NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2016
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
CHRISTOPHER A. KAHL

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher A. Kahl. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil"). Unitil Service provides managerial, financial, regulatory and engineering services to the principal subsidiaries of Unitil. These subsidiaries are Fitchburg Gas and Electric Light Company d/b/a Unitil, Granite State Gas Transmission, Inc. ("Granite"), Northern Utilities, Inc. d/b/a Unitil ("Northern" or "the Company"), and Unitil Energy Systems, Inc. I am responsible for developing, providing and sponsoring certain reports, testimony and proposals filed with regulatory agencies.

Q. Please summarize your professional and educational background.

A. I have worked in the natural gas industry for over twenty years. Before joining Unitil in January 2011, I was employed as an Analyst with Columbia Gas of Massachusetts ("Columbia") where I had worked since 1997 in supply planning. Prior to working for Columbia, I was employed as an Analyst in the Rates and Regulatory Affairs Department of Algonquin Gas Transmission Company ("Algonquin") from 1993 to 1997.

Prior to working for Algonquin, I was employed as a Senior Associate/Energy Consultant for DRI/McGraw-Hill. I received a Bachelor of Sciences degree and a Masters of Arts degree in Economics from Northeastern University.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or for Unitil?

A. Yes, I testified in Northern's 2015 Summer Period Cost of Gas ("COG") Adjustment Proceeding, Docket No. DG 15-090, and Northern's 2015 / 2016 Winter Period COG Adjustment Proceeding, Docket No. DG 15-393. I have also testified in other COG proceedings.

Q. Please explain the purpose of your and other witnesses' pre-filed direct testimony in this proceeding.

A. Joseph F. Conneely, Senior Regulatory Analyst for Unitil Service, and I are sharing the responsibility in this proceeding for supporting Northern's proposed New Hampshire Division 2016 Summer Period COG, effective May 1, 2016.

Mr. Conneely is sponsoring, discussing and explaining the typical bill impact analyses of the proposed 2016 Summer Period New Hampshire Division COG rates. In addition, Mr. Conneely is providing an update on the Local Delivery Adjustment Clause (LDAC) components.

My testimony is divided into three sections. This first section is an introduction. In the second section, I am sponsoring, describing and explaining the derivation and calculation of the New Hampshire Division Summer COG Reconciliation filing and the calculation of the New Hampshire Division COG rates Northern proposes to bill from May 1, 2016 to October 31, 2016. In the third section I am sponsoring, describing and explaining the customer demand forecast and the resulting projected gas sendout and gas costs developed for the Maine and New Hampshire Divisions. Also, I will describe any impact of the Company's current Hedging Program on the 2016 Summer Season costs and present Northern's financial hedging plan.

Q. Please provide a list of the attachments that you have prepared in support of your testimony.

A. The attachments that I have prepared in support of my testimony are listed below.

Summary Schedule	Supporting Detail to the Tariff Sheets including Working Capital
Schedule 1A	Allocation of New Hampshire Division Fixed Capacity Costs To Months and Seasons
Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 2	Contracts Ranked on a Per-Unit Cost Basis
Schedule 3	New Hampshire Division (Over) / Under-collection Balances and Interest Calculations
Schedule 4	New Hampshire Division Bad Debt (Actual & Forecast)
Schedule 5A	Demand Cost Forecast
Attachment to Schedule 5A	Rate Cost Support
Schedule 6A	Commodity Cost Forecast
Schedule 6B	Detailed City-gate Cost Calculations
Schedule 9	Variance Analysis / Comparison to 2015 Summer Period
Schedule 10A	Allocation of New Hampshire Division Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 10B	New Hampshire Division Sales and Sendout Forecast
Attachments 1 & 2 to Schedule 10B	Detailed Support for Schedule 10B
Schedule 10C	Allocation of New Hampshire Division Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 11A	Normal Year Sendout Volume
Schedule 11C	Capacity Utilization
Schedule 13	Load Migration from Sales to Transportation
Schedule 15	2015 Summer Period Reconciliation
Schedule 20	Annual Hedging Program

Schedule 21	Allocation of Northern Fixed Capacity Costs To New Hampshire and Maine Divisions
Schedule 22	Allocation of Northern Commodity Costs To New Hampshire and Maine Divisions
Schedule 23	Supporting Detail to Proposed Tariff Sheets
Schedule 25	PNGTS Refund Calculation

II. COST OF GAS FACTOR

Q. Please provide an overview of how Northern's COG related costs are allocated to the New Hampshire Division rate classes.

A. Northern allocates costs between Winter and Summer Periods as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. The SMBA approach assigns costs over a three step process. These steps are as follows:

Step 1 – Allocate costs between the New Hampshire and Maine Divisions.

Step 2 - Allocate New Hampshire Division costs to the Summer and Winter Periods.

