NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2022-2023
COST OF GAS FILING

PREFILED TESTIMONY OF
<u>FRANCIS X. WELLS</u>

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Francis X. Wells. My business address is 6 Liberty Lane West, Hampton, NH.

Q. What is your relationship with Northern Utilities, Inc.?

A. I am employed by Unitil Service Corp. (the "Service Company") as Manager of Energy Planning. The Service Company provides professional services to Northern Utilities, Inc.

Q. Please briefly describe your educational and business experience.

A. I earned my Bachelor of Arts Degree in both Economics and History from the University of Maine in 1995. I joined the Service Company in September 1996 and have worked primarily in the Energy Contracts department. My primary responsibilities involve gas supply planning and acquisition.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I have testified as Northern's gas supply witness before the Commission in Northern's Cost of Gas ("COG") proceedings.

Q. Please summarize your prepared direct testimony in this proceeding.

A. The purpose of my testimony is to present and support Northern's gas supply cost forecast, which was used for the calculation of the proposed COG.

The 2022-2023 fixed, annual demand cost estimates are 9% lower than the fixed, annual demand cost estimates provided for the prior 2021-2022 Winter Period COG filing. The major reason for this decrease are due to higher Asset Management Agreement revenue credits, partially offset by higher pipeline transportation charges due mostly to the addition of WXP Project capacity to Northern's portfolio. Estimated average delivered commodity rates for the 2022-2023 Winter Period are 64% higher than the average delivered commodity rates estimated for the 2021-2022 Winter Period COG. The major reason for this increase is higher NYMEX supply costs and higher delivered peaking supply costs. Estimated average delivery commodity rates for the 2023 Summer Period are 42% higher than the average delivered commodity rates estimated for the 2022 Summer Period COG. Higher NYMEX supply costs are the major reason for this increase.

Northern projects combined sales service and delivery service distribution deliveries to be 8,924,865 Dth in the New Hampshire Division for the 2022-2023 Annual Period, which is 2.0% higher than the 2021-2022 Annual Period weather-normalized distribution deliveries and 3.2% higher than the 2020-2021 Annual Period weather-normalized distribution deliveries. Of the 8,924,865 Dth of projected distribution system deliveries, Northern projects that 4,413,297 Dth will be supplied by the Company through Sales Service. In order to supply 4,413,297 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,456,526 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 120,428 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,576,954

Dth for the upcoming year. The details behind these estimates are contained in Attachments NUI-FXW-1 and -2.

Northern's portfolio has 142,844 Dth maximum daily quantity of Pipeline, Storage and Peaking Capacity (each of these Capacity terms as defined in the Company's New Hampshire Division Delivery Service Terms and Conditions). I review the portfolio in more detail in the body of my testimony.   Details of this portfolio are provided in Attachment NUI-FXW-4. I review the portfolio in more detail in the body of my testimony, including updates to the portfolio that have occurred since the 2021-2022 Annual Period COG Filing as well as an update on Northern's implementation of its Price Risk Mitigation Plan.

I project Northern's total company (including both the Maine and New Hampshire Divisions) demand cost for the November 2022 through October 2023 gas year to be $42,229,147. (*See* Attachment NUI-FXW-5). Mr. Chris Kahl, who is also testifying in this proceeding, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the portion of that allocation of annual demand costs between the Winter and Summer COG recoveries. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $5,457,743. (*See* Attachment NUI-FXW-6). I also discuss the updated Capacity Allocators and Capacity Ratio pursuant to the New Hampshire Division capacity assignment program, which are provided as Attachment NUI-FXW-7.

I project that Northern's total company (including both the Maine and New Hampshire Divisions) commodity cost to provide sales service during the 2022-2023 Winter Period will be $84,546,814 at an average rate equal to $8.772 per Dth. (*See* Attachment NUI-FXW-8). 2023 Summer Period commodity cost to provide sales service are projected to be $13,507,267 at an average rate equal to $4.940 per Dth.

Finally, I provide the proposed Re-entry Rate, applicable to Capacity Assigned Delivery Service customers who switch to Northern's Sales Service, and the proposed Conversion Rates, applicable to Capacity Exempt Delivery Service customers who switch to Northern's Sales Service. I also provide the supporting calculations for these proposed rates. These calculations are provided in Attachment NUI-FXW-11.

II. SALES AND SENDOUT FORECAST

Q. Please describe the Company's forecasts sales.

A. The sales forecast for the residential, regular general, and large rate classes are developed by independently forecasting meter growth and usage per meter. The forecasted usage per meter assumes 'normal' weather which is the average of the actual degree days over the last 20 years. In addition, Business Development personnel are consulted for comments on significant usage changes for the Company's large customers which, when necessary, are included in the sales forecast. The forecast seeks to limit subjectivity and typically relies on historical trends.

Q. Please provide the forecast distribution deliveries, meter counts and use-per-meter figures utilized in this COG filing and a comparison of this forecast to weather normalized data for prior periods.

A. I have prepared Table 1, below, which provides a summary of the company's forecast of total billed distribution deliveries (Dth) for the upcoming 2022-2023 Annual Period.

