositive about whether we're able to meet the reliability needs of the of the early 2030.

I do think that some of you asked about market reforms, it's early to say definitively where we fall -- will fall on this. But I think some of the signals that the ISO is considering a prompt and seasonal capacity market is really interesting to replace the three year forward framework. I think that could provide us some new ways to do evaluation of resources that can help to address some of these winter reliability concerns which has been a huge gap I think, in years past. I also think that some of the dockets that FERC is moving forward on the transmission side will also be really valuable in order to help us understand how we can better utilize the transmission infrastructure that we already have, as well as transfer capacity. So those are a few that I would just reference.

MS. TEPPER: That was one of the things I was going to mention too. I think having some fast work on interconnection and on the transmission proposals that we have coming up, I think is helpful and appreciate that ISO is looking at the single source contingency limit. I think that could be very helpful as well. And I would just add, in terms of valuing storage, I think if we could think about that based on how operators are actually going to operate their systems and based the value of storage on that, I think that would be something that would be particularly helpful to and encouraging all available cost effective energy efficiency and demand response.

CHAIRMAN PHILLIPS: Ms. Clements.

COMMISSIONER CLEMENTS: Thank you. A lot of my questions have been covered. So I just have a few points on transmission and on the demand side. First, I was so encouraged to see the multistate collaborative proposal from the states in New England that is on interregional transmission planning. That's what we've been hoping would happen, right? That's an issue that FERC hasn't taken on in a fulsome way yet. This commission, the full picture of transmission into regional planning.

And so the idea that you all are getting together on a bipartisan basis across regions up and down the up partway down the East Coast is exciting. And I think there's a lot of opportunity there. One thing that struck me, this is just more of a more specific point on the cost allocation piece of interregional transmission or transmission planning is this idea that now winter energy adequacy is a benefit.

It could be a benefit. And I know both Commissioner and Secretary from the States, you've commented on that.

And I think you also commented on the multi-value aspects of transmission. But it seems to me if you're connecting offshore wind with and you have resources hooking up that provide winter adequate -- winter adequacy, that's a good thing and might be part of this multi value equation. So I'm wondering if you have any more thoughts about the cost allocation piece, whether it's specific to the winter energy adequacy or more broadly in terms of what you're hoping comes next, what FERC might do?

MR. DIVATIA: I can try to briefly address my views on that. The point of connecting winter energy adequacy and winter reliability is purely to state that the transmission that we're developing to enable those resources has a societal element to it. And it's not just a but for process and it's not just a but for cost allocation and that's it.

I know once you start extrapolating that philosophy, you start getting into how societal is it? Is it a regional, completely regional? Is it partially regional? Those discussions can be held, you know, in a more robust manner with the right folks around the room. But that's the key point, is some of the infrastructure that we're developing is very societal in nature. And therefore, you know, it could be considered as a regional reliability solution.

COMMISSIONER CLEMENTS: I think I'll leave the off shore wind there on. You know, earlier, Vamsi was speaking to the ability of this study to provide a base and a useful tool among several to do effective forward planning. I'm curious, Commissioner Dykes and Secretary Tepper and I asked this question, I think also to chair Bartlett and Gerwatowski earlier. Can this tool help you design programs to target, let's say, the winter, the types of demand response or energy efficiency, gas to electric or otherwise that are useful relative to this winter energy adequacy target?

MS. DYKES: I'm happy to jump in there. That's our understanding. That's why we're so excited about this. And it was great if I heard accurately the earlier comments from Vamsi that the ISO would welcome or be willing to do runs in response to state requests. I mean, we're here talking about winter reliability and, you know, thinking back to the winters of 2013, 14 and 1961 and so on and so forth. But I'm also very -- you know, thinking a lot about the winter of 2035 with our electrification goals.

And so, again, we want to make sure that as we're working on building and transportation electrification programs within our state, jurisdictional aspects, that we have the benefit of all of these planning tools to develop scenario analysis and ensure that we're directing our procurements and or whether it's from solar PV to offshore wind to transmission to be aligned with the resource adequacy needs that we'll have for winter periods and -- you know, in the long term.

So I think this is incredibly important. We are not states in one silo kind of just thinking about decarbonization and public policy and the ISO and its silo over here doing reliability, but states this is very much part of our mission as states to ensure that we have affordable, reliable and clean energy for our citizens. And so that's why a tool like this is so, so helpful.

COMMISSIONER CLEMENTS: Great.

MS. TEPPER: I would agree. Very, very helpful. And, you know, I think in addition, we have some work to do on our front on the on the distribution side. I recently wrote a letter to our utilities asking them, what are you doing to help the winter problem? You know, everybody should be thinking about how we can deal with the winter situation with further energy efficiency and demand response. And so I think tools like this will help us plan for the future. But I also think we also have to do our own homework at home as well.

COMMISSIONER CLEMENTS: Right. Thank you all for participating.

CHAIRMAN PHILLIPS: I know that we're going to have an opportunity for our state regulators to weigh in at the end. But I think now that we sort of have this idea of the infrastructure that we need or don't need on the table, I'd love to hear reaction from the states here with us today. I mean, do you agree with what you're hearing? Do you think that we have the infrastructure that we need or is there something more or some hurdle that we haven't talked about today? And of course, you can always opt out and say we'll talk at the end.

MR. BARTLETT: I'm always happy. I'm always happy to jump in whether I have a great answer or not. I think I think the 2032 analysis is going to be really helpful to help us understand where the deficiencies are. I think there's no question that we're going to need a lot of transmission build out, not only to connect renewable resources but to obviously improve the interconnections to the region. So I think that's job one. I think two. I think we need to have a -- the honest assessment of the role the natural gas is going to be playing over the next 20 years and then figure out what additional infrastructure we may need to accommodate that.

I don't think it serves the region well to assume we can just get by on what we have. If we're struggling now, I think it's only going to get worse if we see significant demand growth, if we're not bringing on enough other resources to augment it.

CHAIRMAN PHILLIPS: Commissioner.

MR. SIMPSON: Thank you, Mr. Chairman. And thank you, fellow members of the commission, for coming here. I reiterate the comments of my sincere appreciation and gratitude for you all making the trip to New England. I think that the conversation today clearly demonstrates that a lot of work lies ahead with respect to infrastructure development and market design. But this dialogue demonstrates our collective sincere commitment. To each other, our states, our country and the region at large. I want to thank the NESCOE staff, the states. ISO New England and EPRI for studying and modeling winter scenarios, both with and without Everett.

While the study does identify risks, it's believed that the region can make it through the most likely scenarios. And New Hampshire does not believe that out of market solutions are necessary to retain Everett. Since you're asking, I do want to take a moment to just offer my thoughts. I wish that I could respond to Commissioner Danly's request for a specific tariff provisions, but I'm unable to do that. But I will take the moment as a regulator, a power system engineer, and an energy attorney to respectfully suggest two things. I think, first, that the states must view their respective jurisdictions as retail energy markets. And second, that the moment is ripe for federal policy, articulating the new rules in which wholesale interstate energy should be regulated.

That gap clearly exists. First, state policies necessitate a more granular operation of distribution systems. It's foreseeable that existing fuel, thermal and centralized resources will continue to retire. We're becoming more and more reliant on intermittent and dispatchable resources, including flexible load. I believe it's possible to operate our energy infrastructure reliably and efficiently, closer to the grid edge. But such a paradigm requires locational and temporal system information and operations and market constructs to facilitate economic dispatch.

We as the states need to focus on building these capabilities. We need to think of ourselves as retail energy market jurisdictions. As to federal reforms, I respectfully suggest that now is the time for an Energy policy Act of 2024. The states continue to grapple with policy, market and operational evolution in a complex and interdependent world. Given the significant energy system investment from the IRA and IIJA and the regulatory gaps that exist regarding current infrastructure, it seems appropriate for the federal government to articulate the regulatory constructs or new rules in which deployed investments will participate, just like PURPA did for independent power. The Natural Gas Act of 1978 did for gas markets, and the Energy Policy Act of 2005 did for organized electricity markets.

States will continue to partner with you and other federal stakeholders to shape how this new paradigm will undoubtedly manifest. I ask myself, how do I, as a regulator, enable truly competitive retail, energy and attributes markets? What centralized systems need to be enabled to operate truly real time intra state Infrastructure. Through the Energy Policy Act of 2005, the Federal Energy Regulatory Commission possesses broad authority over organized electricity markets. Those reforms have enabled supervisory awareness and control over the bulk electric system, essential for reliable long term operation.

Given the conversation today and our reliance on interdependent energy infrastructures determining whether reliability organizations a la NERC should exist for the gas network or other fuel supply chains may represent possible opportunities for federal energy policy reform. Finally, we talked about siting, and I note that clear federal partner support during the local siting of infrastructure in conjunction with local stakeholders can be very impactful.

Federal grants, loans and appetite for new technologies and foundational resources help seed projects to fruition. When the federal and state partners come together, it's beneficial for everyone. I thank you for your time. I look forward to continuing this discussion.

CHAIRMAN PHILLIPS: Thank you. Thank you for your very thoughtful and well said remarks.

MR. GERWATOWSKI: Just I said enough about the gas side of things, but I'm not going to say anything about gas infrastructure at the moment. But there are some comments about the need for transmission in order to advance renewables and there have been developments taking place, at least in the planning stage. But we've been talking about doses of inconvenient realities today about various things. And there's another dose here that's just unfortunate that even when transmission is being put in place to support carbon free energy, there's opposition to it and it's very, very difficult.

And so we have to realise that I've been frustrated because there are environmental groups who are absolutely supporting the carbon free energy sources and renewable energy. But as soon as the transmission project is being proposed and there there's local opposition to it, a lot of the environmental groups are nowhere to be found and it makes siting very, very difficult. I'm not saying that necessarily to ask you to do anything about it, but it's a message that I've been trying to advance.

If we're if we're supporting a clean energy future, you've got to support the transmission, even if it's creating some difficulties in the siting of that. But as we plan ahead and try to figure out how we're going to solve things like winter reliability and we're depending upon transmission to be built, well, we have that also potentially standing in the way as well, because as has been stated many times, you can hardly site anything, no matter what the nature of it is. And some of it is harder than others, but they seemed to be all hard.

CHAIRMAN PHILLIPS: June. I know we're going to hear from you on the final panel. Would you like an opportunity to weigh in?

MS. TIERNEY: Mr. Chair, would you prefer I just saved it for then.

CHAIRMAN PHILLIPS: You can speak any time you want.

MS. TIERNEY: That was the right answer, sir. I won't go into great depth here. Your specific question was, did I agree with everything I've heard here? And I won't pretend that I have absorbed everything I've heard. So I'll just speak very briefly to the things that jump out at me. One Mr. Ethier had suggested that among the reforms needed are in the markets are reforms that make the obligation stick and that there are consequences when people don't deliver. I could not agree more. This is something that I think Commissioner Christie and I talked about last year and in Burlington, where all morning what has been eating at me as I listened to the conversation, which is erudite, well-informed, competent, everybody is doing their job and living up to their responsibilities.

What's been eating at me is there is an unequal distribution in the room of the responsibility to hold a public trust. There are people out there. Rebecca was referring to this and talking about the voices that are not here today. And to credit the efforts, by no question in reaching those voices. But there are voices out there of people who have not been part of these discussions to date and who are also not being directly addressed by this conversation. We keep talking about oil and gas and winter reliability and familiar terms because we're expert and we know these problems and we know there are no easy answers.

But until Rebecca said we need to think about the people who live in the shadow of Everett, I will be the first to tell you that was not foremost in my mind or many of the things that are mentioned in the fix the Grid literature that was distributed at lunch all valid, in my opinion, all relevant health impacts, environmental impacts and so forth.

But, you know, we reduce our conversation to the things that we think we can do. Commissioner Danly Such as the specific tariff provisions when sometimes the conversation has to be about how do we change how we think, how do we bring these voices in? More importantly, how do we convey to them that, they feel that we hear them so that they feel we hear them? And judging by this literature, I don't think we're quite there yet. I've gone on longer than I said I would. But when it comes to specific siting of infrastructure in New England, in Vermont, at least, we have an example of how it can be done.

We got infrastructure, a transmission line licensed and ready to build in Vermont. The issue has been the economics of it, which we hope the DOE funding under the Grid program can address. But it's not like it can't be done. It's that it has to be done in a way that convinces the public that their concerns are being addressed. And that hasn't happened to date. Now, I will go back to being a potted plant until 3:30.

CHAIRMAN PHILLIPS: Excellent. Well, thank you all. I thank you for accommodating me. I called an audible and went off script. So I guess at this point I'll just open it up to my colleagues. Are there any final points on infrastructure before we move on? I see no cards up, so we're going to --

COMMISSIONER DANLY: I'll just make a quick point that people talk a lot about broadening or making more flexible cost allocation. We have to keep in mind that we are constrained by case law and there are limits to how far that can go. So too much trust reposed in some voodoo that makes it broader than it is. I would be wary about that.

CHAIRMAN PHILLIPS: I bet you did not have voodoo on your bingo card today. All right. With that, David, we're going to end a little bit early here, if you would. Let's start a little early for the next panel. Will you instruct us on how much time you need to flip the room?

MR. BURNS: Yes, sir. Well, we'll switch now to Panel 4 and like, do you want to skip the break entirely?

CHAIRMAN PHILLIPS: Can we just take like a five-minute break?

MR. BURNS: You got it.

CHAIRMAN PHILLIPS: Five minute break, everybody. Be back --

MR. BURNS: Be back at 2:05.

CHAIRMAN PHILLIPS: There you go.

(Recess)

CHAIRMAN PHILLIPS: Yeah. We're going to begin Panel 4. We're going to run until 3:15 with this panel. So if anyone, everyone can take their seats, please.

MR. BURNS: So this panel is on market design. Our panelists include Riley Allen, Commissioner, Vermont Public Utility Commission. Michelle Gardner, Executive Director of Regulatory Affairs, Northeast NextEra Energy Resources. Mark Karl, Vice President, Market Development, ISO New England. Donald Creese Consumer Advocate, New Hampshire Office of the Consumer Advocate Pallas Lee Vanschaick Vice President, Potomac Economics. Alex Mitreski, Senior Director of Regulatory Affairs, Brookfield Renewables. Christie Prescott Director, Energy Supply United Illuminating and Andrew Weinstein, Vice President, FERC Market Policy Vistra. Just a reminder to our panelists to avoid any ex-parte discussions. I know I sound like a broken record with that. But with that, Mr. Chairman, I'll turn it over to you and we'll start Panel 4.

CHAIRMAN PHILLIPS: Thank you so much, David. If everybody could take their seats, we're starting the next panel. I'd like to welcome everybody here. Thank you so much for taking the time. I think that this is among one of the most important topics that we can talk about today. I think that when markets work, they provide extreme value. I think what we need to talk about here today are what, if any, market changes or solutions that are on the table that can help us achieve the reliability that we need for the region.

I'm extremely pleased that ISO New England is working on several market improvements right now. Capacity market accreditation as well as day ahead, ancillary services. I appreciate the focus on these efforts, but I think we need to consider whether more can be done on market reform. So my first question is to all the panelists understanding that capacity accreditation, and ancillary service reform are on the table. Do you think? Are these reforms likely to resolve the reliability issues that we have? That's the question. Commissioner. Well, actually, we'll start -- let's start with Mr. Karl.

MR. KARL: Thank you, Chair Phillips and all the FERC staff, Commissioners, state representatives as well. Good to be here. We talked about capacity accreditation and some of the other projects. You know, when you look at the things that we're looking to do in the near term, you know, in the next five or so years, we've got the inventoried energy program coming in.

Can't say too much about that because I know some of that's still before the commission. We've got the ancillary services, we've got resource capacity accreditation and we've got consideration of a prompt seasonal capacity market. I think all of those help move the ball forward. I don't think any of them complete the project or complete the goal of assuring energy adequacy.

In particular, when we look at the day ahead, ancillary services DASI projects, that project in and of itself probably does not do a lot in the short term, but what it is, is a really important platform for us to build on. I know last week I listened to the PJM conference and there was discussion about, you know, the need to have some sort of a longer forward reserve market and, you know, not like three years forward. But something that may be in the interval where people could take action to schedule gas or make whatever arrangements are necessary to make sure that they have fuel.

And that would be built on top of DASI. If you're going to build a forward market, you need something to settle against. And the day ahead, Ancillary service product, is that benchmark that you would settle a day ahead or two day ahead or a week ahead sort of reserves market. In addition, we have in the past talked about the potential for a reserve product may be far enough forward that someone could enter into an LNG contract. So now we're in kind of a six month window, which sort of looks like capacity, but not really. The thought that we had was that this would be a product that would still settle against the reserve market.

And so we've got a lot of projects like that come after the four things that we four anchor projects that we see going on right now. So we do think they help. We do -- and I've got some other things on the list we can talk about that are probably a little bit further forward as well.

CHAIRMAN PHILLIPS: All right. Thank you. We're going to work from this end and go all the way to that end. Yes, sir.

