NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ANNUAL 2017-2018
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 2017-2018 fixed, annual demand cost estimates are $32,773,052, which is 10% higher than the fixed, annual demand cost estimates provided for 2016-2017 in the Annual COG initial filing. Estimated average delivered commodity rates for the 2017-2018 Winter Period are $4.173 per Dth, which is 1% lower than the average delivered commodity rates estimated for the 2016-2017 Winter Period in the Annual COG. Estimated average delivered commodity rates for the 2018 Summer Period are $2.696 per Dth, which is 6% higher 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 2017-2018 combined annual sales service and delivery service distribution deliveries to be 8,611,015 Dth in the New Hampshire Division, which is an increase equal to 4.2% compared to 2016-2017 annual weather-normalized distribution deliveries and an increase equal to 5.4% compared to 2015-2016 annual weather-normalized distribution deliveries. Of the 8,611,015 Dth of projected distribution system deliveries, Northern projects that 4,273,555 Dth will be supplied by the Company through Sales Service. In order to supply 4,273,555 Dth of supply to customer's retail meters, Northern projects a city-gate requirement of 4,327,403 Dth. In addition, Northern expects its Company-Managed Sales obligation to equal 412,142 Dth for the New Hampshire Division, bringing the total projected New Hampshire sendout requirement to 4,739,545 Dth for the upcoming annual period. The details behind these estimates are contained in Attachments 1 and 2 to Schedule 10B.

Northern's portfolio has 128,344 Dth maximum daily quantity of Pipeline, Storage and Peaking Capacity, which is backed by 111,988 Dth of supply resources during the peak winter months, November through March. This total volume of Pipeline, Storage and

Peaking Capacity is the same as last year, but several significant changes to the Capacity portfolio are anticipated for the 2017-2018 gas year. These changes include the following.

- Anticipated turn-back of existing PNGTS contracts and new PNGTS contracts obtained through the PNGTS C2C Open Season, beginning November 1, 2017
- Anticipated turn-back of existing TCPL contract from Union (Parkway) to Iroquois (Waddington) and new TCPL contract from Union pipeline to PNGTS, beginning November 1, 2017
- Termination of pipeline transportation contracts with Vector and underground storage contract with Washington 10, ending March 31, 2018
- New storage contract with Union at the Dawn Hub, beginning April 1, 2018
- Restructuring of the TCPL contract from Union (Dawn) to PNGTS (East Hereford). Effective April 1, 2018, this contract will be replaced with a contract with Union from Dawn to Parkway (TCPL) and a contract with TCPL from Parkway to East Hereford.

The total volume of supply resources are down from 118,564 Dth in 2016-2017, resulting in a decrease equal to 6,576 Dth from the prior winter's maximum deliverability. This decrease is mostly attributable to a reduction in the off-system peaking contracts from 39,861 Dth to 32,386 Dth, reflecting the Company's proposal before the Commission in Docket No. DG 17-104 to discontinue assignment of off-system peaking contracts to retail marketers. The details behind Northern's portfolio are contained in Schedule 12.

In addition to the changes to its portfolio expected to be online for the 2017-2018 annual period, Northern is also has entered into a Precedent Agreement with Algonquin to participate in the Atlantic Bridge project. However, capacity from this expansion is not expected to be in-service during the 2017-2018 Annual Period. I discuss the 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 $32,773,052. (*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 COG rates. I project the demand revenue from the New Hampshire Division's capacity assignment program to be $3,165,518. (*See* Schedule 5B). I also discuss the calculation of the updated capacity allocation factors pursuant to the current New Hampshire Division capacity assignment program and Capacity Ratio pursuant to the proposals in DG 17-104.

I project that Northern's total company (including the Maine Division) commodity cost to provide sales service during the 2017-2018 Winter Period will be $ 37,236,342 at an average rate equal to $4.173 per Dth and the 2018 Summer Period commodity costs to be $6,195,652 at an average rate equal to $2.696 per Dth. (*See* Schedule 6A). I also calculated hedging program costs to be $280,875. (*See* Schedule 7). 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 with the proposal to update the New Hampshire Delivery Service Terms and Conditions in Docket No. DG 17-104.