Step 3 – Allocate New Hampshire Division seasonal costs to the rate classes.

Below I provide a detailed explanation of how these three steps are conducted.

A. Allocation of Demand-Related Costs to the Maine and New Hampshire Divisions

Q. Please explain how the projected fixed capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs and (c) peaking resource capacity costs are allocated between Northern's Maine and New Hampshire Divisions.

A. Northern's total capacity-related costs are allocated between the Maine and New Hampshire Divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed capacity-related gas costs to the Maine and New Hampshire Divisions in a two-step process: (1) capacity-related costs, by resource type[1], are allocated to months by application of MPR allocation factors, and (2) the capacity related costs allocated to each month are allocated to the Maine and New Hampshire Divisions based on the relative shares of Design Year demand[2] in that month. This MPR methodology was approved by the Commission in its Order No. 24,627 in Docket No. DG 05-080.

As I will explain in more detail below, I used the MPR methodology to allocate total Northern annual demand costs to the Maine and New Hampshire Divisions for the 2015 Winter Period (November 2015 through April 2016) and for the 2016 Summer Period (May through October 2016).

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2015 through October 2016 to the Maine and New Hampshire Divisions.

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1 These resources are: pipeline, storage, and peaking.

2 For the MPR allocation process, Design Year demand is calculated as the actual demand to the Maine and New Hampshire Divisions' firm sales and assigned capacity / non-grandfathered transportation customers for the period May 2014 through April 2015, adjusted to reflect design winter conditions from November through April and normal conditions from May through October.

A. I have prepared Schedule 21 to explain how I calculated the MPR factors and how I used these factors to allocate total Northern annual demand costs for November 2015 through October 2016 ("the COG Period") to the Maine and New Hampshire Divisions.

Schedule 21 is arranged in three major sections:

(1) Total fixed capacity costs, by type of resource (pipeline, storage, and peaking and other capacity related costs and credits) are summarized in Lines 1 through 10.

(2) Fixed capacity costs for each resource type are allocated to each month in the COG Period according to MPR allocators that were developed specifically for each resource type, as shown on Lines 13 through 56, where MPR allocators based on design year sendout volumes for each resource type.

(3) Total fixed capacity costs allocated to each month in section 2 are allocated to the Maine and New Hampshire Divisions according to design year total firm sendout as shown on Lines 58 through 90.

I note the last column on Pages 2 and 4 of Schedule 21 are descriptions of the sources of data and explanations of the calculations included in the Schedule on pages 1 and 3. Similar explanations are included in many of the Schedules relating to my testimony.

Q. Are Northern's demand costs shown on Schedule 21 the same as filed in the 2015 /2016 Winter Season COG?

A. No. Typically, Northern's demand costs, once finalized in the Winter Period COG, are usually held constant throughout the Summer Period. This is because demand costs are often stable throughout the year. However, for this Summer Period filing, demand costs changed significantly from those used in the winter season forecast due to a change in the Canadian exchange rate. As a result, Northern has updated its demand costs to reflect the change in the Canadian exchange rate[3].

Q. Please explain how you allocated total Northern Fixed Capacity Costs to the months in the COG Period.

A. Lines 3 through 5 of Schedule 21 show the total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources[4]. Also included are estimates of Northern's Capacity Release and Asset Management revenues (Lines 8 and 9), all of which are recovered in the Winter Period.

The development of the MPR factors and the application of these factors to allocate Pipeline, Storage and Peaking demand costs to each month are shown on Schedule 21, Lines 17 through 22, Lines 33 through 40, and Lines 44 though 49, respectively. In addition, Lines 26 through 29 show the calculation of the Storage Injection Fees by month. Storage Injection Fees represent capacity costs that comprise the portion of Northern's pipeline capacity that is used to transport gas to the underground storage

3 The resulting impact on the MPR allocator factors from this cost change is negligible.
4 The forecast of demand costs is provided in Schedule 5A.

fields. These fees are added to the Storage demand costs, as shown on Line 39, and subtracted from the Pipeline demand costs, as shown on Line 53.

Northern's fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56. Lines 50, 51 and 52 repeat the Pipeline, Storage, and Peaking capacity costs from Lines 22, 40, and 49. Line 53 shows the credit to Pipeline capacity costs that is related to the Injection Fees that have been added to the Storage capacity costs. In addition: (a) 1/5 of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54; and (b) 1/6 of total Asset Management revenues are allocated to each month from November through April, as shown on Line 55.

Q. Finally, how are the total Demand Costs and the Capacity Release and Asset Management revenues, which have been allocated to each month according to the process that you described above, allocated to the Maine and New Hampshire Divisions?