MR. MITRESKI: Good afternoon, everyone. Thank you so much for having me on the panel and thank you so much for taking the time to come to New England again. These are very important issues and we appreciate your interest. Just quickly, I think in terms of the I'll start with the RCA. I think RCA had a good potential in terms of addressing some of the needs. The initial results that came out and the ISO saying that 5,000 MW of the total 10,000 MW roughly of natural gas resources would be derated in the winter period. I think that created a signal that resources would need to firm up their fuel supplies in order to deliver energy in the winter. But now with some of these -- the information the ISO has provided. The modelling may have not accounted for some of the LNG availability or significantly not accounted for some of the LNG availability. I think the expectation is that it will be a lot less winter hours when there will be unserved energy and as such probably a lot less derate on those units.

So if that happens, then sort of the incentive to firm up the fuel becomes a lot less. So I think I'm a little bit more skeptical now in terms of the RCA and the value it will provide with those results, but we'll have to see what those results bring in.

I think DASI itself is a is a phenomenal product and something that I can't believe it took 20 years to deliver. I think it makes sense. This right now is the ISO counting on reserves in the Day-ahead market, but not compensating them and resources not knowing that they're being counted on, which means that they do not provide the fuel in advance of the day ahead market to be able to deliver in the real time market.

So I think this is a great product and ultimately I think. We have to spend more time and effort into the energy and ancillary markets where we think it's the rubber meets the road. That's where the energy really is delivered. And the products like DASI provide the value to reliability. I think the capacity market is important, but I think anyway, we'll probably get into the whole prompt and seasonal, but I think those are also going to be very elaborate discussions that may take away time from discussing some of the ancillary market changes. I'll stop there.

CHAIRMAN PHILLIPS: Thank you. I think you're in good company with your skepticism here today, especially with some of my colleagues. I see your cards. We're going to work this way and I'm going to come back and get you. Yes, sir.

MR. LEEVANSCHAICK: Yeah. Thank you. For those who don't know me, I'm Pallas LeeVanSchaick. I'm with Potomac Economics and we're the external market monitor for the ISO and really appreciate the opportunity to be here today. So I think the centerpiece for any market design effort has to be the capacity accreditation for simple reasons. It's got to be a capacity solution because the capacity market is the venue in which you buy resources to meet your planning reliability requirements.

So as we -- as these requirements emerge, it's important to have a capacity solution to procure those resources. Now it has to be accreditation because the problem is that as we see the changes that we're getting in the resource mix, so you have more and more resources that aren't available 24 - seven, but that do make some contribution to reliability. There needs to be a framework for assessing their value and compensating them appropriately. Now it has to be a marginal mechanism because when you price things based on the marginal value, you provide better investment incentives. And so you get better solutions because you have better investment incentives for doing that.

Now, a related issue is the resource adequacy model, because the mechanism that you use to assess reliability, your requirements, the contributions that resources make to those are your resource adequacy model. Now the concern that I have is that the model that the ISO is using currently may not be really adaptable enough to consider things like oil inventory limitations.

And so, you know, to me, an open question is whether their current resource adequacy model provides that kind of framework that they can build on to provide appropriate accreditation because their current proposal in the stakeholder process kind of separates out the assessment of essentially which resources are energy adequate from the resource adequacy modeling. And I think they've gotten some initial results that don't make a lot of sense.

So I think it's going to take more work to make sure that the resource adequacy model is reflecting those characteristics appropriately. Otherwise, if you don't do that, then you can't compensate your resources appropriately. I think also the prompt seasonal market is very important. We've been advocates of that for a long time. And you know, one of the big benefits of the prompt market, other than it procures allows resources to procure fuel at a time where it's in line with when they're entering capacity obligations. Aside from that it -- backing up the timing of the auction is also something that helps provide more time for making some of the needed capacity market design enhancements.

And so you buy yourself more time if you simply run the auction closer to the delivery period. So I think that's another big benefit of the prompt market. And why -- if the details of the prompt market can't be worked out, at least postponement of the FCA is something that should be on the table.

MR. KREIS: Good afternoon, Mr. Chairman. Honourable members of the Federal Energy Regulatory Commission. I don't have a good answer. I don't think, to the question that the Chairman asked. I will say at the outset that I feel a mighty weight on my shoulders today. There are roughly 40 speakers on today's agenda. Some companies got two bites at the apple, but I am the only person on today's agenda whose job is to advocate for ratepayers. Now, you might say that's fine because the ten of you are safeguarding the public interest. And indeed I can testify that you are in fact doing that because I've met everybody, all ten of you to one extent or another, and I know several of the state regulators well enough to be sure that they -- I can tell you they are exemplary public servants, but your regulatory vigilance is only as good as the information placed in front of you by those participating in your proceedings.

My guess is that I'm the token ratepayer advocate. Not because FERC doesn't like us. I know better than that, but because we don't have the expertise of a Vamsi Chadalavada or a Richard Levitan or even my friend James Daley of Eversource. And guess what? You're right. That's the problem. In my dream world. The New England ratepayer advocates would have what our counterparts in the land of PJM have, a tariff funded organization that gives us at least some of the resources we need to be a truly knowledgeable and empowered voice, not just here before you, but behind the closed doors of NEPOOL.

I was so gratified to hear Commissioner Danly start the day off by saying that he is skeptical because I am also skeptical. So are my counterparts. Bill Harwood of Maine. Liz Anderson of Massachusetts, Claire Coleman of Connecticut, the folks with whom I put out a joint statement. What market mechanisms do we and the ratepayers we represent want? We want ones that are driven by facts and rigorous analysis, not amorphous worries about qualitative considerations or vague notions of resiliency. Now, I'm from New Hampshire, and so let me remind you of our state motto here it is: used and useful. The cost of natural gas infrastructure should not be an non-bypassable electric rates. That's an argument I made to the New Hampshire

Supreme Court in 2017 and a principle reflected in the opinion written by Justice Hicks of that court.

Unfortunately, his was the dissenting opinion. Fortunately, my counterparts in Massachusetts were more successful with that argument at their state Supreme Court. Now we can design markets to force ratepayers to buy every last aliquot of reliability that industry can conjure.

But I beg you not to do that. In particular, I beg ISO New England not to seek and I beg FERC not to approve some new market mechanism or worse, some out of market mechanism to guarantee that the Everett Terminal stays in business. Sometimes at an event like this, someone manages to say the quiet part out loud. Today, my award for doing that goes to Mr. Ochoa of Kinder Morgan, who urged you to force ratepayers to pay for more gas infrastructure. He said, and I quote, "We are going to continue to say that forever." That's why I'm so pleased to hear that Commissioner Danly is skeptical. In fact, I'd like to answer Commissioner Danly's question that he placed to Mr. Chadalavada.

He asked, have we been paying too much for reliability? Well, here's my answer, worded as politely as I possibly can make it. Heck yeah, hundreds of millions of dollars too much. And I and my regional counterparts have been trying to say that all along the way. Now, Mr. Levitan warned that New England could experience a fiasco of the sort that ERCOT suffered beginning on Valentine's Day of 2021. My response is let's be visionaries. Let's not double down on old technologies.

There exists. But Texas apparently did not deploy the metering technology to respond to a capacity deficiency event with targeted load shedding targeted to avoid families shivering in the dark and instead interrupting the big C&I customers that have benefited from restructuring. The Supreme Court's decision in FERC versus EPSA of several years ago teaches that FERC has a role to play in bringing forces to bear. That might look a lot like retail to you, things that happen at the distribution level.

Things that happen behind the meter. Even energy efficiency. The Holy Grail. For me, the FERC has a role to play in bringing those things to bear on the markets that are regulated under the Federal Power Act. And I urge you to do that. And finally, I heard Mr. Ethier say, let's upsize transmission, existing transmission through asset condition projects.

I would urge you to heed the warning of my friends at NESCOE who said asset condition projects in New England are essentially unregulated and unscrutinized right now. That is not okay. So what market mechanisms do we need to guarantee reliability? Well, my written comments give my opinion about the specific initiatives that are pending. My earnest pitch to you is before you do anything new, fix what's already broken about what we have.

CHAIRMAN PHILLIPS: Thank you for your comments. If only you were a capable advocate for consumers, their voice would be represented here today. Thank you so much.

MR. KREIS: I thank you. I appreciate the compliment.

CHAIRMAN PHILLIPS: Ms. Gardner.

MS. GARDNER: Thank you, Chairman, and thank you to the commissioners for setting up today's agenda and for your careful consideration of all the panels. I think the way we are walking through these issues intellectually makes a lot of sense and focusing specifically here on market reforms. I knew I was kicking myself when I was following Don here, so I don't know if I'm going to be as lively.

But I want to answer your question directly about my support for both of the ISO market reforms that are on the table. And then I think, as I've noted in my written position statement, there's still more that needs to be done in general as a short answer. But I also think it's important for us to take a step back. And I think the gentleman from NERC on an earlier panel this morning asked the right question, which is, what are we designing for? And I've noticed this theme through a number of the panels this morning, but I don't think we've specifically articulated it, which is what do we want our capacity market to do and what do we want our energy and ancillary service market to do and what are we building to? And I think not just in this region, I think all the regions to some extent are blurring these lines. Is resource adequacy a 1 in 10 standard or as some of us like to joke -- one in never.

But what is the standard? Is it a steel in the ground type market? We have, at least in New England and PJM kind of moved with capacity performance and pay for performance to creating additional shortage pricing into those markets. So we have evolved those markets, but it's still not clear to me exactly what the new standards are. I think ISO has done a terrific job building an innovative new analytic platform looking at these expected unserved energy in these energy shortfalls. They call it energy adequacy, but I don't know where.

I don't know what we want from each market. And I think that's an important discussion in terms of moving forward and specifically as we talk about resources and incentives, obviously that's going to play into fuel procurement and whether we want a capacity market that creates incentives to shore up fuel supplies and make the right decisions to ensure that you can be there as a capacity resource. Our company believes that a lot of those incentives are better served in the energy and reserve markets, which are markets that are closer in time to a delivery period. We commend ISO. I think the platform, the DASI platform that they are building and we mentioned this a couple of years ago when FERC held an energy and ancillary services conference and had stressed even back then that this design does an excellent job addressing energy imbalances and looking forward to the real time day and looking specifically, particularly for this region where we have so much behind the meter and potential load variations that we're going to continue to see in this region.

The DASI design does an excellent job managing that and we think it is a great platform on which to build. We still think there's more that can be done in as we go to phase two. And I was very happy to see originally ISO had presented a kind of replacement reserve and I think in the most recent comments ISO is more open to concepts and ideas in looking at a type of replacement reserve. We had proposed kind of a strategic reserve, I think regardless of what you call it. The idea is that there's an incentive in the market for resources, either with long lead time to be there and to be able to be deployed or resources to match some of the commitment timelines that those that run on gas are able to secure up before the operating day.

So we do think there's a lot to be done and really commend the ISO for that. I look forward to, I think the discussion on the rest of this panel, but happy to participate and to provide that additional insight.

CHAIRMAN PHILLIPS: Thank you. Commissioner Allen.

MR. ALLEN: So I'll just add my appreciation that have been expressed by others for you coming all the way up here to northern New England to the question I won't spend too much time adding to the comments of others. I think there's a broad agreement. I think what's on the table, what's going through the committee process at ISO New England is good and you know, the process is important.

And so we'll see what kind of makes its way all the way forward. But I do agree with essentially what has been put forward and the importance of the various characteristics of what has been added. I also appreciate the comments of ISO New England and they provided in their written comments. They've added a few other things that I think will certainly be talked about going forward. Their comments about changes to the capacity market, the seasonality make it, making it potentially a prompt market. I agree with others that I think that directionally is a sensible thing and I look forward to those conversations.

They've also made reference to potentially adding some new ancillary services, maybe longer duration products and the ancillary service market that makes sense to me and hasn't been vetted but I certainly like the idea and NextEra added something that I find interesting and I think we kind of talked about it back in September, kind of an insurance product of sorts, but you know, a market for an insurance product. So it's referred to here as kind of a strategic operating reserve. I think as we learn more, we use this EPRI model.

I think we're you know, we're going to find new things over time and we're going to find that there's, you know, that hole that we've observed in the past is going to reemerge at times. And we need to have products or incentives to bring products forward that help to fill that hole. And I think that's strategic operating reserve is something that makes some sense to me. That's all for now.

CHAIRMAN PHILLIPS: Thank you, Commissioner. Good to see you. I'm over my time. I do want to allow the folks on this end to have a word and then we'll move on to Commissioner Danly.

MR. WEINSTEIN: Thank you, Chairman Phillips. I will be brief, and it's good to see all the commissioners today. Quick background. Prior to joining Vistra four years ago, I was at FERC for nine years, including the last five with Commissioner LaFleur as advisor on New England issues. So I am knee deep in what's been going on in New England for the past decade or so. Regarding your question, Chairman

Phillips, I think I agree with what others have said. We do think that RCA and DASI are marked improvements that will enhance reliability, but I think it's also important to kind of keep in mind what we've learned today, which is that the risks, the winter risks in New England as ISO New England has defined them today, are manageable.

So my concern is in terms of what comes next. You know, we've spent the last decade in the region kind of looking to holistically solve the fuel security problems in the region. And frankly, the results have been mixed at times. There's been a lot of different iterations of it. And I think it's important to be kind of deliberate in terms of our next steps you know, for example, I know there's been conversations going on about this, the prompt seasonal market, and I will say that we are very open to it, but I think it's going to be a complicated design and I think that it's going to be critical that we kind of think through the implications of that design.

The benefits it will provide, the costs will provide before proceeding down what would be an 18 month stakeholder process. And know it'd be a shame to spend that time and turns out this is not achieving what we'd want it to achieve. You know, at bottom lights, the lights are staying on the region. Reliability has being maintained. And I just I just want to be careful, you know, putting aside prompt seasonal, I want to be careful regarding our next what our next steps are, because the last thing we want to do in this transition is kind of do a redo in a way that kind of makes things worse than they are right now. I'll leave it at that. Thanks.

CHAIRMAN PHILLIPS: Well put.

MS. PRESSCOTT: And thank you so much. I'm here today representing Avangrid and two of our transmission and electric distribution companies, including Central Maine Power and the United Illuminating Company. And collectively, we serve a million customers, a million electric customers. And so we're certainly obviously concerned and paying close attention to winter reliability. Our customers need electricity and for that matter, heating opportunities. And so we're certainly have opinions and we're very encouraged by what we've heard today. But we still maintain, you know concern. And in terms of your specific question about what's being developed in the market right now, you know, we're watching that closely as well.

We do have some concerns, again, about the timing of when those products are going to become available and if they're going to be able to help us in the near term. And the winter reliability near-term concerns that we still think are important to -- you know, protect against challenges with. Thank you.

CHAIRMAN PHILLIPS: All right. I will now turn it over to Commissioner Danly. Any comments or questions?

COMMISSIONER DANLY: So we have these new analytics, new assumptions. And the question is, based on this new data that apparently says we're not in the terrible position we were before. In what way does that change the efforts that people would have wanted to see for tariff revisions a year ago? Because. It seems like a fairly standard parade of ideas that we've heard in the past. I'm not saying there aren't changes on the margins. I just am curious, going back to the same question again that has been asked now several times.

And actually I'd like to start with Andrew. Will you give me an idea of what specific reforms you would like to see that you think would actually be the direct result of what we have learned from ISO New England's analytics that is specifically tying it to what the revelatory new information in front of us?

MR. WEINSTEIN: Yes. When I when I signed up to do this panel, there was a fuel security crisis and now there's not. So I appreciate that. So in terms of your --

COMMISSIONER DANLY: Member, you can answer whatever question you want now that now that you're answering it. Yeah.

MR. WEINSTEIN: Thank you, Commissioner Danly. So

I guess from my perspective, I guess I would be cautious about doing something significant like Major without actually really appreciating the implications of it. Going back to what I said previously about the prompt seasonal market, I think the ripe area for me is to explore is I think that from a competitive market perspective, I do think that performance constructs are absolutely crucial. I think that performance contracts create incentives for resource to perform, invest, make fuel procurement decisions, and if they don't perform, they face the penalties for it.

COMMISSIONER DANLY: That that despite perhaps without getting into details, recent experience, you are convinced that's the right mechanism.

MR. WEINSTEIN: We are convinced, without getting into specific details that may have occurred somewhere else. Yes. But, you know, that being said, I do think so. If you ask for reforms, I do think that, you know, like any other good market reform, I think that a refresh is warranted. And if you -- I think we should look at whether or not there are reforms that are available to PFP in the region that would actually enhance reliability, enhance performance.

I know ISO New England has done some work on it recently and I think their conclusions, it was unclear their view on whether or not additional kind of work on this matter is warranted. But I think from our perspective, I think a refresh is warranted. I think that we could look to see if incentives could be enhanced. You know, one of the challenges that always occurs in terms of, you know, always raised in terms of PFP is there are very few performance events which kind of don't necessarily promote the right incentives.

The question is, are there other ways in New England to kind of change that metric? I don't have a good answer right now in front of you. I think that's what the stakeholder process is for, but I think that's an area that we should consider exploring. I mean, that was the purpose of PHP on the on the front end was if you go back and look at the original docket, it was to kind of address the winter risks in the region to the extent there are any. And I think that is something we should kind of consider.

