NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL 2016-2017
COST OF GAS ADJUSTMENT 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 Adjustment ("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 2016-2017 fixed, annual demand cost estimates are $29,731,468, which is 5% lower than the fixed, annual demand cost estimates provided for the prior 2015-2016 Winter Period COG initial filing. Estimated average delivered commodity rates for the 2016-2017 Winter Period are $4.211 per Dth, which is 20% lower than the average delivered commodity rates estimated for the 2015-2016 Winter Period COG. Estimated average delivered commodity rates for the 2017 Summer Period are $2.545 per Dth, which is 22% higher than the average delivered commodity rates estimated in the 2016 Summer Period COG. I discuss reasons for these changes in gas supply cost in the body of my testimony.

Northern projects 2016-2017 combined annual sales service and delivery service distribution deliveries to be 8,454,317 Dth in the New Hampshire Division, which is an increase equal to 1.4% compared to 2015-2016 annual weather-normalized distribution deliveries and an increase equal to 4.4% compared to 2014-2015 annual weather-normalized distribution deliveries. Of the 8,454,317 Dth of projected distribution system deliveries, Northern projects that 3,955,484 Dth will be supplied by the Company through Sales Service. In order to supply 3,955,484 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,003,743 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 424,394 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,428,137 Dth for the upcoming annual period. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern has the ability to deliver up to 118,564 Dth of contract supply and on-system peaking capacity per day during the peak winter months, November through March.

This is a decrease equal to 2,010 Dth from the prior winter's maximum deliverability, which was equal to 120,574 Dth. This decrease is attributable to a reduction in the off-system peaking contracts from 41,879 Dth to 39,861 Dth and a reduction in PNGTS winter baseload supplies from 7,474 Dth to 4,983 Dth. This is partially offset by an increase in the volume Northern relies upon from its LNG Plant for planning purposes from 4,181 Dth to 6,500 Dth (an increase equal to 2,319 Dth). Northern's contract supply sources include Chicago City-Gates Supply, PNGTS Receipts, Tennessee Niagara, Tennessee Production, Algonquin Receipts, Maritimes Delivered and PNGTS Delivered baseload supply, Tennessee Firm Storage, Washington 10 Storage and Peaking Supply Contracts. Northern has system peaking LNG capacity in Lewiston, Maine. The details behind Northern's portfolio are contained in Schedule 12. I discuss changes to Northern's portfolio in more detail in the body of my testimony.

I project Northern's total company (including the Maine Division) demand cost for the November 2016 through October 2017 gas year to be $29,731,468. (*See* Schedule 5A). 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 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 $2,403,657. (*See* Schedule 5B). I also discuss the calculation of the updated capacity allocation factors pursuant to the current New Hampshire Division capacity assignment program.

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2016-2017 Winter Period will be $35,724,471 at an average rate equal to $4.211 per Dth and the 2017 Summer Period commodity costs to be $5,858,770 at an average rate equal to $2.545 per Dth. (*See* Schedule 6A). I also calculated hedging program costs to be $161,700. (*See* Schedule 7). Mr. Kahl calculates the allocation of these costs to the New Hampshire Division.

Finally, I provide an overview of changes to Northern's capacity portfolio that are expected to be in place for next winter, beginning November 1, 2017. Most significantly, Northern plans to increase the volume of pipeline capacity on PNGTS and Maritimes pipelines for the purpose of reducing future exposure to PNGTS and Maritimes Delivered Supplies.

II. SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm deliveries?

A. To forecast billed distribution deliveries for the Company's residential and small commercial (G40, G50, G41 and G51) classes, the Company has utilized time-series techniques to develop two forecast models for each customer class: use-per-meter and the number of meters. The forecast monthly billed deliveries for each customer class was calculated by multiplying forecast customers times forecast use-per-customer. To forecast billed distribution deliveries for the Company's large commercial and industrial rate classes, the Company utilized individual customer forecasts.

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 for the upcoming 2016-2017 Winter and Summer Period.

