NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL 2018-2019
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 2018-2019 fixed, annual demand cost estimates are $35,735,528, which is 9% higher than the fixed, annual demand cost estimates provided for 2017-2018 in the Annual COG initial filing. Estimated average delivered commodity rates for the 2018-2019 Winter Period are $4.341 per Dth, which is 4% higher than the average delivered commodity rates estimated for the 2017-2018 Winter Period in the Annual COG. Estimated average delivered commodity rates for the 2019 Summer Period are $2.441 per Dth, which is 10% lower than the average delivered commodity rates estimated in last year's Annual COG. I discuss reasons for these changes in gas supply cost in the body of my testimony.

Northern projects 2018-2019 combined annual sales service and delivery service distribution deliveries to be 8,736,780 Dth in the New Hampshire Division, which is an increase equal to 2.8% compared to 2017-2018 annual weather-normalized distribution deliveries and an increase equal to 6.0% compared to 2016-2017 annual weather-normalized distribution deliveries. Of the 8,736,780 Dth of projected distribution system deliveries, Northern projects that 4,298,458 Dth will be supplied by the Company through Sales Service. In order to supply 4,298,458 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,362,075 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 171,356 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,533,431Dth for the upcoming annual period. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Schedule 12 shows Northern's portfolio has a 128,344 Dth maximum daily quantity of Pipeline, Storage and Peaking Capacity (each of these Capacity terms as defined in the

Company's Maine Division Delivery Service Terms and Conditions). In April 2018, Northern successfully transitioned from Washington 10 storage in Michigan to Union Dawn storage in Ontario, Canada. I review the 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 $35,735,528. (*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 between Winter and Summer Season COG rates. I project the demand revenue from the New Hampshire Division's capacity assignment program to be $3,258,243. (*See* Schedule 5B). I also discuss the calculation of the updated capacity allocation factors and Capacity Ratio 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 2018-2019 Winter Period will be $39,571,017 at an average rate equal to $4.311 per Dth and the 2019 Summer Period commodity costs to be $5,680,320 at an average rate equal to $2.439 per Dth. (*See* Schedule 6A). Mr. Kahl calculates the allocation of these costs to the New Hampshire Division.

I provide the supporting calculations for 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. These rates have been calculated consistent the New Hampshire Delivery Service Terms and Conditions, as updated in Docket No. DG 17-104.

Finally, I provide an overview of proposed changes to the Peaking Service Demand Charge.

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 2018-2019 Winter and Summer Period.

Table 1. 2018-2019 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years

Month	2018-2019 Forecast[1]	2017-2018 Actual[2]	2018-2019 minus 2017-2018	Percent Change	2016-2017 Actual[2]	2018-2019 minus 2016-2017	Percent Change
Nov	717,704	681,817	35,887	5.3%	664,929	52,775	7.9%
Dec	933,244	932,460	784	0.1%	910,231	23,012	2.5%
Jan	1,293,866	1,228,507	65,359	5.3%	1,169,554	124,312	10.6%
Feb	1,267,828	1,231,407	36,421	3.0%	1,164,164	103,664	8.9%
Mar	1,045,573	1,043,397	2,176	0.2%	1,035,769	9,803	0.9%
Apr	881,516	826,476	55,040	6.7%	803,777	77,739	9.7%
May	602,510	574,552	27,959	4.9%	568,537	33,974	6.0%
Jun	386,934	399,882	-12,948	-3.2%	385,479	1,456	0.4%
Jul	399,733	384,003	15,730	4.1%	387,504	12,229	3.2%
Aug	382,551	378,753	3,799	1.0%	366,064	16,487	4.5%
Sep	363,501	365,109	-1,607	-0.4%	356,844	6,658	1.9%
Oct	461,821	448,653	13,168	2.9%	427,725	34,095	8.0%
Winter	6,139,730	5,944,063	195,667	3.3%	5,748,425	391,304	6.8%
Summer	2,597,051	2,550,951	46,100	1.8%	2,492,152	104,898	4.2%
Annual	8,736,780	8,495,014	241,767	2.8%	8,240,578	496,203	6.0%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data through May 2018. Projected data beginning June 2018.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2018-2019 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 2018-2019 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2017-2018 and 2016-2017 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 2018. For small and medium Delivery Service customers (G40, G50, G41 and G51 rate classes) Northern weather normalized the billed usage of these specific customers. For large Delivery Service customers (G42 and G52 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-18	828,021	423,274	429,453	26,400	455,853
Dec-18	1,121,187	662,765	672,439	29,560	701,999
Jan-19	1,296,608	802,113	813,822	32,410	846,232
Feb-19	1,126,633	676,567	686,443	26,920	713,363
Mar-19	1,052,445	597,813	606,539	28,420	634,959
Apr-19	714,836	326,458	331,223	4,830	336,053
May-19	511,656	174,994	177,548	3,844	181,392
Jun-19	345,363	119,085	120,823	3,720	124,543
Jul-19	393,916	99,676	101,131	3,844	104,975
Aug-19	384,934	100,830	102,302	3,844	106,146
Sep-19	383,225	105,407	106,946	3,720	110,666
Oct-19	577,958	210,335	213,405	3,844	217,249
Winter	6,139,730	3,488,990	3,539,919	148,540	3,688,459
Summer	2,597,051	810,328	822,156	22,816	844,972
Annual	8,736,780	4,299,318	4,362,075	171,356	4,533,431