Table 1. 2022-2023 Annual New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2022-2023 Forecast	2021-2022 Weather-Normalized Actual	2022-2023 minus 2021-2022	Percent Change	2020-2021 Weather-Normalized Actual	2022-2023 minus 2020-2021	Percent Change
Nov	707,240	686,286	20,954	3.1%	681,275	25,964	3.8%
Dec	1,044,293	986,864	57,428	5.8%	1,006,190	38,102	3.8%
Jan	1,253,703	1,245,140	8,563	0.7%	1,185,985	67,718	5.7%
Feb	1,276,489	1,202,527	73,962	6.2%	1,216,725	59,764	4.9%
Mar	1,140,573	1,187,573	-47,001	-4.0%	1,153,597	-13,024	-1.1%
Apr	831,157	812,221	18,936	2.3%	800,853	30,304	3.8%
May	591,576	558,280	33,296	6.0%	598,944	-7,367	-1.2%
Jun	424,207	422,350	1,856	0.4%	396,066	28,141	7.1%
Jul	390,362	388,256	2,106	0.5%	399,523	-9,161	-2.3%
Aug	379,912	377,834	2,078	0.6%	365,908	14,004	3.8%
Sep	385,483	383,775	1,709	0.4%	366,793	18,691	5.1%
Oct	499,870	498,659	1,211	0.2%	475,230	24,640	5.2%
Winter	6,253,454	6,120,613	132,842	2.2%	6,044,625	208,830	3.5%
Summer	2,671,411	2,629,155	42,256	1.6%	2,602,464	68,947	2.6%
Annual	8,924,865	8,749,768	175,098	2.0%	8,647,089	277,776	3.2%

Forecast distribution deliveries are projected to increase 2.0% compared to the 2021-2022 weather-normalized actual sales. Page 1 of Attachment NUI-FXW-1 shows that the increase in sales is explained by a 2.3% projected increase in meter counts and a 0.3% decrease in projected average use per meter.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2022-2023 Annual Period in Attachment NUI-FXW-1. Page 1 of Attachment NUI-FXW-1 provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2022-2023 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2021-2022 and 2020-2021 Winter Periods. The changes in the distribution deliveries from the prior period are presented in terms of changes in meter counts and changes in use-per-meter. The middle section of each page presents forecasts and a comparison to prior period actual meter counts. The bottom section of each page of Attachment NUI-FXW-1 provides a calculation of the use-per-meter, which has been calculated using the distribution deliveries and meter count data presented in the top and middle sections of the page.

Q. How does the Company allocate total distribution deliveries between Sales Service and Delivery Service deliveries?

A. For each rate class, the Company calculated the percentage of total distribution deliveries that were attributable to Sales Service for the 12-month period May 2021 through April 2022. These percentages were used to estimate the percentage of billed sales that would be supplied by the Company under Sales Service. Delivery Service sales were allocated between Capacity Assigned and Capacity Exempt based on monthly percentage of weather-normalized deliveries by rate class over the same 12-month period.

Q. Please summarize the Company's forecast of sales service deliveries and city-gate receipts required to meet the projected sales service deliveries.

A. I have prepared Table 2, below, which provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries, Company Managed Deliveries and City-Gate Receipts[1] for the upcoming Winter Period.

[1] When I use the term "City-Gate Receipts", I refer to the volume of gas needed to be received by the distribution system in order to deliver the projected volumes of sales service. These volumes are measured at the Company's interconnections with Granite State Gas Transmission, an affiliated pipeline, and Maritimes and Northeast, L.L.C and the Company's LNG facility.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary				
Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-22	892,002	469,181	22,530	496,306
Dec-22	1,128,540	677,718	24,499	708,855
Jan-23	1,291,829	799,512	28,481	835,824
Feb-23	1,144,769	685,333	21,637	713,683
Mar-23	1,056,868	582,909	23,281	611,900
Apr-23	739,448	336,088	0	339,380
May-23	503,741	186,357	0	188,183
Jun-23	398,215	120,723	0	121,906
Jul-23	395,168	103,147	0	104,158
Aug-23	396,846	104,010	0	105,029
Sep-23	407,549	115,370	0	116,500
Oct-23	569,892	232,948	0	235,230
Winter	6,253,454	3,550,740	120,428	3,705,948
Summer	2,671,411	862,556	0	871,006
Annual	8,924,865	4,413,297	120,428	4,576,954

The detailed calculations can be found in Attachment NUI-FXW-2. On Pages 1 and 2 of Attachment NUI-FXW-2, I present calendar month and billed sales service deliveries by rate class. The Sales Service deliveries for each rate class were summed to determine the total Sales Service deliveries for the New Hampshire Division. An annual summary of the impact of migration by rate class can be found in Attachment NUI-FXW-19.

On Page 3 of Attachment NUI-FXW-2, I present my calculations of the city-gate receipts. First, I estimated Company Gas Allowance by multiplying the forecast Sales Service Deliveries and the Company Gas Allowance percentage. Company Gas Allowance includes both Company Use and Lost and Unaccounted For. The Company Gas Allowance Percentage was based on the recent history of actual data, which are presented in Attachment NUI-FXW-3. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire Division's capacity assignment program.