Lastly, I calculate an adjustment to the allocation of off-system peaking demand costs between the New Hampshire and Maine Divisions, intended to assure an equitable allocation of these costs in light of changes to discontinue the assignment of these services to retail marketers in Maine, which was effective November 1, 2016 and the proposal to discontinue such assignments to retail marketers in New Hampshire effective November 1, 2017.

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 2017-2018 Winter and Summer Period.

Table 1. 2017-2018 Winter New Hampshire Division Billed Distribution Service Volumes Forecast Compared to Prior Years							
Month	2017-2018 Forecast[1]	2016-2017 Actual[2]	2017-2018 minus 2016-2017	Percent Change	2015-2016 Actual[2]	2017-2018 minus 2015-2016	Percent Change
Nov	700,579	666,138	34,440	5.2%	650,669	49,910	7.7%
Dec	942,253	908,053	34,200	3.8%	930,157	12,095	1.3%
Jan	1,247,556	1,167,440	80,116	6.9%	1,171,750	75,806	6.5%
Feb	1,253,684	1,168,051	85,633	7.3%	1,182,558	71,126	6.0%
Mar	1,100,889	1,039,001	61,887	6.0%	1,016,381	84,508	8.3%
Apr	853,662	801,958	51,704	6.4%	781,131	72,531	9.3%
May	591,835	568,537	23,298	4.1%	546,425	45,410	8.3%
Jun	384,303	385,479	-1,176	-0.3%	388,602	-4,299	-1.1%
Jul	339,973	387,504	-47,531	-12.3%	330,291	9,682	2.9%
Aug	358,456	349,605	8,851	2.5%	362,108	-3,652	-1.0%
Sep	359,118	363,128	-4,010	-1.1%	362,479	-3,361	-0.9%
Oct	478,708	461,400	17,308	3.8%	450,914	27,794	6.2%
Winter	6,098,622	5,750,642	347,980	6.1%	5,732,646	365,977	6.4%
Summer	2,512,392	2,515,653	-3,260	-0.1%	2,440,819	71,574	2.9%
Annual	8,611,015	8,266,294	344,720	4.2%	8,173,464	437,550	5.4%

Note 1: Company Forecast.
Note 2: Actual Weather-Normalized Data through July 2017. Projected data beginning August 2017.

I provide a detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2017-2018 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 2017-2018 Annual Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2016-2017 and 2015-2016 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 2017. 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-17	811,196	423,478	428,728	24,802	453,530
Dec-17	1,096,188	645,153	653,151	93,243	746,394
Jan-18	1,296,612	798,078	807,972	101,573	909,545
Feb-18	1,146,094	700,540	709,225	109,035	818,260
Mar-18	1,060,463	600,935	608,385	83,489	691,874
Apr-18	688,069	319,111	323,067	0	323,067
May-18	492,469	162,822	164,841	0	164,841
Jun-18	372,077	111,735	113,120	0	113,120
Jul-18	341,114	97,266	98,472	0	98,472
Aug-18	362,257	97,789	99,001	0	99,001
Sep-18	385,548	102,650	103,923	0	103,923
Oct-18	558,927	214,853	217,517	0	217,517
Winter	6,098,622	3,487,296	3,530,529	412,142	3,942,671
Summer	2,512,392	787,115	796,874	0	796,874
Annual	8,611,015	4,274,411	4,327,403	412,142	4,739,545

[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"). The Company Managed Sales forecast is based on the Company's proposal in DG 17-104. Under the proposed Delivery Service Terms and Conditions for the New Hampshire Division, Pipeline Capacity and Storage Capacity would be assigned as a Company Managed Sales if Northern is 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
- Washington 10, as the Washington 10 storage contract is not releasable

The proposed Delivery Service Terms and Conditions would limit Peaking Capacity Company Managed Sales to the on-system LNG plant. Northern proposes to discontinue the practice of assigning off-system peaking contracts and replace 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, 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 & Supply Summary (Dth/Day)

