NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
NOVEMBER 2016 / OCTOBER 2017 ANNUAL PERIOD
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 have testified before the Commission in the 2015 / 2016 Winter Period Cost of Gas ("COG") proceeding, Docket No. DG 15-393; and the 2016 Summer Period COG proceeding, Docket No. DG 16-309. I have testified in numerous other Cost of Gas proceedings as well.

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

A. In Docket No. DG 16-564, the Commission approved Northern's request to submit its Winter Period[1] COG rates and Summer Period[2] COG rates in a single annual filing[3]. In addition, the Order allowed Northern to submit an annual reconciliation filing in lieu of separate summer and winter period reconciliation filings. Prior to this Order, Northern had submitted two separate COG filings and reconciliations; one in September for Winter Period COG rates, and one in March for Summer Period COG rates. This filing reflects the first annual reconciliation and COG filing and will present both 2016 / 2017 Winter Period and 2017 Summer Period COG rates. I, Francis Wells, Manager of Gas Supply for Unitil Service, and Joseph Conneely, Senior Regulatory Analyst for Unitil Service are sharing the responsibility of supporting the proposed New Hampshire Division 2016 /

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[1] Winter Period is also referred to as Winter Season.
[2] Summer Period is also referred to as the Summer Season.
[3] Order No. 25,940, issued August 25, 2016.

2017 Annual COG and other proposed rate adjustments in this proceeding with testimony.

Mr. Wells's testimony is with regard to the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. Mr. Wells also describes the impact of the Company's Hedging Program on the 2016 / 2017 Winter Period costs.

Mr. Conneely's testimony concerns the calculation of the 2016 / 2017 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2016 / 2017 Winter Period and 2017 Summer Period COG rates.

My testimony presents and explains the New Hampshire Division's 2015 / 2016 Annual Reconciliation, the calculation of the 2016 / 2017 annual COG and the rates Northern proposes to charge customers for the November 1, 2016 to April 30, 2017 Winter Period, and for the May 1, 2017 to October 31, 2017 Summer Period.

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
Schedule 1A	Allocation of New Hampshire Fixed Capacity Costs To Months and Seasons
Schedule 1B	New Hampshire Division Commodity Cost Analysis
Schedule 3	New Hampshire Division (Over) / Under-collection Balances and

	Interest Calculations
Schedule 4	Bad Debt
Schedule 9	Variance Analysis / Comparison to 2015-2016 Winter & 2016 Summer
Schedule 10A	Allocation of New Hampshire Demand Costs To New Hampshire Firm Sales Rate Classes
Schedule 10B	Division Sales and Sendout Forecast
Schedule 10C	Allocation of New Hampshire Variable Gas Costs To New Hampshire Firm Sales Rate Classes
Schedule 14	Northern Utilities Inventory Activity
Schedule 15A Schedule 15B	2015-2016 Winter Period COG Reconciliation November 2015 – October 2016 Annual Reconciliation
Schedule 18	Supplier Balancing Charge
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 24	Short Term Debt Limit Calculation
Schedule 25	PNGTS Refund
Schedule 26	NH PUC Consultant Costs

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. The allocation of Northern's costs to the New Hampshire Division rate classes is derived through three steps. They are as follows:

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

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

Step 3 – Allocate New Hampshire Division seasonal costs by rate class.

I will 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 demand/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. Total Northern 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[4], are allocated to calendar 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[5] in that month. This MPR methodology was approved by the Commission on December 30, 2005 to be effective January 1, 2006. Subsequently, on June 1, 2006, the Commission issued 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-related costs to the Maine and New Hampshire Divisions for the

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4 These resources are pipeline, storage, and peaking.

5 For the MPR allocation process, Design Year demand is calculated as the actual demand of the Maine and New Hampshire Divisions' firm sales and assigned-capacity / non-grandfathered transportation customers for the period May 2015 through April 2016, adjusted to reflect design winter effective degree day ("EDD") conditions from November through April and normal EDD conditions from May through October.

2016 / 2017 Winter Season (November 2016 through April 2017), and for the 2017 Summer Season (May through October 2017).

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2016 through October 2017 to the Maine and New Hampshire Divisions.

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 the period November 2016 through October 2017 ("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), are summarized in Lines 1 through 10.

(2) Total 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 (Schedule 21, pages 1 and 3), with the MPR allocators based on design year sendout volumes for each resource type.

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

I note the last column of Pages 2, 4, 6, 8 and 10 of Schedule 21 are descriptions of the sources of data and explanations of the calculations included in the schedule. Similar explanations are included in other attachments to my testimony.