Q. What are Company Managed Sales?

A. Company Managed Sales are a form of Capacity Assignment. Capacity Assignment is a means of transferring the demand cost responsibility for capacity contracts from Northern to the retail marketers on its system. Whenever a retail marketer enrolls a customer, who is "capacity assigned," the retail marketer assumes cost and benefits of a pro-rated portion of the capacity contracts entered into by Northern, subject to the capacity assignment provisions of each division. These capacity contracts can include interstate pipeline contracts, underground storage contracts and on-site peaking facilities. Such transfer may be achieved by releasing capacity directly to the retail marketer ("Capacity Release"), who may then purchase their own supplies and utilize the released contracts to deliver supplies to their customers. Pursuant to Northern's Delivery Service Terms and Conditions for its New Hampshire Division, all upstream pipeline and underground storage capacity that delivers to Northern's system is assigned via Capacity Release except for upstream pipeline and storage capacity resources that require the Bay State Exchange Agreement. These excepted pipeline and storage resources are assigned via Company Managed Supply. On-system peaking capacity, such as Northern's Lewiston LNG plant, is also assigned via Company Managed Supply. Under the Company Managed Supply form of capacity assignment, Northern bills the retail marketer for a pro-rated portion of these capacity resources at their respective actual costs and offers a city-gate delivered supply service. Such city-gate supplies are priced in accordance with the capacity assignment provisions of each division. Such arrangements are known as "Company Managed Sales."

Q. Please explain the process used to project Company Managed Sales.

A. Company Managed resources for the New Hampshire Division include pipeline (specifically Iroquois Receipts and Algonquin Receipts capacity paths) and on-system peaking resources (Lewiston LNG plant). The maximum daily volume of each Company managed resource was estimated based on the allocations presented in Attachment NUI-FXW-6. Northern allows marketers to nominate their peaking Company managed resources on a daily basis. In addition, marketers are required to purchase pipeline baseload supplies that are associated with the Company Managed pipeline resources. The Company Managed Sales forecast assumes that marketers will utilize all Pipeline and Peaking Company-managed supply available to them under the capacity assignment program.

III. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its Sales Service customers and meet Company Managed Supply obligations.

A. I have prepared Table 3, below, which provides an overview of the sources of supply available to Northern through its portfolio of contracts, including transportation contracts, storage contracts, baseload and peaking supply contracts and an exchange agreement with Bay State Gas Company.

Table 3. Northern Capacity Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Zone 0 and Zone L Pools	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Leidy Hub Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
PXP Dawn Hub	9,965
WXP Dawn Hub	9,965
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	50,551
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Dawn Hub Storage	39,863
Total Storage Capacity	42,507
Peaking Capacity Paths	
LNG - On-System	6,500
Peaking Contract 1	39,860
Peaking Contract 2	2,990
Additional Granite Capacity	436
Total Peaking Capacity	49,786
Total Design Day Capacity	142,844

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2022-2023 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

Table 3 can also be found on page 1 of Attachment NUI-FXW-4. Subsequent pages of Attachment NUI-FXW-4 include capacity path diagrams and capacity path details for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

Northern's portfolio of transportation contracts includes contracts with Granite State Gas Transmission, Inc. ("GSGT" or "Granite"), Maritimes & Northeast Pipelines, L.L.C. ("MNUS" or "Maritimes"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited

("TransCanada"), Enbridge Gas, Inc. ("Enbridge" or "Union") , Algonquin Gas Transmission Company ("Algonquin"), Iroquois Gas Transmission System, L.P. ("Iroquois") and Texas Eastern Transmission System, L.P. ("Texas Eastern" or "TETCO"). The gas supply portfolio also includes long-term storage contracts with Enbridge and Tennessee. Northern's gas supply portfolio for 2022-2023 includes a multi-year peaking contract ("Peaking Contract 1") and a single-year peaking contact ("Peaking Contract 2"). The multi-year peaking supply arrangement was procured through a Request-For-Proposals ("RFP") and has a delivery period November through March for 4 years beginning November 2019. Peaking Contract 2 has a delivery period from November through March for the 2022-2023 Winter Period. Peaking Contract 2 was procured via an RFP process that concluded in June 2022. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which Northern relies on to produce 6,500 Dth per day with a storage capacity of approximately 12,000 Dth of LNG. Also through an RFP Northern has procured an LNG Contract for up to 3,000 Dth per day with an annual contract quantity of up to 75,000 Dth beginning November 2022 and ending October 2023 in order to supply this facility. The gas supply portfolio includes an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement"), which is needed to bring the Iroquois Receipts, Leidy Hub Supply and Transco Zone 6, non-NY capacity path supplies into Northern's system, as the delivery points on these capacity paths are on the Bay State Gas Company system.

The portfolio I used to project gas supply costs for the 2022-2023 winter season includes the Westbrook XPress ("WXP") project. Northern's precedent agreement for the WXP project was approved by the Commission in Docket No. DG 19-116. This supply source is new to the portfolio for the 2022-2023 Annual Period.

The capacity path diagrams and capacity path details in Attachment NUI-FXW-4 show how Northern has combined its transportation, storage and peaking supply contracts, along with the BSG Exchange, to move natural gas supplies from the sources of supply listed in Table 3 to Northern's distribution system. Each of these contractual arrangements represents a segment in one or more capacity paths. The capacity path diagrams show how each segment in the path is interconnected within the path. The capacity path details provide basic contract information, such as product (transportation, storage, peaking supply or exchange), vendor, contract ID number, contract rate schedule, contract end date, contract maximum daily quantity ("MDQ"), contract availability (year-round or winter-only), receipt and delivery points of the contract and interconnecting pipelines with the contract delivery point.

Q. Please describe the Company's process for procuring its gas supply commodity supplies.

A. Northern's practice is to secure most of its gas supply and asset management services through an annual RFP for terms beginning April 1 and running through March 31 each year. In March Northern completed its annual RFP for the delivery period of April 1, 2022 through March 31, 2023. Northern has entered into asset management agreements for the Atlantic Bridge Ramapo, Iroquois Receipts, Algonquin Receipts, Niagara, Tennessee Zone 0/L, PXP Dawn Hub, WXP Dawn Hub and Dawn Hub Storage capacity paths. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for LNG supplies for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2022-2023 Annual Period compared to the portfolio relied upon for the 2021-2022 Annual Period.