Pipeline Capacity Paths	
Tennessee Long-Haul	13,109
Tennessee Niagara	2,327
Iroquois Receipts	6,434
Dawn Supply (New TCPL, PNGTS C2C)	5,982
Leidy Supply (Texas Eastern, Algonquin)	965
Transco Zone 6, non-NY Supply (Algonquin)	286
Total Pipeline Capacity	29,103
Storage Capacity Paths	
Tennessee Firm Storage	2,644
Washington 10 Storage	33,881
Total Storage Capacity	36,525
Peaking Capacity Paths	
LNG - On-System	6,500
Maritimes Delivered Baseload	7,474
Peaking Contract 1	2,491
Peaking Contract 2	29,895
Additional Granite Capacity	16,356
Total Peaking Capacity	62,716
Total Design Day Capacity	128,344
Total Design Day Capacity Required	119,134
Design Day Capacity Excess/(Deficiency)	9,210
Total Design Day Supply (Total Capacity Less Additional Granite)	111,988
Total Design Day Supply Required	110,936
Capacity Excess/(Deficiency)	1,052

Table 3 presents a summary of the Pipeline, Storage and Peaking Capacity for the 2017-2018 Winter Period. Total Design Day Capacity is calculated by adding the total Pipeline, Storage and Peaking Capacity figures above.

This is then compared to Northern's projected Design Day Capacity Requirement, showing that Northern holds 9,210 Dth more Capacity than its design day planning load. The Design Day Capacity Requirement is calculated by adding Northern's Sales Service Design Day plus its Capacity Assigned Delivery Service Design Day requirements. Page 1 of Schedule 12 provides supporting calculations.

Total Design Day Supply is calculated by subtracting Additional Granite Capacity (listed in the Peaking Capacity section) from the Total Capacity. Total Design Day Supply is compared to the Total Design Day Supply Requirement, showing that Northern anticipated 1,052 Dth more supply than it needs on design day. Total Design Day Supply Requirement was calculated by subtracting projected assignment of Granite capacity without any upstream Pipeline or Storage Capacity ("Granite Only") to both Maine and New Hampshire retail marketers. Details of these calculations are also included on Schedule 12.

Subsequent pages of Schedule 12 include capacity path diagram and capacity path detail for each of the supply sources listed above, showing the transportation, storage and supply contracts required to provide the Northern 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"), 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"), Tennessee and Texas Eastern. 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 2017 and ending March 2018. 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 is currently in the process of completing an RFP for LNG beginning November 2017 and ending October 2018 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 discuss the end of the long-term release of Texas Eastern Contract 800384.

A. Northern's long-term release of its Texas Eastern Contract 800384 ends October 31, 2017. This contract provides 965 Dth of capacity from Leidy Storage in Zone M-3 to Lambertville, NJ, which matches up with the 965 Dth of the 1,251 Dth of Algonquin Contract 93201A1C. The Company will be able to use this capacity to replace purchases at Lambertville with lower-priced supplies at Leidy Storage, beginning November 1, 2017.

Q. Please discuss the anticipated turn-back of existing PNGTS Capacity and procurement of PNGTS C2C Capacity.

A. Northern has previously entered into a Precedent Agreement with PNGTS for 15-year contracts, with service expected to begin November 1, 2017. These contracts are for 34,000 Dth (part of the W-10 Capacity Path) and 6,003 Dth (part of the Dawn Supply Capacity Path), respectively. Although no construction is required, PNGTS requires FERC approval of an increase in its certificated capacity. This approval is still pending. The demand and commodity cost projections included in my testimony presume FERC approval of this request and timely implementation of the new transportation contracts. Upon implementation of the new PNGTS contracts, existing PNGTS contracts 1997-003 (1,100 Dth) and 1997-004 (33,000 Dth winter only) would be turned back to PNGTS. In the event that FERC approval is delayed, Northern will use its existing PNGTS capacity to ship purchases under the Washington 10 AMA to Granite for the 2017-2018 Winter Period. Northern will wait until FERC approves PNGTS' requested increase in certificated capacity and the contracts contemplated by the Precedent Agreement are executed before contracting under an RFP for both the Dawn Supply and Iroquois Receipts asset management agreements. If such approval is delayed, Dawn Supply could be used to feed the Bay State Exchange, using existing Union and TCPL capacity to feed Iroquois and downstream Tennessee and Algonquin Capacity found on Page 4 of Schedule 12. This would reduce the total deliverability into Granite on PNGTS and the Company would purchase incremental PNGTS Delivered supplies.

Q. Please discuss the anticipated turn-back of existing TCPL Capacity from Union (Parkway) to Iroquois (Waddington) and procurement of TCPL Capacity from Union to PNGTS (East Hereford).

