NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2021-2022
COST OF GAS FILING

PREFILED TESTIMONY OF
FRANCIS X. WELLS

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 2021-2022 fixed, annual demand cost estimates are 1% higher than the fixed, annual demand cost estimates provided for the prior 2020-2021 Winter Period COG filing. The major reasons for this increase include the projected increased Canadian pipeline demand costs due to less favorable exchange rates, higher Granite demand costs and higher peaking supply demand costs, partially offset by higher Asset Management Agreement revenue. Estimated average delivered commodity rates for the 2021-2022 Winter Period are 74% higher than the average delivered commodity rates estimated for the 2020-2021 Winter Period COG. The major reason for this increase is higher NYMEX supply costs and higher delivered supply costs, including baseload and peaking supplies added to the portfolio due to higher projected demands. Estimated average delivery commodity rates for the 2022 Summer Period are 31% higher than the average delivered commodity rates estimated for the 2021 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 9,169,707 Dth in the New Hampshire Division for the 2021-2022 Annual Period, which is 5.9% higher than the 2020-2021 Annual Period weather-normalized distribution deliveries and 9.6% higher than the 2019-2020 Annual Period weather-normalized distribution deliveries. The increase in the forecast reflects the recovery from the use per customer impacts of the COVID-19 pandemic on the economy by the beginning of 2022 and expected usage increases from two large customers from the prior year. Of the 9,169,707 Dth of projected distribution system deliveries, Northern projects that 4,424,636 Dth will be supplied by the Company through Sales Service. In order to supply 4,424,636 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,480,645 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 127,737 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,608,382 Dth for the upcoming Winter Period. 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), assuming that the Atlantic Bridge project is placed into service. I review the portfolio in more detail in the body of my testimony.

I project Northern's total company (including both the Maine and New Hampshire Divisions) demand cost for the November 2021 through October 2022 gas year to be $46,657,517. (*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 to be recovered in the Winter COG rate. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $5,012,735. (*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 2021-2022 Winter Period will be $53,379,334 at an average rate equal to $5.339 per Dth. (*See* Attachment NUI-FXW-8). 2022 Summer Period commodity cost to provide sales service during the 2022

Summer period are projected to be $10,424,440 at an average rate equal to $3.470 per Dth.

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.

Finally, I discuss the outage replacement supply costs that were incurred by the Company in June 2021 due to an outage of the PNGTS-MNUS interconnect that was necessitated due to construction on the PNGTS system. This resulted in approximately $207,000 in gas supply cost, which the Company seeks recovery through the COG.

II. SALES AND SENDOUT FORECAST

Q. Please describe the Company's forecasts sales.

A. The sales forecast has been updated in light of the pandemic and its effects on the economy. Historically, for the residential, regular general, and large rate classes, the sales forecast is developed by independently forecasting meter growth, base usage per meter, and a weather-driven usage per meter assuming 'normal' weather (average degree days during over the last 20 years) for the forecast period. Also forecasted is the Company's meter read cycle. In addition, Business Development personnel are consulted for comments on significant usage changes for the Company's large customers. The forecast seeks to limit subjectivity and typically relies on historical trends. However, average usage per C&I customer has declined as a result of the deterioration of the economic environment caused by the unprecedented COVID-19 crisis. Consequently, historical usage per customer levels are unlikely to be illustrative of future sales over the short to medium terms. The sales forecast assumes that usage per customer will return to pre-pandemic levels at the beginning of 2022. This timing decision reflects an apparent consensus among macroeconomic forecasts reviewed by the Company. The forecast assumes a recovery for usage per customer back to pre-pandemic levels at a linear rate through the beginning of 2022.

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 2021-2022 Annual Period.

