NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL PERIOD 2020-2021
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 2020-2021 fixed, annual demand cost estimates are 70% higher than the fixed, annual demand cost estimates provided for the prior 2019-2020 Annual Period COG filing. The major reasons for this increase include the projected beginning of service for Portland XPress and Atlantic Bridge capacity and the decrease in projected Asset Management Revenues.

Estimated 2020-2021 Winter Period average delivered commodity rates are 20% lower than the average delivered commodity rates estimated for the 2019-2020 Winter Period in last year's Annual COG filing. The major reason for this decrease is the replacement of PNGTS and Maritimes Delivered Baseload supplies with lower priced supplies accessed via the Portland XPress and Atlantic Bridge capacity contracts. The decrease in commodity prices are partially offset by a 28% increase in NYMEX futures prices for the upcoming 2020-2021 Winter Period compared to prices utilized in the 2019-2020 Annual COG initial filing. Estimated 2021 Summer Period average delivered commodity rates are 22% higher than the 2020 Summer Period average delivered commodity rates that were estimated in last year's Annual COG filing, reflecting 22% higher NYMEX futures prices.

Northern projects combined sales service and delivery service distribution deliveries to be 8,209,228 Dth in the New Hampshire Division for the 2020-2021 Annual Period, which is 1.0% higher than the 2019-2020 Annual Period weather-normalized distribution deliveries and 6.5% lower than the 2018-2019 Annual Period weather-normalized distribution deliveries. The reduction in the forecast reflects the impacts of the COVID-19 pandemic on the economy. The sales forecast reflects a gradual recovery to normal use per customer levels at the beginning of 2023. Of the 8,209,228 Dth of projected distribution system deliveries, Northern projects that 4,295,862 Dth will be supplied by the Company through Sales Service. In order to deliver 4,295,862 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,352,444 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 124,217 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,476,661 Dth for the upcoming Winter Period. The details behind these estimates are contained in Schedules 16-FXW and 17-FXW.

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 provide an update on the status of the Portland XPress ("PXP") and Atlantic Bridge ("AB") projects, which the Company expects will be in service on or before November 1, 2020. In addition I discuss Northern's request to recover a one-time acquisition fee that it paid to Emera Energy in order to take assignment of the Precedent Agreement for the Atlantic Bridge project. Northern requests that Asset Management Revenue associated with the AB capacity be offset by the one-time acquisition fee Northern paid to gain assignment of the AB precedent agreement from Emera 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.

I project Northern's total company (including both the New Hampshire and Maine Divisions) demand cost for the November 2020 through October 2021 gas year to be $45,258,751. (*See* Schedule 20-FXW). Mr. Chris Kahl, who is employed by Unitil Service Corp. as a Senior Regulatory Analyst, presents the allocation of the total annual demand cost to Northern's New Hampshire Division and the allocation of annual demand costs between the Winter and Summer COG rates. I also projected the demand revenue from the New Hampshire Division's capacity assignment program to be $4,419,945. (*See* Schedule 21-FXW). I also discuss the updated Capacity Allocators and Capacity Ratio pursuant to the New Hampshire Division capacity assignment program, which are provided as Schedule 22-FXW.

I project that Northern's total company (including both the New Hampshire and Maine Division) commodity cost to provide sales service during the 2020-2021 Winter Period will be $28,564,215 at an average rate equal to $3.101 per Dth. (*See* Schedule 23-FXW).

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 Schedule 36-FXW.

Finally, I discuss the unexpected CNG supply costs that were incurred by the Company in June 2020 due to an outage of the Eliot Granite State meter that was necessitated due to construction on the PNGTS system. This resulted in approximately $286,000 in gas supply cost. The Company seeks recovery of the portion of these costs allocated to the New Hampshire Division 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 2023. 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 2023.

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 2020-2021 Annual Period.