A. The following changes have been made to Northern's portfolio for the 2022-2023 Winter Period.

1. WXP Dawn Hub Capacity Path is expected to commence November 1, 2022. This will provide Northern with an additional 9,965 Dth of capacity from its system back to the Dawn Hub. All Dawn Hub capacity (including Dawn Hub Storage, PXP Dawn Hub and WXP Dawn Hub) is supplied through a single asset management agreement and commodity cost projections provided in Attachments NUI-FXW-8 and -9 present these capacity paths as a combined resource, although each of the corresponding pipeline contracts are modeled separately.
2. For the 2021-2022 Winter Period, Northern procured a short-term peaking supply contract with a maximum daily quantity equal to 10,000 Dth per Day and seasonal quantity equal to 300,000 Dth[2]. For the 2022-2023 Winter Period, this peaking supply has been replaced with Peaking Contract 2, which provides a maximum daily quantity equal to 3,000 Dth and a seasonal quantity equal to 60,000 Dth. Additionally, PNGTS Delivered Baseload supplies of 2,500 Dth per Day from December 2021 through February 2022 have not been replaced for the 2022-2023 Winter Period. Addition of the WXP Dawn Hub capacity to the portfolio provides Northern the ability to reduce these peaking supply purchases.
3. For the 2021-2022 Winter Period, Northern targeted protecting 70 percent of its November through March projected sendout requirements from NYMEX volatility. Northern has implemented a Price Risk Mitigation Plan in response to the

[2] This peaking supply contract was referred to as "Peaking Contract 2" in the 2021-2022 Winter COG filing.

volatility that has occurred in the last year. Under the Price Risk Mitigation Plan, Northern has updated this target to 75 percent of its November through March projected sendout requirements. In addition to normal underground storage inventory purchases, conversions of pipeline purchases for November through March delivery from variable NYMEX prices to fixed NYMEX prices took place in four blocks from June through September. Northern has completed each of these four blocks prior to the initial filing in this proceeding.

4. Effective April 1, 2023, Northern will increase the maximum storage balance of its Enbridge Dawn Storage from 4,000,000 Dth to 6,000,000 Dth. The new storage contract (Contract No. LST155) has a five year term. Increased storage capacity will allow the Company to rely less on baseload supplies to meet its 75 percent target for supplies protected from increases in NYMEX prices beginning the 2023-2024 Winter Period and beyond.

Q. Please provide an overview of Northern's Price Risk Mitigation Plan.

A. In response to the sharp increases and volatility observed during the pendency of Northern's 2021-2022 Annual Period COG filing, Northern locked in the NYMEX portion of its physical supply contracts to achieve a 70 percent hedged from further NYMEX volatility. I prepared Supplemental Testimony in this proceeding for the purpose of explaining this action taken to mitigate the risk of COG rate increases to Northern's customers during the 2021-2022 Winter Period increases. In that Supplemental Testimony, I explained that Northern would develop a plan on how its procurement process may need to be modified to protect against price volatility in the future. Northern developed its Price Risk Mitigation Plan ("Plan") during the spring of 2022. The Plan is summarized in Figure 1, below.

Figure 1. Summary of Price Risk Mitigation Plan	
Goals and Objectives:	Northern's objective is to mitigate the risk of significant mid-Winter Period Cost of Gas increases and to provide improved price certainty for customers during the Winter Season when usage is highest, while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors.
Target Ratio:	Northern plans to hedge 75 percent ("Target Ratio") of November through March projected volumes against increases in NYMEX prices. The Target Volume will be determined by multiplying Northern's projected sales service volumes times the Target Ratio.
Contracting Process:	Northern plans to utilize physical gas purchases to implement NYMEX hedges, in the form of underground storage and physical gas purchases under which the NYMEX portion of the price is fixed in advance of the Winter Season The volume of physical gas purchases with fixed NYMEX pricing will be determined by subtracting underground storage deliverability from the Target Volume.
Timing:	Northern plans no changes to its current underground storage injection practices[3]. NYMEX price locks under the Plan for baseload pipeline supplies would be implemented in 4 monthly blocks during June through September and be completed prior to the update in the Winter CGF filing such that all fixed price supply is reflected in the final approved CGF rates.
New England Spot Price Exposure:	In addition to the changes discussed above, Northern will continue to limit exposure to daily New England spot prices, including the Algonquin city-gates and Tennessee Zone 6 daily index prices.

In accordance with the Maine PUC Order in Docket No. 2021-00249, Northern filed testimony in Maine on May 6, 2022, which explained the Plan and described the analysis it used to formulate the Plan. At a high level, Northern analyzed the probability of a major mid-season cost of gas rate increase at various levels of NYMEX hedging, utilizing

[3] Enbridge Dawn storage injection occurs April through September. Tennessee FS-MA storage injection occurs April through October.