[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. Northern achieves this transfer by either releasing capacity directly to the retail marketer ("Capacity Release") or by selling the supply to the retail marketer and billing the pro-rated demand and commodity cost ("Company Managed Sales"). Under the Delivery Service Terms and Conditions for the New Hampshire Division, Pipeline Capacity and Storage Capacity are assigned as a Company Managed Sales if Northern in contractually prohibited from releasing the

Capacity or if the Capacity cannot physically reach Northern's system. For Pipeline and Storage Capacity, the Company Managed Supplies include:

- Iroquois Receipts Capacity that requires the Bay State Exchange (841 out 6,434 Dth of this capacity path physically reaches Northern and does not require the Bay State Exchange.)
- Algonquin Receipts Capacity (Leidy Hub and Transco Zone 6, non-NY) that requires the Bay State Exchange

The Delivery Service Terms and Conditions limit Peaking Capacity Company Managed Sales to the on-system LNG plant. Northern has discontinued the practice of assigning off-system peaking contracts and has replaced this with a Capacity Release from its Granite capacity contract.

Q. Please explain the process used to project Company Managed Sales for the New Hampshire Division.

A. The maximum daily volume of each Company Managed Supply, listed above, 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 and peaking Company managed supply available to them under the capacity assignment program.

Q. Why are there no storage Company Managed resources for 2018-2019?

A. Since Northern's new underground storage contract with Union began April 1, 2018, all storage capacity resources have been assigned via capacity release. This results in a significant decrease in Northern's Company Managed obligations going forward.

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 its Capacity Assignment 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
Total Pipeline Capacity	23,121
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
Maritimes Delivered Baseload	7,474
PNGTS Delivered Baseload (Dec-Feb)	7,474
Peaking Contract 1	39,860
Additional Granite Capacity	1,408
Total Peaking Capacity	62,716
Total Design Day Capacity	128,344

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2018-2019 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

Schedule 12 includes 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.

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 2018-2019 includes a single short-term peaking contract. This peaking supply arrangement was procured through a Request-For-Proposals ("RFP") and has a delivery period beginning November 2018 and ending March 2019. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which Northern relies on to produce up to 6,500 Dth per day with a maximum 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 2018 and ending October 2019 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. Please describe the addition of Union Storage to Northern's portfolio.

A. As discussed in the 2017-2018 Annual COG filing, Northern has replaced its Washington 10 Storage contract located in Michigan with Union Storage in Dawn, Ontario, as of April 1, 2018. The Union Dawn Storage contract allows Northern the flexibility to release capacity to its retail marketers, rather than relying on the Company Managed form of Capacity Assignment. This transition has gone smoothly with retail marketers now having direct control over the Union Dawn Storage capacity path allocated to them, including the downstream transportation capacity needed to move gas from Union Dawn to Northern's city-gates.