Table 1. 2020-2021 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2020-2021 Forecast[1]	2019-2020 Actual[2]	2020-2021 minus 2019-2020	Percent Change	2018-2019 Actual[2]	2020-2021 minus 2018-2019	Percent Change
Nov	659,578	696,660	-37,082	-5.3%	711,579	-52,001	-7.3%
Dec	946,024	949,247	-3,224	-0.3%	947,842	-1,819	-0.2%
Jan	1,139,404	1,190,037	-50,633	-4.3%	1,248,735	-109,331	-8.8%
Feb	1,223,700	1,278,231	-54,531	-4.3%	1,327,296	-103,596	-7.8%
Mar	1,100,828	1,047,338	53,490	5.1%	1,086,718	14,110	1.3%
Apr	774,735	750,676	24,059	3.2%	845,541	-70,806	-8.4%
May	570,317	519,041	51,276	9.9%	632,151	-61,834	-9.8%
Jun	397,160	382,043	15,118	4.0%	430,401	-33,241	-7.7%
Jul	346,583	333,729	12,854	3.9%	391,025	-44,442	-11.4%
Aug	347,374	324,955	22,419	6.9%	380,773	-33,399	-8.8%
Sep	356,180	335,134	21,046	6.3%	375,181	-19,002	-5.1%
Oct	425,676	402,137	23,539	5.9%	485,413	-59,737	-12.3%
Winter	5,844,268	5,912,189	-67,920	-1.1%	6,167,711	-323,442	-5.2%
Summer	2,443,290	2,297,039	146,251	6.4%	2,694,945	-251,655	-9.3%
Annual	8,287,558	8,209,228	78,331	1.0%	8,862,656	-575,097	-6.5%

Note 1: Forecast Data begins May 2020.
Note 2: Actual Data through April 2020 is weather normalized

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2020-2021 Annual Period in Schedule 16-FXW. Page 1 of Schedule 16-FXW 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 2020-2021 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2019-2020 and 2018-2019 Annual 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 Schedule 16-FXW 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 forecast Sales Service deliveries?

A. To forecast Sales Service deliveries, Northern identified those customers utilizing Delivery Service as of July 2020. The Company weather normalized monthly usage for each customer and aggregated this data by rate class for both Capacity Assigned and Capacity Exempt customers. This aggregated rate class forecast was adjusted down in a manner consistent with the overall reduction in the forecast of distribution deliveries. The forecast billed usage of current Delivery Service customers was subtracted from the distribution deliveries of the entire system, provided in Schedule 16-FXW in order to estimate Sales Service deliveries. Schedule 34-FXW provides an annual summary of the C&I sales by rate class, breaking out Sales Service and Delivery Service from Total Sales.

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 to meet the Sales Service Deliveries[1] for the upcoming Annual Period.

[1] When I use the term "City-Gate Receipts to meet the Sales Service Requirements", 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-20	820,296	455,239	22,380	483,615
Dec-20	1,066,085	661,996	25,562	696,277
Jan-21	1,225,633	788,638	29,216	828,242
Feb-21	1,076,714	670,482	23,933	703,246
Mar-21	1,000,325	580,219	23,126	610,987
Apr-21	655,216	333,168	0	337,556
May-21	475,998	170,934	0	173,185
Jun-21	362,639	114,418	0	115,925
Jul-21	340,761	96,459	0	97,730
Aug-21	354,292	97,904	0	99,193
Sep-21	371,993	106,590	0	107,993
Oct-21	537,608	219,817	0	222,712
Winter	5,844,268	3,489,741	124,217	3,659,923
Summer	2,443,290	806,121	0	816,738
Annual	8,287,558	4,295,862	124,217	4,476,661

The detailed calculations can be found in Schedule 17-FXW. On Pages 1 and 2 of Schedule 17-FXW, 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 Maine Division.

On Page 3 of Schedule 17-FXW, 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 Schedule 18-FXW. Finally, I added Northern's projection of Company Managed Sales pursuant to the New Hampshire's 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 responsibility for 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 for the New Hampshire Division.

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 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
Union Dawn Storage	39,863
Total Storage Capacity	42,507
Peaking Capacity Paths	
LNG - On-System	6,500
Peaking Contract 1	39,860
Additional Granite Capacity	13,391
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 2020-2021 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above. This information can also be found on page 1 of Schedule 19-FXW.