Table 1. 2016-2017 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2016-2017 Forecast[1]	2015-2016 Actual[2]	2016-2017 minus 2015-2016	Percent Change	2014-2015 Actual[2]	2016-2017 minus 2014-2015	Percent Change
Nov	660,056	628,976	31,080	4.9%	616,168	43,888	7.1%
Dec	943,886	943,772	114	0.0%	912,666	31,221	3.4%
Jan	1,207,370	1,201,487	5,883	0.5%	1,173,275	34,095	2.9%
Feb	1,163,394	1,180,626	-17,232	-1.5%	1,171,279	-7,885	-0.7%
Mar	1,071,970	1,079,523	-7,553	-0.7%	1,057,087	14,884	1.4%
Apr	798,995	762,611	36,384	4.8%	760,690	38,305	5.0%
May	570,150	546,425	23,725	4.3%	463,370	106,779	23.0%
Jun	421,274	411,569	9,706	2.4%	406,358	14,917	3.7%
Jul	394,374	385,537	8,837	2.3%	377,555	16,819	4.5%
Aug	349,398	341,637	7,762	2.3%	328,341	21,057	6.4%
Sep	378,856	370,287	8,568	2.3%	363,264	15,592	4.3%
Oct	494,594	482,750	11,845	2.5%	464,142	30,452	6.6%
Winter	5,845,671	5,796,994	48,677	0.8%	5,691,164	154,507	2.7%
Summer	2,608,646	2,538,204	70,442	2.8%	2,403,029	205,617	8.6%
Annual	8,454,317	8,335,198	119,119	1.4%	8,094,193	360,124	4.4%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data through May 2016. Projected data beginning June 2016.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2016-2017 Annual Period in Attachment 1 to Schedule 10B. Page 1 of Attachment 1 to Schedule 10B 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 2016-2017 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2015-2016 and 2014-2015 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 Attachment 1 to Schedule 10B 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 June 2016. For small and medium Delivery Service customers (T40, T50, T41 and T51 rate classes) Northern weather normalized the billed usage of these specific customers. For large Delivery Service customers (T42 and T52 rate classes) Northern utilized the individual forecast for these specific customers. The forecast billed usage of current Delivery Service customers was subtracted from the billed distribution deliveries of the entire system, provided in Attachment 1 to Schedule 10B in order to estimate Sales Service deliveries.

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 year.

Table 2. Distribution and Sales Service Deliveries & Required City-Gate Receipts Summary					
Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)	Company Managed Deliveries (Dth)	City-Gate Receipts (Dth)
Nov-16	781,130	389,681	394,317	31,730	426,047
Dec-16	1,009,641	557,234	563,863	84,278	648,141
Jan-17	1,265,286	740,873	749,687	122,548	872,235
Feb-17	1,129,880	653,115	660,885	115,808	776,693
Mar-17	981,432	523,577	529,806	70,030	599,836
Apr-17	678,302	291,390	294,857	0	294,857
May-17	482,591	159,559	161,457	0	161,457
Jun-17	391,618	112,535	113,874	0	113,874
Jul-17	394,552	98,227	99,396	0	99,396
Aug-17	359,030	100,751	101,950	0	101,950
Sep-17	400,920	111,298	112,622	0	112,622
Oct-17	579,935	218,431	221,030	0	221,030
Winter	5,845,671	3,155,870	3,193,415	424,394	3,617,809
Summer	2,608,646	800,800	810,328	0	810,328
Annual	8,454,317	3,956,670	4,003,743	424,394	4,428,137

[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.

The detailed calculations can be found in Attachment 2 to Schedule 10B. On Pages 1 and 2 of Attachment 2 to Schedule 10B, 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.