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

A. Lines 3 through 6 of Schedule 21 show total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources. The forecasted demand costs were provided to me by Mr. Wells.[6] Mr. Wells also provided estimates of Capacity Release revenues and Asset Management revenues, which I have summarized as credits in Lines 8 and 9 of Schedule 21.

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 Injection Fees by month. Injection Fees are the capacity costs of that portion of Northern's pipeline capacity that is used to transport gas to the underground storage fields. The Injection 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.

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[6] The forecast of demand costs that Mr. Wells prepared is provided in Schedule 5A.

Northern's fixed capacity costs that have been allocated to each month are summarized and consolidated on Lines 50 through 56 of Schedule 21. 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) 1/5th of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54; and (b) 1/6th 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. Total Northern Demand Costs and Capacity Release and net Asset Management revenues that are allocated to each month are then allocated to the Maine and New Hampshire Divisions according to the design year total sendout for the Maine and New Hampshire Divisions, which is shown in lines 61 and 62 of Schedule 21. The calculated percentages are provided in lines 65 and 66. The design year sendout quantities 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 conditions from May 2015 through April 2016.

As shown on Line 90 of Schedule 21, 43.73% of Northern's total demand costs from November 2015 through October 2016 will be allocated to the New Hampshire Division and the remaining 56.27%, as shown on Line 81, will be allocated to the Maine Division.

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 2016 / 2017 Winter Season and the 2017 Summer Season.

A. Northern allocates costs between the seasons as well as among customer classes through the Simplified Market Based Allocation ("SMBA") method. 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 utilizing the SMBA method.

Lines 2 through 4 of Schedule 1A summarize the Pipeline and 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 for firm sales customers, which is Total Demand Costs allocated to the New Hampshire Division less the capacity assignment revenues from New Hampshire Division transportation customers. The Winter and Summer Season rates that will be charged to New Hampshire Division firm sales customers from November 2016 through October 2017 will recover: (1) the Net Pipeline Demand costs shown on Line 20; (2) the

Net Storage costs shown on Line 21; and (3) the Peaking demand costs shown on Line 22 of Schedule 1A.[7]

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.[8] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2017[9] 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") allocator that is used to allocate (a) Remaining Use Net Pipeline Demand costs, (b) Storage and Peaking costs and (c) Supplier Refunds related to Firm Sales customers for twelve months, November 2016 through October 2017. Lines 52 through 57 show the calculation of the PR factor that is used to allocate (d) Capacity Release and Asset Management revenues and (e) Interruptible margins and Delivery-to-Sales revenues to the Winter Season months, November 2016 through April 2017. These

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[7] These direct demand costs are adjusted by Capacity Release and Asset Management revenues (Line 76); Interruptible margins (Line 77); Re-Entry Fee Credits (Line 78); and PNGTS Refunds (Lines 79 & 80).

[8] 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.

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

PR factors are summarized by type of capacity cost in lines 61 through 65. Line 61 of Schedule 1A shows that 1/12th of the net annual Base Use pipeline demand costs is allocated to each month, and Lines 68 through 86 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.

As shown on Line 81 of Schedule 1A, $8,327,997 of direct demand costs are allocated to the 2016/ 2017 Winter Season, and $838,422 is allocated to the 2017 Summer Season.

C. Allocation of New Hampshire Winter and Summer Season Demand Costs to Customer Classes

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter and Summer Seasons are 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 costs for a 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 Winter and Summer Season base demand-related costs 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. The base and remaining sendout values for each class are used to allocate the seasonal demand costs to the New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Winter and Summer Season 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 Winter Season and Summer Season month as shown in Schedule 1A, Lines 67 through 81, and (b) the Rate Class allocators as shown Schedule 10B, Lines 49 to 80. 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. 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

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[10] for firm sales. Mr. Wells prepared a forecast of Northern's variable gas costs by month, which is provided in Schedule 6A. 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 / 2017 Winter and Summer Season variable gas costs between the Maine and New Hampshire Divisions.

