NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2015
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 2014 Summer Period Cost of Gas ("COG") Adjustment Proceeding, Docket No. DG 14-077, and Northern's 2014 / 2015 Winter Period COG Adjustment Proceeding, Docket No. DG 14-239. 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 2015 Summer Period COG, effective May 1, 2015.

Mr. Conneely is sponsoring, discussing and explaining the pending changes to the 2015 Summer Period Local Distribution Adjustment Clause (LDAC) and the typical bill impact analyses of the proposed 2015 Summer Period New Hampshire Division COG rates.

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, 2015 to October 31, 2015. 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 2015 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 5	Demand Cost Forecast
Attachment to Sched 5	Rate Cost Support
Schedule 6A	Commodity Cost Forecast
Schedule 6B	Detailed City-gate Cost Calculations
Schedule 9	Variance Analysis / Comparison to 2014 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	2014 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

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 2014 through April 2015) and for the 2015 Summer Period (May through October 2015).

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2014 through October 2015 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 2013 through April 2014, 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 2014 through October 2015 ("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 2014 /2015 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, Northern will revise the demand costs if large changes are expected due to rate case filings by interstate pipelines. As will be discussed later in my testimony, PNGTS has revised their rates downward due to a recent FERC Order. This change in PNGTS' rates is included in the calculation of the Winter COG rates.

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[3]. 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. These revenues and costs are the same as those estimated in the 2014 / 2015 Winter Period filing.

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

[3] The forecast of demand costs is provided in Schedule 5A.

Northern's pipeline capacity that is used to transport gas to the underground storage 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, 47.66% of Northern's total demand costs from November 2014 through October 2015 will be allocated to the New Hampshire Division and the remaining 52.34%, 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 2014-2015 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 2014 / 2015 Winter Period and the 2015 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[4]. for firm sales customers, which represents Total Demand Costs allocated to the New Hampshire

[4] 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.[5] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2015[6] 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 2014 through October 2015. Lines 52 through 57 show the calculation of the PR factors used to allocate (c) Capacity Release and Asset Management revenues; and (d) Interruptible margins and Delivery-to-Sales revenues 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 1/12 of the net

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5 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.

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

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 2015 Summer Period COG rates, $901,217, is shown in Schedule 1A, on Line 80, "Summer" column. These costs, in addition to $95,875 of indirect demand costs, as shown in Schedule 1A, Line 85, are recorded as Summer Period capacity related costs, and are collected in six even increments.

C. Allocation of New Hampshire Summer Period Demand Costs to Customer Classes

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 to sales customers 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 80, and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80[7]. 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

[7] 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[8] 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 2015 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, 2015. 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

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8 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)[9].

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[10]. 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

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9 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.

10 Additional commodity cost allocation support is provided in Schedule 23.

New Hampshire Division Base Commodity and Base Hedging costs[11] 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[12] 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. Refunds

Q. Are there any refunds included in this filing?

A. There are no currently no refunds in this filing. However, as I discuss later in my testimony, Northern is currently preparing a proposal to flow back an expected refund from PNGTS.

F. 2014 Summer Period Reconciliation

Q. Please explain the 2014 Summer Period over and under-collections.

A. The 2014 Summer Period COG Adjustment Reconciliation (Form III), filed with the Commission on February 3, 2015, provides a detailed explanation of the Summer Period over-collection of $470,799 as of October 31, 2014. The Reconciliation submitted with this filing, has one more informational note than the version filed on February 3rd. In Attachment D, Supplier Refunds, a note was added that explains the derivation of the

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

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

November 2013 beginning balance. No other changes have been made to the Reconciliation. I have provided this Reconciliation as Schedule 15 in this filing.

G. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2015 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 2015 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 2015 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 2015 Summer Period, the projected Average Cost of Gas is $0.3333 per therm (Line 73), which is the sum of the average Total Direct Cost of Gas, $0.3814 per therm (Line 66), and the average Indirect Cost of Gas, ($0.0481) per therm (Line 70).