Q. Please provide an update on Northern's Precedent Agreement for the Atlantic Bridge Project.

A. As discussed in Northern's 2016-2017 and 2017-2018 Annual COG filing, Northern entered into an assignment agreement with Emera Energy Services, Inc. under which it takes assignment of a Precedent Agreement between Algonquin and Emera for 7,599

Dth of Atlantic Bridge capacity. This assignment agreement includes an obligation by Northern to pay Emera a one-time commission of $375,000 for assigning the 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 in Beverly, MA 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. Upon Algonquin's request, Northern has agreed to an amendment to the Atlantic Bridge Precedent Agreement, moving the latest allowable in-service date of the project from November 1, 2019 to November 1, 2020.

The Atlantic Bridge project is not expected to be completed for the 2018-2019 Annual Period. As such, Northern will continue to purchase Maritimes Delivered Baseload supplies to meet its customer demand requirements.

Q. Please describe the Company's Precedent Agreement for the Portland XPress Project.

A. Northern has entered into a Precedent Agreement with Portland Natural Gas Transmission System ("PNGTS") for firm natural gas transportation capacity on Phase III of the Portland XPress Project ("PXP PA" or the "Agreement"). The PXP PA will provide Northern the ability to transport 10,000 Dth/day of natural gas from the Dawn Hub in

Ontario, Canada to Granite at Newington, New Hampshire and other delivery points on the PNGTS system for a 20 year initial term, with an option to extend. The projected in-service date for Phase III of Portland XPress is November 1, 2020.

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 completed its annual RFP process for the delivery period of April 1, 2018 through March 31, 2019 when it 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 completed its RFP process for off-system peaking supplies and LNG supplies when it entered into contracts for the upcoming winter.

Q. Please describe any other changes in Northern's portfolio for the upcoming 2018-2019 Winter compared to the portfolio relied upon for the 2017-2018 Winter.

A. Other changes in the portfolio include the following items.

1. Northern has increased its Off-System Peaking Contracts from 32,386 Dth to 39,860 Dth. This increased volume is primarily needed due to higher observed peak day requirements during the 2017-2018 Winter Period, leading to relatively higher Design Day requirements.
2. Northern has added a PNGTS Delivered Baseload Supply of 7,500 Dth per Day for December through February for the 2018-2019 Winter Period, which was not part of the winter portfolio for 2017-2018. Also, Northern has increased the

duration of its 7,500 Dth per Day Maritimes Delivered Baseload Supply from December through February to November through March. Increased baseload supply purchases will aid in limiting exposure to daily spot prices, which continue to be highly volatile in peak winter weather conditions.

3. The TCPL, PNGTS and GSGT transportation contracts that made up the Dawn Supply path for 2017-2018 have been moved to the Union Dawn Storage path. This change was anticipated as the incremental TCPL and PNGTS transportation contracts went into service last winter while the Union Dawn Storage contract did not go into service until April 2018. The Union Dawn Storage path is now fully in place, with maximum daily deliverability to Northern of 39,863 Dth, an increase over the Washington 10 deliverability of 33,881 Dth.

4. Northern is changing its supply plan for its Tennessee Contract 5083 (Tennessee Zone 0 and Zone L capacity path - 13,155 Dth). In prior winters, Northern has used this capacity to ship baseload supplies from the Tennessee Zone 4 200 Leg Pool (Station 219 located in Pennsylvania) for 5,000 Dth of this capacity to either the interconnection between Tennessee and Granite at Pleasant St. or Bay State's city-gates as exchange gas. The remainder of the capacity (after Maine and New Hampshire capacity assignment releases) was used to ship daily swing supplies at the primary receipt points in Tennessee Zones 0 and L (located in Texas and Louisiana), through an asset management agreement. For the 2018-2019 Winter Period, Northern will change its utilization of Tennessee Contract 5083, replacing the 5,000 Dth of Tennessee Zone 4 200 Leg Pool (Pennsylvania) baseload supply with 5,000 Dth Tennessee Zone 0 and L (Texas and Louisiana) baseload supply. This supply will be purchased through an asset management agreement. This change will increase the priority of service of this supply to Primary In-Path (the highest priority). This change is necessary due to the

increasing constraints and restrictions on Tennessee (due to increasing pipeline utilization), which have caused increasing curtailments of Secondary In-Path priority service.