Q. Please explain Schedule 22.

A. Lines 1 through 10 of Schedule 22 show the projected sendout volumes, by month and by resource type, which Mr. Wells provided to me. Mr. Wells also provided the projected variable costs by month and by type of gas supply resource that are shown on Lines 12, and Lines 19 through 21 of Schedule 22. This Schedule also shows projected Off-system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of August 28, 2016. Lines 27 through 35 show the estimated gains and losses based on the Company's hedging program[11]. The variable gas costs and hedging gains and losses for firm sales service that are summarized

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

[11] These costs are allocated to the Winter Season only.

on Lines 38 and 35, respectively, are allocated to the Maine and New Hampshire Divisions based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 53, 54, 58 and 59. Schedule 22 also shows the allocation of (a) Commodity costs (Maine Division: Lines 64, 66, 67, and 68; New Hampshire Division: Lines 73, 75, 76, and 77); and (b) net hedging costs (Lines 65 and 74) to the Maine and New Hampshire Divisions respectively. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 98 to 100), 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 Winter Season, using the firm sales remaining sendout allocators (Lines 114 to 116).

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

Q. Please explain how you calculated the inventory finance costs for underground storage and LNG resources that are included in Schedule 22, Lines 70, 79, and 88.

A. The inventory finance charges that are shown on Lines 70, 79, and 88 of Schedule 22 are derived from the inventory finance costs that are shown on Lines 98 and 99 of Schedule

22[12]. These inventory finance costs were calculated based on forecasted inventory activity calculations which are shown in Schedule 14.

Q. Why are no inventory finance costs (or "carrying costs") shown for Washington 10 Storage on Schedule 22 or calculated in Schedule 14?

A. Under its current Asset Management Arrangement, which runs through March 2017, the Company does not incur inventory finance costs on the Washington 10 inventories, and the Company anticipates contracting for similar terms beginning April 1, 2017. For this reason, no inventory finance costs for Washington 10 Storage were calculated or included in rates.

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. 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 New Hampshire Division Base Commodity and Base Hedging costs[13] 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

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[12] Schedule 22 shows November through April commodity costs. Inventory finance costs for May through October are included in the total annual costs (i.e. November through October) shown in Column N of Lines 98 through 100. Total 2016 / 2017 inventory finance costs allocated to New Hampshire (Line 104) are recovered in the Winter Season, as shown on Line 79 of Schedule 22.

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

Commodity and Remaining Hedging costs[14] 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. In April 2015, Northern received a $22 million refund from PNGTS, of which about $10.4 million is allocated to Northern's New Hampshire Division. This refund is being flowed back to both sales and non-exempt delivery service customers over a three year period with 50% flowed back the first year, 30% the second year and 20% the third year. The crediting of PNGTS refund began in the summer of 2015. Therefore, the Winter 2016 / 2017 COG Period reflects the second half of the second year's refund, and the Summer 2017 COG Period reflects the first half of the third year's refund.

Consistent with the methodology approved in the 2015 Summer Period COG proceeding, Northern is applying the refund to Sales Service customers as a credit to Northern's total expected demand costs included within the Summer and Winter COG periods. By applying the refund to total demand costs, the refund will flow back to sales service customers in the same manner as the PNGTS over-collection was charged. Non-exempt Delivery Service customers receive their refund on a prospective basis through a reduction in their Company Managed Demand Charge. The crediting of the PNGTS

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

refund to Sales Service customers for the Winter Period portion of the second year, and the Summer Period portion the third year is shown in Schedule 1A on lines 79 and 80.

I have provided Schedule 25 to show how the net refund allocated to Northern's sales customers is derived for the both the 2016 / 2017 Winter Period and the 2017 Summer Period. Column D of Schedule 25 shows the expected remaining balance at the start of the second year of the refund (May 1, 2016). Of this amount, 60% of the balance is allocated to the second year of the refund (30% of the total refund) as shown in Column E. From this amount, the estimated portion allocated to marketers (Column F) is subtracted as well as the amount credited back over the 2016 Summer Period (Column H). The difference, $1,990,806 (Column I), represents the amount of the refund to be credited to Sales Customers in the 2016 / 2017 Winter Period. Schedule 25 also provides an estimate of the refund to be credited back in the 2017 Summer Period, $99,400 (Column K).

F. <u>2015 / 2016 Annual Reconciliation</u>

Q. As stated earlier in your testimony, Northern is submitting an annual reconciliation in lieu of a Winter Season reconciliation that is typically submitted at this time of year. Please explain the 2015 / 2016 Annual COG reconciliation in greater detail.