Table 1. 2021-2022 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2021-2022 Forecast1	2020-2021 Actual2	2021-2022 minus 2020-2021	Percent Change	2019-2020 Actual2	2021-2022 minus 2019-2020	Percent Change
Nov	742,238	706,201	36,038	5.1%	710,939	31,300	4.4%
Dec	1,012,081	974,136	37,945	3.9%	967,728	44,354	4.6%
Jan	1,300,722	1,195,414	105,308	8.8%	1,190,671	110,051	9.2%
Feb	1,335,467	1,256,408	79,058	6.3%	1,255,585	79,881	6.4%
Mar	1,107,637	1,052,431	55,206	5.2%	1,023,935	83,702	8.2%
Apr	877,111	812,809	64,303	7.9%	739,593	137,518	18.6%
May	631,324	583,125	48,199	8.3%	565,494	65,830	11.6%
Jun	446,553	426,376	20,177	4.7%	396,103	50,450	12.7%
Jul	401,291	384,587	16,704	4.3%	347,265	54,026	15.6%
Aug	401,013	385,149	15,864	4.1%	330,714	70,300	21.3%
Sep	408,450	392,793	15,657	4.0%	386,921	21,529	5.6%
Oct	505,819	486,861	18,958	3.9%	452,419	53,400	11.8%
Winter	6,375,256	5,997,398	377,858	6.3%	5,888,450	486,806	8.3%
Summer	2,794,451	2,658,891	135,560	5.1%	2,478,916	315,536	12.7%
Annual	9,169,707	8,656,289	513,418	5.9%	8,367,366	802,341	9.6%

Forecast distribution deliveries are projected to increase 5.9% compared to the 2020-2021 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 3.6% increase in projected use per customer. The increase in use per customer is explained by the continued recovery in use per customer explained above.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2021-2022 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 2021-2022 Winter Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2020-2021 and 2019-2020 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 2020 through April 2021. 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.

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-21	904,460	471,318	23,850	501,134
Dec-21	1,138,582	672,045	25,927	706,478
Jan-22	1,311,721	788,030	30,414	828,419
Feb-22	1,165,490	677,460	22,901	708,937
Mar-22	1,079,498	579,426	24,645	611,406
Apr-22	775,504	345,654	0	350,029
May-22	525,996	190,761	0	193,176
Jun-22	421,906	125,725	0	127,316
Jul-22	410,447	107,420	0	108,780
Aug-22	419,208	109,042	0	110,423
Sep-22	428,956	120,812	0	122,341
Oct-22	587,938	236,943	0	239,943
Winter	6,375,256	3,533,933	127,737	3,706,403
Summer	2,794,451	890,703	0	901,979
Annual	9,169,707	4,424,636	127,737	4,608,382

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

[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.

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 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 current capacity assigned transportation customer data. 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
Atlantic Bridge Ramapo	7,500
Total Pipeline Capacity	40,586
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
PNGTS Delivered Baseload (Dec-Feb)	2,491
Peaking Contract 1	39,860
Peaking Contract 2	9,965
Additional Granite Capacity	935
Total Peaking Capacity	59,751
Total Design Day Capacity	142,844

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2021-2022 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 diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern Capacity listed for each source of supply.

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

("TransCanada"), Enbridge Gas, Inc. ("Enbridge" or "Union")[2], 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 2021-2022 includes a multi-year peaking contract ("Peaking Contract 1"), a PNGTS Delivered Baseload supply 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. The PNGTS Delivered Baseload supply has a delivery period from December through February for the 2021-2022 Winter Period. Peaking Contract 2 has a delivery period from November through March for the 2021-2022 Winter Period. These shorter-term peaking supplies were procured via an RFP process that concluded in August 2021. 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 2021 and ending October 2022 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

[2] Enbridge Gas, Inc. was formed on January 1, 2019 with the amalgamation of Enbridge Gas Distribution and Union Gas Limited.

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 2021-2022 winter season includes the Portland XPress ("PXP") and Atlantic Bridge ("AB") projects. These supply sources are relatively new to the portfolio, having been added to the portfolio since the last COG filing.

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, in order 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, 2020 through March 31, 2021. Northern has entered into asset management agreements for the PXP Dawn Hub, Atlantic Bridge Ramapo, Iroquois Receipts, Algonquin Receipts, Niagara, Tennessee Zone 0/L 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 2021-2022 Winter compared to the portfolio relied upon for the 2020-2021 Winter.