Monte Carlo sampling of NYMEX prices, and used this analysis to help guide what level of hedging could provide reasonable protection from major mid-season Cost of Gas rate increases while maintaining a high level of portfolio flexibility to respond to changes in demand due to weather, retail choice and other factors

Q. Please provide an update on the Atlantic Bridge ("AB") Project.

A. The AB project was subject to additional process established by an Order Establishing Briefing issued by the FERC on February 19, 2021 in Docket No. CP16-9 ("Briefing Order"). FERC's Briefing Order stated that in response to a request for rehearing of its September 24, 2020 order authorizing Algonquin Gas Transmission, LLC ("Algonquin") to place the Weymouth Compressor Station into service and "numerous other pleadings expressing safety concerns regarding the operation of the project," the FERC determined that "concerns raised regarding the operation of the project warrant further consideration by the Commission." The Briefing Order specifically requested that parties address whether it is consistent with the Natural Gas Act to allow the Weymouth Compressor Station to remain in service, whether the FERC should reconsider the current operation of the Weymouth Compressor Station in light of changed circumstances, whether the FERC should impose additional mitigation measures on Weymouth Compressor Station and what the consequences would be if the FERC reversed or stayed the Authorization Order. The Briefing Order permitted Weymouth Compressor Station to remain in service while the FERC considers these issues. Initial and Reply Briefs were filed pursuant to the Briefing Order.

The Briefing Order, itself, had been challenged in federal court with Algonquin challenging the FERC's authority to consider any changes to its authority to modify the operation of the Weymouth Compressor Station. On January 20, 2022, the FERC terminated the Briefing Order.

However, numerous legal challenges to the Weymouth Compressor Station remain both at the federal and state levels. These include challenges to the FERC Certificate and challenges to the Massachusetts waterways permit. Success of any of these legal challenges could result in the loss of availability of Atlantic Bridge Ramapo capacity path supplies.

Northern's supply plan and corresponding estimated cost of gas supply assumes continued operation of the Weymouth Compressor Station, which is necessary to ship supplies from the Algonquin system into the Maritimes system for ultimate delivery to Northern. Should Atlantic Bridge supplies become unavailable during the 2022-2023 Winter Period, Northern would attempt to replace this supply with delivered supplies as needed.

IV. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to Mr. Kahl to calculate the 2022-2023 Winter and 2023 Summer COG rates.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2022 through October 2023, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities
- New Hampshire Division Capacity Assignment program demand revenues
- Northern's commodity costs

The allocation of Northern's supply costs to the New Hampshire Division was performed by Mr. Kahl. The figures I present in my testimony relate to total company costs, inclusive of both the Maine and New Hampshire Divisions.

Q. Please provide Northern's demand cost forecast.

A. Please refer to Table 4, below, titled, "Estimated Gas Supply Demand Costs."

Table 4. Estimated Gas Supply Demand Costs
November 1, 2022 through October 31, 2023

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 24,102,032	Att NUI-FXW-5, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 21,827,803	Att NUI-FXW-5, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 4,206,606	Att NUI-FXW-5, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,598,890	Att NUI-FXW-5, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 11,428,417	Att NUI-FXW-5, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (20,934,600)	Att NUI-FXW-5, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 42,229,147	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Attachment NUI-FXW-5. Page 1 of Attachment NUI-FXW-5 provides the summary data presented here in Table 4. On page 2 of Attachment NUI-FXW-5, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Attachment NUI-FXW-5, I designate each transportation contract as a pipeline, storage or peaking resource and allocate transportation costs based upon these designations. Pages 4 and 5 of Attachment NUI-FXW-5 provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Attachment NUI-FXW-5, I forecast the capacity release and asset management revenue the Company expects to receive. Support for the transportation, storage and supply demand rates used in Attachment NUI-FXW-5 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How does the 2022-2023 Winter COG forecasted annual demand cost compare with the 2021-2022 Winter COG forecasted annual demand cost?

A. 2021-2022 Winter COG forecasted annual demand costs were equal to $46,657,517. 2022-2023 Winter COG forecasted annual demand costs are equal to $42,229,147, reflecting a decrease in forecasted annual demand costs equal to $4,428,370 or 9%.

The majority of the change in projected demand cost is explained by the following.

1. <u>Increase in projected Asset Management Agreement revenue by $11,032,500.</u> Higher AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting higher overall value obtained through asset management agreements.
2. <u>The increase in projected Asset Management Agreement revenue is partially offset by increases in Pipeline, Storage and Peaking Supply Contract costs equal to $6,604,130.</u> Pipeline capacity contract cost estimates increased $5,326,412 due mostly to the addition of WXP capacity contracts and an anticipated increase in Granite demand rates. Higher Storage capacity contract cost estimates increased $1,246,968 due to increasing Enbridge Dawn Hub storage volumes and demand rates in the new storage contract beginning April 1, 2023. Peaking Supply Contract cost estimates increased $30,750 due to the increased LNG Contract demand costs as a result of the annual RFP for LNG supply.

Q. Please provide Northern's forecast of Capacity Assignment Demand Revenues for the New Hampshire Division.

A. When a retail marketer enrolls one of Northern's New Hampshire Division customers, the retail marketer is assigned a portion of Northern's capacity. I present the detailed calculations of the demand revenues from capacity assignment in Attachment NUI-FXW-6. On page 1 of Attachment NUI-FXW-6, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Attachment NUI-FXW-6, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Attachment NUI-FXW-6. The 2022-2023 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $5,457,743.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2022 through April 2023?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of Attachment NUI-FXW-6. The proposed Peaking Service Demand Charge is equal to $72.72 per Dth, as shown in Attachment NUI-FXW-6 and presented in the proposed revised Appendix A to the Delivery Service Terms and Conditions. Please note that the Peaking Service Demand Charge applies only to capacity assignment pertaining to the on-system LNG plant.

Q. Please provide the Capacity Allocation Factors to be used for Capacity Assignment under the current New Hampshire Division Delivery Service tariff for effect November 1, 2022.