COMMISSIONER DANLY: We should probably just go down the line. Go ahead.

MS. PRESSCOTT: Avangrid supports the consideration of a seasonal capacity prompt capacity market. In theory, the market with appropriate accreditation could result in clearing winter capacity auction at a price that may be able to compensate resource owners to secure firm gas supply. And we believe that in liquid inventories, and particularly if that auction occurs at the same time that the generators are securing fuel supplies for the upcoming winter, I think that will be something that we'd like to see further consideration of.

COMMISSIONER DANLY: Thanks. Go ahead.

MR. MITRESKI: Yeah, I'll touch on quickly on the prompt and the seasonal and then I'll actually give you four proposed solutions that we can maybe think about for the future in terms of the prompt and the seasonal market. I think they do address some issues, but they also create new issues. So I think there's always trade offs and I think that's where I think from a stakeholder perspective, we need to discuss this and where I think of it is it definitely the prompt market addresses the phantom megawatts that we've been seeing in terms of projects not being ready to come in three years forward? We've seen that in the past and I think this will address that. I think it will also address fuel procurements in terms of accreditation because it gets closer to when fuel is contracted for and being qualified for the auction. But then I think it's really severely opens up the possibility for RMRs people should not have short memory. This was happening in New York. We had multiple RMRs there because of this issue.

And I think it could be for retirement or transmission issues. And I think that's a very serious issue that we need to address in terms of trade offs, in terms of four specific solutions that I've thought of. I think the first one is cheapest, easiest and quickest, and I think that's the ISO to allow the energy market itself to just work. We saw this in 2017 and '18 when the winter we had the most recent cold snap. The ISO took over the steering wheel and dispatched the fleet the way that they thought should be dispatched in terms of posturing the oil and gas units. What that did is. It potentially maintain reliability, but at a cost of muting the price signals.

The reserve prices over the span, the December and January of that period was $1, but apparently were close to a shortage events. So muting those signals creates bad incentives for resources to not contract for fuels during those times. So I think I think the ISO has learned from those mistakes and we saw that in the most recent event where they saw that there's going to be a PFP event, but they realized that reliability was not at stake and they allowed the market to play out and we saw a PFP event.

So I'm encouraged by that and I hope that we will continue to do that. So then tying it to the next solution, which is reforms to the pay for performance to personally I think the 9000 and -- we're talking with folks and nobody even remembers what the new rate is. But $9,000 is insane amount of money. And in terms of a penalty and it does just as much job if it was $900 because it's a strong signal to penalize or reward the performing resources. But if we have these rare events, they are really ripe for black swan events like we saw in PJM in New England.

So resources that will get penalized for $900 will get the fuel, whether they're penalized for 9,000 or 900. So having the beauty of the PFP is that it's a zero sum game between performers, good performers and bad performers, and in many ways load is insulated from that construct. And I know, Commissioner Daniel, you've been talking about PFP itself. The second piece is no IEP. I think in terms of overpaying for reliability. I think IEP, the inventoried to energy program is discriminatory. I think creates muted signals as well. I think the capacity market, if we're going to procure the capacity and find different ways to accredit that there is no need to sort of prop and stimulate certain technologies over the others.

And the last and fourth proposal is something that the SS had mentioned in their comments is something that I've been thinking about is, is really spending more time into the energy ancillary services. I think the current reserves and the way I think of it are more of a two dimensional product, which is quantity and when you will need them. But they don't account for the length, which is kind of the three dimensional piece. So maybe adding a four hour reserve product.

I think the replacement reserves the ISO talked about is maybe dispatching units four hours into the future, but again, not having the duration I think is the missing piece. And this is where a product could come in to say you need to have at least four hours of reserves, eight hours of reserves. So that way the ISO knows that there is the ability to dispatch these types of resources that will be able to generate. So those are kind of my specific proposals for potential solutions.

CHAIRMAN PHILLIPS: Thank you.

MR. LEEVANSCHAICK: Yeah. So I'm not this might not really be an answer to your question, but we're not saying a lot of different things as a result of this study. I think the prescription is still the same. You need better capacity accreditation and a shift to a prompt seasonal market. I think the difference is that if it turns out that your risk is less severe, a well designed market should produce a different set of outcomes that are likely to be lower prices, save consumers money, which is which is a good thing. The sooner you get these market design reforms in place, you know, assuming they're well designed, the sooner that you can affect business decisions.

So you know, instead of having these resources that we know provide a lot of reliability value to the system, you'll provide them with incentives to stay in service and let less fuel secure resources go. So, you know, the sooner you can get these things in place, the less severe the situation will get.

MR. KREIS: Commissioner Danly. I'm probably the least qualified person on this panel to answer your question. So I will just say on behalf of ratepayers that I think all of the initiatives that are currently under discussion, including several of the ones that we just heard mentioned, are all potentially intriguing ideas. As long as whatever decisions we make about what mechanisms and tariffs to implement are based on rigorous risk analysis and by rigorous risk analysis, I mean, we could pay for a system that incurs no risk or virtually no risk. It would cost a fortune and ratepayers wouldn't be able to pay their bills. So obviously we have to make some reasoned calculations about how much risk is worth incurring. I worry all the time as a ratepayer advocate that we are being forced to pay for the same thing twice.

So I would urge everybody to think carefully about avoiding overlapping and duplicative solutions to the winter reliability crisis. If it still is a crisis, there's almost nothing that you can do that would be by bad, bad by definition, as long as it doesn't involve forcing electric ratepayers to keep the Everett Marine terminal open. Just make sure that it's based not on guesswork, but on rigorous risk analysis.

MR. KARL: So first I wanted to make a couple of comments about the prompt seasonal market. I think the first thing to realize is we could we're kind of running that together, you know, as we consider how to move forward with changes to the capacity market. We could talk about prompt annual market. We could talk about forward seasonal market, or we can talk prompt seasonal market, which is what most of us seem to be talking about right now. At the moment. My staff is still in the evaluation process. We need to think through what are the pluses and the minuses, potential consumer impacts, potential reliability impacts.

And so I want to assure I know some people are worried about the memo that came out last week. You know, the ISO hasn't written in the concrete that's hardening that we're going to do that. We still need to evaluate the prompt and or seasonal market. We need to come to the stakeholder process, consult with the states and move that forward. So that's not locked in place. That is an assessment that's important that we're doing right now. A point that I would make picks up on an issue that Ms. Gardner raised, which is criteria.

One of the things that we saw in doing the analysis for RCA, you know, the capacity accreditation, which is also an issue if we wanted to do a seasonal market, are the reliability criteria. The criteria are annual. And so one of the things that the technical team realized as they were digging into how to do capacity accreditation, they were doing sensitivity analysis and looking at more severe, less severe winter.

And as the winter became more severe, the model was saying we should buy more summer resources because as the winter performance got worse, the annual standard could be met by doing a little better in the summer. That's not really what we were looking to do. So one of the things that we need to look at is what those criteria should be for seasonal market before we go crashing into it. More directly to the question that you put to us, Commissioner, what would we do differently from a market design standpoint? Actually, probably not a lot different from the path that we were on.

And the reason that I say that is when we look at the markets and the capacity market in particular, they were designed 20 years ago for a portfolio and a grid that is going away. You know, we had resources that were fuel secure and they were all fossil. We're moving in a direction, you know, with state support where we're moving toward intermittent resources that are zero, low or zero carbon emitting, but they're all energy limited.

And so we need to be thinking as we go forward, once we get past the kind of the five year threshold where we are right now, how do we accommodate -- better accommodate those limited energy resources, whether we're talking about wind or we're talking about solar or we're talking about storage. And one of the things that we're looking to move toward is what we're calling multi period optimization, where we look at dispatching the power system rather than on an hour by hour basis or on a five minute basis, and trying to optimize that portfolio and those limited resources that they all bring to the table over a longer period forward so that we make more effective use of storage, of wind.

You know, let the wind run right now, even though maybe it's not economic at the moment. Maybe there's something cheaper that could be running, but that's something cheaper could be running later when the wind's not blowing. And so we need to be thinking about moving in that sort of a direction from a computational standpoint, we're not able to do that sort of analysis today. But by the time we get there, we expect that the computational capability will have grown to the point where we'll be able to solve those optimization problems. And those are the sorts of things when you're looking at a five year forward to ten year forward, how do we get to 20, 30, 35, 2040?

Those are the sorts of projects that we need to be working on and they go toward what I think a lot of us here are saying, which is focusing more on the energy and ancillary markets and letting the capacity market kind of fade. I don't think it'll go away, but become less important because what'll happen is the resources that we want will be earning money through these other markets and then taking money out of the capacity market and shifting it to resources that are doing the sorts of jobs that we need them to do.

COMMISSIONER DANLY: Thank you.

MS. GARDNER: Commissioner Danly. I think in direct response to your question, I just want to underscore, I think a lot of what Mr. Karl was saying about taking the additional analytics and information that we have and have reflecting on today and looking at better ways to incorporate that both in the products, the ancillary service design going forward. I do want to emphasize, like others on the panel have noted, it is time to prioritize pay for performance reform and to go back to what is it that we should define as a trigger and making sure that we have fully integrated the incentives in our markets and that we don't we're not solving for different problems, that it is integrated fully.

So I definitely underscore everything that Mr. Karl said, but I wanted to add one more comment. As an entity that is developing and managing resources throughout the country, we certainly have seen challenges in other areas and other RTOs that have a greater penetration of renewable resources and intermittents. And I think coming into this conference today, one of my biggest cautions is that we weren't just solving the problem today, that we were really thinking forward of all the new challenges that are going to be coming onto the system. And so I think for that reason we are supportive of efforts to consider seasonal.

We think it makes the most sense going forward, given the various profiles of resources and their ability to deliver in different seasons. Look forward to that discussion in the region. We do think that's a worthwhile effort. I did want to make one comment though, like others, some others on the panel, I am very concerned about the idea of moving to a prompt market. We don't currently have a formal position on whether we should or shouldn't move to a prompt market, but as we saw in PJM's last auction in December, the timelines of resources and auctions are very much tied to planning processes, both in terms of assumptions on new resources coming into the market, even if it's through state policies as well as transmission. And so I am very worried that unless we really think through what that would mean in terms of those assumptions, we could be creating situations where we end up with more RMRs and transmission doesn't have the ability to solve for weather security violations or other concerns that could come out of a retirement bid.

So don't have a formal position, but I think there's a lot there. I don't know personally if that's the one I would prioritize. I think we definitely have a lot on our plate moving forward.

COMMISSIONER DANLY: So before I turn it back to you, Mr. Chairman, just two observations. Number one, yes, let markets work and you never want anything to happen that blunts or obscures price signals, though I do think that when staring down both barrels of a reliability catastrophe, the idea that the economic purist like you and me are going to win the argument, I think it's probably pretty low. So just a dose of reality on that. And then second, the takeaway here for me is that based on my question, not all that much has changed before and after that is ex-ante. We had an idea of what we wanted to do generally and now ex post after the revelations, to use that word again, it's still basically more or less the same thing, which furthers my confusion and I am still bewildered by how it is we arrived at this new understanding of the situation I assume New England is in. So thank you, Mr. Chairman. I'm five minutes early.

CHAIRMAN PHILLIPS: Thank you, Commissioner. Commissioner Clemens.

COMMISSIONER CLEMENTS: Thank you. I'm just struck by the complexity of the challenge you are dealing with and impressed with the perspective. There's a lot going on here and I'm kind of stuck on which part to even start asking questions about. I think this idea of what are we planning to is a really important question. And when we're thinking about the trade offs that Alex, you mentioned and I think, Andy, you mentioned between spending stakeholder time limited resources and time on reforms to the capacity market versus taking next steps after DASI and the energy ancillary service market our hard questions.

So I appreciate all the thought you are putting into them. First maybe more specific question just to get back to a comment that, Michel, you just made. Pallas Maybe you can respond. One question is the connection between a prompt market and new entry and a prompt market and retirement, and is it on the retirement side at least? Is it possible to decouple retirement notifications from the timing of the market, although they have been coordinated historically in these designs, does that get at any of the concern? That's just one of the specific repeated concerns I hear about a prompt market.

MR. LEEVANSCHAICK: Okay. Yeah. So if you were to transition to a prompt market, it's probably in many ways better for development timeframes and fuel procurement timeframes. There aren't that many units that are developed in the time frame of the 39 months that's allowed under the FCA. And even gas units usually take longer than that anyways, so it's not really good for them. On the retirement side, I don't think you really lose anything with a prompt market. You know, units retire for one of two reasons. Either something breaks unexpectedly or the economics aren't there.

So something breaks. And it's a pivotal resource for reliability. That's just as much of a problem for a three year ahead market because you've already bought capacity from a resource that's incapable of meeting its capacity obligation. So then on the economic side, I don't think that the prompt market really has a disadvantage there either because when resources retire due to economics and then it leaves a -- like something that would lead to an RMR, I think we've found time and again it's a deficiency in the in the locational pricing of the capacity market.

That's really the issue. It's not that capacity markets are somehow unable to provide incentives for resources that are needed. So I really don't see the problem there in going to a prompt market.

COMMISSIONER CLEMENTS: Thanks. And there have been a lot of concerns expressed today about the lack of incentives for the procurement of firm fuel. And I guess I'd be skeptical that a blanket requirement as a capacity resource you must have firm fuel would be the right approach from a cost perspective. Does this six month piece get added? Is there -- are there other ways that we should be thinking about that piece of the equation and where it lives in the market design? I'm not just asking anyone who has a perspective.

MR. LEEVANSCHAICK: Okay.

MR. KARL: So sorry. Go ahead. Go over me.

MR. LEEVANSCHAICK: So I think that the six month ahead time frame is going to -- you know, if it's six months ahead of the summer, because you're doing the forward framework that we have now, that's annual or sorry, not forward. I'm sorry if you're doing an annual market for a 12 month period. The problem is that that the procurement would have to occur probably more than six months before the winter. So that's not as ideal as in a seasonal framework.

If you're doing seasonal and prompt and you have the ability to line up the fuel procurement really during the summer or, you know, some comparable time period where it lines up better with, with the fuel procurement timeline for the winter. So there is some advantage in the seasonal framework that you get because it does allow you to tune that better than you would get in a 12 month in the annual auction.

MR. KARL: We think that a blanket firm fuel requirement would probably not be a good idea and it probably would be uneconomic. And the reason is, when you think about the fuel situation in New England, there's a certain quantity of fuel that can get into the region. And in particular, I'm thinking about gas right now. There's only so much you can get in. So some resources will sign firm fuel contracts and probably already have. And then everyone else is competing for the rest of that space that's available.

So the question is, how do we assume that space gets allocated? And that's one of the -- Pallas had talked about some of the debate that we've had about some of the proposals that ISO has gone out there right now in the RCA. You know, there's a couple of ways you could administratively assume that it works. You could just peanut butter it all over the resources that are out there. Or you could turn around and say, well, on a marginal basis, nobody can get fuel.

So we're not going to give credit to anyone. Or you could take a step back and say, well, some resources are situated differently, both geographically and operationally. So if I have a gas resource that's in a particular favorable point on the gas system and I've got a really low heat rate, I know that there's a pretty good chance that I'm going to be at the front of the line to get gas.

And so somebody else who's in a bad location and has a high heat rate has the opposite situation. So peanut butter disadvantages me and helps them doing the marginal thing and giving no one credit. Well, that hurts both of us.

And we believe the better way to allocate that would be through some sort of auction type process, some sort of an optimization or a constraint in some sort of a clearing mechanism where my favorably situated efficient resource can compete for that limited space against somebody who's not as favorable. I'm probably willing to offer at a lower price in whatever this market is that we're looking at.

So I get the credit the other guy doesn't. And so we've talked about this in the stakeholder process. I think there's fairly broad agreement that would be a good way to go. It's just in the time frame that we were working toward the FCA 19 timeframe, redesigning the auction process, the capacity auction process would be a big lift and probably would be more efficient from a not only from the ISOs development standpoint, but the ability of everybody else to absorb it would be more efficient to do that in the context of moving to some sort of a seasonal product. But we believe that's really would be a preferable way to go rather than some blanket sort of firm fuel requirement.

COMMISSIONER CLEMENTS: Thank you. Andy.

MR. ANDY: Thank you for the question, Commissioner Clements. Just a brief kind of word of caution on thinking about firm fuel procurement as kind of a benefit for prompt. I think it was discussed in the context of the RCA stakeholder process, and it makes some sense theoretically. But the question is in terms of now we're learning that the data may show that there may be no need for derating gas non-firm gas in the winter given the outcomes.

So then the question is what is the incentive or why would you need to incorporate your firming into your capacity offers a year out? So I understand it may change down the road, but if you're looking at prioritizing and timing, the question is if there is no derating for non-firm in the capacity under RCA, then there is no incentive to incorporate it. So what's the need now? It's really a question. Once again, we're still open minded on this, but that's what I'm struggling with.