A. Northern has previously entered into a Precedent Agreement with TCPL for 6,333 GJ (6,003 Dth) of capacity from Union (Parkway) to PNGTS (East Hereford). This capacity is anticipated to be in-service effective November 1, 2017 and is planned to be part of the Dawn Supply Capacity path, as presented on Page 5 of Schedule 12. TCPL has previously received approval for the pipeline upgrades required by this new contract and is now in the construction phase of this project. When this capacity goes into service and contracts contemplated by the Precedent Agreement are executed, Northern will turn back its existing 6,264 GJ (5,937 Dth) of TCPL Capacity from Union (Parkway) to Iroquois. Any delays in the in-service date of this capacity would trigger the re-routing of Dawn Supply and incremental need for PNGTS Delivered Supply discussed in reference to the event of a delay in PNGTS C2C contracts.

Q. Please explain the termination of Vector pipeline capacity and Washington 10 underground storage contracts.

A. Northern's Vector and Washington 10 contracts are due to terminate in accordance with their own terms effective April 1, 2018. Northern determined through an RFP process that it would be more cost effective to purchase underground storage capacity at the Dawn Hub, rather than continue to purchase Washington 10 and Vector capacity. As part of this transition, Northern will need to ensure that its Washington 10 capacity is empty before the storage contract terminates. Northern has decided not to enter into PNGTS Delivered Baseload supply contracts in advance of the 2017-2018 Winter Period in order to have the flexibility to meet this contractual requirement.

Q. Please describe the addition of Union Storage to Northern's portfolio.

A. Union Storage was selected through an RFP process for a 5-year storage contract beginning April 1, 2018. The Maximum Daily Withdrawal Quantity will be 42,800 Dth and the Maximum Storage Volume will be 4,000,000 Dth, compared to the current Washington 10 withdrawal volume of 34,000 Dth and storage space volume of 3,400,000 Dth. In order to ship this higher volume of storage gas, the Dawn Supply (Schedule 12, page 5) capacity will be utilized as Storage Capacity beginning November 1, 2018 (the first withdrawal season for the new storage contract) in addition to the portions of the current Washington 10 Capacity Path that will be remaining at that time. Also, pro-rated shares of the new Union Storage contract will be assignable to both retail marketers and asset managers, consistent with the proposal in Docket No. DG 17-104 to remove the restriction on releasing Canadian capacity. Therefore, effective with the implementation of this new storage contract on April 1, 2018, the Company will begin releasing pro-rated shares of the new Union Storage capacity and downstream Union, TCPL, PNGTS and Granite transportation contracts.

Q. Please describe the restructuring of the TCPL Contract 33322 planned to be effective April 1, 2018.

A. Currently, TCPL Contract 33322 provides 35,872 GJ (34,000 Dth) of capacity from Dawn to East Hereford. Effective April 1, 2018, TCPL Contract 33322 will be amended to change the receipt point from Dawn to Parkway. Northern’s contract quantity with Union from Dawn to Parkway will increase by 36,522 GJ (34,616 Dth) to replace this portion of the TCPL contract including corresponding fuel. 35,872 GJ (34,000 Dth) of this increase was effectuated by an assignment of Union Transmission By Others (“TBO”) capacity from TCPL to Union and the remaining 650 GJ (616 Dth) was procured through a Precedent Agreement between Northern and Union to cover the fuel loss across TCPL to PNGTS. This change is expected to result in demand cost savings.

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

A. As discussed in Northern's 2016-2017 Annual COG filing, Northern entered into an assignment agreement with Emera Energy Services, Inc. under which it took 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 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.

The Atlantic Bridge project is not expected to be completed for the 2017-2018 Annual Period. As such, Northern will continue to purchase Maritimes Delivered Baseload supplies to meet its Lewiston, ME demand requirements.

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, 2017 through March 31, 2018. Northern has entered into asset management agreements for its Algonquin Receipts capacity path (both Leidy and Transco Zone 6, non-NY portions), 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 off-system peaking supplies and is in the process of completing its LNG RFP for the upcoming winter. Northern will issue an RFP for asset management agreements for its Iroquois Receipts and Dawn Supply when in-service dates for PNGTS C2C and TCPL expansions are known and firm contracts are executed to complete these capacity paths.