A. Northern's total Demand Costs and Capacity Release and net Asset Management revenues allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total firm sendout for the Maine and New Hampshire Divisions which is shown on lines 61 and 62 of Schedule 21; the calculated percentages are provided on lines 65 and 66. The design year sendout quantities for the COG period as shown on lines 61 and 62 are the sendout quantities required to serve Maine and New Hampshire Divisions' firm sales and transportation customers that are subject to the assigned capacity requirements under Design Winter conditions from May 2014 through April 2015.

As shown on Line 90 of Schedule 21, 42.43% of Northern's total demand costs from November 2015 through October 2016 will be allocated to the New Hampshire Division and the remaining 57.57%, as shown on Line 81, will be allocated to the Maine Division. These percentages have changed very slightly (0.01%) from the initial percentages determined in the 2015-2016 Winter Period. Consistent with prior Summer COG filings in which there is a change in demand costs, Northern is proposing to retain the initial percentages calculated in the winter filing.

B. Allocation of New Hampshire Demand-Related Costs to Seasons

Q. Please explain how the projected annual demand-related costs that are allocated to the New Hampshire Division are then assigned to be recovered in the 2015 / 2016 Winter Period and the 2016 Summer Period.

A. I have prepared Schedule 1A to show detailed support for the allocation of New Hampshire Division Sales Customer demand costs to months, and then to seasons.

Lines 2 through 4 of Schedule 1A summarize the Pipeline, Storage and Peaking demand costs that are allocated to the New Hampshire Division, as determined in Schedule 21. Lines 13 through 23 of Schedule 1A show the calculation of Net Demand Costs[5] for firm sales customers, which represents Total Demand Costs allocated to the New Hampshire

[5] These direct demand costs are adjusted by Capacity Release and Asset Management revenues net of PNGTS litigation costs (Line 76); Interruptible margins (Line 77); and Re-Entry Fee Credits (Line 78).

Division less the expected capacity assignment revenues from New Hampshire Division transportation customers

Lines 27 through 41 of Schedule 1A show the calculation of pipeline demand costs for sales customers, separated into (1) Base Use demand costs and (2) Remaining Use demand costs.[6] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2015[7] for all firm sales classes; the Base Use Pipeline Demand cost that is shown on Line 40 of Schedule 1A is calculated by multiplying Base Use times the weighted average annual cost of pipeline capacity, as shown on Line 36 of Schedule 1A. Line 41 shows the Remaining Use Net Pipeline Demand costs for sales customers, which is the difference between total net pipeline demand costs and Base Use pipeline demand costs.

Lines 45 through 50 of Schedule 1A show the calculation of the Proportional Responsibility ("PR") factors for all months that are used to allocate (a) Remaining Use Net Pipeline Demand costs; and (b) Storage and Peaking costs related to Firm Sales customers for twelve months, i.e., November 2015 through October 2016. Lines 52 through 57 show the calculation of the PR factors used to allocate (c) Capacity Release and Asset Management revenue, (d) Interruptible margins and Delivery-to-Sales revenues and (e) Re-entry Fee credits to the Winter Period months only. Lines 61 through 65 summarize the PR factors by type of capacity cost. Line 61 of Schedule 1A shows that

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6 This separation is necessary because the SMBA allocation methodology allocates Base Use demand costs to seasons on a different basis than Remaining Use demand costs.

7 Average Projected Daily demand by class in July and August is shown in Schedule 10B, Line 48.

1/12 of the net annual Base Use pipeline demand costs is allocated to each month and Lines 69 through 80 show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peak Months Only" allocation factors.

The total direct demand costs to be recovered in the 2016 Summer Period COG rates, $933,408, is shown in Schedule 1A, on Line 81, "Summer" column. These costs, in addition to $117,870 of indirect demand costs, as shown in Schedule 1A, Line 86, are recorded as Summer Period capacity related costs, and are collected in six even increments.

C. <u>Allocation of New Hampshire Summer Period Demand Costs to Customer Classes</u>

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Summer Period are then allocated to each sales rate class.

A. The New Hampshire Division sales service base demand-related costs for each month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sendout under normal weather conditions in that month. The remaining demand-related monthly costs for each month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sales design day temperature-sensitive demand.

I have prepared Schedule 10B to show the calculation of the factors that are used to allocate New Hampshire Division sales service Summer Period base sendout and remaining sendout for each month to each sales service rate class. The firm sales forecast, shown on Lines 1 to 16, and the firm sendout forecast by class, shown on Lines 18 to 33, are used to determine: daily base use, shown on Lines 35 to 48; base use sendout, shown on Lines 49 to 64; and remaining use sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Summer Period demand costs to New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Summer Period New Hampshire Division Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Summer Period month as shown in Schedule 1A, Lines 69 through 81, and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80[8]. The Base Sendout allocators, which are used to allocate base demand costs to firm sales rate classes, are shown on Lines 3 through 22 of Schedule 10A and the Remaining Design Day allocators, which are used to allocate all other demand-related costs and credits to firm sales rate classes, are shown on Lines 39 through 48.