A. The Capacity Allocation Factors are provided in the proposed tariff sheet, Appendix C to the New Hampshire Division's Delivery Service Terms and Conditions. My calculations are provided in Attachment NUI-FXW-7. These Capacity Allocation Factors reflect a Capacity Ratio equal to 0.946, which is equal to Total Design Day Capacity of 142,844 Dth divided by the Total Design Day Planning Load (inclusive of both Maine and New Hampshire) of 151,040 Dth.

Q. Please describe Northern's process for forecasting commodity costs.

A. I base the Company's commodity cost forecast on Northern's projected city-gate receipts for sales service customers, which I calculated in Attachment NUI-FXW-2, and the supply sources available to Northern, which I presented in Attachment NUI-FXW-4. I forecast supply prices at each supply source, utilizing NYMEX natural gas contract price data and a forecast of the adder to NYMEX for the price of supply at each supply source available to Northern through its portfolio. To the extent that Northern's supply contract for a particular supply source provides for a fixed adder to the NYMEX Last Day Settlement, the contract prices are used to forecast the adder. If Northern's supply contract for a particular supply source does not provide for a fixed adder to the NYMEX Last Day Settlement, an estimate of the adder is based on the basis futures prices, through the Intercontinental Exchange ("ICE"). I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. Then, I utilized the PLEXOS® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.[4]

As discussed previously, Northern has completed NYMEX price locks on 4 monthly blocks to achieve a target ratio of hedged NYMEX supplies to total supplies of 75 percent (the "Target Ratio"). The effect of these price locks were accounted for after the PLEXOS® model run was completed.

Q. Please present the Company's commodity cost forecast for the 2021-2022 Annual Period.

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[4] PLEXOS is an energy optimization software package, which was developed by Energy Exemplar. In April 2021, Unitil contracted for the use of PLEXOS to update and replace the functionality the Company had previously utilized Sendout® to perform. Unitil ended its service agreement for Sendout® in October 2021.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter and Summer Period in Tables 5 and 6, respectively.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes November 2022 through April 2023			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Base Pipeline Resources	$ 54,005,233	6,035,977	$ 8.947
Storage Resources	$ 24,862,476	3,347,592	$ 7.427
Peaking Resources	$ 5,679,104	254,522	$ 22.313
Total Commodity Costs	$ 84,546,814	9,638,091	$ 8.772

Table 6. Summer Period Estimated Delivered City-Gate Commodity Costs and Volumes May 2022 through October 2022			
Supply Source	Summer Period Delivered City-Gate Costs	Summer Period Delivered City-Gate Volumes	Summer Period Delivered Cost per Dth
Pipeline Resources	$ 12,986,496	2,723,230	$ 4.769
Storage Resources	$ -	-	
Peaking Resources	$ 520,772	11,040	$ 47.171
Total Commodity Costs	$ 13,507,267	2,734,270	$ 4.940

In summary, Winter Period net projected delivered commodity costs equal approximately $84.5 million at an average delivered rate of $8.772 per Dth, and Summer Period net projected delivered commodity costs equal approximately $13.5 million at an average delivered rate of $4.940 per Dth. In support of this forecast, I prepared Attachment NUI-FXW-8 to show the monthly forecasted commodity cost by supply option. Page 1 of Attachment NUI-FXW-8 provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Attachment NUI-FXW-8 provides monthly delivered volumes (Dth) by supply source. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources. Attachment NUI-FXW-12 provides a seasonal summary of each supply source for Winter and Summer Periods, ranked by average delivered commodity cost.

The detailed calculations of the delivered commodity cost are found in Attachment NUI-FXW-9. For each supply source, I have provided the detailed monthly calculations for supply cost, fuel losses and variable transportation charges, which will be incurred by Northern to deliver its supplies to Northern's city-gates for ultimate consumption by our customers. Support of the supply prices and variable transportation charges found in Attachment NUI-FXW-9 are found in the Attachment NUI-FXW-10, Supplier Prices.

Q. How do forecasted commodity costs for the 2022-2023 Winter Period (November through April) compare with the forecasted commodity costs presented for the 2021-2022 Winter Period COG?

A. As show in Table 5, above, the 2021-2022 Winter Period COG forecasted commodity costs are equal to $84,546,814 at an average delivered rate of $8.772 per Dth. The 2021-2022 Winter Period COG forecasted commodity costs were equal to $53,379,334 an average delivered rate of $5.339 per Dth. Overall, 2022-2023 forecasted Winter Period commodity costs are 58% higher than 2021-2022 forecasted Winter Period costs due primarily to a 64% increase in projected average unit cost. The 2022-2023 projected delivered volume is 4% lower than was projected in 2021-2022. Projected NYMEX prices are 44% higher at the time of this 2022-2023 Annual Period COG filing (averaging $7.32 per Dth), compared to projected NYMEX prices at the time of last year's 2020-2021 Annual Period COG filing (averaging $5.08 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices. The projected average unit cost also reflects an increase in peaking supply commodity costs. Commodity rates for the short-term peaking supplies, specifically the LNG Contract and Peaking Contract 2 are significantly higher than the peaking supply commodity costs utilized for the 2021-2022 Winter Period. Addition of WXP Dawn Hub capacity to the portfolio mitigates the impact of these significantly higher commodity rates for peaking supplies by reducing the overall need for peaking supply.

Q. Please describe some of the factors that are impacting the increase in NYMEX natural gas prices for the 2022-2023 Winter Period relative to prior winter periods.