On Page 3 of Attachment 2 to Schedule 10B, I present my calculations of the city-gate receipts. First, I estimated Company Use by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, I added Company Use to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Then, I added an estimate for Lost and Unaccounted for Gas. Each of the estimates used in these calculations was based on the recent history of actual data, which are presented in Attachment 3 to Schedule 10B. 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 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, peaking supply 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 either the Bay State Exchange Agreement or Canadian pipeline capacity for delivery to Northern's system. These excepted pipeline and storage resources are assigned via Company Managed Supply. Peaking capacity, including both Northern's Lewiston LNG plant and its peaking contracts, 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 delivered supplies are priced at cost, in accordance with Northern's Delivery Service Terms and Conditions for the New Hampshire 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 Chicago City-Gates and Algonquin Receipts capacity paths), storage (Washington 10) and peaking resources (Lewiston LNG plant and off-system peaking contracts). 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 storage and 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, storage and peaking Company managed supply available to them under the capacity assignment program.

Q. Please explain why Northern provides Company Managed sales in its city-gate sendout projections and its gas supply dispatch analysis.

A. Company Managed sales are a significant portion of Northern's gas supply obligation. Since Northern maintains resources to fulfill these Company Managed supply obligations for both the Maine and New Hampshire Divisions, it is appropriate to include them in the gas supply dispatch analysis in order to demonstrate the expected utilization of resources.

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 Paths (Dth per Day)		
Supply Source	Nov 2016 through Mar 2017	Apr 2017 through Oct 2017
Tennessee Long-Haul	13,109	13,109
Algonquin Receipt Points Supply	1,251	1,251
Chicago City-Gates & Iroquois Receipts	6,434	6,434
PNGTS Receipts	1,096	1,096
Tennessee Niagara	2,327	2,327
Maritimes Delivered Baseload Supply	7,474	0
PNGTS Delivered Baseload Supply - (Nov - Mar)	4,983	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Contract 1	4,983	0
Peaking Contract 2	14,948	0
Peaking Contract 3	9,965	0
Peaking Contract 4	9,965	0
Lewiston On-System LNG Production	6,500	6,500
Total Deliverable Resources	**118,564**	**19,001**

I have also prepared a 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 Deliverable Capacity listed for each source of supply. This information is found in Schedule 12.

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"), Vector Pipeline L.P. ("Vector"), 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 Washington 10 Storage Corporation ("Washington 10" or "W10") and Tennessee. Northern's gas supply portfolio also includes short-term peaking contracts. These peaking supply arrangements were procured through a Request-For-Proposals ("RFP") and have a delivery period beginning November 2016 and ending March 2017. 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. Northern has entered into an LNG Contract beginning November 2016 and ending October 2017 in order to supply this facility. Finally, as I mentioned previously, the gas supply portfolio consists of an exchange agreement with Bay State Gas Company ("BSG Exchange" or "Bay State Exchange Agreement").

The capacity path diagrams and capacity path details in Schedule 12 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. Has the Company entered into any long-term releases of capacity?

A. Yes. Effective May 1, 2009, Northern released Texas Eastern Contract 800384 for the remaining term of the agreement, which is through October 31, 2017. This release is at the maximum allowable rates, benefiting customers by fully recovering the costs of the released contract.

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. Northern has recently completed its annual RFP for the delivery period of April 1, 2016 through March 31, 2017. Northern has entered into asset management agreements for its Chicago capacity path, Algonquin Receipts capacity path, Niagara capacity path, a portion of its Tennessee Production capacity path and its Washington 10 capacity path. Northern also entered into baseload supply agreements through this RFP. Northern has also completed its RFP process for peaking supplies in early July, including an LNG Contract for the upcoming winter.

Q. Please describe any changes in Northern's portfolio for the upcoming 2016-2017 Winter compared to the portfolio relied upon for the 2015-2016 Winter.

A. The major changes in the portfolio include the following items.

1. The Capacity rating for the LNG Plant has been increased by Northern from 4,181 Dth to 6,500 Dth.
2. Northern has decreased its off-system Peaking Contracts by approximately 2,000 Dth over the 2015-2016 Winter portfolio. This decrease in Peaking Contract capacity is due to the change in the Maine Capacity Assignment Program,

whereby retail marketers in the Maine Division are no longer assigned off-system peaking contracts. This change was part of the 2015 Settlement in Docket No. 2014-00132.