Subsequent pages of Schedule 19-FXW 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"), Tennessee Gas Pipeline Company ("TGP" or "Tennessee"), Portland Natural Gas Transmission System ("PNGTS"), TransCanada Pipelines Limited ("TransCanada"), Union Pipelines Ltd. ("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 Union and Tennessee. Northern's gas supply portfolio for 2020-2021 includes a single multi-year peaking contract. This 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. 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 5,000 Dth per day with an annual contract quantity of up to 125,000 Dth beginning November 2020 and ending October 2021 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 2020-2021 winter season presumes that the Portland XPress ("PXP") and Atlantic Bridge ("AB") projects are in service by November 1, 2020. If the in-service date for either project is delayed, Northern will replace these supplies with PNGTS or Maritimes delivered supplies, if necessary.

The capacity path diagrams and capacity path details in Schedule 19-FXW 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 its Iroquois Receipts capacity path, Algonquin Receipts capacity path, Niagara capacity path, its Tennessee Zone 0/L capacity path and its Union Dawn Storage capacity path. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for LNG supplies for the upcoming winter. In the case of PXP and AB capacity, Northern will issue an asset management RFP to secure gas supply for these capacity paths when the in-service dates for the relevant facilities are finalized.

Q. Please describe any changes in Northern's portfolio for the upcoming 2020-2021 Winter compared to the portfolio relied upon for the 2019-2020 Winter.

A. Upon the applicable in-service dates, the PXP Dawn Hub capacity path will replace PNGTS Delivered Baseload Supply purchases and that AB Ramapo capacity path will replace Maritimes Delivered Baseload Supply purchases.

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

A. Northern expects PXP to be in-service on November 1, 2020 and that the capacity contracts will begin, as planned.

Northern expects that all AB facilities will be constructed prior to November 1, 2020. There was a possibility that the in-service date would be delayed due to a June 3, 2020 order remanding and vacating Algonquin's air permit from the Massachusetts Department of Environmental Protection ("MA DEP") by the First Circuit Court of Appeals, requiring the MA DEP to assess whether an electric motor was the Best Available Control Technology ("BACT") for the compressor station located in Weymouth, MA, which is needed in order to move gas from the Algonquin pipeline onto the Maritimes pipeline. The MA DEP expects to complete its determination on the BACT analysis on September 29, 2020. The process for any appeals to this determination would be completed on January 19, 2021. Algonquin requested rehearing of the First Circuit Court order, arguing that its permit should not be vacated during the pendency of the MA DEP's process for considering whether an electric motor would be the BACT. On August 31, Algonquin's rehearing request was granted by the First Circuit Court, effectively reinstating the required air permit to place the Weymouth compressor station into service and begin Atlantic Bridge service to Northern on October 1, 2020, assuming completion of construction and commissioning activities, FERC approval to place the Weymouth compressor into service and a favorable finding by the MA DEP on September 29, 2020.

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 2020-2021 Winter COG.

A. I have provided Mr. Kahl the following cost estimates for the period beginning November 2020 through October 2021, 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 New Hampshire and Maine 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, 2020 through October 31, 2021

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 17,304,236	Att NUI-FXW-4, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 20,299,374	Att NUI-FXW-4, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 2,962,375	Att NUI-FXW-4, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,658,003	Att NUI-FXW-4, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 11,109,167	Att NUI-FXW-4, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (8,074,404)	Att NUI-FXW-4, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 45,258,751	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 20-FXW. Page 1 of Schedule 20-FXW provides the summary data presented here in Table 4. On page 2 of Schedule 20-FXW, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Schedule 20-FXW, 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 Schedule 20-FXW provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Schedule 20-FXW, I forecast the capacity release and asset management revenue the Company expects to receive. Please note that I have not included an estimate of asset management revenue for PXP and AB capacity paths. When in-service dates for these capacity contracts has been confirmed, Northern will issue an Asset Management RFP for these resources and plans to update the Company's COG Filing, as appropriate. Support for the transportation, storage and supply demand rates used in Schedule 20-FXW are found in the Schedule 29-FXW, Supplier Prices.

Q. Please explain Northern's proposal to recover the one-time acquisition fee associated with Northern's Atlantic Bridge capacity.