MR. MITRESKI: Yeah. And I think just to add to what Andy was saying. The way the RCA analysis initially came out, it when it looked at the unserved energy hours between summer and winter, the split was 75% summer and 25% winter. And it also, like I said, it degraded gas only units by 50%, their capability in the winter. But then on an annual basis, their due rate was roughly 17%. So what that says is, is there enough incentive for resources to get the gas to procure the firm gas to get the higher accreditation? And Mr. Levitan, when he did a presentation at one of the committees, he said, well, the price really needs to be around $6 to get the incentive for resources to firm up and get the firm gas. Perhaps $6 is not a high price if you do go to a seasonal auction because perhaps the summer price would be lower. And then when you add the two, the net benefit or the net increase may be minimal. But that was all under a scenario where we had data before we realized that the modeling was not appropriate. So now if we get this data where the unserved energy in winter is zero and the rates are minimal, again, my fear is against the trade off.

They will spend so much time on this forward and seasonal market, but the decrease will be minimal and there will be very small incentive to firm up the gas. But I think potentially another solution is to maybe create some sort of a forward reserve market or anything, not specifically reserve market, but some kind of procurement of fuel that will incentivize natural gas resources to have sort of the backup or dual offer of at a high threshold price where they can switch from a regular gas to an LNG price. And that way they can offer on a forward basis what they think their costs would be and be able to recover.

It wouldn't be just limited to LNG resources, but still buy that product. That will give an opportunity for gas units to recover their fuel based on that forward procurement.

COMMISSIONER CLEMENTS: Thank you. Go ahead, Michelle, and then I'll be done.

MS. GARDNER: I just want to make one quick comment, maybe as a follow up here. And I do appreciate the ISO and kind of recognizing errors in the GE modeling, the ability to kind of retrench, go back, see what makes sense. But I agree with others. I mean, we're finding the no winter risk and the going forward, does it really make sense to price in firm fuel even on a seasonal basis? Does that make sense? But I just wanted to make one comment as we think about our reliability on resources going forward. We've seen a number of oil units and firm fuel units that are going to be needed in the market, at least in the foreseeable future, to help manage this energy transition gap, as well as being the owner of Seabrook Nuclear Power Plant.

As I think about the firm fuel that our facilities are able to provide in the region, and particularly Seabrook with emissions free kind of baseload support, the pause I have when we think about these firm fuel discussions is maybe flipping instead of just looking at adding firm fuel, making sure that we're still valuing the resources that actually are providing firm fuel onto the system. Because time and time again, even in the RCA process, a plant like Seabrook was actually seeing a derate because of the way ISO was doing its modeling because it was a large resource.

So not only were we seeing a situation where gas wasn't getting derated, but we were looking at a result that actually showed Seabrook getting a derate, which didn't make sense to us given the reliability that a unit like that provides. So that's just another way to think about it, as well as, again, the transition. If we think of kind of the transition and the oil steam units that are in the market today and what continued incentives can we put in our markets to make sure that those firm fuel resources stay around for as long as we need them. Thank you.

CHAIRMAN PHILLIPS: Commissioner Christie.

COMMISSIONER CHRISTIE: I'm going to Mr. Kreis. Mr. Kreis. You said a lot that I could talk to you about for about 3 or 4 hours, but I'm not going to take up everybody's time. But I do want to ask you a couple of things. You said the state motto of New Hampshire was not live free or die, but used and useful. Now, when are they going to put that on the license plates?

MR. KREIS: That was a loose

translation of our state motto.

COMMISSIONER CHRISTIE: Okay. Because I'd love to see used and useful on license plates if you do that. New Hampshire sent me one because I'm going to use it. I will get good trade in value with that, because my car is 12 years old. That might be consumer fraud actually, but it would be state endorsed. So if you're for used and useful, let me ask you. Let's look at the capacity market. I presume that under the principle of used and useful, you would really not be for a long-term capacity market, because you're paying for capacity three years in advance before you know it's going to be used and useful. Correct?

MR. KREIS: That's correct. I've inured myself to that reality, however.

COMMISSIONER CHRISTIE: Okay. Let me move to transmission. You would not be in favor, for example, QUIP and AFUDC, because those are awarded before a project is used and useful or ever will be used and useful.

MR. KREIS: Absolutely. New Hampshire is the anti-QUIP state. We've had an anti-QUIP statute on the books in New Hampshire since May 5th, 1979.

COMMISSIONER CHRISTIE: Okay. And one additional thing on transmission. You mentioned the concern you had that transmission projects, certainly local supplemental maintenance; they're called different things in different states. I don't know what they're called up here in PJM. They'd be supplementals, but local to the LSC are not being vetted and not being properly scrutinized before they go into formula rates. Is that your concern?

MR. KREIS: That is my concern. And again, I'm echoing what I've heard NESCOE say as well.

COMMISSIONER CHRISTIE: Right. So then you and I presume that you would not think that FERC should be giving a presumption of prudence when these projects are not thoroughly vetted or adequately vetted at the state level.

MR. KREIS: Absolutely not.

COMMISSIONER CHRISTIE: Man. There we go. One thing I would say to you, just to finally disagree and not really a disagreement, but you made the comment that state consumer advocates don't have the resources and the time to participate in a lot of these processes. And you're absolutely right. And you wanted to be in ISO New England. I'll tell you from experience, as someone who argued to get one in PJM, it's not a magic bullet. It really isn't. It's what we really need is a ratepayer advocate at FERC, and we don't have one. But that's for Congress to decide.

MR. KREIS: Indeed. Perhaps the Energy Policy Act of 2024 that my friend: Commissioner Simpson.

COMMISSIONER CHRISTIE: Commissioner Simpson is going to get and maybe have that in there, but we won't.

MR. KREIS: I don't want to mislead anybody. I heartily agree with you that what I suggested is not a magic bullet.

COMMISSIONER CHRISTIE: It's not.

MR. KREIS: I mean, there's nothing that we can do that would guarantee that we would be as empowered as we ought to be as the only wallet in the room.

COMMISSIONER CHRISTIE: Okay. Thank you. Tell me when those license plates come out.

MR. KREIS: Will do.

CHAIRMAN PHILLIPS: All right. We thank everybody here. We are at the close of this panel. I'm going to turn it back to David. I think we all have earned a brief break. I think we can take like a five minute break and then come right back. Is that good?

MR. BURNS: Works for me if it works for you.

CHAIRMAN PHILLIPS: Okay.

MR. BURNS: We'll see everyone at 3:15. Thank you.

(Recess.)

MR. BURNS: I'd like to welcome our panelists to the table for this panel or roundtable, shall I say. We have Phil Bartlett, chair of the Maine Public Utilities Commission. Katie Dykes, Commissioner; Connecticut Department of Energy and Environmental Protection; Ronald Gerwatowski, Chairman of the Rhode Island Public Utilities

Commission; Jim Robb, President and CEO, North American Electric Reliability Corporation; Carlton Simpson, Commissioner; New Hampshire Public Utilities Commission. Rebecca Tepper, Secretary, Massachusetts Executive, Office of Energy and Environmental Affairs; June Tierney, Commissioner, Vermont Department of Public Service; and Gordon Van Welie, President and CEO of ISO New England. Mr. Chairman.

CHAIRMAN PHILLIPS: Thank you again, David. And thank you, everybody. We have a full house to the end here today. And I think that this panel I've been looking forward to all day long. And so I'm not going to belabor any points. I'm going to get right to it. And I can imagine each of you could have written my question that I'm going to ask. I want to know what your top takeaway is from today. And I'll go ahead and put all my questions out. And then I want to know from you. What is the next step? What is the most important next step that we need to take? And finally: who needs to take that step. And so, I will start with you, Mr. Robb.

MR. ROBB: I had a different question in mind. But yours is better. Thank you, Mr. Chairman. I appreciate being here. You know, I wish these issues were easy and non-controversial, like inter-regional transmission capacity assessments and those sorts of things. I think there's first of all, here's the top thing that strikes me, right? This was a much more encouraging conversation than I think we had back in September. For whatever set of reasons, I think there's some facts and analysis on the table that might have been missing last time. And I think we had a good robust conversation around that. You know, pro and con. I think the thing that stands out for me among the 6 kind of major takeaways that I have from today is that really managing the pace of this transition continues to be my number one concern. And the one thing that we need to always keep our eyes open to is that we don't remove facilities until we can replace them in full.

And I think the need for some of the assets that we've talked about today, whether it be the Everett Terminal specifically, whether it be reinforcements of the natural gas system, the other kind of very exciting new resources that are coming on the system here, the offshore wind, which is terribly exciting in terms of how transformational that could be for the region and the expansion of solar up here.

All of these things make a great soup, but they got to be added in the right order and in the right quantities in order to make this whole thing work. And I would just kind of continue to raise to the region's awareness to be very, very thoughtful about how we move from the system we're at today to the one that we will be at in the future at some date and not to be short-sighted about what we're going to need to make that transition work reliably.

CHAIRMAN PHILLIPS: Mr. Van Welie.

MR. WELIE: Thank you, Mr. Chairman and Commissioners and fellow state colleagues for joining us here today. So my top takeaway is the reality that the gas and electric systems are highly interdependent. But we are still overseeing, analyzing, operating and planning these systems in silos. And you heard it today in multiple panels. So I observed or heard your comments last week and read them in the press clips where you pointed out that there's a lack of oversight over the gas industry. And it doesn't have to be FERC. It has to be somebody that has to provide that oversight. And I do agree with that. Commissioner Simpson earlier today called on new legislation to remedy that problem. Now, I'm not naive. I don't think Congress is going to click his fingers and change that overnight. So we have to live with the reality that we have. But I think it's the source of much of the confusion and frustration that we heard during the course of the day. And I believe that we need new standards, new regulatory requirements.

I think you heard Vamsi speak earlier on about if we're going to solve this energy adequacy issue through a market. We need to define the metric for it. So I think the work that the team has done has pointed us in the right direction with regard to coming up with an energy shortfall standard. We're still going to have to agree on what that looks like before you can clear such a thing through a market.

But I think one thing that all the regulators here at this table can do to help is to require that the gas industry do as comprehensive a job on the operational performance, the dynamic operational performance of the gas system, as we're attempting to do on the electric system. Only then do I think you will see the full picture, because I think we're making an assumption which has been challenged today that the gas system will be reliable.

So if you give me a few more minutes, I just want to run through a couple of other things. So the results from the the so-called pre-analysis freely admits that this is an incomplete study at this point. We had a choice. Do we put out an incomplete study or withhold it? Knowing that the information is in? That study was very germane and pertinent to this conversation. Because the other thing I heard today was what's at play here really is the cost allocation problem around average. Who's going to pay for it in the short run?

So I'll come back to that. There are two sort of primary assumptions upon which that study rests. The first is that the gas system will continue to perform at historic levels without Everett. Is that a good assumption or a bad assumption? We need the gas industry to tell us what we heard today during the course of some of these panels is that that may not be a good assumption. But still surprising to me that after 20 years of talking about this issue, we still do not have a regular, rigorous analysis of whether the gas system is going to meet not only the firm customers, but also the electric generation needs of the system, whether they're firm or not.

So I think that's a regulatory gap that has to be addressed. The other big assumption that our study rests upon is the fact that the region, the ISO and the Commission will follow through on a long list of very important market design reforms, which are going to be very difficult: resource capacity accreditation. I think DASI is going to be easier because we've tried that one before and we're coming back with the second time. But you heard both Bob and Michael put out a long list of things that we would like to do: capacity accreditation and service reform replacement reserves, and possibly prompt seasonal auction and IEP's in the mix.

These are all very difficult topics. So to assume that we're going to get through all of these issues on time is a big assumption. And we've learned through experience that often that may not be the case. So what are the risks?

So the good news is in the short run, the risks seem to be abating a little bit.

And I'm very happy to see that. And that's really because of the work that the states have done on energy efficiency and the solar penetration. Really modest demand growth and high solar penetration have offset some of the energy adequacy risk.

We didn't see that until we did this analysis. But what are the risks in the longer term? The risks in the longer term are that the 2 prior big assumptions that I mentioned turned out to be incorrect: that the gas system will perform and that we'll get all these market design improvements done on time. The second big one is load growth.

So we just put out a revised load forecast for the 2031, 2032 period. We're showing an addition of some 6 gigawatts of additional load. That's dramatic. That's going to look like a hockey stick in the second part of this decade, and that's to meet the forecasted electrification goals. So that's a big variable. And then, of course, retirements, particularly of the oil units, because what you've heard is as we rely less on gas, we become more dependent on oil. And then the fourth one is: will the offshore wind be here on time? And we've seen some delays there.

So there are big variables out there with regard to the future. And so if you ask me, how do I feel about the risks, I'm not feeling sanguine about the risks to Commissioner Danly's question earlier on. In the short run, I'm feeling a little more relaxed about where we are given the analysis.

But in the longer run, I'm still as concerned as I've ever been. And there are too many variables out there that could break in a negative direction for us. And therefore, I would say that from the perspective of answering the question of whether the region needs to retain Everett or not, to me it's a simple decision. The region should retain Everett. It's prudent. That's why we said it's prudent to do so. I think it would be extremely unwise were we to let that facility go until we know where we are with regard to these variables.

And so then your question was: what are the next steps? We've got a long list of next steps ahead of us. We have to complete the analysis. We have to look at 2032. We have to continue to make progress on these various market design initiatives. But I'd also say to all of you, please, let's make sure we get the gas side of this equation understood. That's not something that we have the power to control. All of you collectively have the power to do that. And I'd ask you to do that, please.

CHAIRMAN PHILLIPS: Thank you, Chairman Bartlett.

MR. BARTLETT: Thank you. I think my biggest takeaway is that we're better informed than we were the last time we spoke. When I spoke in Vermont, one of the things I mentioned was that we needed to better define energy adequacy, understand what it was, how we were going to measure it, so that we have something to work towards. That is, we come up with solutions. We knew the problem we were trying to solve. I think the study has gone a long way in that regard, giving us a sense of the risk and the magnitude of those risks. And I think from here, we need to work with the ISO. The state and the ISO need to work together to develop that energy adequacy metric. What is it that we need to solve for based on this analysis? And I think that's going to be incredibly important, as we see the 2032 analysis. I think the 2027 gives us a little comfort.

I expect that 2032 will pose a lot more challenges for some of the reasons that Gordon has mentioned. I think we get that, I think we need to sort of reconvene and focus on what needs to be done over the next couple of years. That will get us ready and that will solve the energy adequacy challenges that are likely to be put right in front of us when we get that 2032 analysis.

So I think the core message is that we all need to remain vigilant and keep a sense of urgency. This problem is not solved. At most, we have a bit of a reprieve, and we need to continue to dig in. And then finally, I agree with Gordon's point, that we absolutely need to better understand the gas system and the interdependencies with the electric system. That is a huge gap we need to do. I think it's a combination of studies and coming up with new mechanisms for ongoing sort of dialogue measurement, so that we have a better understanding of the problem in real time before we get ourselves into too much trouble.

MS. DYKES: I think that today has been really valuable in helping to shift our focus a bit. If that's the takeaway, I think that it will be a huge success. I think that to the extent that we've looked at the 2027 results. I don't think we should be taking away from those results. This is a time to relax or to feel a reprieve or to feel a breath of a sigh of relief, or that we have some time. I think that what those results should be telling us is that we need to work quickly to get the 2032 analysis, because we have a very limited amount of time to start on the path of deploying the resources that are going to be necessary for reliability and to support electrification in the next decade. And it takes 5, 7, 8 or up to 10 years sometimes to build transmission, to get offshore wind, a nascent resource, that's in a very dynamic moment right now: deployed. Right?

So let's take those two examples. So we probably have 6, 12, maybe 18 months and decisions that will be taken during that time frame that are going to be determined where we're going to be in 2032. So I really commend FERC for hosting these forums. I think they happened because there was a sense of urgency that we were about to lose a critical resource and that we all had to come together lest we face the microphones, you know, around rolling blackouts.

But I think we're still in that urgent emergency moment. And so I would share my colleagues view that I think another, you know, a reconvening, because it's a lovely to come up and visit New England. A reconvening would be very helpful when we have the 2032 results, so we can really build out the robust list of what needs to happen next, because it's all within the time that we are all collectively going to be sitting in the seats that we're sitting in. The decisions will be made that will dictate what the reliability result will be in 2032.

So I really hope that we'll continue to have that level of elevated, heightened sense of urgency that can convene and bring us all together, because there's not one specific action or reform or investment that will determine all of this. It's going to be a host of different things: state decisions, ISO market design, FERC decisions, as well as federal funding through the IRA and the bipartisan infrastructure law that is accelerating decision-making investments.

So I think getting the band back together after the 2032 results are out would be really helpful. One last thing I just want to say: the ISO New England market; it's geographically isolated. It's a small market, and it's vulnerable to exercises of market power as a result. And we have for, you know, over the last two decades, evolved a market design capacity market that is built around the investment needs of natural gas resources.

Whether you're enthusiastic about decarbonization goals or not, the bottom line is that we don't have the gas delivery infrastructure to support that level of gas dependence.

And so I think the 2032 study, you know, as we look at those results, feels to me like finally an opportunity, a generational opportunity, to break free from this sort of single resource dependency that has locked in so much market power and so much exercise of leverage that it's to the detriment of our ratepayers. And I'm excited about that. I think that it also means that we need to think about where we're putting our focus. The capacity market is sort of like the Everett of energy issues. It takes up so much bandwidth and so much stakeholder focus. We only have so much stakeholder focus.