3. For the 2015-2016 Winter Portfolio, Northern had purchased 2,500 Dth per day of PNGTS supply for December through February. The 2016-2017 Winter Period portfolio does not reflect this purchase. Northern plans to assess its need for incremental baseload supplies during the course of the winter. This will give Northern the flexibility to respond to changes in demand forecasts due either to weather or migration.

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 2016-2017 Winter COG.

A. I have provided Mr. Kahl the following cost estimates, which he used to calculate the proposed COG.

- Northern's fixed demand costs, including revenue offsets due to capacity release and asset management activities for the period November 2016 through October 2017
- Maine Division Capacity Assignment program demand revenues for the period November 2016 through October 2017
- Northern's commodity costs for the period November 2016 through October 2017

- Northern's financial hedging program costs period November 2016 through March 2017

The allocation of Northern's fixed demand, commodity and hedging costs to the Maine 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, 2016 through October 31, 2017

Line	Description	Estimate	Reference
1.	Pipeline Demand Costs	$ 8,950,792	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 22,954,032	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,029,855	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,438,984	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 3,390,000	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (10,032,196)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 29,731,468	Sum Lines 1 through 6.

I present the detailed calculations of this demand cost forecast in Schedule 5A. Page 1 of Schedule 5A provides the summary data presented here in Table 4. On page 2 of Schedule 5A, I have calculated the annual demand cost forecast for Northern's portfolio of transportation contracts. On page 3 of Schedule 5A, 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 5A provide my calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of Schedule 5A, I forecast the capacity release and asset management revenue the Company expects to receive for the 2016-2017 Gas Year. Support for the transportation, storage and supply demand rates used in Schedule 5A are found in the Attachment to Schedule 5A, Supplier Prices.

Q. How do 2016-2017 Winter COG forecasted annual demand costs compare with the 2015-2016 Winter COG forecasted annual demand costs?

A. 2015-2016 Winter COG forecasted annual demand costs were equal to $31,158,821. 2016-2017 Winter COG forecasted annual demand costs are equal to $29,731,468, reflecting a decrease in forecasted annual demand costs equal to $1,427,353 or approximately 5%. The decrease in projected demand costs is attributable to the following:

1. <u>Decrease in pipeline contract demand cost equal to $192,144.</u> This is due to lower Vector demand rates and a more favorable exchange rate. These items are partially offset by higher Granite costs.
2. <u>Decrease in peaking contract demand costs equal to $833,000.</u> Peaking supply contract costs are lower than 2015-2016 due to lower volumes purchased and lower unit demand costs through the 2016-2017 RFP.
3. <u>Increase in projected AMA credits by $402,209.</u> Projected AMA credits are higher due to the results of Northern's request for proposals process.

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 5B. On page 1 of Schedule 5B, I present a summary of the Company's forecast of Maine

Division capacity assignment demand revenues. On pages 2 through 6 of Schedule 5B, I present the Company's detailed calculations for each component of capacity assignment, itemized on page 1 of Schedule 5B. The 2016-2017 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,939,774. I project that the New Hampshire Division Retail Marketers will be allocated $536,118 of the PNGTS Refund, yielding a net Capacity Assignment Demand Revenue equal to $2,403,657.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2016, through April 2017?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 7 of Schedule 5B. The proposed Peaking Service Demand Charge is equal to $20.82 per Dth, as shown in Schedule 5B and presented in the proposed revised Appendix A (Page 153) to the Delivery Service Terms and Conditions.

Q. Please provide the Capacity Allocation Factors to be used for Capacity Assignment under the New Hampshire Division Delivery Service tariff for effect November 1, 2016.

A. The Capacity Allocation Factors are provided in the proposed tariff sheet, Page 168, which is Appendix C to the New Hampshire Division's Delivery Service Terms and Conditions. The calculation of the Capacity Allocation Factors is found on Schedule 19.