A. Northern entered into the Atlantic Bridge Precedent Agreement by way of an assignment and assumption agreement with the original contracting customer party, Emera. The Atlantic Bridge project was fully subscribed at the time the capacity became available and Northern negotiated a reasonable fee to secure the capacity. Northern requests that Asset Management Revenue associated with the AB capacity be offset by the one-time acquisition fee Northern paid to gain assignment of the AB precedent agreement from Emera 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. Northern notes that the Maine Public Utilities Commission determined that this fee was reasonable in light of the benefits to be gained from entering into the Atlantic Bridge agreement. 2016-00229, Northern Utilities, Inc. d/b/a Unitil, Order Part II at 27 (March 2, 2017).

Q. How does 2020-2021 Annual COG forecasted annual demand cost compare with the 2019-2020 Annual COG forecasted annual demand cost?

A. 2019-2020 Annual COG forecasted annual demand costs were equal to $26,584,504. 2020-2021 Annual COG forecasted annual demand costs are equal to $45,258,751, reflecting an increase in forecasted annual demand costs equal to $18,674,247 or 70%.

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

1. Increase in projected pipeline and storage demand contract costs by $12,503,282. PXP is expected to increase annual demand costs by $4,999,148. AB is expected to increase annual demand costs by $6,212,299. $1,305,786 of this figure is attributable to an increase in TransCanada tolls on the Union Dawn Storage capacity path. This increase in tolls will take place in January 1, 2021.
2. Decrease in projected Asset Management Agreement revenue credits by $6,386,196. Lower AMA revenue reflects the results of Northern's annual request-for-proposals process, reflecting lower overall value obtained through asset management agreements. As discussed previously, the AMA revenue excludes any AMA revenue that the Company may obtain from PXP and AB capacity.

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 Schedule 21-FXW. On page 1 of Schedule 21-FXW, I present a summary of the Company's forecast of New Hampshire Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 21-FXW, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 21-FXW. The 2020-2021 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $4,419,945. This represents a significant increase in this item from the 2019-2020 Annual COG Filing, in which the Company projected $3,007,397 in Capacity Assignment Demand Revenue. This increase in Capacity Assignment Demand Revenue is attributable to the increase in overall demand costs, discussed earlier in my testimony.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2020 through April 2021?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of Schedule 21-FXW. The proposed Peaking Service Demand Charge is equal to $64.53 per Dth, as shown in Schedule 21-FXW 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, 2020.

A. The Capacity Allocation Factors are provided in the proposed updated Appendix C to the New Hampshire Division's Delivery Service Terms and Conditions. My calculations are provided in Schedule 22-FXW. These Capacity Allocation Factors reflect a Capacity Ratio equal to 1.056, which is equal to Total Design Day Capacity of 142,844 Dth divided by the Total Design Day Planning Load (inclusive of both New Hampshire and Maine) of 135,242 Dth. Both the Capacity Allocators and the Capacity Ratio calculations assume that PXP and AB capacity are in service. If service is delayed for either or both projects, the Company will need to revise the Capacity Allocators and the Capacity Ratio to best assure equitable allocation of Capacity between Sales Service and Delivery Service customers.

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 Schedule 17-FXW, and the supply sources available to Northern, which I presented in Schedule 19-FXW. 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. The Company's supply price forecast can be found on page 1 of Schedule 29-FXW.

Q. Please present the Company's commodity cost forecast for the 2020-2021 Winter Period and the 2021 Summer Period.

A. I have summarized Northern's commodity cost forecast for the upcoming Winter Period in Table 5, below.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
November 2020 through April 2021

Supply Source	Winter Delivered City-Gate Costs	Winter Delivered City-Gate Volumes	Winter Delivered Cost per Dth
Base Pipeline Resources	$ 8,258,046	2,635,323	$ 3.134
Remaining Pipeline Resources	$ 12,668,508	3,140,843	$ 4.033
Storage Resources	$ 5,242,569	2,885,522	$ 1.817
Peaking Resources	$ 1,332,538	307,647	$ 4.331
Total Commodity Costs	$ 27,501,662	8,969,336	$ 3.066