This is an amazing community in Nepal, you know, in New England, to get together and work through these issues in a multi state ISO. But there's only so many hours of the day that we can spend in these types of meetings. So focusing on energy and ancillary services reforms to me is more valuable. Not to diminish all the discussions about the capacity market, but that's where the resources that are really keeping the lights on are making their money. And so I'm just leaving that as another comment.

MR. GERWATOWSKI: So I think that the prior speakers have identified all the good takeaways, so I won't have much more to add about that. And I don't have any brainiac solutions to offer, but just a few just general comments first. Even though we have this study, even though we have some feelings that maybe it's not so bad as we thought it was, I still retain a instinctive skepticism about that.

It's very difficult for me to go in the last year and a half telling the powers that be in Rhode Island, that the skies might be falling this winter. And then I go back and say it's all manageable and maybe it is manageable, but I still worry about that. In fact, even when you assume a normal winter, it is manageable. We still are one contingency away from something really bad. And what my other fear, maybe because I'm a worrier about these things, is that if something like that happens, then we're going to be faced with drastic actions that are going to be demanded that could make things worse, not better.

So I live with that because I don't think it's a good message to leave this conference in saying everything's okay now. Everything's not okay. We still have risks. We still have to keep our eye on the ball on this. And I think the market reforms is directionally the best thing that we can do right now with ancillary services, the capacity accreditation and the seasonal market reforms. And while I share with Don Chris the tendency to say provocative things, I don't always agree with them on everything. But I do agree with this. When we look at those reforms, we really need to have a rigorous assessment to make sure it really is addressing the risks that we're trying to achieve.

I've said enough about Everett, and I think that there is a need to try and get an analysis of the gas side matched with the electric side. I hope there's more dialogue about that. I don't think that, as I said earlier, I don't think that's about FERC issuing orders or the states issuing orders.

That's just trying to get folks together to try to see if we can't develop something sensible. I do. I'll leave you with this. I think it may be something that we all recognize that started last September is that we can all agree that there's certain things that we need to do, and we start going into circles, and we can get a consensus. And then it always comes down to, yeah, but we can't do anything about it. And I feel like that's what happens because of the regulatory gaps.

It's not a blaming of anyone, but we have the federal, and we have the state, and we seem to have this area that leaves us with no one in charge to be able to really say, yes, you must do this or that. So we're going to continue to face, I think, some difficult issues like this potentially in the future. I don't have a good answer for it, but that's my perception of the circumstances. But thank you very much. I, certainly, on behalf of Rhode Island, really appreciate FERC, the Federal Energy Regulatory Commission, coming in and really taking all of this seriously and coming twice. I really appreciate that. Thank you.

MR. SIMPSON: The policy questions that I posed, and I hope I'm not naive, might characterize it as useful youthful naivete, but I think that fundamentally, we're not in Attleboro anymore. Our jurisdictions are getting closer and closer together because they need to. And the data that underpins these various energy infrastructures, whether it's electricity, whether it's the gas network, whether it's the various delivered fuel supply chains, we really need real time information and system status to reliably monitor and operate these interdependent systems.

So at a state level, I think we need to do more with the distribution companies that we regulate. We need to enable customers to have better access to information. And at a federal level, I think that the regulatory constructs that exist need to evolve, just like state policies and regulatory constructs continue to evolve. It will help to enable new market opportunities, which will enable us to value and determine the attributes that different resources provide to the system, provide more transparency, and hopefully ensure continued reliable operation and safety.

MS. TEPPER: I think we're in a better place information wise than we were when you were here the last time. I think that I remember the last time saying that nobody had looked at the actual numbers with respect to Everett. And I do think we're in a better place in terms of having the information that we need to make a good decision, at least on the electric side. I also think that we're coming away from here with a clear consensus among the states about the need to act as a region and together, I think the New England region is right now committed to working together on various issues. I think we're moving in the right direction in lots of fronts.

I think the study showed us if we didn't already know it, the value of solar, even in the winter.
I do agree with the sense of urgency to continue on our clean energy procurements and the benefits that we are going to see from the offshore wind industry, which I believe 100%, that we will have an offshore wind industry off the East Coast. It's just too valuable. We have
some of the best wind in the world, Saudi Arabia of wind here, and it's too valuable of a resource for it not to happen. So, you know, I think: full press on the offshore wind, full press on the transmission to support it, full press on the transmission to support clean energy and full press on the tie lines to be able to bring in renewables from other regions.

MS. TIERNEY: I'll start by thanking the Commission again for coming here and for continuing to join in this process of sifting for insights and looking for the path forward for our decarbonized future that we need to get to safely. As I said last year, which is why I patient myself and listening to the discourse about the role of natural gas in this transition; notwithstanding the fact that every time we say it, there are people out there saying: do you not get it? We need to stop burning fossil fuels. And when the answer becomes, hey, we can burn less of gas because we've got oil, it's not an appreciable improvement. I worry about our conversation today, which again, was expertly, highly incisive and elucidating. I worry about it coming across as tone deaf.

And so if I have a top takeaway today, it's that this is an unforgiving forum, not because we are unforgiving toward each other, but because there are people listening so closely and so carefully, and nuance doesn't go over well. The ISO has taken quite a beating today. Nine months ago, the message was, oh, my word, the sky is falling. Today the message is, well, we've got some breathing room. But I can relate to the bewildered sense that Commissioner Danly has, because I've puzzled about this all day. And I just asked one of my colleagues in one sentence what has changed. And we really struggled to come up with that one sentence. But then Phil said they did the analysis; they did the robust analysis, and they're to be congratulated for that.

And it being ICES analysis, I have no question that it was done well. The problem that I see continues to be to the folks we're trying to reach the hearts and minds of those who need to join us in this process. They continue to feel like they're not included in the study thinking and how can we change that? It was very refreshing to have Don here today talking in a rabid consumer advocate voice. I remember, I think, Rebecca, that was you last year or two years ago, right? More of that, but maybe not just from the consumer advocate now, maybe also from the RJ 40 people, maybe also from the health people who will talk a little more about what it means to be choosing between the air pollution of natural gas and the air pollution of oil, as we seek to secure winter reliability.

Trust seems to be somewhat a trusted partner. The ISO gave us the study result. I trust them. I know many others do as well. But I think Commissioner Danly has put his finger on something or Danly, forgive me, that only a regulator and only a regulator like FERC can do, which is point to the need for some sunshine. How did we get here? How did this happen? That's a pretty simple process. You can pose questions to the ISO and say; why is the analysis only coming now? And can the ISO answer those questions? And my money says they have good answers.

The public needs to know that because the reporting on today's event, no doubt, is going to be: who knew there's no crisis, and we all know that that's not so. It's just that the definition of the crisis, the parameters of the crisis, et cetera have changed on us. But that doesn't mean it's gone away.

I've looked for a suitable analogy, and they've all eluded me. The best I can come up with is that I'm driving a car in a New England winter, and there's ice on the road, and there's a terrible glare. And at that point, my option is to flip that blinder down and hope it does the job. But if you're like me, you're at a cross, an intersection, and the lights are up there, and you can't see them because the blinders are in your way. Is it green yet? I can't tell. But as soon as we stop defining the problem, as there's too much glare on the road from the ice, and instead we say there's too much white light.

That opens up the possibility of getting out your sunglasses if you have some polarized ones and filtering out the white light, and you see the problem differently. And I think that is what the ISO has done and that is what the study shows us. But all that's terribly nuanced, and we need to be able to communicate about that in a way that makes us worthy of the trust that the public invests in us.

So the question was, what's the next step? And I would say build trust. And the next step to building trust is, I don't want to say, further study. I do want to say let's do the study that Gordon has so clearly articulated needs to be done and that Ron so passionately advocated for.

Let us start looking at gas and electric systems as the interdependent systems they are and let us do more, more analysis there, to understand how we can make those systems talk to each other in order to make greater progress on our winter reliability and our transition for how our grid is fueled.

But with that said, let us bear in mind as we do that, that we are talking to a significant portion of a society that is saying we can't be burning any more fossil fuels. We can't be doing what we've always done before. It's beyond ironic that we're now looking into the particulars of a system that at this very moment we also need to have go away.

Let's do it, because we have to build the trust, and we have to get to that new world where we have a decarbonized grid safely. And whether I like it or not, natural gas has a role to play in that. Who needs to take that next step? Oh, Chairman Phillips, you know what I'm going to say? You know, I'm going to say FERC, and I'm going to say thank you, but I'm going to surprise you.

I'm going to say FERC has a unique convening authority. And Commissioner Christie, I know you know that as a former state regulator, you are very well versed in the powers of the state. And I know with the time you spent at FERC, you are also now well versed in the convening authority of FERC. And nobody can make ISO and the states and the industry and stakeholders who want in on the conversation sit up and pay attention and speak their minds in the presence of each other the way FERC can.

So this is not a gratuitous use of your time. This is, I think, the way we plug the regulatory gap that has become clear between our state jurisdiction and our federal jurisdiction, where we all see that we are terribly reliant on collaboration. As you pointed out, Commissioner Clements, you're delighted that we're doing that regional planning now, and FERC was hoping we would do that. And we're barely doing it because we, too, see the urgency. But we don't really know how to do it.

I would love to see ISO be helmed or be steering some of that, but it's not clear to me whether they can or will or won't have the authority. Those are the things that these convening proceedings can clarify for us.

So we need more of that. But states and ISO have a role to play too.

So ISO needs to figure out how to bring more voices into its studies, I think. And I'm sorry, ISO I know I'm throwing that at you and you're probably hating me for it, but it's good medicine, honestly. States! I heard Vamsi's question, and I think FERC took it up as well. What is the risk? What is the appetite we have for risk in the region? What is the standard we are designing toward? If we have quantified the amount of risk we can take, and that's a fair question. The flip side of that is, okay, having assumed that risk, how do we harden our people so that they can bear the downside of that risk. And I think that is a state mission. We can use the partnership and help of FERC in educating people about how they can help. This is back to demand response energy efficiency behaviours like making sure your backup battery is charged when a storm is coming. We need your help with that, of course.

But fundamentally, it is also for the states to be looking at how do we harden our people to deal with the risks that we necessarily have to bear, because as Don so eloquently put it, we can't afford the perfect system. We just can't. I'm sorry if I tried your patience and going over too much. But that was my takeaway today.

CHAIRMAN PHILLIPS: Thank you, Commissioner Clements.

COMMISSIONER CLEMENTS: Thank you. I will undoubtedly fail at ingesting all of the great guidance you just provided, because it takes a lot to process the idea that we are speaking at an expert level that doesn't bring everybody in. And I very much appreciate the comment and apologize in advance to the extent that I'm not able to switch over. I guess I didn't hear today that it's either everything's fine, or the world is falling and now everything's fine. What my takeaway in reaction to all of yours is that the rest of the world isn't static. We have a question about an asset, a big asset, an important asset, and things around it are changing. And there has been an intuition about the problem for a decade that's been around fuel security and through this quantification process, we see that other things around in the world are changing and will continue to change and that's great. That's encouraging.

That doesn't mean we have a large amount of breathing room, or we can go out and not worry about it. It does give us a little bit of breathing room. It gives you a little bit of breathing room, but less bad doesn't make it okay. The amount of information that was presented in the last panel on market design is intimidating. And it may be that breathing room is the time where you all as a region and stakeholders get to have the hard conversations. You know, I have spoken favorably about seasonal constructs, especially as relates to the flexibility that demand side resources might get from that relative to participation, affordable participation, cheaper in that market.

That doesn't mean I think that's the only answer or the right answer I have written about my interest in.

I'm intrigued by the proposal on a prompt front. That doesn't mean I know that's the right answer or the only answer. I think from where I sit on across this Commission, I am open to the idea that maybe it is that piece of the capacity market that needs to be the top priority, or maybe it is, as some people said today, the energy and ancillary services and what comes next they know we're 80 to 90% of the revenues live for any resource. So I want to be supportive of whichever place that limited amount of resources can go to. And I hope in comments following this day, you can help us understand maybe as you process it, what would be most helpful from.

Is it giving you that space and time to figure these things out? Is it providing more perspective on a set of principles? Do we need to dig in more discreetly on loss of unserved energy, on what the design criteria are? You know, we can be helpful. We can take leadership in that way. But it would be helpful to get your perspective on what that looks like in addition to what you've already said to us today. And so I don't think I have additional questions, but just to express appreciation and certainly take to heart, Commissioner Tierney's and Secretary Tepper's comments about how we broaden the conversation. But go ahead.

MR. WELIE: So, Commissioner, I just wanted to pick up on one thing you said, because I heard the same conversation about his further capacity market reform: the most important thing we should be doing. So we did a study that we published last year; a study that came out of request from the states that looked at what's called the pathway study that was intended to look at how does one drive clean energy resources through a market. But what we were also looking at is what happens to the revenue stream and to the existing resources in the market.

And so what that study showed very clearly as we load more and more renewables onto the system is going to tend to compress energy market prices, which is going to make the capacity market ever more important going forward or some mechanism that takes over the function of a capacity market. So as I look out into the future here, I don't see how we can lower the priority on that issue, and because it's going to become the balancing revenue stream to deal with paying for resources that are going to have ever lower capacity factors over time.

COMMISSIONER CLEMENTS: Thanks. My comments weren't to suggest you shouldn't. It was to suggest I don't know what the right answer is. So thank you all for participating today.

CHAIRMAN PHILLIPS: Commissioner Christie.

COMMISSIONER CHRISTIE: I love coming to New

England. A century after the Attleboro case and hearing a commissioner from Rhode Island talk about a regulatory gap: some things never change. I thought we fixed that a hundred years ago, but it's great to hear. Here's what I want to ask, and I'm going to ask this because we have like five state commissioners on this panel. So I think it's appropriate. Commissioner Tierney just mentioned this.
Secretary Tepper mentioned it. Everybody always mentions, as part of the long-term solution, we're going to do DR. We're going to plug the gap with DR. You know, we're going to lose gas. We're going to lose coal.

We're going to plug the gap with DRs. Let me ask you this. We have five state commissioners. The most effective DR program, which also picks up conservation, does two things. Each energy efficiency reduces load over the course of the year. It's an efficiency program that just reduces load on a secular basis is about reducing peak, sometimes called peak shaving. And the most effective way to do it is through time varying rates and dynamic pricing. That's the most effective way to do it.

Everybody gets to participate. It's available to all consumers. And it's proven to really, really work. It's both peak shaving, and it's also efficiency over the course of the year but it's a retail rate issue.

It's not a FERC issue. Okay? It's a retail rate issue. Nobody in the retail rate world is going to know what LNP is at a given time. You cannot take a FERC wholesale market and make residential consumers know what LNP is every five minutes.

So it's a retail rate issue. How many of you are working on or have already instituted a time varying dynamic pricing rate structure designed to a) reduce load on a secular basis over the course of the year and b) especially do peak shaving. How many states are doing that? Just start with Phil.

MR. BARTLETT: What I say is we have adopted some time of use rates, particularly focused around EV and heat pumps, because those are newer technologies, and we think we can get people to engage. I agree with you that the demand response has to be at the retail level. And I certainly take that challenge and know that's something that we need to work on. I think the whole region could work effectively to come up with better demand response models. I do think the study, the EPRI study, may give us some insight into how valuable that can be, which can then help justify the cost of it.

I also think it goes back to the other point that has been made about trying to bring the public along. You know, time of use rates as a mandatory rate or dynamic pricing is very, very unpopular. Most consumer advocates are opposed to it. A lot of consumer groups are opposed to it. They are very concerned about the impact on vulnerable folks.

So we have a long way to go. I mean, I think we are going to be looking at rate design issues in Maine for sure. We'd like to get to a place where we had a mandatory time of use rate, because I think or some sort of dynamic pricing is exactly how we help to balance supply and demand. But we're a long way from that in terms of trying to get the public to understand it, support it and embrace it. So I think in the shorter term we're working on these voluntary programs, opt in programs, to try to demonstrate the effectiveness and the benefits of them. But I absolutely agree with you that that's a retail issue.

COMMISSIONER CHRISTIE: And I would just say this. It is unpopular. There's a lot of pushback. A lot of consumer advocates don't like it. But, you know, it's about trade offs. If you want to shut down all these fossil fuel plants and if answer is always DR, it is going to be to fill the gap. Well, this is what it means. I mean, you have to start looking at rate designs that really incent people to cut back. That's just so straight offs.

MR. SIMPSON: Thank you. Prior to joining the New Hampshire Commission, I had worked on time of use rate designs, and I'm a time of use rate customer. We have multiple utilities in New Hampshire that offer optional time of use rates for a variety of applications. I think that as with so much in this space, incrementalism is really important. And engagement, public engagement, educating folks about these options and how they could change their behavior to mitigate system conditions, save money, reduce emissions, and a variety of different applications. But offering those rate opportunities for customers I think is a foundational component.

And that's why I always seem to get back to the data question. We have to have more real time information in order to enable a time of use paradigm. But that's a long conversation to have. It is a challenging topic, and we need to engage with the public, understand their concerns, the dimension of the issues, and what the cost implications would be in order to realize whether that is what customers really want.