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 2 to Schedule 10B, and the supply sources available to Northern, which I presented in Schedule 12. 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 utilizing both forward basis prices and Northern's contractual commitments. I also forecast variable fuel retention factors and rates for Northern's transportation and storage contracts. This forecast is provided in Attachment to Schedule 5A, Supplier Prices. 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 2016-2017 Winter 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 2016 through April 2017

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 25,791,550	5,863,588	$ 4.399
Storage Resources	$ 7,453,274	2,572,308	$ 2.898
Peaking Resources	$ 3,798,072	446,684	$ 8.503
Total Commodity Costs	$ 37,042,896	8,882,581	$ 4.170
Company Managed Revenue	$ (1,318,425)	(399,885)	$ 3.297
Net Sales Service Commodity Costs	$ 35,724,471	8,482,696	$ 4.211

In summary, net projected delivered commodity costs equal approximately $35.7 million at an average delivered rate of $4.211 per Dth. In support of this forecast, I prepared Schedule 6A to show the monthly forecasted commodity cost by supply option. Page 1 of Schedule 6A provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of Attachment Schedule 6A 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.

I have also prepared Schedule 2, which provides a seasonal summary of commodity costs, by supply source, ranked from lowest to highest on the basis of Delivered Cost per Dth.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. 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 6B are found in the Attachment to Schedule 5A, Supplier Prices.

Q. How do 2016-2017 Annual COG forecasted Winter Period (November through April) commodity costs compare with the 2015-2016 Winter COG forecasted commodity costs?

A. As show in Table 5, above, the 2016-2017 Winter COG forecasted Winter Period commodity costs are equal to $35,724,471 at an average delivered rate of $4.211 per Dth. The 2015-2016 Winter COG forecasted Winter Period commodity costs were equal to $43,667,878 at an average delivered rate of $5.233 per Dth. 2016-2017 forecasted Winter Period commodity costs are 18% lower than 2015-2016 forecasted Winter Period costs due primarily to 20% lower average delivered rates.

Lower forecasted 2016-2017 average delivered rates compared to projected 2015-2016 average delivered rates reflect the following factors:

- Basis prices for PNGTS and Maritimes Delivered Baseload supplies are significantly lower for the 2016-2017 Winter Period than for the 2015-2016 Winter Period. These supplies were procured through the annual RFP process. Also, as discussed previously, the 2016-2017 Winter Period commodity cost budget includes less PNGTS Delivered Baseload Supply. This resulted in projected average pipeline supply unit costs decreasing from $5.636 per Dth to $4.399 per Dth. These figures are presented in Table 5 of my testimony in the 2015-2016 and 2016-2017 Winter COG initial filings, respectively.
- Projected peaking supply prices are lower due to lower forward curve for New England delivered supplies. This resulted in projected average peaking supply unit costs decreasing from $11.844 per Dth to $8.503 per Dth. Again, these figures are presented in Table 5 of my testimony in the 2015-2016 and 2016-2017 Winter COG initial filings, respectively.
- The decrease in PNGTS and Maritimes Delivered Baseload Supply and Peaking Contract prices is partially offset by a modest increase in the average NYMEX prices for November through April have decreased since Northern filed its 2015-2016 Winter COG. NYMEX prices for November 2015 through April 2016 averaged $3.01 per Dth in the Company’s initial 2014-2015 Winter COG filing (based on September 4, 2015 NYMEX data). This filing reflects November 2016 through April 2017 NYMEX prices that average $3.21 per Dth (based on August 28, 2016 NYMEX data), which is an increase equal to 10%.

While New England based supply volumes remain expensive relative to supplies that can be accessed using Northern’s portfolio of transportation contracts, New England based supply prices are lower than they were a year ago. Northern remains concerned about the volatility of the New England gas supply market and the exposure of customers to New England gas prices. Northern seeks to manage its portfolio of gas supply contracts in a manner that can reliably meet its customer's needs and protect customers from the extremely volatile and high prices, such as those recently observed in the New England natural gas market.