5. Finally, Northern has increased the daily refill capability of its LNG Contract from 3 trucks per day (approximately 3,000 Dth) to 5 trucks per day (approximately 5,000 Dth). This will aid in being able to keep the Lewiston LNG plant supplied during cold weather events, like that which occurred last winter in late December to mid-January.

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 2018-2019 Annual 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 2018 through October 2019
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2018 through October 2019
- Northern's commodity costs for the period November 2018 through October 2019

The allocation of Northern's fixed demand and commodity 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, 2018 through October 31, 2019

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 5,933,077	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 21,768,704	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 2,979,855	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 2,186,690	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 9,888,800	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (7,021,600)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 35,735,528	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 Capacity 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 2018-2019 Annual Period. 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 2018-2019 Winter COG forecasted annual demand costs compare with the 2017-2018 Winter COG forecasted annual demand costs?

A. 2015-2016 Winter COG forecasted annual demand costs were equal to $32,773,052. 2017-2018 Winter COG forecasted annual demand costs are equal to $35,735,528, reflecting an increase in forecasted annual demand costs equal to $2,962,476 or approximately 9%.

The increase in projected demand costs is attributable to an increase in projected Peaking Supply Demand costs equal to $7,777,363. Projected Peaking Supply Demand costs are higher due to increased Off-System Peaking Contract volumes (as discussed above as a change in the Winter Period portfolio) as well as increased demand prices seen through Northern's RFP process. Northern has also purchased peaking supply contracts that avoid exposure to daily index prices, which also contributes to the increase in demand costs for this portion of supply.

The decrease in projected peaking supply contract costs is partially offset by the following.

1. <u>Decrease in projected pipeline contract costs by $2,070,032.</u> Lower projected pipeline contract costs are attributable to the termination of the Vector contracts and the restructuring of the TCPL Contract 33322 (Dawn to East Hereford), which were discussed in the 2017-2018 Winter Period CGF filing. These changes both began April 1, 2018 and provided 7 months of savings for 2017-2018. Annual savings from these changes will increase in 2018-2019 since they will be in effect for the full year.
2. <u>Increase in projected Asset Management Agreement revenue credits by $2,776,522.</u> Higher AMA revenue reflects the results of Northern's annual RFP process, reflecting higher overall value obtained through asset management agreements. It also reflects that at the time of filing the 2017-2018 Annual COG, Northern had not yet secured Asset Management Agreements for Iroquois Receipts and the Dawn Supply capacity paths, since the PNGTS C2C capacity was not yet approved by FERC.

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 2018-2019 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $3,258,243.

Q. Have you calculated the proposed Peaking Service Demand Charge to be billed to retail marketers for the period November 2017 through April 2018?

A. Yes. The calculation of Peaking Service Demand Charge rate is provided on page 6 of Schedule 5B. The proposed Peaking Service Demand Charge is equal to $50.35 per Dth, as shown in Schedule 5B and presented in the proposed revised Appendix A (Page 153) to the Delivery Service Terms and Conditions. The Proposed Peaking Service Demand Charge rate is applicable only to capacity assignment of the Company's on-system LNG plant.

Q. Please provide the Capacity Allocation Factors and Capacity Ratio to be used for Capacity Assignment under the New Hampshire Division Delivery Service tariff for effect November 1, 2018.

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.

These Capacity Allocation Factors reflect a Capacity Ratio equal to 0.989, which is equal to Total Design Day Capacity of 128,344 Dth divided by the Total Design Day Planning Load of 129,819 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 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. 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 2018-2019 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 2018 through April 2019			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 12,295,776	3,556,660	$ 3.457
Storage Resources	$ 9,504,825	3,359,925	$ 2.829
Peaking Resources	$ 18,126,305	2,262,593	$ 8.011
Total Commodity Costs	$ 39,926,906	9,179,179	$ 4.350
Company Managed Revenue	$ (1,035,298)	(219,252)	$ 4.722
Net Sales Service Commodity Costs	$ 38,891,608	8,959,927	$ 4.341

In summary, net projected delivered commodity costs equal approximately $38.9 million at an average delivered rate of $4.341 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 2018-2019 COG forecasted Winter Period (November through April) commodity costs compare with the 2017-2018 COG forecasted Winter Period commodity costs?