Q. What are the major components of the 2015 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	$433,739	3
2	Purchased Gas Supply Costs	$1,829,100	4
3	Storage and Peaking Capacity Costs	$467,478	7
4	Storage and Peaking Commodity Costs	$80,863	8
5	Hedging (Gain) / Loss	$0	10
6	Total Anticipated Direct Cost of gas	$2,811,180	18

Q. What are the major components of the 2015 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	$(470,799)	22
2	Interest[13]	$(11,671)	24
3	Refunds		25
4	Working Capital Allowance	$1,928	35
5	Bad Debt Allowance	$30,253	41
6	Local Production and Storage	$0	43
7	Miscellaneous Overhead	$95,875	45
8	Total Anticipated Indirect Cost of Gas	$(354,413)	47

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

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

A. Northern's Working Capital Allowance Percentage, 0.0824%, is multiplied by the projected direct cost of gas in order to determine the Working Capital Allowance $2,315 (line 32). This is then added to the prior Summer Period Working Capital Reconciliation balance, $(387) (Line 33) for a total Working Capital Allowance of $1,928 (Line 35).

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

A. The Bad Debt allowance, $30,253 (Line 41 of the Summary Schedule), is the sum of the current period bad debt allowance, $29,333 (Line 38), plus the prior Summer Period Bad Debt Reconciliation balance, $921 (Line 39).

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2015 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 $700,000. 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 2014, this percentage is 4.19%. Applying this percentage to Northern's projected write-offs yields $29,333. 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 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, 18.7%, or $95,875 is assigned to the Summer Period as shown in the Summary Schedule at line 45.

H. Summary Analyses

Q. How does the proposed 2015 Summer Period COG compare to the actual 2014 Summer Period COG?

A. I have prepared Schedule 9 to compare the proposed 2015 Summer Period COG to the actual average 2014 Summer Period COG. Schedule 9 indicates the projected 2015 Summer Period average COG rate of $0.3333 per therm is $0.3145 per therm lower than the actual 2014 Summer Period Total Adjusted COG rate of $0.6478 per therm. The overall change in the proposed 2015 Summer Period average rate compared to the 2014 Summer Period actual average rate is primarily due to a lower commodity costs, a higher demand forecast, and an over-collection in the 2014 summer reconciliation compared to an under-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 timeseries 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. Separate sets of forecast models were developed for both the total distribution system deliveries (based on historic total distribution system sales data) and for sales service deliveries (based on historic sales service data).

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 2015 Summer Period.

Table 1. 2015 Summer New Hampshire Division Billed Distribution Service Deliveries Forecast Compared to Prior Years

Month	2015Forecast[1]	2014 Actual[2]	2015 minus 2014	Percent Change	2013 Actual[2]	2015 minus 2013	Percent Change
May	555,928	529,156	26,772	5.1%	493,031	62,897	12.8%
Jun	429,229	414,423	14,806	3.6%	380,854	48,375	12.7%
Jul	350,230	333,540	16,690	5.0%	311,193	39,037	12.5%
Aug	357,240	327,519	29,721	9.1%	317,208	40,032	12.6%
Sep	364,504	339,140	25,364	7.5%	323,141	41,363	12.8%
Oct	461,920	415,928	45,991	11.1%	409,469	52,450	12.8%
Summer	2,519,052	2,359,706	159,346	6.8%	2,234,898	284,154	12.7%

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 2015 Summer Period is provided in Attachment 1 to Schedule 10B. Page 1 this Attachment 1 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 2015 Summer Period distribution deliveries forecast and a comparison of that forecast to actual, weather normalized data for the 2014 and 2013 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 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. 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 and City-Gate Receipts to meet the Sales Service Deliveries[14] for the upcoming Summer Period.

[14]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.