Q. Please present the Company's commodity cost forecast for the 2017 Summer Period.

A. I have summarized Northern's commodity cost forecast for the 2017 Summer Period in Table 6, below.

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2017 through October 2017

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 5,774,799	2,289,044	$ 2.523
Storage Resources	$ -	-	
Peaking Resources	$ 83,971	13,156	$ 6.383
Total Commodity Costs	$ 5,858,770	2,302,200	$ 2.545
Net Sales Service Commodity Costs	$ 5,858,770	2,302,200	$ 2.545

Pages 3 through 6 of Schedule 6A provide monthly support by supply source for this forecast, in the same manner as for the Winter Period. Additionally, Schedule 6C provides detailed calculations in the same manner as Schedule 6B does for the Winter Period.

Q. How do 2016-2017 Annual COG forecasted 2017 Summer Period (May through October) commodity costs compare with the 2016 Summer COG forecasted commodity costs?

A. As show in Table 6, above, the forecasted 2017 Summer Period commodity costs are equal to $5,858,770 at an average delivered rate of $2.545 per Dth. The 2016 Summer COG forecasted commodity costs were equal to $5,186,841 at an average delivered rate of $2.084 per Dth. 2016 forecasted Summer Period commodity costs are 13% higher than 2016 forecasted Summer Period costs due primarily to 22% higher average delivered rates.

Higher forecasted 2017 Summer average delivered rates compared to projected 2016 Summer average delivered rates are largely driven by changes in NYMEX natural gas futures pricing. The 2016 Summer COG forecast was based on March 4, 2016 prices for the NYMEX natural gas futures contracts for May through October 2016 , which averaged $1.98 per Dth. The 2017 Summer COG forecast is based on August 28, 2016 prices for the NYMEX natural gas futures contracts for May through October 2017, which averaged $3.02 per Dth, an increase of 53%. The increase in NYMEX natural gas futures prices is partially offset by lower projected adders to NYMEX.

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

A. Please refer to Schedules 11A, 11B and 11C. Schedule 11A provides monthly supply volumes for Northern's normal weather scenario. The data in Schedule 11A is also found in Schedule 6A. Schedule 11B provides monthly supply volumes for Northern's design cold weather scenario. Schedule 11C 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 11D.

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 11E.

Q. Please provide the Company's monthly projections of storage inventory balances for the period November 2016 through October 2017.

A. Please refer to Schedule 14. These results are based upon the Company's Sendout® analysis.

Q. Please provide the results of the hedging program related to the Company's proposed COG rates.

A. Northern projects hedging program costs to be $161,700 for the upcoming winter peak season, which reflects the premium paid by Northern for call option contracts for November 2016 through March 2017. Since the strike price for each call option contract purchased is above current NYMEX prices as of August 28, 2016, Northern projects no settlement value for these call options as they expire over the course of the coming winter. Please refer to Schedule 7 for the monthly hedging calculations.

V. PORTFOLIO UPDATES

Q. Please describe the upcoming changes to Northern's portfolio of natural gas transportation capacity.

A. Northern plans the following changes to its portfolio of natural gas transportation capacity.

- Addition of Atlantic Bridge capacity
- Replacement of the Washington 10 Storage Path with a new Dawn Storage Path
- Replacement of the Chicago Path with an Iroquois Receipts Path

- Recall of currently released Texas Eastern capacity to be utilized as part of the Algonquin Receipts Path

Q. Please describe the Atlantic Bridge capacity.

A. Northern has entered into an assignment agreement under which it takes assignment of a Precedent Agreement for 7,599 Dth of Atlantic Bridge capacity. The Atlantic Bridge project capacity will be able to receive gas at Ramapo or Mahwah, NJ and deliver it to the interconnection between Algonquin and Maritimes at sufficient pressure to be moved north onto Maritimes' system. Ramapo is the interconnection between Millennium Pipeline and Algonquin and Mahwah is the interconnection between Tennessee Zone 5 300 Leg and Algonquin. Both Millennium and Tennessee Zone 5 300 Leg have access to the Marcellus natural gas producing region. This Precedent Agreement is contingent upon Northern having access to 7,500 Dth of Maritimes capacity, which would be necessary to deliver to Northern's system. Northern plans to elect a primary delivery point of Lewiston, ME for the Maritimes capacity. The addition of Atlantic Bridge capacity is intended to reduce Northern's need for Maritimes Delivered Baseload supplies.