COMMISSIONER CHRISTIE: Thanks. Secretary Tepper.

MS. TEPPER: Well, as I said earlier, I think that the states have some work to do in this area. In Massachusetts, we don't have smart meters yet, so we need to put in our smart meters. But I agree with you that the key here is to make sure that everybody's not on the system at the same time. So I don't think that time varying rates are the only way you can do that. We have a clean peak standard in Massachusetts, and I think virtual power plants are going to be a way for us to control the peak without having to do necessarily with the rates.

I think people are going to have storage in their house. They're going to have storage in their car; they're going to have solar on their roof. All of that can be managed in a way to control the peak. So I think there are a couple of ways to get at that to get at that same issue. But I agree with you that there is more work to be done.

COMMISSIONER CHRISTIE: Mr. Tierney.

Ms. TIERNEY: Briefly, we have a variety of arrangements like that in Vermont. And perhaps more importantly, you missed your opportunity to ask Commissioner Allen from Vermont about this. He is an expert in the subject and while he was serving at the department with me, he did extensive study of the subject involving all of our distribution utilities, recalling that we are still vertically integrated in Vermont. And as Rebecca pointed out, having the ability to do that depends on having smart meters, which we do pervasively have in Vermont.

Interesting, though, there's still that element that does not. And that's an equity issue because now once you're talking about smart meters, you're talking about broadband. So, you know, these are things to keep in mind. A philosophical debate that's unfolded in Vermont is often, you know: do we ask consumers to be involved on that level or do we empower our utilities to have systems that effectuate the same outcome without asking consumers to be involved in that level?

COMMISSIONER CHRISTIE: You'll find out.

MS. TIERNEY: Well, you know, we have one program that comes to mind, if I'm not mistaken. It's our Powerwall program where the idea there was the consumer installs a Powerwall at the house and has a tariff arrangement with the utility whereby they can draw power out of that battery at moments when needed to meet, say, peak demand and the like. And there's an appropriate tariff offset for that. So these are things that we are doing at the state level in pursuit of the very thing you're talking about. I hope that answers your question.

COMMISSIONER CHRISTIE: Well, Riley's an economist, so I'm sure he understands the benefit for sure.

MS. TIERNEY: Right. And I'm a behaviorist, and we always had very robust debates about that in my office.

COMMISSIONER CHRISTIE: That's interesting dichotomy Commissioner Gweratowski.

MR. GWERATOWSKI: I didn't want you to think, Commissioner Christie, that on behalf of Rhode Island, and I'm ignoring your inquiry. I have an advanced metering infrastructure case in front of me now that implicates it. So I'm not going to comment, but I just wanted to let you know that. Okay.

COMMISSIONER CHRISTIE: I could comment on your case, but I won't. It's a slogan called smart meters plus dumb rates equals zero. Nevertheless. Katie.

MS. DYKES: I'm happy to add just to round out your tour of the States. We're not in such a dissimilar space from some of the other states in terms of AMI deployment and then putting in the rate structures. We've got time to use block rates. But there certainly are dockets underway at the Public Utilities Regulatory Authority that could be an opportunity to explore further. But I do think that this very question is one of the great I, think, results or perhaps, I don't know, conversations that's become possible because of the Eprix analysis, because in all these discussions about winter reliability, for years and years we've talked about, you know, solar PV efficiency and DR don't really help here. Right? But now with the results on the solar PV, those insights right now, it brings these kinds of resources into the spotlight from a winter reliability standpoint.

So when that happens, then it makes it possible for states, for example, we administer the utility: the budgets and the programs for our utility administrative efficiency programs now go into our cost effectiveness testing and start to value some of these winter reliability contributions, and that can unlock different levels of incentives and so on and so forth that could bring more of these resources forward.

CHAIRMAN PHILIPS: Commissioner Danly.

COMMISSIONER DANLY: So, Gordon, we went from, last year, a discussion which the plan was let's hope for a mild or moderate winter. Something at the time I derisively referred to as regulation by rain dance. You're hoping that a certain weather pattern shows up to a declaration that it is manageable; whatever that word means for now, but who knows what happens in 4 or 5 years? And so rather than just immediately get into it, I will offer you the opportunity to respond to the question I'd asked before. I think that's only fair, which is, what about the plans for market design have changed before and after we have gotten the analytics you've gotten?

MR. WELIE: So the plans haven't really changed. Perhaps the new thing that's on the table more explicitly than it was a year ago is the possibility of moving to a seasonal market. And we think that we should also consider a move to a prompt market. You've heard the caveat around that. That's not a set in stone discussion at this point. We need to have the conversation with our stakeholders. So I'd say that's kind of the new thing from an ISO perspective; a market monitor has been advocating for that for several years now.

The reason that things haven't really changed is we don't think the energy adequacy risk has gone away. Right? So I don't think that this is sudden, as I was a bit worried about some of the commentary on some of the earlier panels that made it sound like, because we've come out with one part of a study that shows some positive results for energy adequacy in the near term, that suddenly we should forget about that problem. We should reform every aspect of our market that has anything to do with incenting performance, for example. I think that would be a mistake. So I think there's a lot of work ahead of us. I'm not naive about how hard it's going to be.

Resource capacity accreditation is going to be, to use a technical term, a food fight, as we look at how do we sharpen the price signals within the capacity market and accredited resources. So the work ahead is clear to us how quickly we're going to get through it is not clear to me.

It's going to require support from our stakeholders, from the states and ultimately from the Commission. These are going to be hard things to do.

COMMISSIONER DANLY: So do you think that I am misinterpreting this, and that I am loading too much meaning into the euphemism of manageable? Or do you think that I am taking this as too rosy an assessment? Because I kind of caught that criticism there. Is that your view?

MR. WELIE: So manageable, does not equate does not equate to comfortable. So when Vamsi or Stephen George say things will be manageable when we have 100,000 megawatt-hour energy shortfall, what does that look like? That will look like California last summer. That's not going to be a comfortable situation. That will be the ISO speaking directly to the states, getting the governors out there appealing for conservation. Et cetera. Et cetera.

That's not a comfortable scenario. What was surprising to us when we looked, when we did the study, was that the magnitude of the shortfall wasn't as big as what we had previously modeled in deterministic studies. So, you know, maybe a word here on deterministic studies versus probabilistic studies. These are just studies, by the way. They're not gospel. They all embody assumptions and ultimately data sets from prior experience. So if you look at our journey, we came out of the winters of 2017 and 2018 with a very near-miss event. You know, so. We were within a few days of depleting our stored fuels within the region, and the debate within the control room was: do we run the flag up with DOE and declare an energy emergency or not?

The judgment was made that we thought we would get replenishment, because the weather was going to break on the other side of the weekend. We held firm, but that experience really alarmed us, because we had no way to either measure the risk at that point or communicate the risk to the public at large and to policy makers.

So that resulted in us starting the first round of analysis that we did, which was deterministic analysis. It started off really as a spreadsheet and eventually evolved into an optimization program, which is now the core of the 21-day rolling forecast that we do along the way. We had a lot of requests for bringing in more probabilistic analysis around what the future weather probabilities might do to our deterministic analysis, more probabilistic analysis around outages and so forth.

That really was the genesis of the study. You heard Ramsey say it took us 18 months to get to this point. We're not done yet. So we have another 3 to 4 months before we can publish the 2032 study.

Then we'll be running more scenarios on behalf of stakeholders. So that's been a two-year journey, which if you go back in time, you know, I wouldn't have thought it would take that long to set this up. So the work that ePrix has done, the climate modeling, is modeling they have today wasn't available five years ago.

So what you're seeing is an evolving state of the art with regard to the modeling. If I look at the 2032 analysis, it's going to have some level of determinism bolted on to a probabilistic study, because there's no other way of doing it. You're going to have to make assumptions about what the resource mix looks like in 2031, 2032.

You have to make assumptions about retirements and load growth. So really we'll be having scenarios and then the great debate around assumptions will recommence. Which side of the assumptions do you want to be on: the more pessimistic side or the more optimistic side? Frankly, when I look at what's ahead of us, given everything that we've got to do: all the market design work, all the work the states have to do with regard to dynamic pricing and retail rates, all the work that's got to be done and all the supply chain issues in terms of getting the offshore wind up and running. There's an enormous amount of work there. So how that's all going to play out is not clear to me.

The one thing that I have started seeing happening is load growth is coming. So people are not waiting around for us to start installing heat pumps not only in their homes, but in the Charles River to produce clean steam. We have cities and towns basically declaring a moratorium on gas after 2030. So that's going to drive load growth independent of whether we get all of this other work done. That can become the biggest driver on the energy adequacy risk if we're not careful.

That's why, this is a long-winded way of saying to you that I don't think that the energy adequacy risk has gone away, and it doesn't change the path we were on already. With regard to market design, there's a huge mountain to climb here.

COMMISSIONER DANLY: So when you say manageable, it means what specifically? Because you can manage the sinking of the Titanic? Right? So what is it?

MR. WELIE: What does it mean? So what it means is that if you have some forewarning of this, which is what the tool gives us, because really what New England rests on during the winter time is the depletion rate of stored fuels. That's what it comes down to. You're monitoring your oil levels, and you're monitoring the LNG levels. If you see a weather pattern coming in and you know things about the system in, you know, real time or near to real time, within days or weeks, you can then make decisions about whether or not you face additional risk(s) and you can start priming the system to respond to that ahead of the event.

So it's a bit like, you know, if Texas had had this capability, they could have been doing things the week before the event to drive some conservation. So if you can drive conservation the week before, you're slowing down the burn rate on your stored fuels. So that's what we mean by managing.

COMMISSIONER DANLY: But the follow up to that is that I took that to be what it meant. You gave, in Burlington, a list of contingencies, any one of which, pardon me, would be very problematic. Those still exist.

MR. WELIE: They still exist.

COMMISSIONER DANLY: So this is, and I'm really not trying to force you to take my language. So reject it if you like. But it seems as though this is, it seems to me, at a marginal discovery that allows you to manage marginal risk for a specific time period only. But all the contingencies that we listed nine months ago are still there, and the system's stability is threatened. Should any of those come to pass? Right? Fight me on that if you want.

No, no, I think that's correct. So the question really is, what's the probability of those events occurring? Once you commit to a probabilistic analysis methodology, you lose the freedom to just insert a specific contingency into that analysis. But that said, if we were to have one of the large nuclear units be out for a month during the middle of the winter, we would lose the tie lines to Quebec for a month in the middle of the winter or even a week, actually. That's going to be a real crisis for the region.

So I think the problem is, if we were to put out a study that suggests that that is a high probability, which it's not, then I think we face criticism from another angle. You're sort of damned if you do and you're damned if you don't. What we've tried to do is play it as best as possible down the middle of the fairway.

COMMISSIONER DANLY: So the one last question I have then for you is you said that you had a choice of either withholding the study, which was incomplete because it only goes to a certain period of time and has certain assumptions built into it. You didn't
that or waited until you had the full complete picture. Right? But you released it because it was relevant to the conversation I think was the phrase you used. What conversation are you specifically referring to if this isn't a paradigm shift? Is that term again, on what potential market reforms are being advanced?

MR. WELIE: Well, actually, I think it's relevant to the conversation around Everett, not with regard to the long-term trajectory and market design reforms. So, one of the questions that was on the table was how does one retain Everett? As we did our analysis, the first thing we came to was if we were to let Mystic go to Commissioner Christie's point, there is no jurisdictional hook to retain Everett. And we knew that we didn't have the justification to continue to retain the domestic units. So that left open the question of whether one would retain the average Marine Terminal. We still believe that that's a sensible thing to do. So then the question of whether or not the electric system should cover some of the costs of Everett or not is to some degree a question of what the analysis shows.

So, the analysis is not giving comfort in the short run. It may, in the long run, but that's going to depend on which side you sit on these various assumptions. So that's the thing that I find very frustrating about this, to be honest with you. I mean, it goes back to the jurisdictional gap. This is an interdependent system. When we did a load shedding exercise, a tabletop exercise with the utility companies last year, one of the things we learned through that process was that: it is an interdependent system?

MR. WELIE: The low pressure gas system can't tolerate load shedding. So there's an interdependency at the wholesale level in the sense that the wholesale bulk power system is dependent on the gas system. At the distribution level, the gas system is dependent on the reliability of the electric system. Our regulatory system actually makes no sense from an engineering perspective. We really need to be looking at this holistically, but we sort of stuck with the paradigm we have because of the fact that 30 years ago, 40 years ago; these two systems were not interdependent.

COMMISSIONER DANLY: So the one thing I'll say in response to that is FERC has its narrow jurisdictional powers and the states have everything else. And so to the extent to which there is residual responsibility, it's not ours; it's theirs. And there is a tendency, I think, sometimes for state regulators to feel some comfort in the fact that the ISO is there to take the first incoming shots, but in reality it will ultimately fall to them.

That's just me editorializing. So the final thing is for Mr. Robb, really quickly, having heard all of this and presumably looking at the analysis with as much enthusiasm as we have, are you sanguine about the circumstances over the near term, knowing that long term is a big question mark?

MR. ROBB: Absolutely not. I think this region is at the edge. I think it's going to stay at the edge. I think there is a potential for a weather system like we saw last year, right, if Elliott, had been a couple hundred miles further east, we'd be having a very different conversation right now. The resource mix that we're moving towards here is full of all kinds of performance issues that we don't yet understand. I am encouraged that there seems to be a slightly changed view towards the importance of the natural gas system. The natural gas system up here is absolutely critical, it needs to be reinforced and it needs to be integrated in the electric sector planning is pretty much what everyone has mentioned on this panel, and that is a huge gap in the energy policy of this region.

COMMISSIONER DANLY: So the way I see the circumstances, as much as they were nine months ago, resource constrained can't build. New infrastructure prices are really, really high, and nobody wants to pay for anything. And so the question that I'm always left with every time here is are the rates just and reasonable, and that that is fundamentally only interest that the Commission should have. So anyway, with that, Mr. Chairman, thank you.

CHAIRMAN PHILLIPS: Thank you, Commissioner. Thank you to all the panelists. I had a whole little speech written that I was going to say at the end of this thing, but I'll save it for another day. I will say this: the leadership here in New England is superb. So you don't need me to tell you what you need to do, but I'll leave you with this. I was a scout and at the end of a hard day, long day's work, there's a song we sing and it's called Vespers. Are there any Scouts in the room? Girl Scouts? Boy Scouts? You know what I'm about to say? You ask yourself a bunch of questions. It asks you to reflect upon the day. At the end of it you say, you know, have I done? I'm not going to sing.

Don't worry about that. But you say, have I done and have I dared everything to be prepared? That's a charge I leave you with. You all go back. Look at yourself and say, have I done everything I can to ensure that the people can count on me? I'm going to show up for them and they're not going to be in the dark. Let's all do that. Okay? I want to thank all the people at FERC, all the staff, everybody from the folks who picked this hotel, and the folks who helped stream everything and everybody who came here. All right? We did good work today. This concludes our forum. Thank you so much.

(Whereupon, at 4:21pm, the conference was concluded.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the matter of:

Name of Proceeding:

2023 NEW ENGLAND WINTER

GAS-ELECTRIC FORUM

Docket No.: AD22-9-000

Place: Portland, ME

Date: Tuesday, June 20, 2023

was held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission and is a full correct transcription of the proceedings.

Mike Williams

Official Reporter

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**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

New England Winter Gas-Electric Forum	**))))**	**Docket No. AD22-9-000**

**POST-FORUM COMMENTS OF
REPSOL ENERGY NORTH AMERICA CORPORATION**

Pursuant to the Notice Inviting Post-Forum Comments issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") on July 10, 2023 ("Notice"), Repsol Energy North America Corporation ("Repsol") hereby submits these post-forum comments with respect to the questions posed in the Notice concerning Panel 1: Should Everett be Retained and if so, how? Robert Neustaedter, Director of Regulatory Affairs for Repsol was a panelist on Panel 1. Repsol also notes that its affiliate Saint John LNG Limited Partnership ("Saint John LNG") owns and operates an LNG import terminal in Canada, which Repsol utilizes on an exclusive basis to serve a diverse set of customers throughout New England, including local distribution companies ("LDCs") and power generators.

Repsol previously submitted pre-forum comments on June 20, 2023[1] and its position following the forum remains the same: while those that receive service from the Everett LNG terminal should determine if Everett is needed for the reliable operation of their gas or electric systems, the procurement of and compensation for regasified LNG from Everett must be market-based and not reflect any out-of-market subsidies or support. Otherwise, there will be significant and adverse market impacts that will jeopardize the proper functioning of the natural gas market as a result of providing a special out-of-market support to just one market participant. Likewise,

[1] FERC Accession No. 20230620-5018 (June 20, 2023) ("Repsol Pre-Forum Comments").

such support would adversely impact the electric market, which relies on a competitive natural gas market for fuel supply.