Table 2. Required City-Gate Receipts Summary			
Month	Total Distribution Service Deliveries (Dth)	Sales Service Deliveries (Dth)	City-Gate Receipts (Dth)
May-15	459,409	151,229	152,188
Jun-15	389,947	100,740	101,379
Jul-15	360,358	91,500	92,080
Aug-15	373,904	95,117	95,720
Sep-15	392,321	104,127	104,787
Oct-15	543,113	194,921	196,157
Summer	2,519,052	737,634	742,311

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, calculations of the city-gate receipts are presented. First, I estimated Company Use by multiplying the forecast Total Deliveries and the estimated ratio of Company-Use to Total Deliveries. Then, Company Use is 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 is added. Each of the estimates used in these calculations was based on the recent history of actual data[15].

[15] Provided in Attachment 3 to Schedule 10B of the 2014-2015 Winter COG filing.

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.

Table 3. Northern Capacity by Supply Source (Dth per Day)

Supply Source	2014-2015 Winter	2015 Summer
Chicago City-Gates Supply	6,434	6,434
PNGTS	1,096	1,096
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	7,474	0
Tennessee Firm Storage	2,644	2,644
Washington 10 Storage	32,885	0
Peaking Supply 1	19,930	0
Peaking Supply 2	19,957	0
Lewiston On-System LNG Production	10,000	10,000

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" 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 includes two separate peaking supply agreements. These peaking supply arrangements were procured through a Request-For-Proposals and have a delivery period beginning November 2014 and ending March 2015. Northern also owns and operates a Liquefied Natural Gas ("LNG") facility in Lewiston, ME, which is capable of producing approximately 10,000 Dth per day and storing approximately 12,000 Dth of LNG. Northern plans to replace its current LNG Contract (which ends March 31, 2015) 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 portfolion since the 2014-2015 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 commodity supplies through annual requests-for-proposal ("RFP") for terms beginning April 1 and running through March 31 each year. Northern submitted its annual RFP for the delivery period beginning April 1, 2015 through March 31, 2016, on February 25, 2015. This RFP sought 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. This summer, Northern plans to issue an 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 2015 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 2014 through October 2015
- New Hampshire Division Capacity Assignment program demand revenues for the period November 2014 through October 2015
- Northern's commodity costs for the period May 2015 through October 2015

- Gains and losses due to Northern's financial hedging program for the period May 2015 through October 2015

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, 2014 through October 31, 2015			
Line	Description	Amount	Reference
1.	Pipeline Demand Costs	$ 8,898,754	Schedule 5A, Page 3 - Pipeline Allocated Cost
2.	Storage Allocated Pipeline Demand Costs	$ 25,879,093	Schedule 5A, Page 3 - Storage Allocated Cost
3.	Storage Demand Costs	$ 3,036,846	Schedule 5A, Page 4 - Annual Fixed Charges
4.	Peaking Allocated Pipeline Demand Costs	$ 1,490,461	Schedule 5A, Page 3 - Peaking Allocated Cost
5.	Peaking Contract Costs	$ 3,271,550	Schedule 5A, Page 5, Annual Fixed Charges
6.	Asset Management and Capacity Release Revenue	$ (11,345,672)	Schedule 5A, Page 6 - Total Asset Management and Capacity Release Revenue
7.	Total Demand Costs	$ 31,231,031	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 2014-2015 Gas Year are forecast.

Support for the transportation and storage demand rates used in Schedule 5A are found in the Attachment to Schedule 5A[16].

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. The 2014-2015 Capacity Assignment Demand Revenue for the New Hampshire Division is projected to be $2,923,632[17]. No changes have been made to this calculation since the 2014-2015 Winter Season filing.