Q. Please describe the Dawn Storage Path.

A. The 'Dawn Storage Path' path replaces the former Washington 10 Storage Path. Northern will transition from Washington 10 storage to Dawn storage on April 1, 2018. The Washington 10 Storage path has long been Northern's largest source of supply, providing 3.4 Bcf of storage with maximum daily withdrawal capacity that can deliver up to 32,885 Dth/day into Northern during the five (5) winter months. The Dawn Storage Path will provide 4.0 Bcf of storage that can deliver up to 39,863 Dth/day year round, sourced from Dawn Storage during the winter or via purchases at the Dawn Hub year round. The additional transportation capacity was made possible by using the Union contract (M12205) currently used for the Chicago Path and replacing the TransCanada contract (k41235) that was part of the Chicago Path with new TransCanada capacity that has an East Hereford delivery point.

Northern made changes to its PNGTS contracts effective November 1, 2017 that were the result of participation in PNGTS' C2C Project. Specifically, Northern amended its two PNGTS contracts (k1997-003, k1997-004) such that they terminate on the effective date of a new service agreement under the C2C project for 34,000 Dth/day. In addition, Northern entered into a precedent agreement for an additional 6,003 Dth/day to complete the path enabled by moving the delivery point on TransCanada contract (k41235). Thus, effective November 1, 2017, Northern will have year round PNGTS capacity totaling 40,003 Dth/day. It is Northern's intent to consolidate multiple firm transportation contracts with each of Union, TransCanada and PNGTS into single contracts with each entity during 2018.

Q. Please describe the Iroquois Receipts Path.

A. The 'Iroquois Receipts Path' will replace the 'Chicago Path'. Effective April 1, 2017, Northern will have terminated the Vector capacity that was part of the Chicago Path, temporarily moving the receipt point from St. Clair to Dawn. Effective November 1, 2017, the Union Gas Limited ("Union") capacity that was part of the 'Chicago Path' path will be utilized to feed TransCanada Pipelines Limited ("TransCanada") capacity that will deliver to PNGTS at East Hereford. The TransCanada capacity (k41235) that delivers to Waddington, NY will be turned back effective November 1, 2017 so that Northern can replace it with TransCanada capacity that delivers to East Hereford into PNGTS.

Effective November 1, 2017, the ‘Iroquois Receipts’ path will initiate at Iroquois (Waddington, NY). No changes to the Tennessee and Algonquin pipeline transportation capacity within this path have been made. Northern will determine its ongoing need for the Iroquois capacity on a year to year basis as it continues to monitor the progress of the proposed Constitution Pipeline Project, which would provide supply for the TGP contracts within this path at Wright, NY. Deliveries made on TGP and AGT from this path feed Granite in Haverhill, MA as well as the Bay State Exchange at Agawam, MA and Brockton, MA.

Q. Please describe the changes to the Algonquin Receipts capacity path.

A. Effective November 1, 2017, Northern will recall its Texas Eastern Transmission, LP (“TETCO”) capacity which had been under a long term release in the secondary capacity release market. Northern will combine the TETCO capacity with its Algonquin long-haul capacity providing access to Leidy storage in Pennsylvania, which is a liquid supply hub. Northern’s Algonquin contract includes receipt capacity at the interconnection between Algonquin and TETCO’s Zone M3 at Lambertville, NJ and at the interconnection between Algonquin and Transcontinental Gas Pipe Line (“Transco”) in Zone 6 at Centerville, NJ. This capacity has primary delivery rights to Bay State’s Algonquin city-gate at Taunton, MA. Northern utilizes this capacity as a winter baseload in order to supply the Bay State Exchange.

Q. Does this conclude your testimony?

A. Yes it does.