Repsol submits these post-forum comments largely to provide more detailed information regarding Saint John LNG's capabilities, as well as to correct certain unsupported statements made in presentations at the forum regarding the scope and reliability of services that Repsol provides to New England utilizing the Saint John LNG facility. Repsol also expands on the points made in its pre-forum comments regarding the fundamental guiding principle that any commercial agreements or other support for Everett must avoid causing adverse impacts to other market participants and be market-based. This holds true regardless of whether such arrangements involve wholesale natural gas market participants, wholesale electric market participants, or LDCs in the state-jurisdictional retail markets. Given the integration and interdependencies of the New England electric and natural gas wholesale and retail markets, contracts or other arrangements at any level that do not rely on gas-on-gas competition and market-based pricing will have adverse impacts in all of these markets.

I. Comments

Please comment on whether Everett is needed for the reliable operation of the electric and/or natural gas systems in New England during the upcoming winters and beyond. As part of these comments, please address the following:

a. Is there sufficient information available to make this assessment? If not, what additional information would be most useful to determine whether there is a need to retain Everett (e.g., information about the uses of, beneficiaries of, and costs to maintain the Everett facility)?

As noted above, Repsol stated in its pre-forum comments that it does not rely upon Everett and believes that those that take service from Everett should make that decision. However, at the forum, it largely was the case that market operators and other participants in the FERC-jurisdictional markets (interstate wholesale natural gas and electric markets) clearly stated that they do not need to rely on Everett to ensure reliability of service. For example, ISO New England

Inc. ("ISO-NE") prepared and presented an analysis showing that Everett is not needed for reliable operation of the wholesale electric market.[2] A major south-to-north interstate natural gas pipeline that delivers supply to New England – Tennessee Gas Pipeline – also stated that it does not rely on Everett for reliable operation ("Kinder Morgan [parent company of Tennessee Gas Pipe Line] would like to make it clear at the outset that Kinder Morgan's assets in New England and in the Northeast more broadly do not rely on Everett for the provision of continuous and reliable firm service to Kinder Morgan's customers.").[3] Enbridge, Inc., which is the parent company of both Algonquin Gas Transmission and Maritimes & Northeast Pipeline, did not indicate that it relied upon Everett for reliability, instead focusing on the need for new natural gas pipeline infrastructure in New England that, in part, could help displace the use of fuel oil for generation.[4]

Moving to the state-jurisdictional retail markets, National Grid USA stated that it had a specific need for Everett for peak winter supply, including for "vapor distributed directly into our gas LDC in Boston."[5] There remains uncertainty regarding the full extent that National Grid and other LDCs rely on Everett for winter reliability, although the Massachusetts Department of Public Utilities ("Mass DPU") has initiated an inquiry by issuing data requests to the Massachusetts LDCs on this issue. Thus, the need for Everett may be limited to certain market participants in certain discrete areas.

If one or more market participants believe that they need to continue to rely on Everett, whether for supply in the FERC- or state-jurisdictional markets, Repsol wants to make clear that it does not oppose those market participants entering into arrangements to retain the services they

[2] *See, e.g.,* ISO-NE, *Opening Presentation: Winters 2023/2024 and 2024/2025 in New England and the Role of Everett & Extreme Weather Risks to ISO-NE, Presentation of the EPRI Study*, FERC Accession No, 20230609-5196 (June 9, 2023).
[3] *See, e.g.*, Kinder Morgan, Inc., *Pre-Forum Comments of Kinder Morgan, Inc.*, at 2, FERC Accession Number: 20230616-5177 (June 16, 2023).
[4] 2023 New England Winter-Gas Electric Forum Transcript ("Forum Tr.") at 133-135 (remarks by R. Paglia, Vice Present, Enbridge, Inc.).
[5] Forum Tr. at 43-44 (remarks by J. Holodak, Vice President, National Grid USA).

need from Everett. However, those arrangements must be appropriately tailored to the size and nature of the reliability need, market-driven, and based on price competition to maintain the proper functioning of the New England gas and electric markets. They should not include any out-of-market solution that may threaten the continued participation of the rest of the natural gas suppliers in New England that rely on competitive markets to send the right price signals to attract supply and set appropriate compensation for their services. Decisionmakers and stakeholders should be aware that subsidization in the gas market for one facility will invariably have second and third order consequences, adversely impacting the broader gas market, as well as the electric market, which depends on natural gas. An out-of-market solution for one natural gas supplier impacts the price of natural gas in the market, jeopardizing the ability of other natural gas suppliers to recover their fixed and variable costs through the market price.

With respect to peaking supply specifically, distorted natural gas prices resulting from the subsidization of one market participant would not send the appropriate signals to the global LNG markets and to domestic gas suppliers to send sufficient supply to New England to cover periods of high demand and constrained supply, leaving the New England natural gas market short on peak days. This results because a subsidy provided to a market participant causes a misalignment between prices and supply costs, which prevents efficient outcomes, diverts needed resources to less productive uses, and reduces competition in the market. Since Everett alone cannot supply the region's peak needs, all sources of supply in the region's market are critical to meeting demand – including those that would be damaged by preferential subsidization of a single market participant.

Without the proper price signals and everyone competing together on a level playing field, Repsol would not be able to make pre-arranged sales to LDCs and other market participants and procure on an advanced basis the LNG cargoes required to provide supply to be in the tanks at

Saint John LNG for the winter. Absent a properly functioning gas market, Repsol will either be put in a position to seek subsidies for Saint John LNG itself or review whether operations at the facility can continue. From a reliability perspective, Everett simply cannot replace Saint John LNG because it does not have the same storage capacity, injection capacity, pressure capabilities, or access to the same broad range of natural gas and electric market participants within New England (see Section I.b.1 below for a review of Saint John LNG's capabilities).

While Constellation LNG has stated that it is not seeking an out-of-market solution ("We are not advocating for an out of market solution. We are looking to see whether there is sufficient bilateral contract support for the facility."),[6] it does not appear that an out-of-market option is off the table for consideration. For example, the New England Power Generators Association, Inc. ("NEPGA") has stated that "Commission-approved interstate pipeline tariffs can be used to facilitate recovery of costs on a regional basis that maintain operations of EMT,"[7] which would function not just as an out-of-market subsidy, but could also result in the allocation of costs to parties that do not rely on Everett in contravention of the cost causation principle. Similarly, the Mass DPU data requests to LDCs imply that an arrangement that could result in cross-subsidization may be under consideration ("How would any contractual agreement with Constellation supporting Everett's continued operation ensure that the costs are shared fairly and equitably among gas and electric entities across New England that benefit from Everett's continued operation including, without limitation, wholesale pipeline operators, natural gas fired generation facilities, and LDCs?").[8] Even bilateral contracting could be considered an out of market subsidy if the procurement process is not competitive, is not tailored to the level and nature of the reliability

[6] Forum Tr. at 38 (remarks by C. Allen, Vice President, senior vice president, Constellation Energy Generation).
[7] NEPGA, *Position Statement of Dan Dolan on behalf of New England Power Generators Association, Inc.*, at 4, FERC Accession No. 20230609-5135 (June 9, 2023).
[8] Mass DPU, *Letter to All Investor-Owned Gas Distribution Companies Regulated by the Department of Public Utilities, RE: Impact of Everett Marine Terminal*, at 3 (June 30, 2023).

need, or is based on subsidized pricing. Therefore, Repsol urges both the Commission and state regulators to take into account the harmful consequences of subsidization in reviewing proposed arrangements aimed at retaining Everett and ensure that any solution be market-based.

b. Is LNG from other sources (e.g., Repsol and/or Excelerate) a full substitute for the LNG from Everett? If not, under what circumstances is it not a full substitute and are there conditions under which electric system and/or gas system operators would be unable to meet electric and/or gas demand or maintain reliable service if Everett retires?

In order to help ensure fully informed analysis and decision-making, Repsol provides below a more detailed analysis of Saint John LNG's capabilities than provided in Repsol's pre-forum comments. Saint John LNG has been repeatedly mentioned as an alternative to Everett, and there appears to be a lack of full and accurate information as to the facility's capabilities, practices, and track record of reliable service to New England. Moreover, the magnitude of the service provided by Saint John LNG, including service to those markets not reachable by Everett, further underscores the point that market disruption caused by subsidization could result in a greater loss to the market if Saint John's participation in the market were impaired or if it were forced to leave the market altogether. Subsidization of Everett will further exasperate already tenuous market conditions, and force Repsol to reevaluate continued operations at Saint John LNG, as it will eliminate the possibility of sufficient net revenues on a going-forward basis because Saint John LNG would be unable to adequately recover its operating costs through market pricing due to the distortion caused by subsidization. Thus, by subsidizing one facility with a limited set of capabilities, that in turn could result in substantial harm to a larger set of facilities that are depended upon by numerous market participants, including natural gas-fired generators in the power market.

Separately, a number of comments were made at the forum that Repsol wishes to correct for the record below.

1. *Capabilities of Saint John LNG*

The following is a summary of Saint John LNG's capabilities, provided for informational purposes to assist in the evaluation of LNG deliveries to the New England market with and without Everett, and to identify what capabilities may be lost to the New England Market if price signals in the natural gas market are impacted by an out-of-market solution for one natural gas supplier:

	Saint John LNG
Storage Capacity	10 Bcf
Vapor Sendout Capacity	1.2 Bcf/d
Accessibility for LNG Tanker Types	Saint John LNG can receive up to the largest Q-Max LNG tankers, which results in full access to all supply sources and greater flexibility to purchase spot cargoes.
Storage Management	Saint John LNG's large storage capacity across three thanks allows greater flexibility to manage receipt of LNG cargoes and ensure all injections fully meet pipeline specifications.
Pressure Support for Pipeline Operations Generated by Vapor Sendout	Saint John LNG provides pressure support to Maritimes, Algonquin and Tennessee via Maritimes, with deliveries at a minimum of 1,100 PSIA.
Ability to Access Delivery Points in the New England Market	Except for direct deliveries to Boston Gas (National Grid) off of Algonquin's "J System," Saint John LNG can deliver to any and all power generators and LDCs in New England
Firm Pipeline Transportation	Repsol markets 100% of the sendout of Saint John LNG to New England, using its 730,000 Dth/day firm transportation with Maritimes & Northeast. Repsol also can contract for incremental available firm gas transportation on Algonquin and Tennessee and would do so if the market committed to contracts with Repsol. Typically. Repsol makes deliveries of gas from Saint John LNG to Dracut and/or Beverly, and customers holding firm service downstream of these locations deliver to meters on Algonquin and Tennessee on a firm service basis.

Having 10 Bcf of storage enables Saint John LNG to provide service with the following characteristics that are relied upon by New England LDCs and other market participants:

- Injections of natural gas on demand into the Algonquin and Tennessee pipeline systems in eastern Massachusetts, providing service to any LDC or power plant throughout New England.

- Substantial quantities of stored energy.

- Management of storage capacity in a manner that does not require Saint John LNG to "dump" stored LNG at below market prices to make room for incoming cargoes. Any gas supply contract for natural gas sourced from Saint John LNG does not require customers to provide for or bear the cost of forced send out.

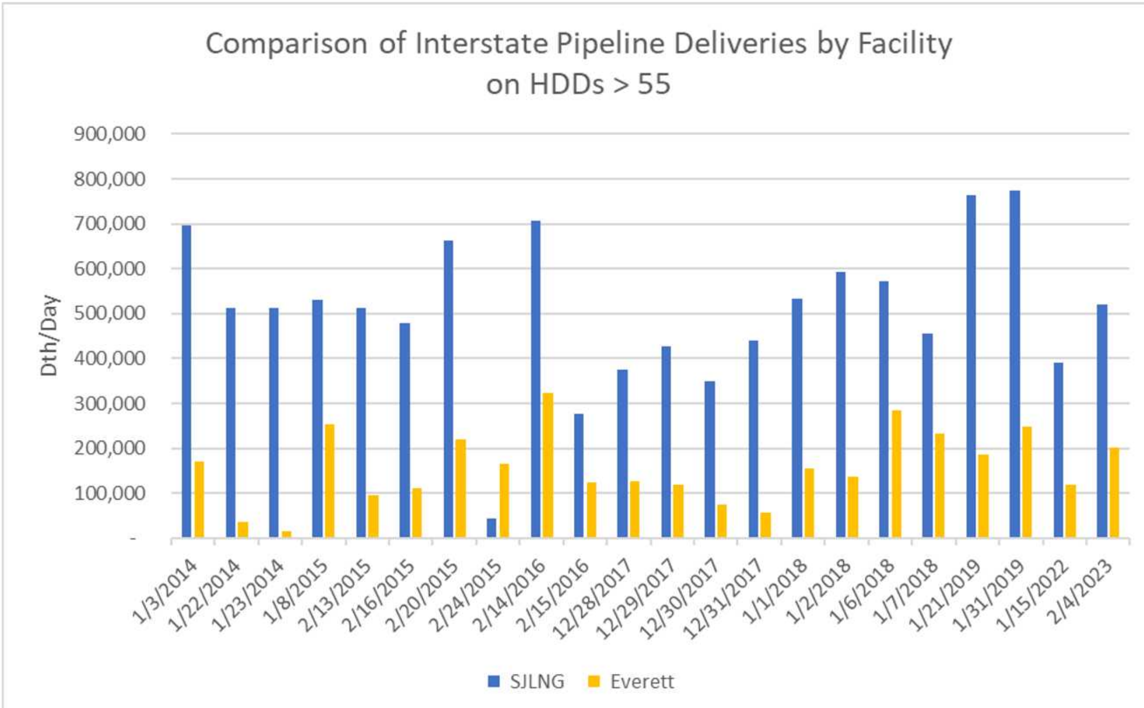
- No minimum commitment requirements. Customers contract for only what they have forecasted their demand to be. They do not have to contract for more gas supply than necessary to meet any minimum LNG cargo requirements of upstream LNG suppliers.

- Receipt of LNG from any size ship and from any supplier in the world

- Service to LDCs and power plants located anywhere in New England, including northeastern Massachusetts, New Hampshire, and Maine.

With respect to its operational track record, Saint John LNG has been in service since 2009 and has never failed to meet any of its contractual obligations. With respect to its ability to perform on those coldest of peak winter days; using the same 22 coldest days from 2014 through 2023 to date as identified in the Levitan & Associates, Inc. ("Levitan") presentation at slide 12,[9] Saint John LNG's total sendout was 11.1 Bcf (all delivered to New England). Everett's pipeline sendout on those same days was 3.5 Bcf. Over those same days, Saint John LNG's average sendout was 0.505 Bcf/d and Everett's was 0.157 Bcf/d. A chart showing the deliveries on each day is set forth below:

[9] Levitan, *Winter Reliability in New England*, at 12, FERC Accession No. 20230627-4001 (June 27, 2023).



2. *Corrections for the Record regarding Saint John LNG*

During the Forum, Richard Levitan made several off-the-cuff remarks regarding Saint John LNG's and Repsol's capabilities that appeared to be based on supposition, not facts. First, Levitan suggested that "the fleet of generators in northern New England would be siphoning off flow and pressure along the way, meeting ISO's call in the day-ahead and the real-time market so the quantities that flow south to the terminus at Beverl[y]and Dracut would not be necessarily close to the 0.8 BCF that represents the Saint John LNG entitlement flowing south to the Maritimes and Northeast [pipeline]."[10] However, deliveries are based on contractual commitments and gas is not "siphoned off" in a manner that impairs those commitments. Further, the Maine markets are comparatively small in size compared to markets located further south, and Maine and Maritimes Canada is also primarily served by Portland Natural Gas Transmission System. As a result, most

[10] Forum Tr. at 31.

of the gas from Saint John LNG, which is transported via firm transportation capacity on Maritimes, is delivered on a physical basis to Beverly and Dracut, which are the interconnections of Maritimes with Algonquin and Tennessee pipelines, respectively.

Second, while Levitan acknowledges that Saint John LNG can provide pressure support, his remarks imply that it requires "smart" management of the pipeline system to effectuate, including "reading the meteorological outlook [and] packing the pipe." This is not out of the ordinary and does not depend upon a trader at risk desk finding a "smart" revenue opportunity. Reviewing forecasts and ensuring that there is sufficient line pack and pressure on cold days is typical management of pipeline systems undertaken by prudent pipeline operators. As reflected in the chart above, sendout at Saint John LNG on the coldest days is "normal" practice and a critical part of maintaining winter reliability in New England. Saint John LNG can vaporize 1.2 Bcf/d, and Repsol holds firm transportation capacity on M&NE of 0.73 Bcf/d with primary delivery points on Tennessee at Dracut and on Algonquin at Beverly. While not located in Boston Harbor, Saint John LNG's location does not diminish its ability to deliver quantities of natural gas into the systems of Tennessee and Algonquin (at pressures significantly greater than Everett) when needed, no different than gas supplies from the Gulf of Mexico and Pennsylvania are available when needed in New England.

Third, Levitan remarked that "arbitrage across the pond is not a bankable risk mitigation strategy,"[11] suggesting that because Repsol's affiliates are involved in the international LNG market and delivering LNG to Europe that Saint John LNG and Repsol may not provide reliable service to New England. Levitan offered no support for this allegation, again posing a "what if" without accounting for the facts or probabilities. Nevertheless, as Repsol's long track record demonstrates, Levitan's observation is wrong. As explained in its pre-forum comments, "[o]ver

[11] *Id.* at 46.

the 14 years that Saint John LNG has served New England, it has never failed to meet its obligations to its customers."[12] In particular, this was the case over the past several years, during both COVID and the start of the war in Ukraine. Further, while LNG demand in Europe has increased, the global LNG market is robust. Demand and competition in that market improves availability of LNG; it does not diminish it. Thus, Repsol can, and does, reliably procure natural gas supply for any customer willing to enter into an agreement with Repsol that in turn supports the firm procurement of LNG.