Q. Please describe any other changes in Northern's portfolio for the upcoming 2017-2018 Winter compared to the portfolio relied upon for the 2016-2017 Winter.

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

1. Northern has decreased its Off-System Peaking Contracts by approximately 7,500 Dth over the 2016-2017 Winter portfolio. Lower Off-System Peaking Contract purchases reflect higher anticipated Pipeline Capacity and Storage Capacity volumes due to the PNGTS C2C capacity noted above and the proposal to discontinue assignment of Off-System Peaking Contracts to retail marketers in New Hampshire.
2. For the 2016-2017 Winter Portfolio, Northern had purchased 5,000 Dth per day of PNGTS supply for November through March. The 2017-2018 Winter Period portfolio does not reflect this purchase. The supply is replaced by the Dawn Supply through the C2C capacity, discussed above. 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.

3. The delivery period for Maritimes Delivered Baseload has been reduced from November through March for the 2016-2017 Winter Period to December through February for the 2017-2018 Winter Period. This will provide Northern with additional flexibility, while still assuring adequate supplies during the highest demands of the Winter Period. Northern will continue to assess need for additional supplies throughout the season.

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 2017-2018 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 2017 through October 2018
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2017 through October 2018
- Northern's commodity costs for the period November 2017 through October 2018
- Northern's financial hedging program costs period November 2017 through March 2018

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 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, 2017 through October 31, 2018

Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 9,265,284	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 20,506,530	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,000,689	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	$ 2,058,938	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (4,245,078)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 32,773,052	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 2017-2018 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 2017-2018 Winter COG forecasted annual demand costs compare with the 2016-2017 Winter COG forecasted annual demand costs?

A. 2015-2016 Winter COG forecasted annual demand costs were equal to $29,731,468. 2017-2018 Winter COG forecasted annual demand costs are equal to $32,773,052, reflecting an increase in forecasted annual demand costs equal to $3,041,583 or approximately 10%.

The increase in projected demand costs is attributable a decrease in projected AMA credits equal to $5,787,118. Projected AMA credits are lower due to the results of Northern's request for proposals process. There may be a modest increase in the projected AMA credit when the RFP for Dawn Supply and Iroquois Receipts Capacity Paths are issued and completed following PNGTS C2C and TCPL capacity contract execution discussed above.

The decrease in projected AMA credits is partially offset by the following.

1. <u>Decrease in projected peaking contract demand costs equal to $1,331,063.</u> Peaking supply contract costs are lower than 2016-2017 due to lower volumes purchased and lower unit demand costs through the 2017-2018 RFP.
2. <u>Decrease in projected pipeline contract costs by $1,385,305.</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), discussed above. Annual savings from these changes will increase in 2018-2019 when they will be in effect for the full year.
3. <u>Decrease in projected storage contract costs by $29,167.</u> Annual Union Storage demand charges will be lower than the current Washington 10 contract even at the higher storage capacity volumes purchased.

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 2017-2018 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $3,165,518. I project that the New Hampshire Division Retail Marketers will be allocated $349,735 of the PNGTS Refund, yielding a net PNGTS Refund credit to the Cost of Gas equal to $1,387,970. This calculation is also included in Schedule 5B.

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 7 of Schedule 5B. The proposed Peaking Service Demand Charge is equal to $35.51 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, as proposed in Docket No. DG 17-104. Under this proposal Peaking Service previously backed by Peaking Contracts would be replaced by Granite Capacity Release.

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, 2017.

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 1.077, which is equal to Total Design Day Capacity of 128,344 Dth divided by the Total Design Day Planning Load of 119,134 Dth. If approved by the Commission in Docket No. DG 17-104, Capacity Assigned Delivery Service Customer design day projections will be multiplied by this Capacity Ratio in order to calculate the Total Capacity Quantity ("TCQ") for each Customer. Northern issued updated TCQ to retail marketers on August 1, 2017, to become effective on November 1, 2017 subject to approval of the Commission.