A. For this filing, I have provided two reconciliations. The first is for the 2015 / 2016 Winter Period and is provided as Schedule 15A. This reconciliation was initially submitted on August 1, 2016 and precedes the approval of Northern's annual reconciliation proposal. The second reconciliation represents Northern's initial annual reconciliation and is provided as Schedule 15B. For this annual reconciliation, I have separated many of the Form III schedules into three parts[15]. The first and top part of the schedules provide the reconciliation of the November 2015 to April 2016 Summer Period which had not previously been reconciled. The second and middle part of the schedules provide the November 2015 to April 2016 portion of the Winter Period reconciliation that was submitted on August 1, 2016. The third and bottom part of the schedules combines the Summer and Winter Period reconciliations for November 2015 through April 2016, and provides the annual reconciliation values for May 2016 through July 2016. In addition, the third part includes estimates of the August 2016 to October 2016 period. As Page 1 of Schedule 15B indicates, the October 31, 2016 Annual Ending Balance is projected to be an under-collection of $1,065,828.

I have also modified Page 1 of the Annual Reconciliation to show how the ending balance will be allocated between the upcoming 2016 / 2017 Winter and 2017 Summer Seasons. As Page 1 illustrates, the allocation between seasons will be based on the portion of projected sales that occur in each season. Similar allocations are provided for Attachment A (Working Capital) and Attachment B (Bad Debt).

G. Miscellaneous Charges and Credits

Q. Are you projecting that Northern will receive any Re-Entry Fee Credits from transportation customers returning to sales service during the 2016 / 2017 Winter Season?

[15] For example, see Form III Schedule 2 where the top of Page is the Summer Season, the middle of Page is the Winter Season and the bottom of Page is the Annual Period.

A. Northern is projecting no Re-Entry Fee Credits in this period.

Q. How were Northern's Working Capital Costs derived?

The Working Capital Costs were based on a formula was approved in Northern's 2011 base rate proceeding, Docket No. DG 11-069. This formula derives the working capital percentage by dividing the supply related net lag of 9.25 days by 365 days and then multiplying the result by the prime rate. Based on the current prime rate of 3.5%, the Working Capital Percentage is 0.0887%. This percentage, when multiplied by the each season's forecasted Direct Cost of Gas, yields a 2016 / 2017 Winter Season Working Capital Cost of $19,386 and a 2017 Summer Period Working Capital Cost of $2,572. These amounts are included in the Summary Schedule at lines 32 and 143.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2016 / 2017 Winter Season and 2017 Summer Season COGs?

A. To develop its bad debt projections, Northern forecasts 12 months of customer write-offs for both supply and distribution service. This forecast is based on actual experience and any recent unexpected increases or decreases in the number of customer write-offs.

As shown on Line 3 of Schedule 4 for the 12-months ended July 31, 2015, actual write-offs for Northern's New Hampshire Division were $390,581. For the twelve months ended December 31, 2017, Northern projects annual Bad Debt expense to be $438,000 (Line 14).

The projected annual Bad Debt expense was then allocated to supply (47%) and distribution (53%) services based on the actual Bad Debt experience of these components over the 12-months ended July 31, 2016. This is shown on Lines 7 and 5, respectively, of Schedule 4. The annual Bad Debt expense forecast allocated to supply, $206,045 as shown on Line 15, was then allocated further to the 2016 / 2017 Winter Season (91%) and 2017 Summer Season (9%) based on the allocation of demand costs between the Winter and Summer Seasons. This breakout establishes the Winter Season Bad Debt of $187,199 (Line 19) and a Summer Season Bad Debt expense of $18,846. I have included these expenses at lines 39 and 150 in the Summary Schedule.

Q. Please explain the costs related to the Company's local production and storage facilities, and Other Administrative and General ("A&G") expenses that are included in the Winter Season COG.

A. Northern's local production and storage costs were set at $420,658 in the Company's most recent base rate case proceeding, Docket No. DG 13-086, and are recovered solely in the Winter Season. Also in the last base rate case proceeding, A&G expenses were set at $512,686. Of this amount, $408,908 is recovered from sales customers in the Winter Season and $103,760 is recovered in the Summer Season. These amounts are included in the Summary Schedule on lines 43, 45, 154 and 156.

Q. Please explain the line item "NHPUC Consulting Costs" that appears on lines 23 and 134 of the Summary Schedule.

A. Per RSA 365:38 and 365:38-a, the Company is proposing to recover NHPUC Consulting Costs incurred by the New Hampshire PUC for consultants hired to work on Northern's Docket No. IR 15-009. I have provided support for these amounts in Schedule 26.

Q. Has the Company recovered consulting costs through it Cost of Gas Clause before?

A. Yes, in Docket No. DG 11-045, Northern recovered the New Hampshire Division's share of consulting costs incurred by the NHPUC for work on a Granite State Gas Transmission Pipeline rate case at FERC, RP 10-896.

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

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2016 / 2017 Winter Season and the 2017 Summer Season.