The following table shows the location in Schedule 10A of the Net Demand-related costs and credits by component allocated to each firm sales rate class:

Demand Cost Component	Schedule 10A
Base Capacity	Lines 24 through 37
Remaining Pipeline Capacity	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Capacity Release and Asset Management	Lines 86 through 102
Non-Firm Margins	Lines 104 through 120
Remaining Re-Entry Fee Credit	Lines 122 through 138
Total Non-Base Capacity Costs	Lines 140 through 154
Total Capacity Costs	Lines 156 through 174

[8] Additional demand cost allocation support is provided in Schedule 23.

D. Allocation of Variable Costs

Q. Please provide a description of Variable costs, and explain how Variable costs are allocated to Northern's Maine and New Hampshire Divisions.

A. Variable costs include commodity costs and variable pipeline and storage costs[9] for firm sales. These variable gas costs have been allocated between the Maine and New Hampshire Divisions based on each Division's percentage of monthly firm normal sendout. I have prepared Schedule 22 to show the allocation of the 2016 Summer Period variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Schedule 22.

A. Lines 1 through 9 of Schedule 22 show the projected sendout volumes, by month and by resource type. The projected variable costs by month and by type of gas supply resource are shown on Line 12, and Lines 19 through 21 of Schedule 22. Line 22 of Schedule 22 also provides off-system sales revenues. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of March 4, 2016. Lines 27 through 35 show the determinants for estimated gains and expenses based on the Company's hedging program including projected NYMEX prices. The variable gas costs and hedging gains and losses for firm sales service that are summarized on Lines 47 and 48 are allocated to the Maine and New Hampshire Divisions based on projected monthly

[9] Variable costs include pipeline usage/commodity charges, pipeline fuel retention, storage commodity injection and withdrawal charges, and storage fuel retention.

firm sales sendout in each division (Lines 53 and 54); the allocators are shown on Lines 58 and 59. Schedule 22 also shows the allocation of (a) Commodity costs (Maine Division: Lines 64, 66, and 67; New Hampshire Division: Lines 73, 75 and 76); and (b) hedging gains and losses and off-system sales (Lines 65, 68, 74 and 77) to the Maine and New Hampshire Divisions. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 98 to 99); the allocation of these costs to the Maine and New Hampshire Divisions (Lines 103 to 105), and the allocation of New Hampshire Division's allocated share of annual inventory finance costs to the Summer Period, using the firm sales remaining sendout allocators (Lines 114 to 116)[10].

I have prepared Schedule 1B to summarize the New Hampshire Division variable gas costs that were determined in Schedule 22; this Schedule also shows the calculation of base and remaining commodity costs.

Q. Please explain how the New Hampshire Division variable gas costs for sales customers are allocated to each firm sales class.

A. I have prepared Schedule 10C to show the allocation of New Hampshire Division variable gas costs to each firm sales class[11]. Lines 1 to 21 show the calculation of the Base Sendout allocators by rate class. Lines 22 to 49 show the allocation of the monthly

[10] Schedule 14 provides the forecasted storage inventory and related finance costs that are allocated to each division in Schedule 22. However, these charges are collected only during Winter Season.
[11] Additional commodity cost allocation support is provided in Schedule 23.

New Hampshire Division Base Commodity and Base Hedging costs[12] to each rate class. Lines 50 to 70 show the calculation of the Remaining Sendout allocators by rate class. Lines 71 to 98 show the allocation of the monthly New Hampshire Division Remaining Commodity and Remaining Hedging costs[13] to each rate class. A summary of all commodity costs allocated to the New Hampshire Division's firm sales classes is shown on Lines 99 to 140.

E. <u>Refunds</u>

Q. Are there any refunds included in this filing?

A. Yes. As approved in the Commission's Order No. 25837, in Docket No. DG 15-090, Northern is crediting back to sales customers the PNGTS refund over a three year period. Fifty percent of the refund is being credited back the first year, thirty percent the second year and twenty percent the third year. This refund is being credited back as a reduction to demand charges as opposed to through a separate rate component. By flowing the refund back as reduction to demand costs, customers that paid more for the higher PNGTS rates will receive a larger refund credit.

Q. How much of the refund will be flowed back to sales customers for the 2016 Summer Season?

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12 New Hampshire Division Winter Season Base Commodity costs and Hedging costs by month are shown in Schedule 1B Lines 37 and 38.

13 New Hampshire Division Winter Season Remaining Commodity costs and Hedging costs by month are shown in Schedule 1B Lines 39 and 40.

A. Northern is flowing back $128,190 to its sales customers. The supporting calculations for this refund amount are shown on Schedule 25.