A. The 2021-2022 Winter Portfolio includes the short-term peaking supplies referenced above, 2,500 Dth per Day of PNGTS Delivered Baseload (Dec – Feb) and Peaking Contract 2, which has a maximum daily volume of 10,000 Dth and a seasonal quantity of 300,000 Dth. These additional short-term peaking supplies were procured to assure that Northern has sufficient supplies to meet it projected Design Winter demands for its Sales Service customers.

Q. Please provide an update on the PXP and AB projects.

A. All facilities required for both PXP and AB projects have been constructed and placed into service. Northern has fully executed service agreements for transportation capacity anticipated in the related precedent agreements.

The AB project is currently 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 states 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 has determined that "concerns raised regarding the operation of the project warrant further consideration by the Commission." The Briefing Order specifically requests parties to address whether it is consistent with the Natural Gas Act to allow the Weymouth Compressor Station to remain in service, whether the Commission 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 does permit Weymouth Compressor Station to remain in service while the Commission considers these issues.

Initial and Reply Briefs have been filed pursuant to the Briefing Order. FERC has not issued any substantive order related to the Briefing Order at this time. The Briefing Order, itself, has 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.

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.

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 2021-2022 Winter COG.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2021 through October 2022, 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, 2021 through October 31, 2022

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 17,953,274	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 22,032,867	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 2,959,638	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 2,216,171	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 11,397,667	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (9,902,100)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 46,657,517	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. Asset Management Revenue associated with the AB capacity will offset by the one-time acquisition fee Northern paid to gain assignment of the AB precedent agreement until such time as AMA revenue or other non-core service revenues derived from use of the Atlantic Bridge capacity exceed the one-time acquisition fee. 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 2021-2022 Winter COG forecasted annual demand cost compare with the 2020-2021 Winter COG forecasted annual demand cost?

A. 2020-2021 Winter COG forecasted annual demand costs were equal to $46,230,726. 2021-2022 Winter COG forecasted annual demand costs are equal to $46,657,517, reflecting an increase in forecasted annual demand costs equal to $426,791 or 1%.

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

1. <u>Increase in projected pipeline and storage demand contract costs by $ $1,490,882.</u> The increase reflects a lower exchange rate for demand costs related to Union and TransCanada pipeline charges (combined $1,231,726) and higher Granite demand costs due to the increase in Granites' rates set forth in Granite's limited Section 4 FERC filing ($341,738). These increases are offset by decreases in Tennessee and Texas Eastern demand costs due to lower filed rates (combined decrease equal to $79,845).
2. <u>Increase in projected Peaking Supply Contract demand costs by $288,500.</u> The increase in Peaking Supply Contract demand costs reflects higher LNG demand costs due to higher demand prices bid via the RFP for LNG supply conducted by Northern. Northern has elected a lower volume of LNG supply to partially offset this increase.
3. <u>These increases are partially offset by an increase in projected Asset Management Agreement revenue credits by $1,352,591.</u> Higher AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting higher overall value obtained through asset management agreements.

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 2021-2022 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $5,012,735.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2021 through April 2021?

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 $71.85 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, 2021.

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 0.958, 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 149,082 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-3. 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 Sendout® natural gas supply cost model to determine the optimal use of Northern's natural gas supply resources to meet its projected city-gate requirements.

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

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

Table 5. Winter Period Estimated Delivered City-Gate Commodity Costs and Volumes November 2021 through April 2022			
Supply Source	Winter Period Delivered City-Gate Costs	Winter Period Delivered City-Gate Volumes	Winter Period Delivered Cost per Dth
Pipeline Resources	$ 32,159,520	5,861,225	$ 5.487
Storage Resources	$ 10,403,958	3,348,512	$ 3.107
Peaking Resources	$ 10,815,857	787,782	$ 13.730
Total Commodity Costs	$ 53,379,334	9,997,519	$ 5.339

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	$ 10,352,007	2,993,295	$ 3.458
Storage Resources	$ -	-	
Peaking Resources	$ 72,433	11,040	$ 6.561
Total Commodity Costs	$ 10,424,440	3,004,335	$ 3.470

In summary, Winter Period net projected delivered commodity costs equal approximately $53.4 million at an average delivered rate of $5.339 per Dth, and Summer Period net projected delivered commodity costs equal approximately $10.4 million at an average delivered rate of $3.470 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 summary 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 in order 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 2021-2022 Winter Period (November through April) commodity costs compare with the forecasted commodity costs presented for the 2020-2021 Winter Period COG?