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 10B, and the supply sources available to Northern[18]. 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

[16] The 2014- 2015 Winter Period filing provides an expanded version of Attachment 5A that includes tariff rate pages and supplier contracts.
[17] Support for this number is provided in the 2014-2015 Winter Period Filing, Revised Schedule 5B, Page 1.
[18] Diagrams of capacity paths along with details for each supply source were provided in Schedule 12 in the 2014-2015 Winter Period filing.

cost model was then used 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 2015 Summer Period.

A. Northern's commodity cost forecast for the upcoming Summer Period is summarized in Table 5, below[19].

Table 5. Estimated Delivered City-Gate Commodity Costs and Volumes
May 2015 through October 2015

Supply Source	Delivered City-Gate Costs	Delivered City-Gate Volumes	Delivered Cost per Dth
Pipeline Resources	$ 3,790,308	1,522,866	$ 2.489
Storage Resources	$ -	-	$ -
Peaking Resources	$ 166,186	12,880	$ 12.903
Total Commodity Costs	$ 3,956,495	1,535,746	$ 2.576
Company Managed Revenue	$ -	-	$ -
Off-System Sales Revenue	$ -	-	$ -
Net Sales Service Commodity Costs	$ 3,956,495	1,535,746	$ 2.576

In summary, projected delivered commodity costs equal approximately $4.0 million at an average delivered rate of $2.58 per Dth. In support of this forecast, Schedule 6A shows the monthly forecasted commodity cost by supply option[20]. Page 1 of this Schedule provides forecasted delivered variable costs, including commodity charges, transportation fuel charges, and transportation variable charges by supply option. Page 2 of this Schedule provides monthly delivered volumes (Dth) by supply source[21]. Finally, Page 3 provides monthly delivered cost per Dth by supply source. Each page provides summary data for all supply sources.

[19] This table is also provided in Schedule 2.
[20] Schedule 11C provides the capacity utilization of the resources listed in Schedule 6A.
[21] A modified version of Page 2 of Schedule 6A is provided in Schedule 11A.

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 2015 Summer Period?

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

C. NORTHERN HEDGING PLAN FOR NOVEMBER 2015 THROUGH APRIL 2016

Q. Please provide an update as to the status of Northern's financial Hedging Program.

A. During 2013, changes were made and approved to Northern's Hedging Program such that purchases of natural gas futures contracts have been replaced with purchases of options contracts on futures contracts[22]. The new program's design continues the previous method used to determine the required number of financial hedges, which provides for 70 percent of expected supply requirements at a fixed or capped price using both physical and financial resources. The period covered by the new program's design includes only the traditional gas winter months of November through March, with purchases of option contracts for each future month being executed 18 months prior to contract expiration.

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

The new Hedging Program uses a budget approach to determine option and strike prices whereby the budget is established as a percentage of the futures price at the time of purchase. The Company proposed a budget of 2.5 percent of the futures price at the time of purchase, subject to review each year when it files its Hedging Program plan with the spring cost of gas factor filing.

Q. Has Northern developed a plan for financial hedging the period of November 2016 through March 2017?

A. Yes. Page 1 of Attachment Schedule 20 provides the Hedging Program plan for 2016-17. As shown, option purchases would be made beginning in late April 2015 for the winter month of November 2016 and continue for five months until late August 2015 when the contracts for March 2017 would be purchased. A total of 177 contracts are scheduled to be purchased, which total covers both the Maine and New Hampshire Divisions. Northern proposes to retain the metric of 2.5 percent of futures price to determine the option budget. Using recent market prices and a 2.5 percent budget, the expected cost would be $159,153 and strike prices would range from $4.93 to $5.05.

Q. Are there any impacts from this new Hedging Program on proposed rates covered by this filing, May 2015 through October 2015?

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

E. FERC PIPELINE RATE CASE UPDATE

Q. Please list the interstate pipeline rate cases currently affecting Northern.

A. Northern is currently involved in the following pipeline rate cases at the FERC:

- Portland Natural Gas Transmission System ("PNGTS") has filed rate cases under FERC Docket Nos. RP08-306 ("2008 PNGTS Rate Case") and RP10-729 ("2010 PNGTS Rate Case").