A. A number of factors contribute to the current high NYMEX prices.

1. An increase in LNG exports from the United States due to increased LNG liquefaction capabilities at a time when demand for LNG in both Europe and Asia are at historic highs.
2. High demand for natural gas from the power sector due to higher than normal temperatures nationally and a decreasing ability for the power sector to switch to coal because of higher coal prices and lower coal-fired generation capability nationally, as the U.S. transitions to cleaner power supply sources.
3. Domestic supplies have been slower to increase in response to higher demand and higher prices than they have in the past. This has been attributed to less aggressive investment by natural gas producers to increase supplies due to a focus on returning cash flow to investors rather than on deploying that cash flow to increase production. Another contributing factor to slower production growth has been the slower pace of regulatory review of pipeline expansion capacity needed to connect new supplies to the market.
4. These factors have resulted in consistently lower U.S. storage inventory volumes relative to last year and the five-year average. Combined, these factors have resulted in higher, more volatile NYMEX pricing than had been observed in recent years.

Q. Please provide a summary of Northern's projected hedge ratio relative to the Target Ratio in Northern's Price Risk Mitigation Plan.

A. Northern's projected supply volume for November 2022 through March 2023 is 8,606,982 Dth. Supplies that are not subject to NYMEX fluctuations during this period total 6,717,592 Dth, which is 78%, slightly higher than the 75% Target Ratio. Fixed supplies are comprised of 3,347,592 Dth of underground storage fixed price supplies, 3,310,000 Dth of NYMEX hedged baseload supplies and 60,000 Dth (Peaking Contract 2) of fixed peaking supplies. All 3,310,000 Dth of NYMEX hedged baseload supplies are currently locked.

Q. Please summarize the NYMEX price locks executed under the Price Risk Mitigation Plan for the 2022-2023 Winter Period to date.

A. Table 7, below, summarizes the price locks that have been entered to date. Currently, these price locks compare favorably to the NYMEX price utilized for the commodity price estimates I have provided. However, as stated in the Price Risk Mitigation Plan, the goal and objectives of the Price Risk Mitigation Plan are to provide greater cost certainty while maintaining flexibility needed to meet customer demands in a reliable fashion.

Table 7. NYMEX Price Locks

Item	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23
Block 1 Nov-Mar NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Block 1 Nov-Mar NYMEX Lock Price	$ 8.610	$ 8.610	$ 8.610	$ 8.610	$ 8.610
Block 1 Nov-Mar NYMEX Lock Cost	$ 645,750	$ 667,275	$ 667,275	$ 602,700	$ 667,275
Block 1 Dec-Feb NYMEX Lock Volume		155,000	155,000	140,000	
Block 1 Dec-Feb NYMEX Lock Price		$ 8.800	$ 8.800	$ 8.800	
Block 1 Dec-Feb NYMEX Lock Cost		$ 1,364,000	$ 1,364,000	$ 1,232,000	
Block 2 Nov-Mar NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Block 2 Nov-Mar NYMEX Lock Price	$ 5.660	$ 5.660	$ 5.660	$ 5.660	$ 5.660
Block 2 Nov-Mar NYMEX Lock Cost	$ 424,500	$ 438,650	$ 438,650	$ 396,200	$ 438,650
Block 2 Dec-Feb NYMEX Lock Volume		155,000	155,000	140,000	
Block 2 Dec-Feb NYMEX Lock Price		$ 5.830	$ 5.830	$ 5.830	
Block 2 Dec-Feb NYMEX Lock Cost		$ 903,650	$ 903,650	$ 816,200	
Block 3 Nov-Mar NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Block 3 Nov-Mar NYMEX Lock Price	$ 7.460	$ 7.460	$ 7.460	$ 7.460	$ 7.460
Block 3 Nov-Mar NYMEX Lock Cost	$ 559,500	$ 578,150	$ 578,150	$ 522,200	$ 578,150
Block 3 Dec-Feb NYMEX Lock Volume		155,000	155,000	140,000	
Block 3 Dec-Feb NYMEX Lock Price		$ 7.765	$ 7.765	$ 7.765	
Block 3 Dec-Feb NYMEX Lock Cost		$ 1,203,575	$ 1,203,575	$ 1,087,100	
Block 4 Nov-Mar NYMEX Lock Volume	75,000	77,500	77,500	70,000	77,500
Block 4 Nov-Mar NYMEX Lock Price	$ 8.350	$ 8.350	$ 8.350	$ 8.350	$ 8.350
Block 4 Nov-Mar NYMEX Lock Cost	$ 626,250	$ 647,125	$ 647,125	$ 584,500	$ 647,125
Block 4 Dec-Feb NYMEX Lock Volume		155,000	155,000	140,000	
Block 4 Dec-Feb NYMEX Lock Price		$ 8.650	$ 8.650	$ 8.650	
Block 4 Dec-Feb NYMEX Lock Cost		$ 1,340,750	$ 1,340,750	$ 1,211,000	
Total NYMEX Lock Volume	300,000	930,000	930,000	840,000	310,000
Weighted Average NYMEX Lock Price	$ 7.520	$ 7.681	$ 7.681	$ 7.681	$ 7.520
Total NYMEX Lock Cost	$ 2,256,000	$ 7,143,175	$ 7,143,175	$ 6,451,900	$ 2,331,200
Current NYMEX (September 7, 2022)	$ 7.901	$ 8.035	$ 8.115	$ 7.818	$ 6.705
Hedging Impact on Cost of Gas	$ (114,300)	$ (329,375)	$ (403,775)	$ (115,220)	$ 252,650

Since these fixed price NYMEX hedges are incorporated into Northern's physical supply contracts, these overall block purchases are allocated to individual contracts. Specifically, Dawn Hub, Tennessee Long-Haul, Iroquois Receipts, Niagara and Atlantic Bridge supply contracts have been amended to reflect these NYMEX hedge prices. Details of the allocations can be seen in Attachment NUI-FXW-9 for these individual contracts.