A. As show in Table 5, above, the 2021-2022 Winter Period COG forecasted commodity costs are equal to $53,379,334 at an average delivered rate of $5.339 per Dth. The 2020-2021 Winter Period COG forecasted commodity costs were equal to $27,501,662 at an average delivered rate of $3.066 per Dth. Overall, 2021-2022 forecasted Winter Period commodity costs are 94% higher than 2020-2021 forecasted Winter Period costs due primarily to a 74% increase in projected average unit cost. The 2021-2022 projected delivered volume is 11% higher than was projected in 2020-2021. Projected NYMEX prices are 62% at the time of this 2021-2022 Annual Period COG filing (averaging $5.08 per Dth), compared to projected NYMEX prices at the time of last year's 2020-2021 Annual Period COG filing (averaging $3.15 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices. The projected average unit cost also reflects an increase in must-take delivered supplies, specifically the short-term PNGTS Delivered Baseload supplies and Peaking Contract 2 supplies discussed previously in my testimony. The Company secured these incremental delivered supplies in order to 1.) assure its ability to meet Design Winter demand requirements of the Company as the Company projects an 11% increase in normal sendout requirements and 2.) replace the reduced LNG Contract volume, as the new LNG contract will have an annual contract quantity equal to 75,000 Dth rather than 125,000 Dth contracted for during the 2020-2021 Winter Period.

Q. How do forecasted commodity costs for the 2022 Summer Period (May through October) commodity costs compare with the forecasted commodity costs presented for the 2021 Summer Period COG?

A. As show in Table 6, above, the 2022 Summer Period COG forecasted commodity costs are equal to $10,424,440 at an average delivered rate of $3.470 per Dth. The 2021 Summer Period COG forecasted commodity costs were equal to $6,290,994 at an average delivered rate of $2.652 per Dth. Overall, 2022 forecasted Summer Period commodity costs at the time of this 2021-2022 Annual Period COG Filing are 66% higher than 2021 forecasted Summer Period costs at the time of last year's 2020-2021 Annual Period COG Filing due to a 31% increase in projected average unit cost and a 27% increase in projected delivered volumes. Projected NYMEX prices are 37% higher for the 2022 Summer Period (averaging $3.86 per Dth), compared to projected NYMEX for the 2021 Summer Period (averaging $2.82 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 2021 through October 2022.

A. These results are based upon the Company's Sendout® 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 2021-2022 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, 2022. 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.

VI. OUTAGE REPLACEMENT SUPPLY EXPENSES

Q. Did Northern incur unexpected gas supply costs this past summer?

A. Yes, Northern incurred $90,000 in incremental supply demand costs and $117,200 in incremental supply commodity costs to provide replacement supply service to firm customers during a pipeline outage from June 17, 2021 through June 23, 2021 during the construction of PNGTS' Westbrook Xpress Project (WXP) (collectively the "Outage

Replacement Supply Costs”). The WXP construction involved adding a new compressor to the Westbrook Compressor Station. During the outage, supplies were unable to move from north of the Westbrook interconnect between PNGTS and Maritimes (“the PNGTS-MNUS interconnect”) onto the Joint Facilities, where the Westbrook, Eliot and Newington receipt points to Granite are located. During this time, deliveries on the Joint Facilities could not be sourced from either Dawn Hub via PNGTS or Canaport via Maritimes, requiring supply to Northern to be dependent upon its Atlantic Bridge capacity via the Weymouth Compressor Station, which had been experiencing both operational and regulatory challenges. As a result, Northern purchased incremental supplies to supplement its portfolio and assure continuity of service during the WXP outage. Fortunately, there was no interruption of Atlantic Bridge supplies during the WXP outage, but the outage replacement supplies procured by the Company were needed to protect against the uncertainty posed by Atlantic Bridge’s operational and regulatory history.

Q. Does this conclude your testimony?

A. Yes it does.