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 2017-2018 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 2017 through April 2018			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 23,085,717	5,517,570	$ 4.184
Storage Resources	$ 10,593,079	3,521,529	$ 3.008
Peaking Resources	$ 5,893,956	539,332	$ 10.928
Total Commodity Costs	$ 39,572,752	9,578,431	$ 4.131
Company Managed Revenue	$ (2,336,410)	(654,973)	$ 3.567
Net Sales Service Commodity Costs	$ 37,236,342	8,923,458	$ 4.173

In summary, net projected delivered commodity costs equal approximately $37.2 million at an average delivered rate of $4.173 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 2017-2018 Annual COG forecasted Winter Period (November through April) commodity costs compare with the 2016-2017 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 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 1% lower than 2016-2017 forecasted Winter Period.

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 2018 through October 2018

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 6,109,399	2,284,591	$ 2.674
Storage Resources	$ -	-	
Peaking Resources	$ 86,253	13,156	$ 6.556
Total Commodity Costs	$ 6,195,652	2,297,747	$ 2.696
Net Sales Service Commodity Costs	$ 6,195,652	2,297,747	$ 2.696

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 2017-2018 Annual COG forecasted 2018 Summer Period (May through October) commodity costs compare with the 2017 Summer COG forecasted commodity costs?

A. As show in Table 6, above, the forecasted 2017 Summer Period commodity costs are equal to $6,195,652 at an average delivered rate of $2.696 per Dth. The 2017 Summer COG forecasted commodity costs were equal to $5,858,770 at an average delivered rate of $2.545 per Dth. 2018 forecasted Summer Period average unit commodity cost is 6% higher than the 2017 forecasted Summer Period average unit commodity cost.

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.

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 $280,875 for the upcoming winter peak season, which reflects the premium paid by Northern for call option contracts for November 2017 through March 2018. Since the strike price for each call option contract purchased is above current NYMEX prices as of September 7, 2017, 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. PROPOSED RE-ENTRY AND CONVERSION SURCHARGES

Q. Please describe the proposed Re-entry Surcharge.

A. In Docket No. DG 17-104, Northern proposes that Capacity Assigned Customers who return to Sales Service would pay the Re-entry Surcharge during the stay period. The Re-entry Surcharge would equal 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 would be 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 18B, which shows the calculation of the proposed Re-entry surcharge for the 2017-2018 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. Line 1 shows the Winter Demand Cost of Gas, inclusive of the PNGTS Refund adjustment since, because in the case of Capacity Assigned Delivery Service customers, their allocation of the PNGTS Refund would follow them back to Sales Service, as directed by the Commission in Order No. 25,816 in Docket No. DG 15-090. Line 3 shows the Winter Indirect Cost of Gas, reflecting the removal of the prior period over recovery. The weighted average Winter Cost of Gas Rate (Exclusive of Credits) is shown on line 4, which is $0.7188 per therm. This is higher than the weighted average Winter Cost of Gas Rate for incumbent Sales Service Customers as shown on Line 5, which is equal to $0.7106 per therm. Therefore, Line 6 shows the proposed Re-entry Surcharge for the 2017-2018 Winter Period is $0.0082 per therm.

Lines 8 through 11 determine the Summer Cost of Gas Rate, exclusive of prior period credits. Line 1 shows the Summer Demand Cost of Gas. The PNGTS Refund is completed prior to the 2018 Summer Period. Line 3 shows the Summer Indirect Cost of Gas, reflecting the removal of the prior period over recovery. The weighted average Summer Cost of Gas Rate (Exclusive of Credits) is shown on line 11, which is $0.4246 per therm. This is higher than the weighted average Summer Cost of Gas Rate for incumbent Sales Service Customers as shown on Line 12, which is equal to $0.4161 per therm. Therefore, Line 13 shows the proposed Re-entry Surcharge for the 2018 Summer Period is $0.0085 per therm.