Q. Please explain some of the factors that are impacting the increase leading to significantly higher peaking supply commodity prices.

A. When New England natural gas demand exceeds the capacity of the pipeline system connecting New England to North American supplies, supply must be supplemented by imported LNG to meet all demand. New England as a whole, including Northern, is reliant upon imported LNG to reliably meet demand for natural gas during periods of cold weather. Therefore, peaking supply contracts (including those in Northern's portfolio) are sourced on imported LNG. The global LNG market has been seen extremely high prices, especially since the disruption of the supply of gas from Russia into Europe caused by the Russian invasion of Ukraine, has caused European countries to seek replacement of Russian pipeline gas supply with imported LNG, which has resulted in extremely high prices in Europe. In order to attract LNG cargoes to New England to provide peaking service, the price must be attractive relative to high European and Asian markets for LNG, which currently exceed $50 per Dth for November through March deliveries.

Q. How do forecasted commodity costs for the 2023 Summer Period (May through October) compare with the forecasted commodity costs presented for the 2022 Summer Period COG?

A. As show in Table 6, above, the 2023 Summer Period COG forecasted commodity costs are equal to $13,507,267 at an average delivered rate of $4.940 per Dth. The 2022 Summer Period COG forecasted commodity costs were equal to $10,424,440 at an average delivered rate of $3.470 per Dth. Overall, 2023 forecasted Summer Period commodity costs at the time of this 2022-2023 Annual Period COG Filing are 30% higher than 2022 forecasted Summer Period costs at the time of last year's 2021-2022 Annual Period COG Filing due to a 42% increase in projected average unit cost and a 9% decrease in projected delivered volumes. Projected NYMEX prices are 38% higher for the 2023 Summer Period (averaging $5.33 per Dth), compared to projected NYMEX for the 2022 Summer Period (averaging $3.86 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices.

Q. Please provide a summary of capacity utilization by supply source projected for the upcoming year.

A. Please refer to Attachments NUI-FXW-13, -14, -15 and -16. Attachment NUI-FXW-13 provides monthly supply volumes for Northern's normal year weather scenario. The data in Attachment NUI-FXW-13 is also found in Attachment NUI-FXW-8. Attachment NUI-FXW-14 provides monthly supply volumes for Northern's design cold year weather scenario. Attachment NUI-FXW-15 calculates the capacity utilization of all supply resources under the normal weather scenario. Attachment NUI-FXW-16 calculates the capacity utilization of all supply resources under the design cold weather scenario.

Q. Please provide Northern's Design Day Report for the upcoming Winter Period.

A. Northern's Design Day Report is found in Attachment NUI-FXW-17.

Q. Please provide Northern's 7-Day Cold Snap Analysis for the upcoming Winter Period.

A. Northern's 7-Day Cold Snap Analysis is found in Attachment NUI-FXW-18.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2022 through October 2023.

A. These results are based upon the Company's PLEXOS® analysis, which I provided to Mr. Kahl, and are the basis for his calculations in Attachment NUI-CAK-7.

V. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES

Q. Please describe the Re-entry Surcharge and the Conversion Surcharge.

A. The Re-entry Surcharge is applicable to all Capacity Assigned Delivery Service customers who switch from a retail marketer to Northern's Sales Service, and the

Conversion Surcharge is applicable to all Capacity Exempt Delivery Service customers who switch from a retail marketer to Northern's Sales Service. I have prepared proposed updated Re-entry and Conversion Surcharges to be effective for the 2022-2023 Winter Period. Customers electing to migrate and purchase their supply from Northern shall be required to continue purchasing Northern's Sales Service until April 30, 2023. After this time, such customers may elect to either switch to a retail marketer or continue purchasing Sales Service from Northern under the normal cost of gas rates.

Q. Please provide the proposed Re-entry Surcharge and the proposed Conversion Surcharge.

A. Proposed Appendix D to the Delivery Service Terms and Conditions, provides the Re-entry Surcharge and the Conversion Surcharge. The Re-entry Surcharge and Conversion Surcharge will be applied as a surcharge in addition to the normal cost of gas rates. These surcharges shall only be applicable to customers switching from Delivery Service to Sales Service.

Q. Please provide your calculations for the Re-entry Surcharge and the Conversion Surcharges.

A. Please refer to Attachment NUI-FXW-11. Page 1 shows the Re-entry Surcharge and Conversion Surcharge calculations. The Re-entry surcharge reflects the removal of any prior period credits, such as an over-recovery due to incumbent Sales Service Customers. The Conversion Surcharge reflects the removal of prior period credits due to incumbent Sales Service customers plus the incremental cost to serve the customers, based on estimated incremental commodity prices. Conversion customers will have a floor price equal to the COG for Low Load Factor customers, removing prior period credits.

Page 2 is the Incremental Commodity Price Worksheet. Pages 3 through 9 are the Load Shape Price Factor Worksheet. Page 10 is the projected city-gate sendout forecast of Delivery Service loads that are not currently subject to Capacity Assignment.

Q. Does this conclude your testimony?

A. Yes it does.