Q. How far along is the Company in flowing back the refund?

A. The 2016 Summer Season will reflect the start of the second year of the refund.

F. <u>2015 Summer Period Reconciliation</u>

Q. Please explain the 2015 Summer Period over and under-collections.

A. The 2015 Summer Period COG Adjustment Reconciliation ("Reconciliation") was filed with the Commission on February 1, 2016. The Reconciliation provides a detailed explanation of the Summer Period's under-collection of $23,260 as of October 31, 2015, and is included in this filing as Schedule 15.

G. <u>Cost of Gas Factor</u>

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2016 Summer Period.

A. The Summary Schedule, which is similar to the Company's COG tariff Pages 42 and 43, has been prepared to explain the calculation of the proposed 2016 Summer COG factors. The text descriptions in the added column on page 2 and 4: (1) explain the calculations on this tariff page; and (2) provide references to other schedules for the sources of the data that appear on COG tariff Pages 42 and 43. This Summary Schedule shows the calculation of the 2016 Summer Period COG for each of Northern's three COG Rate

Groups: (1) Residential classes R-1 and R-2, (2) C&I Low Winter use classes G-50, G-51 and G-52; and (3) C&I High Winter use classes G-40, G-41 and G-42.

As shown on the Summary Schedule for the 2016 Summer Period, the projected Average Cost of Gas is $0.3196 per therm (Line 73), which is the sum of the average Total Direct Cost of Gas, $0.3042 per therm (Line 64), and the average Indirect Cost of Gas, $0.0154 per therm (Line 68).

Q. What are the major components of the 2016 Summer Period Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$525,885	3
2	Purchased Gas Supply Costs	$2,040,682	4
3	Storage and Peaking Capacity Costs	$407,523	7
4	Storage and Peaking Commodity Costs	$49,933	8
5	Hedging (Gain) / Loss	$0	10
6	Total Anticipated Direct Cost of gas	$3,024,024	18

Q. What are the major components of the 2016 Summer Period Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	$23,260	22
2	Interest[14]	$(335)	24
3	Refunds		25
4	Working Capital Allowance	$2,251	36
5	Bad Debt Allowance	$10,117	41
6	Local Production and Storage	$0	43
7	Miscellaneous Overhead	$117,870	45
8	Total Anticipated Indirect Cost of Gas	$153,163	47

Q. How is Northern's current period Working Capital Allowance derived?

A. Northern's Working Capital Allowance Percentage, 0.0887%, is multiplied by the projected direct cost of gas in order to determine the Working Capital Allowance $2,682 (line 32). This is then added to the prior Summer Period Working Capital Reconciliation balance, $(431) (Line 34) for a total Working Capital Allowance of $2,251 (Line 36).

Q. Please explain the calculation of the Bad Debt factor or allowance.

A. The Bad Debt allowance, $10,117 (Line 41 of the Summary Schedule), is the sum of the current period bad debt allowance, $22,890 (Line 39), plus the prior Summer Period Bad Debt Reconciliation balance, ($12,773) (Line 40).

[14] Support for the interest calculation is provided in Schedule 3.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2016 Summer Period?

A. Northern's Bad Debt expenses are based on the Company's actual forecast of Bad Debt. In Northern's Winter Period COG, the amount of annual projected write-offs was $500,000. Of this amount, Northern then determined the portion of write-offs attributable to non-distribution service during the Summer Period. For the 12 months period that ended July 2015, this percentage is 4.58%. Applying this percentage to Northern's projected write-offs yields $22,890. This is shown in Schedule 4 at line 20.

Q. What are the Company's local LNG and LP production and storage capacity costs that are included in the Summer Period COG?

A. In Northern's most recent base rate case proceeding, Docket No. DG 13-086, total local production capacity and storage costs were established at $420,658, all of which is assigned to the Winter Period. In addition, Other Administration and General ("A&G") expenses related to local production and storage costs are $512,686. Of this amount, 22.99%, or $117,870 is assigned to the Summer Period as shown in the Summary Schedule at line 45.

H. Summary Analyses

Q. How does the proposed 2016 Summer Period COG compare to the actual 2015 Summer Period COG?

A. I have prepared Schedule 9 to compare the proposed 2016 Summer Period COG to the actual average 2015 Summer Period COG. Schedule 9 indicates the projected 2016

Summer Period average COG rate of $0.3196 per therm is $0.0171 per therm higher than the actual 2015 Summer Period Total Adjusted COG rate of $0.3025 per therm. The overall change in the proposed 2016 Summer Period average rate compared to the 2015 Summer Period actual average rate is primarily due to a slightly higher demand costs and an under-collection in the 2015 summer reconciliation compared to an over-collection in the prior year.