A. As show in Table 5, above, the 2018-2019 Winter COG forecasted Winter Period commodity costs are equal to $39,571,017 at an average delivered rate of $4.211 per Dth. The 2017-2018 Winter COG forecasted Winter Period commodity costs were equal to $37,236,342 at an average delivered rate of $4.173 per Dth. 2017-2018 forecasted Winter Period average unit commodity costs are 4% higher than 2017-2018 forecasted Winter Period.

Q. Please explain why projected Winter Period delivered commodity costs are increasing compared to the estimate provided in the last Annual COG filing.

A. The increase in projected delivered commodity costs is attributable to an increase in PNGTS and Maritimes Delivered Baseload Supplies in 2018-2019 compared to 2017-2018. Total projected volume of PNGTS and Maritimes Delivered Baseload supplies are increasing from 675,000 Dth in the 2017-2018 Winter Period CGF to 1,805,138 Dth for 2018-2019. As I discussed when explaining the changes in the supply portfolios for 2018-2019, increased Delivered Baseload supplies will aid in avoiding exposure to daily spot prices, which were extremely high and volatile last winter. While PNGTS and Maritimes Delivered Baseload supplies are expensive relative to Pipeline and Storage Resources, the 2018-2019 Winter Period supply plan under which baseload supplies are procured in advance of the heating season will aid in preventing the need for mid-winter baseload supply purchases, as occurred in the 2017-2018 Winter Period.

Please note that I have reclassified the PNGTS and Maritimes Delivered Baseload Supplies from Pipeline Resources to Peaking Resources in the 2018-2019 presentation. This change was made because the Granite Capacity used to move PNGTS and

Maritimes Delivered Baseload Supplies into Northern's system are already categorized as Peaking Capacity under Northern's Delivery Service Terms and Conditions.

Increases in Delivered Baseload Supply volumes are partially offset by a decrease in NYMEX prices. NYMEX prices for the respective November through April Winter Periods declined from $3.17 per Dth to $3.06 per Dth, a decrease equal to 3.5%. This contributed to lower projected supply cost for Pipeline Resources and lower projected inventory costs for Storage Resources for 2018-2019 compared to 2017-2018.

Q. Please present the Company's commodity cost forecast for the 2019 Summer Period.

A. I have summarized Northern's commodity cost forecast for the 2019 Summer Period in Table 6, below.

Table 6. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2019 through October 2019

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 5,588,824	2,316,392	$ 2.413
Storage Resources	$ -	-	
Peaking Resources	$ 88,655	12,880	$ 6.883
Total Commodity Costs	$ 5,677,479	2,329,272	$ 2.437
Company Managed Revenue	$ (74,579)	(33,488)	$ 2.227
Net Sales Service Commodity Costs	$ 5,602,900	2,295,784	$ 2.441

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 2018-2019 COG forecasted 2019 Summer Period (May through October) commodity costs compare with the 2018-2019 COG forecasted Summer Period commodity costs?

A. The 2018 Summer COG forecasted commodity costs were equal to $6,195,652 at an average delivered rate of $2.696 per Dth. 2019 forecasted Summer Period average unit commodity cost is 10% lower than the 2018 forecasted Summer Period average unit commodity cost. This decrease is explained primarily by lower NYMEX natural gas futures prices, which are projected to be $2.93 per Dth for the 2019 Summer Period and were projected to be $2.65 per Dth for the 2018 Summer Period, a decrease equal to 10%.

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 2017 through October 2018.