- On November 28, 2014, Canada's National Energy Board ("NEB") approved TransCanada Pipelines Limited settlement agreement ("Settlement") that it reached with the three largest Canadian local distribution companies ("Canadian LDCs"). The Settlement increases tolls on Northern's contracts with TransCanada by approximately 50 percent above the tolls approved by the NEB in its March 27, 2013 decision on the 2014 and 2015 TransCanada Tolls Application ("NEB Order").

Q. Please provide an update to the 2008 PNGTS Rate Case.

A. On May 21, 2014, PNGTS refunded reservation charges that were paid subject to refund, including interest, to Northern. As I mentioned earlier in my testimony, this refund was flowed through to customers in the 2013-2014 Winter Season filing as well as in the 2014 Summer Season filing. On February 19, 2015, the FERC issued Opinion No. 51-B which denied PNGTS' appeal of FERC's initial decision in this case thereby concluding this rate proceeding.

Q. Please provide an update on the 2010 PNGTS Rate Case.

A. FERC issued its Order on the 2010 PNGTS Rate Case Initial Decision ("Opinion 524") on March 21, 2014. Requests for Rehearing on Opinion 524 were filed by the Portland Shippers Group ("PSG") and PNGTS in April 2014. On February 19, 2015, FERC issued Opinion 524-A denying most of PSG's and PNGTS's requests for rehearing of its initial Order. Also, in Opinion 524-A, FERC ordered PNGTS to submit revised tariff sheets by March 23, 2015, and to submit refunds by April 20, 2015.

Q. Has Northern made any adjustments to COG rates as a result of the FERC Order?

A. Yes. PNGTS submitted its compliance tariff sheets on March 6, 2015, effective December 1, 2010. These tariff sheets reflect the PNGTS rates per the FERC Order. I have included these rates in my COG calculations.

Q. How large of a refund is Northern expecting to receive from PNGTS?

A. Northern is expecting to be refunded approximately $22 million. Of this amount, the portion allocated to the New Hampshire Division is estimated to be slightly less than half.

Q. How is Northern proposing to flow back the PNGTS refund to its sales customers?

A. Typically, Northern would flow back PNGTS Supplier Refunds (less outstanding litigation costs) to sales customers through a separate refund account over a 12-month period with interest calculated at the prime interest rate. From this account, Northern derives a single per therm credit applicable to all rate classes. This is consistent with the Supplier Refund provision of Northern's tariff. However, due to the size of the PNGTS refund, the Company proposes to flow back the refund to sales customers using an alternative methodology ("Alternative Refund Proposal"). With the Alternative Refund Proposal, Northern will flow back the PNGTS refund over a three-year period with interest calculated at the Company's short-term borrowing rate. In addition, the refund will be applied to the Company's projected demand costs as opposed to through a separate Supplier Refund account.

Q. Why does Northern propose to use the Alternative Refund Proposal for flowing back the PNGTS refund?

A. Northern proposes using the Alternative Refund Proposal for two main reasons. First, flowing back the refund over a three-year period helps promote rate stability. If the entire refund is returned to sales customers over a one-year period, then COG rates will be unusually low for one year and then substantially higher the following year as COG rates return to market-based levels. Highly unstable COG rates make it difficult for sales customers to anticipate and plan for their heating needs and/or energy budgets. In addition, the refund amount has been built up over a period of four plus years. Thus, Northern, believes the proper flow back of this refund is also over a multi-year period. Second, the Company believes the return of the PNGTS refund should mirror and track the same method used by the Company to assign PNGTS demand costs to the customer classes, especially since this refund is due to past PNGTS demand cost overcharges. Northern believes utilizing a single per therm refund credit results in a return that is unfair to certain customer classes. By applying the refund as a credit to demand costs, customers that paid the higher per unit rate for PNGTS costs in the past will rightfully receive in the future a higher per unit credit (via a reduced demand charge) from the refund. Therefore, the Alternative Refund Proposal is more equitable to the customer classes.