III. FORECAST OF CUSTOMER DEMAND AND GAS SUPPLY COSTS

A SALES AND SENDOUT FORECAST

Q. How does the Company forecast firm distribution deliveries?

A. To forecast metered distribution deliveries for the Company's residential, small commercial and larger industrial/commercial 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.

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. Table 1, below, provides a summary of the company's forecast of total billed distribution deliveries for the upcoming 2016 Summer Period.

Table 1. 2016 Summer New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years							
Month	2016 Forecast[1]	2015 Actual[2]	2016 minus 2015	Percent Change	2014 Actual[2]	2016 minus 2014	Percent Change
May	567,582	463,370	104,212	22.5%	529,156	38,426	7.3%
Jun	447,712	406,358	41,354	10.2%	414,423	33,289	8.0%
Jul	353,738	377,555	-23,817	-6.3%	333,540	20,198	6.1%
Aug	361,107	328,341	32,766	10.0%	327,519	33,588	10.3%
Sep	363,906	363,264	643	0.2%	339,140	24,766	7.3%
Oct	430,326	464,142	-33,815	-7.3%	415,928	14,398	3.5%
Winter	2,524,372	2,403,029	121,342	5.0%	2,359,706	164,666	7.0%

Note 1: Company Forecast. Notes 2: Actual Data.

A detailed review of Northern's forecast of metered distribution deliveries, meter counts and use-per-meter calculations for the 2016 Summer Period is provided in Attachment 1 to Schedule 10B. Page 1 of this Attachment provides total data for the New Hampshire Division. Pages 2, 3 and 4 provide data for non-heating residential rate class, heating residential rate class and commercial and industrial rate classes, respectively. The top section of each page provides the 2016 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2015 and 2014 Summer 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 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 1, 2015. Then, Northern weather normalized the billed usage of these specific customers. The weather normalized 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. Table 2, below, provides a summary of the Company's forecast of Total Deliveries, Sales Service Deliveries[15] and City-Gate Receipts to meet the Sales Service Deliveries[16] for the upcoming Summer Period.

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)
May-16	468,559	203,949	205,906
Jun-16	384,186	135,858	137,161
Jul-16	354,253	123,397	124,581
Aug-16	367,657	128,275	129,506
Sep-16	387,884	140,427	141,774
Oct-16	561,833	262,874	265,395
Summer	2,524,372	994,781	1,004,323

[15] Sales Service Deliveries reflect Company Use gas.

[16] The term "City-Gate Receipts to meet the Sales Service Requirements", refers 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 to Table 2 can be found in Attachment 2 to Schedule 10B. On Pages 1 and 2 of this Attachment, 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, the calculations of the city-gate receipts are presented. First, Company Use was estimated by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, Company Use was added to the total Calendar Sales Service Deliveries, calculated on Page 1 ("Sales Service plus Company Use"). Then, an estimate for Lost and Unaccounted for Gas was added. Each of the estimates used in these calculations was based on the recent history of actual data[17].

B. NORTHERN'S GAS SUPPLY PORTFOLIO

Q. Please provide an overview of the gas supply portfolio that the Company uses to supply its sales customers.

A. Table 3, below, provides an overview of the sources of supply available to Northern.

[17] Provided in Attachment 3 to Schedule 10B of the 2015-2016 Winter COG filing.

Table 3. Northern Capacity by Supply Source (Dth per Day)		
Supply Source	Nov 2015 through Mar 2016	Apr 2016 through Oct 2016
Chicago City-Gates & Iroquois Receipts	6,434	6,434
PNGTS Receipts	1,096	1,096
Tennessee Niagara	2,327	2,327
Tennessee Production	13,109	13,109
Algonquin Receipt Points Supply	1,251	1,251
Maritimes Delivered Baseload Supply	7,474	0
PNGTS Delivered Baseload Supply - (Nov - Mar)	4,983	0
PNGTS Delivered Baseload Supply - (Dec - Feb)	2,491	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Contract 1	9,965	0
Peaking Contract 2	14,948	0
Peaking Contract 3	5,000	0
Peaking Contract 4	11,966	0
Lewiston On-System LNG Production	4,181	4,181
Total Deliverable Resources	**120,754**	**31,042**

The above capacity makes use of many contracts in getting gas supplies delivered to Northern. The Company'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"). 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 includes four separate peaking supply agreements. These peaking supply arrangements were procured through a Request-For-Proposals and have a delivery period beginning November 2015 and ending March 2016. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 4,181 Dth per day and storing approximately 12,000 Dth of LNG. Northern has entered into a LNG contract beginning November 2015 and ending October 2016 in order to supply this facility. Finally, the gas supply portfolio consists of an exchange agreement with Columbia Gas of Massachusetts ("BSG Exchange" or "Bay State Exchange Agreement").

For the Summer Period, there have been no changes to Northern's gas supply portfolio since the 2015-2016 Winter Period filing was submitted.