This is the same reason why any concerns of "market power" are unfounded. The domestic natural gas and global LNG markets are competitive, and parties willing to enter into contracts in advance for supply are able to assure availability of supply when it is needed. Saying that Repsol would have "market power" rests on a fundamental misunderstanding of the larger natural gas market. LNG procurement is not completely separate from the larger gas market, and thus Repsol, like any other gas marketer, must compete with supply across the market from multiple sources, not solely other LNG import facilities. The relevant market is the market for natural gas, not just the market for LNG. As Repsol stated in its pre-forum comments:

> LNG competes with all of the natural gas coming into the New England market from multiple sellers and sources across multiple pipelines. Because the New England natural gas market is highly competitive and diversely sourced, it is unclear how the retirement of Everett would change that. In fact, since Everett has been dedicated to just Mystic in recent years and not the natural gas market generally, there has been no distortion to that market other than that caused by the subsidized sale of natural gas from Everett. LNG also is contracted for on a competitive long-term basis and at prices that are based on market indices. This further precludes a seller of regasified LNG from exercising any market power. Finally, the interstate natural gas market is regulated by the Commission, who is fully empowered to enforce the prohibition against market manipulation or other improper conduct that adversely impacts the interstate natural gas market.[13]

[12] Repsol Pre-Forum Comments at 4.
[13] Repsol Pre-Forum Comments at 4.

Repsol has limited abilities to participate in spot sales of natural gas in the winter; the supply in the tanks is for the customers that have prearranged or contracted for it. For Repsol to enter into spot sales during the winter, there needs to be a clear plan on how replacement gas will be reinjected into the tanks to ensure that all future obligations can be met. Most, if not all, spot sales for peak winter demand is provided by marketers that have purchased peaking options, utilities that have alternate fuel options that enable them to fuel switch and market east-end supply to meet peak demand, or the LDCs' asset managers.

Fourth, Levitan commented that: "So as far as incrementality [from Saint John], it's hard to say that there would be any additional flow."[14] Saint John LNG's capacity for peaking services is not fully contracted or maxed out on peak days. Repsol is able to sell additional natural gas supply to any market participant that contracts for it on a pre-arranged basis. Accordingly, Levitan is incorrect that additional flows from Saint John LNG are not available.

II. Conclusion

As discussed above, if it is decided that Everett should be retained, any next steps should consist of broadly available, market-based solutions that are developed in a transparent manner with input from all market participants. Decisionmakers and stakeholders should carefully consider not just the primary impact of any arrangement between market participants and Everett, but also ensure that no adverse second and third order consequences occur that adversely impact the broader natural gas and electric markets. Any solution that conveys an unnatural advantage to Everett, risks the continued participation by Saint John LNG and other natural gas suppliers in the market.

[14] Forum Tr. at 31-32 (Levitan).

Respectfully submitted,

/s/Robert Neustaedter

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Dated: August 24, 2023

Unitil

July 21, 2023

James M. Van Nostrand, Chair
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: <u>Fitchburg Gas and Electric Light Company d/b/a Unitil</u>
<u>Response to Department Inquiry Regarding Everett Marine Terminal</u>

Chairman Van Nostrand,

Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil" or the "Company") has reviewed your letter of June 30, 2023 regarding the potential retirement of the Everett Marine Terminal and appreciates the opportunity to provide the Company's input on this critical issue.

New England's gas and power infrastructures are heavily reliant upon imported LNG and the region cannot afford the retirement of the Everett facility or any facility that brings imported LNG into the region. Imported LNG serves as a critical source of gas supply to the region that supplements domestic gas supplies during peak periods or when curtailments occur on the heavily constrained pipeline systems that deliver gas into New England. There is no new gas pipeline infrastructure being constructed in New England, yet demand growth persists. Additionally, it is worth noting that Unitil and other New England LDCs must still plan for design winter conditions. The Everett Terminal supplies liquid to LDCs in the region, including Unitil, as well as vapor transported on the Tennessee and Algonquin pipeline systems. This supply provides critical pressure support for those pipelines which benefits the entire region. The location of the Everett terminal, in the heart of the market area, allows incremental supply to access market areas that reside in the most constrained parts of the pipeline systems.

In addition to needing the Everett Marine Terminal, the region also relies heavily upon the deliveries of supply that are sourced from the St. John LNG Terminal in New Brunswick. Both sources of imported LNG are critical to Unitil specifically and to New England's energy infrastructure generally. Like Everett, St. John deliveries to the region bypass pipeline constraints which limit access to domestic supplies and provides incremental supply directly into the market area. St. John supplies also bolster pipeline pressures. Both of these LNG importers provide unique services to the region and removing either or both facilities from the market would exacerbate an already critical scarcity of supply.

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Unitil offers the following responses to the questions set forth in your letter:

1. Indicate whether the LDC relies on the Everett LNG facility for gas supply for its customers, including whether the LDC may rely on the Everett LNG facility on a design day.

Response: Unitil relies on the Everett Marine Terminal for LNG delivered as liquid via truck to supply its Westminster LNG plant. Critically, the Westminster LNG plant is relied upon to provide pressure support for the Gardner area when the end of line pressure drops to 55 psig, which is typically at a 40 effective degree-day (EDD). As such, Unitil relies on LNG from Everett much more often than on peak days. Unitil's dependence on the LNG from Everett is particularly high due to the Westminster plant's limited storage, which is 3,172 Dth. Unitil relies on the Westminster plant for 3,172 Dth on a design day, meaning the plant has only one day of storage and therefore requires steady replenishment if the plant is to remain available, which is essential given the pressure support requirement.

2. Describe in detail your LDC's plans to replace the gas supply currently sourced from Everett, if any, if Everett ceases operations next year. Please include a discussion of whether expanded demand-side resources will be explored.

Response: Unitil has regularly conducted competitive solicitations to better understand the availability, operational feasibility and price competitiveness of alternative sources of LNG supply. Everett has always been the preferred LNG source for Unitil because of its proximity to Westminster and its ability to schedule deliveries quickly. Everett is located approximately 50 miles from Westminster and deliveries are available upon 48 hours of notice with willingness to accommodate for shorter notice in certain circumstances. Reliable alternatives that have been identified are approximately 300 miles away from Westminster and require 72 hours of notice to be given on business days only.

In order to reduce reliance on Everett, Unitil is exploring adding storage to the Westminster LNG plant and adding locations where compressed natural gas ("CNG") can be delivered. In terms of adding LNG storage, preliminary engineering is being undertaken to identify proposals on how the plant could be reconfigured to receive more over-the-road tankers. The Company is also reviewing regulatory requirements that will need to be addressed in order to add modular storage. This effort is currently targeting a 2025 implementation if determined to be feasible. In terms of CNG, Unitil has conducted initial work to identify potential locations in the Gardener area where it may be feasible to site, construct, and operate CNG interconnections.

Unitil supports the implementation of all cost-effective demand-side resources, but has not discussed expanded or targeted energy efficiency resources specifically to address dependence on the Everett Terminal.

3. What are the cost implications for LDC consumers if Everett ceases operations next year?

Response: If Everett ceases operations next year, then Unitil will need to quickly implement alternatives such as those discussed in response to Question 2. At this point, the cost of such alternatives is unclear. LNG supply purchased from greater distances would likely be less expensive, but also would likely require a reduction in the amount of capacity the Company relies on from the Westminster LNG plant unless adequate supplemental storage is added. Such a reduction would likely require that CNG supply be added to supplement the plant. In addition to cost of supply, a degradation in reliability would increase the risk of outages which can be very costly and impactful to human health and well-being.

4. What, if any, new DPU-jurisdictional distribution infrastructure would be required to maintain gas system reliability if Everett ceases operations? What, if any, new FERC-jurisdictional pipeline infrastructure would be required to maintain gas system reliability if Everett ceases operations?

Response: Any new pipeline infrastructure into the region would be FERC-jurisdictional and would likely take many years to obtain all required regulatory and land use approvals and permits and therefore would not be a viable substitute for the loss of Everett. The Company's assessment of its infrastructure requirements in the absence of the Everett LNG facility are premised on an underlying assumption that the loss of Everett LNG would not impact the reliability of Tennessee Gas Pipeline from which the majority of the Company's design day, cold snap and winter supplies are sourced. The Company can only rely on assurances from Tennessee Gas Pipeline that loss of Everett LNG would not impact its ability to transport gas to the Company's system. However, it should be noted that the gas and power systems in New England are interconnected. To the extent that the New England power system currently relies on the availability of Everett LNG supplies to fuel natural gas generation during winter peaks, it would be imperative that the power market independently and intentionally address the loss of this supply, if Everett LNG were to cease operations. Failure of the power market to address the potential loss of Everett LNG supply could potentially impact the delivery volume and pressure to LDCs by the pipeline system.

5. What is the current status of negotiations, if any, between the LDCs and Constellation regarding continued operation of Everett? Please provide a proposed schedule for providing the Department with regular updates on the status of any negotiations with Constellation.

Response: Unitil is participating in negotiations with Constellation LNG regarding multi-year contracts that would keep the Everett Terminal operational during the term of the contracts. Given that any resulting contracts would be longer than one year, DPU approval will be required. The Mystic Station cost of service contract expires on May 31, 2024, beyond which we understand Constellation does not intend to operate the Terminal absent contracts that support the economic viability of the Terminal. Expedited Department review and approval may be required if approved contracts are to be in place by June 1, 2024. The Company can provide updates on the status of negotiations on a monthly basis, or otherwise at the guidance of the Department.

6. How would any contractual agreement with Constellation supporting Everett's continued operation ensure that the costs are shared fairly and equitably among gas and electric entities across New England that benefit from Everett's continued operation including, without limitation, wholesale pipeline operators, natural gas fired generation facilities, and LDCs?

Response: Any contracts between an LDC and Constellation would not create costs or obligations for other entities such as electric generators, natural gas pipelines or electric utilities. However, the LDC contracts with Constellation could contain language that requires any new revenue stream received by Constellation from incremental customers of the Everett Terminal or from new market mechanisms, perhaps designed to promote regional reliability or to monetize services provided by the facility resulting in charges to those entities who benefit from such services, to be shared equitably with the contracting LDCs.

a. To inform such cost sharing arrangements, please indicate whether there is interest in undertaking, with the Department's participation and oversight, an expedited analysis quantifying the services provided by the Everett facility and the extent to which entities on the gas and electric systems receive these benefits. If this expedited analysis is of interest, please include a proposed scope of work and timeline for draft and final results.

Response: The Company applauds the Department's suggestion that an analysis to quantify the services provided by the Everett Terminal and the extent to which entities on the gas and electric systems benefit from these services be conducted. The ISO New England study discussed during the June 20 FERC Gas Electric Forum in Portland, Maine[1] did not address the value of the Everett Terminal to the regional gas system, despite the reliance of substantial gas-powered generation on availability of supply from the gas system. In addition, the ISO-NE study simply assumed that Repsol's St. John LNG facility would be available despite repeated statements from Repsol that long term contracts are required for the facility to remain viable. Moreover, discussion at the Forum suggested that the States will ultimately decide the future of Everett and the same appears true for St. John LNG. The Company's position is that both the Everett Terminal and St. John LNG are necessary to balance the New England energy market, inclusive of both natural gas and power, and that any study undertaken should address the benefits provided by both facilities and the reliability risks of losing either or both facilities.

[1] https://www.ferc.gov/media/iso-ne-epri-presentation

A very important take away from the Forum was the acknowledgement that it is necessary for regional planners to understand more about the gas systems in order to make any definitive statement as to the need for Everett. The Department's suggested study could help to build understanding of natural gas infrastructure and logistics and better inform assumptions about what gas supply would be available to supplement the loss of supply sourced from Everett or St. John LNG in a subsequent regional power system reliability study.

As to timing, as explained in response to Question 5, there is limited time to negotiate contracts with Constellation and then file them with the Department for approval. As such, study results would not be available prior to contracts being executed, assuming the negotiations are successful. Whether study results would be available prior to a Department decision (and similar decisions from other state regulatory agencies) remains to be seen. Notwithstanding the timeframe for analysis, such study results would be very useful in defining the services provided by both the Everett Marine Terminal and St. John LNG to the region and the extent to which Constellation and Repsol are compensated for those services, which would ideally inform ISO-NE's approach regarding fuel security and, if supported by study results, lead to market design rules that incent contracting with both facilities.

b. If and to the extent LDCs outside of Massachusetts benefit from retaining Everett, how are costs proposed to be allocated between the respective jurisdictions? What is the basis for such inter-jurisdictional cost allocation?

<u>Response</u>: As with the electric sector, any contracts between a Massachusetts LDC and Constellation will not create costs or obligations for LDCs from other states. That said, LDCs from other states are also negotiating with Constellation, including Unitil's affiliate Northern Utilities, Inc., which operates in Maine and New Hampshire.

7. If Everett continued operating, what measures would your LDC take to systematically transition away from reliance on Everett during any retention period? Please discuss plans for securing demand-side solutions to reduce your LDC's dependence on Everett instead of supply-side resources.

<u>Response</u>: If Everett continues in operation, Unitil would ideally place added LNG storage at the Westminster plant and have dedicated locations for supplemental pressure support from CNG. In terms of demand-side solutions, Unitil would explore targeted energy efficiency and promoting electrification, although Unitil is not the electric company for Gardner, Massachusetts, the area of Unitil's gas system that would be most affected by the loss of Everett.

Thank you for your assistance with this matter.

Sincerely,

Patrick H. Taylor
Attorney for Unitil

Enclosure

cc: Service List

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Office of Public Advocate's Data Requests – Set 1
Issue Date: November 7, 2023

Data Request OPA-001-009:

What new pipeline facilities would need to be constructed (by TCPL or others) for TCPL to provide 13,600 GJ/day of Empress-to-East Hereford FT service for Northern beginning in 2027?

Confidential Response:

[redacted]

- [redacted]
  - [redacted]
- [redacted]
  - [redacted]
- [redacted]
  - [redacted]
- [redacted]
  - [redacted]

[redacted]

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Office of Public Advocate's Data Requests – Set 1
Issue Date: November 7, 2023

Date: November 14, 2023 **Person Responsible:** Francis X. Wells

State of Maine
Public Utilities Commission

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Office of Public Advocate's Data Requests – Set 1
Issue Date: November 7, 2023

Data Request OPA-001-013:

Please explain why Northern did not include either a PNGTS/TCPL path from Parkway or a PNGTS/TCPL/Enbridge path from Dawn in the Landed Cost Analysis or the Modeled Cost Analysis.

CONFIDENTIAL Response:

[BEGIN CONFIDENTIAL.] [redacted] [END CONFIDENTIAL.]

Date: November 13, 2023 **Person Responsible:** Francis X. Wells

State of Maine
Public Utilities Commission

Confidential

Northern Utilities, Inc. Docket No. 2023-00254

State of Maine
Public Utilities Commission
Request for Expedited Approval
of Empress Capacity Agreements
Office of Public Advocate's Data Requests – Set 1
Issue Date: November 7, 2023

Data Request OPA-001-015:

Attachment 7 shows the estimated expense profile for Northern's portion of the shared facilities cost for the 2027 Eastern System Expansion. What percentage of the total pre-service costs for the project would Northern be responsible for?

REDACTED Response:

[BEGIN REDACTED.] [redacted] [END REDACTED.]

Date: November 13, 2023 **Person Responsible:** Francis X. Wells

PORTLAND NATURAL GAS TRANSMISSION SYSTEM

December 14, 2023

Portland Natural Gas Transmission System
700 Louisiana Street, Suite 1300
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David A. Alonzo
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email david_alonzo@tcenergy.com
web www.pngts.com

Mr. Joseph Conneely, Vice President
Northern Utilities, Inc.
6 Liberty Lane West
Hampton, NH 03842

Re: Portland Natural Gas Transmission System
Federal Energy Regulatory Commission Approval of Expansion in Docket No. CP23-548-000

Mr. Conneely,

Portland Natural Gas Transmission System (PNGTS) is hereby confirming that requisite approval has been received from the Federal Energy Regulatory Commission for an expansion of PNGTS' system to provide an additional 59,000 Dth/d of capacity. The capacity was certificated as of November 28, 2023, the day after expiration of the 60-day Blanket Prior Notice comment period in Docket No. CP23-548-000.

Northern Utilities, Inc. capacity of 12,500 Dth/d is therefore slated for in-service on April 1, 2024, pending your state regulatory approvals.

Please contact Thomas Lockett, PNGTS Marketing Manager, should you have any questions.

Regards,

PORTLAND NATURAL GAS TRANSMISSION SYSTEM
by its Operator, TransCanada Northern Border Inc.

David A. Alonzo
Manager, Project Authorizations
US Rates & Regulatory