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

V. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES

Q. Please describe the proposed Re-entry Surcharge.

A. The Re-entry Surcharge is applicable to Capacity Assigned Delivery Service Customers, who choose to return to Sales Service. The Re-entry Surcharge equals zero except for reversals of any prior period credits or refunds reflected in the Company's Cost of Gas. The Re-entry Surcharge cannot be negative and therefore would not provide credits for prior period under-collections. A single Re-entry Surcharge is established for High Load Factor and Low Load Factor customers.

Q. Please provide the proposed Re-entry Surcharge and supporting calculations.

A. The calculation of the Re-entry Surcharge is based on the premise that capacity assigned Delivery Service customers returning to Sales Service should pay the current cost of gas rate less any credits or refunds for the costs that were not incurred when the customer was on Delivery Service. Please refer to Page 1, lines 1 through 7 of Schedule 20, which shows the calculation of the proposed Re-entry surcharge for the 2018-2019 Winter Season. This rate is applicable to both High Load Factor and Low Load Factor Delivery Service customers.

Lines 1 through 4 determine the Winter Cost of Gas Rate, exclusive of prior period credits. Lines 1 and 2 show the Winter Demand Cost of Gas and Winter Commodity Cost of Gas, respectively. Line 3 shows the Winter Indirect Cost of Gas, reflecting the removal of any prior period over recovery. The weighted average Winter Cost of Gas Rate (Exclusive of Credits) is shown on line 4. This is compared to the Winter Cost of Gas Rate for Incumbent Sales Service Customers shown on Line 5. Line 6 shows the proposed Re-entry Surcharge for the upcoming Winter Period, which is equal to the positive difference (if any) between Line 5 and Line 4. The proposed Winter Period Re-entry Surcharge is $0.0000 per therm, since the proposed COG does not include prior period over-recoveries or supplier refunds.

Lines 8 through 11 determine the Summer Cost of Gas Rate, exclusive of prior period credits. Lines 9 and 9 show the Summer Demand Cost of Gas and Summer Commodity Cost of Gas, respectively. Line 10 shows the Summer Indirect Cost of Gas, reflecting the removal of any prior period over recovery. The weighted average Summer Cost of Gas Rate (Exclusive of Credits) is shown on line 11. This is compared to the Summer Cost of Gas Rate for Incumbent Sales Service Customers shown on Line 12. Line 13 shows the proposed Re-entry Surcharge for the upcoming Winter Period, which is equal to the positive difference (if any) between Line 12 and Line 11. The proposed Summer Period Re-entry Surcharge is $0.0000 per therm, since the proposed COG does not include prior period over-recoveries or supplier refunds.

Q. Please describe the proposed Conversion Surcharge.

A. The Conversion Surcharge is applicable to Capacity Exempt Delivery Service Customers, who choose to return to Sales Service. During the Winter Period, the Conversion Surcharge is set to charge these customers the higher of the Sales Service rate applicable to Low Load Factor Customers or the incremental cost of supply. Conversion Surcharges are calculated separately for high load factor customers and low load factor customers during the Winter Period. During the Summer Period, the Conversion Surcharge is equal to the Re-entry Surcharge. Like the Re-entry Surcharge, Conversion Surcharges would also be set to remove any prior period credits.

Q. Please provide the proposed Conversion Surcharge and supporting calculations.

Page 2 of Schedule 20 shows the proposed Conversion Rate surcharge for the 2018-2019 Winter Cost of Gas. 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 subject to Capacity Assignment for the 2018-2019 Winter Period.

Please refer to the section of Page 2 with the heading, "Winter Period Conversion Surcharge Calculation." The Total Incremental Cost on Line 5 is compared to the Floor Price on Line 4. Total Incremental Cost is calculated on page 3 of Schedule 20, the Incremental Commodity Price Worksheet. The Floor Price is equal to the Winter Cost of Gas Rate, applicable to Low Load Factor customers, exclusive of prior period credits, which is calculated by summing Lines 1 through 3 above. Lines 1 and 2 are the Winter Demand Cost of Gas Rate and Winter Commodity Cost of Gas Rate, applicable to Low Load Factor customers. Line 3 shows the Low Load Factor Winter Cost of Gas, recalculated to remove any prior period over collection. The Total Conversion Rate on Line 6 is calculated by taking the maximum of Line 4 and Line 5. The positive difference between the Total Conversion Rate on Line 6 and the Winter Cost of Gas Rate for Incumbent Sales Service customers on Line 7 is provided on Line 8, the Conversion Surcharge. The proposed 2018-2019 Winter Period Conversion Surcharge is $0.1211 per therm for HLF customers and $0.0041 per therm for LLF customers. The proposed 2018 Summer Period Conversion Surcharge is equal to the 2018 Summer Period Re-entry Surcharge, $0.0000 per therm for both HLF and LLF customers.