Q. Has the Company entered into any long-term releases of capacity?

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

Q. Please describe the Company's process for procuring its gas commodity supplies.

A. Northern's practice is to secure its gas supply commodity supplies through annual RFP for terms beginning April 1 and running through March 31 each year. On February 11, 2016, Northern submitted its RFP for the delivery period April 1, 2016 through March 31, 2017. This RFP seeks asset management proposals for Northern's Chicago, Algonquin Receipts, Niagara, Tennessee Production and Washington 10 capacity paths. The Company typically enters into asset management relationships with most of its suppliers in order to optimize delivered supply costs for Northern's customers. In addition, Northern seeks baseload supply through this RFP. This summer, Northern plans to issue a separate RFP for replacement peaking supplies.

B. GAS SUPPLY COST FORECAST

Q. Please provide an overview of the Company's estimated gas supply costs that you provided to calculate the 2016 Summer COG.

A. The following cost estimates were 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 2015 through October 2016;
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2015 through October 2016;
- Northern's commodity costs for the period May 2016 through October 2016.

The figures presented in my testimony here 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, 2015 through October 31, 2016			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,968,294	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 21,913,000	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,029,855	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,252,642	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 4,223,000	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (9,629,987)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 29,756,804	Sum Lines 1 through 6.

The detailed calculations of this demand cost forecast are presented in Schedule 5A. Page 1 of Schedule 5A provides the summary data presented here in Table 4. On page 2 of Schedule 5A, the annual demand cost forecast for Northern's portfolio of transportation contracts is calculated. On page 3 of the Schedule, each transportation contract is separated as to its percentage of pipeline, storage or peaking resource and allocated transportation costs based upon these percentages. Pages 4 and 5 of the Schedule provide calculations of demand costs for storage and peaking supply contracts, respectively. On page 6 of the Schedule, capacity release and asset management revenue the Company expects to receive for the 2015-2016 Gas Year are forecast. Support for the transportation and storage demand rates used in Schedule 5A are found in the Attachment to Schedule 5A[18].

Q. How is Northern's demand forecast different from the one provided in the 2015 / 2016 Winter Period Cost of Gas Proceeding?

A. Total demand costs are lower by approximately $1.4 million. This is due to a decline in the Canadian exchange rate which impacts the costs of TransCanada PipeLines and Union Gas. The exchange rate has fallen from 0.79 per US dollar, used in the 2015 / 2016 Winter Period filing, to 0.69 per US dollar.

Q. Have any other revisions been made due to the change in the Canadian exchange rate?

A. Yes the capacity assignment revenue has been revised downward to reflect the lower demand costs. The 2015 / 2016 Capacity Assignment Demand Revenue for the New Hampshire Division is now projected to be $2,597,013[19].

Q. Please describe Northern's process for forecasting commodity costs.

A. The Company's commodity cost forecast is based on Northern's projected city-gate receipts for sales service customers, which were calculated in Attachment 2 to Schedule

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[18] The 2015- 2016 Winter Period filing provides an expanded version of Attachment 5A that includes tariff rate pages and supplier contracts.
[19] A description of Northern's initial forecast of Capacity Assignment Demand Revenue is provided in the 2015 / 2016 Winter Period CGF filing, Page 17 of the testimony of Francis X. Wells.

10B, and the supply sources available to Northern[20]. Supply prices are forecasted 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. Variable fuel retention factors and rates for Northern's transportation and storage contracts are also forecasted. The Sendout® natural gas supply cost model was then used to determine the optimal dispatch of Northern's natural gas supply resources to meet its projected city-gate requirements.

Q. Please present the Company's commodity cost forecast for the 2016 Summer Period.

A. Northern's commodity cost forecast for the upcoming Summer Period is summarized in Table 5, below.

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes May 2016 through October 2016			
Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 5,064,105	2,475,421	$ 2.046
Storage Resources	$ -	-	
Peaking Resources	$ 122,736	13,064	$ 9.395
Total Commodity Costs	$ 5,186,841	2,488,485	$ 2.084
Company Managed Revenue	$ -	-	$ -
Net Sales Service Commodity Costs	$ 5,186,841	2,488,485	$ 2.084

In summary, projected delivered commodity costs equal approximately $5 million at an average delivered rate of $2.084 per Dth. In support of this forecast, Schedule 6A shows the monthly forecasted commodity cost by supply option[21]. Page 1 of this Schedule provides forecasted delivered variable costs, including commodity charges, transportation

[20] Diagrams of capacity paths along with details for each supply source were provided in Schedule 12 in the 2015-2016 Winter Period filing.
[21] Schedule 11C provides the capacity utilization of the resources listed in Schedule 6A.

fuel charges, and transportation variable charges by supply option. Page 2 of this Schedule provides monthly delivered volumes (Dth) by supply source[22]. Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources. The per unit costs listed on Page 3 of Schedule 6A are also provided in Schedule 2. This schedule ranks the per units costs of each supply source, from lowest to highest.