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2021 through October 2021

Supply Source	Summer Delivered City-Gate Costs	Summer Delivered City-Gate Volumes	Summer Delivered Cost per Dth
Base Pipeline Resources	$ 6,217,391	2,361,169	$ 2.633
Remaining Pipeline Resources	$ -	-	
Storage Resources	$ -	-	
Peaking Resources	$ 73,602	11,040	$ 6.667
Total Commodity Costs	$ 6,290,994	2,372,209	$ 2.652

In summary, the 2020-2021 Winter Period net projected delivered commodity costs equal approximately $27.5 million at an average delivered rate of $3.066 per Dth, and the 2021 Summer Period net projected delivered commodity costs equal approximately $6.3 million at an average delivered rate of $2.652 per Dth. In support of this forecast, I prepared Schedule 23-FXW to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 23-FXW provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Schedule 23-FXW 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.

The detailed calculations of the delivered commodity cost are found in Schedule 24-FXW. 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 Schedule 24-FXW are found in the Schedule 29-FXW, Supplier Prices.

Q. How do forecasted commodity costs for the 2020-2021 Winter Period (November through April) presented here compare with the forecasted commodity costs presented for the 2019-2020 Winter Period in last year's Annual COG filing?

A. As show in Table 5, above, the 2020-2021 Winter Period forecasted commodity costs are equal to $27,501,662 at an average delivered rate of $3.066 per Dth. The 2019-2020 Winter Period forecasted commodity costs were equal to $36,929,508 at an average delivered rate of $3.840 per Dth. Overall, 2020-2021 forecasted Winter Period commodity costs are 26% lower than 2019-2020 forecasted Winter Period costs due primarily to a 20% decrease in projected average unit cost. The 2020-2021 projected delivered volume is 7% lower than was projected in 2019-2020. Projected NYMEX prices are 28% higher heading into the 2020-2021 Winter Period (averaging $3.15 per Dth), compared to projected NYMEX prices heading into the 2019-2020 Winter Period (averaging $2.45 per Dth). The Company's unit cost forecast reflects these higher NYMEX prices. Lower projected average unit cost is attributable to replacement of PNGTS and Maritimes Delivered Supplies with lower cost supplies via PXP and AB capacity paths, respectively.

Q. How do forecasted commodity costs for the 2021 Summer Period (May through October) presented here compare with the forecasted commodity costs presented for the 2020 Summer Period in last year's Annual COG filing?

A. As show in Table 6, above, the 2021 Sumer Period forecasted commodity costs are equal to $6,290,994 at an average delivered rate of $2.652 per Dth. The 2020 Summer Period forecasted commodity costs were equal to $5,384,034 at an average delivered rate of $2.170 per Dth. Overall, 2021 forecasted Summer Period commodity costs are 17% higher than 2020 forecasted Summer Period costs due primarily to a 22% increase in projected average unit cost. The 2021 projected delivered volume is 4% lower than was projected for 2020. The increase in Summer Period unit commodity costs reflects an overall increase in NYMEX natural gas supply prices. Projected NYMEX prices for the 2021 Summer Period are 22% higher (averaging $2.82 per Dth), compared to projected NYMEX prices for the 2020 Summer Period (averaging $2.32 per Dth).

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

A. Please refer to Schedules 30-FXW, 31-FXW and 32-FXW. Schedule 31-FXW provides monthly supply volumes for Northern's normal year weather scenario. The data in Schedule 30-FXW is also found in Schedule 23-FXW. Schedule 31-FXW provides monthly supply volumes for Northern's design cold year weather scenario. Schedule 32-FXW calculates the capacity utilization of all supply resources in both normal and design cold weather scenarios.

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

A. Northern's Design Day Report is found in Schedule 33-FXW.

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 Schedule 35-FXW.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2020 through October 2021.

A. Please refer to Schedule 10-CAK. These results are based upon the Company's Sendout® analysis.

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 applicable for the 2020-2021 Annual Period. Customers electing to migrate and purchase their supply from Northern shall be required to continue purchasing Northern's Sales Service until April 30 each year. 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 Schedule 36-FXW. Page 1 shows the calculations for the Re-entry Surcharge for both the Winter Period and Summer Period. The Re-entry surcharge reflects the removal of any prior period credits, such as an over-recovery due to incumbent Sales Service Customers.