Q. Why does Northern propose to accrue interest at the Company's short-term borrowing rate as opposed to the prime interest rate?

A. Since the Company proposes to extend the refund period over 3 years, it should not be penalized by its attempt to promote rate stability. The current prime interest rate is 3.25% while the Company's short-term borrowing rate is 1.55%. As an LDC, Northern is continuously borrowing money. In this case, the Company proposes to use the receipt of money from PNGTS to pay down temporarily its short-term debt balance until the entire refund is credited to customers. Since the Company will use outstanding refund amounts to finance short-term debt, paying customers the short-term borrowing rate on these balances is fair because it will not increase the Company's interest expenses over the extended term of the refund payback period. By applying the short-term borrowing rate to outstanding refund balances instead of the prime interest rate, the Company will be neutral with regards to interest payments.

Q. If Northern's proposal to use the short-term borrowing rate is not approved, will the Company still propose to use the Alternative Refund Proposal?

A. No. In the event the short-term borrowing rate is not approved by the Commission, the Company will flow back the PNGTS refund to sales customers in accordance with the Company's current tariff provisions.

Q. **Has Northern utilized the Alternative Refund Proposal for prior pipeline refunds?**

A. Northern has not used the Alternative Refund Proposal in the New Hampshire Division. However, Northern has used a similar methodology to flow back a prior PNGTS refund[23] to its Maine Division sales customers. In that case, the Company flowed back the refund as a reduction to demand costs over a one-year period with interest at the short term borrowing rate. Further, in Northern's 2015 Summer Maine Division COG proceeding, the Company will propose the same methodology but with a return over a three-year period.

Q. When does Northern propose to begin flowing back the PNGTS refund?

A. The Company proposes to file its estimated calculations in support of the refund, which is not scheduled to be made until April 20, 2015, in its revised COG filing or sooner, and to begin flowing back the PNGTS refund to sales customers in this 2015 Summer COG proceeding with rates effective May 1, 2015.

Q. Please provide an update of the TransCanada Application for approval of the Settlement with the Canadian LDCs.

A. On December 20, 2014, TransCanada filed with the NEB for approval of a Settlement with the Canadian LDCs. The Settlement involves segmenting the eastern portion of the mainline from the western portion of the mainline, with increased tolls along the eastern portion reflecting a premium to cover revenue shortfalls on the western portion for the period of 2015-2020. Post 2020, the eastern portion tolls would be separate from the

[23] In FERC Docket No. RP08-306.

western portion. Upon approval, TransCanada would be willing to construct new short haul transportation capacity in the east, but would require 15 year commitments. In response to the NEB order issued in March 2014, TransCanada had taken the position they would not expand its system so long as any capacity remained unsubscribed, including capacity on the western portion of the system.

The Settlement was approved by the NEB on November 28, 2014. As approved, the Settlement increases rates for the last three years of the 2015-2020 period and beyond. Toll increases will be approximately 50 percent above tolls determined in the NEB's most recent Order. In addition, TransCanada would retain its new enhanced pricing flexibility in discretionary markets that were provided for under the NEB Order. TransCanada would also gain the right to unilaterally require shippers, including Northern, to extend agreements whenever TransCanada plans to invest to expand its pipeline to meet new contract requirements. Currently, Northern has the right to extend or terminate its contracts upon two years notice prior to the current termination date.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2015 Summer Period COG if it receives any new or updated information on gas supplier or transportation rates?

A. Yes. The Company plans to file a revised calculation of its 2015 Summer Period COG to reflect updated gas and pipeline transportation cost projections as well as any other cost information a few weeks prior to the effective date of May 1, 2015.

Q. Does this conclude your testimony?

A. Yes it does.