Incremental Commodity Price Worksheet estimates the price to serve Northern's non-capacity assigned loads with incremental supply resources. Page 3 provides the Incremental Commodity Price Worksheet. Lines 1 through 6 provide the projected prices, consistent with the price forecast in Attachment 1 to Schedule 5A, along with

Northern's projected Non-Capacity Assigned Delivery Service Loads. The prices were derived based on NYMEX natural gas futures contracts and the Algonquin basis futures contracts. Algonquin city-gate pricing plus $0.50 per Dth is used as a proxy for the incremental PNGTS delivered supplies that would be needed to serve this additional demand. Projected Non-Capacity Assigned Delivery Service Loads were calculated on Page 11. Line 6 provides the average price for the six Winter Period months, November through April, weighted by the Non-Capacity Assigned Delivery Service Loads. Because Delivery Service customer demands fluctuate with weather, the average price is adjusted on Line 9 by a Load Shape Price Factor (Line 8). Lines 10 through 12 add Granite transportation costs. Lines 13 and 14 convert from a Northern city-gate price ($ per Dth) to a Northern-New Hampshire retail meter price ($/Dth). Finally, the price is converted to $ per therm.

The purpose of the Load Shape Price Factor Worksheet is to estimate the ratio between load following supply prices and baseload supply prices. Please refer to pages 4 through 10 of Schedule 20. The Load Shape Price Factor Worksheet first, provides historic Non-Capacity Assigned Delivery Service Loads observed last winter. Then, it calculates what the load-weighted Algonquin city-gate price for these loads and compares that to the straight daily average of the Algonquin city-gate prices for last winter. The ratio between the two for the last winter period is the Load Shape Price Factor used on Page 3.

Please refer to page 11 of Schedule 20. Capacity Assigned and Capacity Exempt Projected Delivery Service Loads were estimated based on individual customer forecasts. To determine the Non-Capacity Assigned Delivery Service Loads, I took 0% of the Capacity Assigned and 100% of the Capacity Exempt Projected Delivery Service Loads.

Q. Please describe the proposed changes to Section 14 (Peaking Service) of Northern's Delivery Service Terms and Conditions for New Hampshire.

A. Under the proposed change, the only LNG contracts assigned to retail marketers would be those that are included in Northern's annual notice to retail marketers of contracts that will be subject to Capacity Assignment. Any mid-winter LNG purchases would be for Sales Service customers only. Northern recenty implemented the same change to its Maine Delivery Service Terms and Conditions, pursuant to a Settlement Agreement between Northern and Direct Energy filed with the Maine Commission in Docket No. 2017-00202 and approved by the Maine Commission in Docket No. 2018-00124.

Q Please describe the reason for to this proposed change.

A. Northern believes that this proposed change will improve Northern's retail market for natural gas by improving cost certainty related to Peaking Service Demand costs to retail marketers operating in Northern's New Hampshire system. Retail marketers will continue to be responsible for balancing scheduled supplies with their customer's daily and monthly supply requirements. The change will also ensure consistency between the Company's Maine and New Hampshire tariffs.

Q. Could this change result in a misallocation of costs incurred by Delivery Service customers to Sales Service customers.

A. No. Northern will consider only Sales Service requirement when evaluating any mid-winter LNG purchases. To the extent that Northern elects to enter into mid-winter LNG purchases, it will consider only the sendout requirements of its Sales Service customers, thus avoiding any misallocation of LNG contract costs.

Q. Does this conclude your testimony?

A. Yes it does.