Page 2 shows the Conversion Surcharge calculations for the Winter Period. 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 cost of gas rates applicable to Low Load Factor customers, removing prior period credits. The Conversion Surcharge is equal to the Re-entry Surcharge during the Summer Period.

Page 3 is the Incremental Commodity Price Worksheet. Pages 4 through 10 are the Load Shape Price Factor Worksheet. Page 11 is the projected city-gate sendout forecast of Delivery Service loads that are not currently subject to Capacity Assignment.

VI. COMPRESSED NATURAL GAS (“CNG”) SUPPLY EXPENSES

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

A. Yes, Northern incurred gas supply costs of $286,007.85 to provide compressed natural gas (CNG) service to firm customers during a pipeline outage which took all pipeline supply to the Eliot Granite State meter station out of service for one week in the middle of June during the construction of PNGTS’ Portland Xpress Project (PXP). The PXP construction involved adding a new compressor to the Eliot Compressor Station which required the Joint Facilities pipeline to be purged out of service from Eliot to Newington in order to complete the pipeline connections, resulting in the outage. The outage resulted in unanticipated gas supply costs as the Company was required to procure alternative supply on short notice to ensure uninterrupted firm service to customer served on Northern’s Eliot distribution system.

Q. How many customers does Northern serve in Eliot, Maine?

A. Northern serves approximately 500 customers, including approximately 30 commercial customers and the Portsmouth Naval Shipyard (PNSY) on its Eliot distribution system. Prior to the outage, PNSY made arrangements to switch their Co-Generation plant to alternate fuel. The Eliot meter station is not connected to the Granite main line, so consequently the Eliot distribution system is a single-feed system and Northern had no option but to arrange for a non-pipeline supply.

Q. When did Northern first learn of the planned pipeline outage?

A. Northern informally learned of the pending outage in early April, approximately 10 weeks before the outage. The first pipeline notice was posted on April 14, 2020. An updated notice modifying the outage dates was posted on April 24, 2020. The second posting provided an additional two weeks before the start of the Eliot outage, from June 1 to June 15, an adjustment made in response to a request from Unitil.

Q. What actions did Northern take when it learned of the pending outage?

A. Northern scheduled meetings with PNGTS and Maritimes Northeast Operating Company (MNOC), which operates and maintains the Joint Facilities, to better understand the work being done and options to mitigate impacts of both outages. These meetings were held weekly from mid-April to mid-June when the Eliot outage was ending. Northern engaged an outside engineer specializing in CNG decompression to assist with planning and design of CNG options that could serve customers in Eliot, identified and obtained temporary rights for a suitable property, and issued an RFP for CNG service. Northern received competitive offers to provide the CNG service in response to the RFP and awarded a contract to the lowest cost option. Northern worked to expeditiously secure the property for the CNG operation, obtain required permits and approvals, fabricate pipeline interconnections and present a thorough plan to the Maine PUC Safety Staff.

Q. Please describe the expenses incurred in connection with the above-described temporary CNG service that the Company has included for recovery in this Cost of Gas filing.

A. Expenses incurred by the Company in connection with the temporary CNG service are costs that are directly related to procuring and providing safe and reliable firm gas supply to customers. These costs include the CNG service itself, engineering support, temporary property rights, fabrication of the pipeline interconnection, weld inspection tests, and protective barriers for the site. These were all outside service expenses required and incurred to establish the CNG operation and maintain firm service to customers during the outage. Please see Schedule 39-FXW for a list of specific charges.

Q. How does the Company propose to recover these costs?

A. As explained in the testimony of Mr. Kahl, the CNG expenses are proposed to be recovered in the Company's demand charges, subject to allocation to both the New Hampshire and Maine Divisions as well as to both the peak and off-peak seasons.

Q. Is the Company aware of possible future pipeline outages that could similarly require supplemental supply operations?

A. Yes, in 2021 a new compressor will be added to the Westbrook Compressor Station as part of PNGTS' Westbrook Xpress Project (WXP), which received its Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission on June 18, 2020. Also during 2021, a new interconnect will be constructed from the Joint Facilities into Granite at South Berwick, Maine. PNGTS has not yet finalized construction plans for these projects, so specific impacts are not yet known.

Q. Does this conclude your testimony?

A. Yes it does.