The detailed calculations of the delivered commodity cost are found in Schedule 6B. It provides, for each supply source, 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 for the supply prices and variable transportation charges in Schedule 6B are found in the Attachment to Schedule 5A.

Q. Are there any financial hedges for the 2016 Summer Period?

A. No. Summer period hedging was discontinued as part of the new Hedging Program design.

C. NORTHERN HEDGING PLAN FOR NOVEMBER 2017 THROUGH APRIL 2018

Q. What is the status of Northern's hedging program?

[22] A modified version of Page 2 of Schedule 6A is provided in Schedule 11A.

A. Northern's current hedging program involves the purchase of options contracts on natural gas futures for the traditional winter months of November through March, with purchases made 18 months in advance of the months being hedged.[23] The hedging program is designed to provide for 70 percent of expected supply requirements at a fixed or capped price using both physical and financial resources. Thus, the number of financial hedges under the program each year is determined after accounting for physical resources that provide supply at fixed or capped prices. The Hedging Program uses a budget approach to determine option and strike prices whereby the options budget is established as a percentage of the futures price at the time of purchase and strike prices are determined by the options market.

Hedging plans are established each spring for the second following winter period and provided as part of the Summer Period Cost of Gas Factor filing. The first hedging plan under the current program design covered the period of November 2014 through March 2015. The hedging plan for the period of November 2017 through March 2018 is the fourth hedging plan under the current program design.

Q. Please describe Northern's hedging plan for November 2017 through March 2018.

A. Northern developed a hedging plan for the winter of 2017 / 2018, the details of which I present in Schedule 20. Under the plan for this period, 50 percent of projected sales are physically hedged with underground storage, as shown on Page 3 of Schedule20. The

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[23] The current program design was approved for the Maine Division in Docket No. 2012-448 and for the New Hampshire Division in Docket DG 13-119.

financially hedged volume needed for the other 20 percent, in order to cover 70 percent of expected sales with a fixed or capped price, was determined as 1,160,000 Dth. Futures contracts are denominated at 10,000 Dth, so the options contract quantity is 116, which covers both the Maine Division and the New Hampshire Division. On Page 1 of Schedule 20, I detail the procurement and expiration schedule as well as futures prices, options budget and strike prices using market data as of February 9, 2016. Since purchases of options contracts for each future month are executed 18 months prior to contract expiration, option purchases for the winter of 2017/18 begin with a purchase for the November 2017 contract when the May 2016 contract expires in late April 2016, and end with a purchase for the March 2018 contract when the September 2016 contract expires in late August 2016.

Each of the first three hedging plans under the current program design used a budget of 2.5 percent of the futures price at the time of purchase, which was the initial budget percentage proposed. Northern has reviewed the budget percentage and recommends a higher percentage in the plan for 2017/18. Page 2 of Schedule 20 shows the tradeoff between budget percentage and expected strike prices. As the option budget increases, the strike prices associated with the options decrease. Using data from February 9, 2016, holding the budget percentage at 2.5 percent yields an option price of just $0.07 per Dth, but provides options with an average strike price of $5.17. Alternate budget percentages from 2.5 percent to 10.0 percent, in increments of 2.5 percent, were reviewed to show the tradeoff between option prices and strike prices.

In the hedging plan for 2017 / 2018, Northern proposes a budget percentage of 7.5 percent. This budget percentage is expected to result in an average option price of $0.21 per Dth and an average strike price of $3.67. The resulting budget projection of $243,321 is not significantly greater than prior budgets. For example, the budget for 2015/16 was $209,215 and the budget for 2016 / 2017 was $159,153. The experience from the recent hedging plans has been that strike prices are too out of the money. The current low price environment provides an opportunity to assess the impact of a higher budget percentage, with associated lower strike prices, at a modest cost.

Page 3 of Schedule 20 provides the three year outlook and Page 4 of Schedule 20 provides typical bill impacts of the proposed hedging plan, including typical bill impact if the options expire worthless, and if the underlying futures contracts expire at various levels above the average strike price.

Q. Are there any impacts from this new Hedging Program on proposed rates covered by this filing, May 2016 through October 2016?

A. There are no hedges for this time period resulting from the current hedging program.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2016 Summer Period COG if it receives any new or updated information on gas supplier or transportation rates?

A. The Company will file a revised calculation of its 2016 Summer Period COG if there are significant variations in Northern's projected gas and pipeline transportation cost projections as well as any other unforeseen developments that would have a material impact on COG rates. If a revised filing is needed, it will be submitted a few weeks prior to the effective date of May 1, 2016.

Q. Does this conclude your testimony?

A. Yes it does.