Q. Please describe the proposed Conversion Surcharge.

A. In Docket No. DG 17-104, Northern proposes that Capacity Exempt Customers who switch to Sales Service would pay a Conversion Surcharge during the stay period. The Conversion Surcharge would replace the Re-Entry Fee in the current Delivery Service Terms and Conditions. During the Winter Period, the Conversion Surcharge would be set to capture the incremental cost of providing supply that is not backed with capacity. Different Conversion Surcharges would be established apply for high load factor customers and low load factor customers during the Winter Period. Although high load factor customers have high annual load factors, when they come to Sales Service without capacity they impose similar supply costs as a low load factor customer. For this reason, the Winter Period Conversion Surcharge for high load factor customers would be set no lower than the difference between the Low Load Factor and High Load Factor Cost of Gas rates. During the Summer Period, the Conversion Surcharge would equal 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 18B shows the proposed Conversion Rate surcharge for the 2017-2018 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 2017-2018 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 18B, 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. Line 1 is the Winter Demand Cost of Gas Rate, recalculated to exclude PNGTS Refund credits, since Capacity Exempt customers would not be bringing a pro-rated share of the PNGTS credit with them to Sales Service. Line 3 shows the Low Load Factor Winter Cost of Gas, recalculated to remove the 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 2017-2018 Winter Period Conversion Surcharge is $0.1522 per therm for HLF customers and $0.0510 per therm for LLF customers. The proposed 2018 Summer Period Conversion Surcharge is equal to the 2018 Summer Period Re-entry Surcharge, $0.0085 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 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 18B. The Load Shape Price Factor Worksheet first, calculates historic Non-Capacity Assigned Delivery Service Loads. 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 from November 2016 through April 2017. Page 10 provides the Weighted Average Daily Price ($4.394 per Dth) and the Straight Average Daily Price ($4.315 per Dth). The ratio between the two was 1.018 for the last winter period.

Please refer to page 11 of Schedule 18B. 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.

VI. ALLOCATION OF OFF-SYSTEM PEAKING CONTRACT DEMAND COSTS

Q. How does Northern currently allocate off-system peaking demand contract costs between the New Hampshire and Maine Divisions?

A. Currently, such fixed costs are allocated using the Modified Proportional Responsibility Allocator (“MRP Allocator”). The MPR Allocator allocates fixed demand costs to each state based upon the Design Year utilization of Sales Service and Capacity Assigned Delivery Service loads of each state.

Q. Why is the MPR Allocator no longer appropriate for Off-System Peaking Demand Contract costs?

A. As explained in the Testimony of Christopher A. Kahl, effective November 1, 2016, Northern no longer assigns Off-System Peaking Contracts to retail marketers in Maine. M.P.U.C. Delivery Service Terms and Conditions, Third Revised Pages 95, 96. Due to this change in the capacity assignment program, Northern did not include Maine Capacity Assigned Delivery Service requirements when determining the volume of Off-System Peaking Contracts it purchased; rather, itpurchased such supplies to meet only the demands of Maine Sales Service, New Hampshire Sales Service and New Hampshire Capacity Assigned Delivery Service. Application of the MRP Allocator, which assumes the purchase of off-system peaking supply for Delivery Service customers in both states, resulted in the Maine Division being assigned costs for some peaking supplies that the Company purchased solely for New Hampshire Division customers..

Northern has proposed to discontinue the assignment of Off-System Peaking Contracts in the New Hampshire Division effective November 1, 2017 in Docket No. DG 17-104. Off-System Peaking Contract purchases have been made for the upcoming winter, including only the projected requirements of Northern’s Sales Service customers in both

Maine and New Hampshire. Application of the MPR Allocator to Off-System Peaking Contract demand costs would not be appropriate, since it considers Capacity Assigned Delivery Service requirements, which were not considered when making these purchases.

Q. How does Northern propose to modify the allocation of Off-System Peaking Contract demand costs to better allocate these costs?

A. Northern has prepared proposed adjustments to the COG reconciliation for both the 2016-2017 Winter Period and the 2017-2018 Winter Period that adjust the MPR Allocator-based cost allocations by removing the impact of Maine Capacity Assigned Delivery Service loads for both the 2016-2017 Winter Period and the 2017-2018 Winter Period and removing the impact of the New Hampshire Capacity Assigned Delivery Service loads for the 2017-2018 Winter Period. Off-System Peaking Contract demand charges as invoiced would continue to be allocated using the MPR Allocator and an adjustment to the COG reconciliation would be entered to adjust the allocation of these costs.

Q. What are these proposed COG reconciliation adjustments?

A. The proposed adjustment for the 2016-2017 Winter Period is a debit in the amount of $128,693. The supporting calculations are provided on page 1 of Schedule 21A. The proposed adjustment for the 2017-2018 Winter Period is a credit in the amount of $44,199. The supporting calculations are provided on page 2 of Schedule 21A.

Q. Does this conclude your testimony?

A. Yes it does.