A. The Summary Schedule, which is similar to the Company's COG tariff Pages 42, 42.1, 43 and 43.1, has been prepared to explain the calculation of the proposed 2016 / 2017 Winter and 2017 Summer COG factors. The text descriptions in Column D, pages 2, 4, 6, 8 and 10 explain the calculations on this tariff page and provide references to other schedules for the sources of the data that appear on the COG tariff pages. This Summary Schedule shows the calculation of the Winter and Summer Season COGs 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 Page 3 of the Summary Schedule, the 2016 / 2017 Winter Season projected Average Cost of Gas is $0.7558 per therm (Line 68), which is the sum of the average

Total Direct Cost of Gas, $0.6927 per therm (Line 61) and the average Indirect Cost of Gas, $0.0631 per therm (Line 65). As shown of Page 7 of the Summary Schedule, the 2017 Summer Season, the projected Average Cost of Gas is $0.4055 per therm (Line 179), which is the sum of the average Total Direct Cost of Gas, $0.3622 per therm (Line 172) and the average Indirect Cost of Gas, $0.0433 per therm (Line 176).

Also shown on the Summary Schedule are the proposed residential COG Factors for the 2016 / 2017 Winter Period (Line 70) and the 2017 Summer Period (Line 181), the proposed C&I Low Winter Use COG Factors for the 2016 / 2017 Winter Period (Line 74) and 2017 Summer Period (Line 185), and the proposed C&I High Winter Use COG Factors the Winter 2016 / 2017 Winter Period (Line 94) and 2017 Summer Period (Line 205).

1. 2016 / 2017 Winter Season COG

Q. What are the major components of the 2016 / 2017 Winter Season Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown on page 1 in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$2,760,644	3
2	Purchased Gas Supply Costs	$9,964,565	4
3	Storage and Peaking Capacity Costs	$9,240,209	7
4	Storage and Peaking Commodity Costs	$3,496,207	8
5	Hedging Cost / (Gain)	$64,809	10

6	Inventory Financing	$2,083	12
7	Capacity Release and AMA revenue	($3,672,857)	14
8	Total Anticipated Direct Cost of gas	$21,855,615	18

Q. What are the major components of the 2016 / 2017 Winter Season Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown on page 1 in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	$850,112	22
2	NH PUC Consultant Costs	$20,828	23
3	Interest	$(901)	24
4	Interruptible Margins	$0	26
5	Working Capital Allowance	$20,037	36
6	Bad Debt Allowance	$269,875	41
7	Local Production and Storage	$420,658	43
8	Miscellaneous Overhead	$408,908	45
9	Total Anticipated Indirect Cost of Gas	$1,989,516	47

Q. Please explain the calculation of the Working Capital allowances for the 2016 / 2017 Winter Season COG.

As mentioned earlier in my testimony, the total Working Capital allowance, $20,037 is shown on Line 36 of the Summary Schedule is the sum of the current period working capital allowance, $19,386 (Line 32), plus the prior seasonal allocations of Working Capital reconciliation balance, $651 (Line 34).

Q. Please explain the calculation of the Bad Debt factors for 2016 / 2017 Winter COG.

A. As mentioned earlier in my testimony, the Bad Debt allowance, $269,875 (Line 41), is the sum of the current period bad debt allowances, $187,199 (Line 39), plus the seasonal allocations of the Bad Debt reconciliation balance, $82,676 (Line 40).

2. 2017 Summer Season COG

Q. What are the major components of the 2017 Summer Season Anticipated Direct Cost of Gas?

A. The table below identifies the major components of Anticipated Direct Gas Costs, as shown on page 5 in the Summary Schedule.

			Summary Schedule, Line:
1	Purchased Gas Demand Costs	$437,194	114
2	Purchased Gas Supply Costs	$2,032,100	115
3	Storage and Peaking Capacity Costs	$401,228	118
4	Storage and Peaking Commodity Costs	$29,565	119
5	Hedging Cost / (Gain)	$0	121
6	Inventory Financing	$0	123
7	Capacity Release and AMA revenue	$0	125
8	Total Anticipated Direct Cost of gas	$2,900,087	129

Q. What are the major components of the 2017 Summer Season Anticipated Indirect Cost of Gas?

A. The table below identifies the major components of Anticipated Indirect Gas Costs, as shown on page 5 of in the Summary Schedule.

			Summary Schedule, Line:
1	Prior Period (Over) / Under-collection	$215,716	133
2	NH PUC Consultant Costs	2,169	134
3	Interest	$(17,900)	135
4	Interruptible Margins	$0	137
5	Working Capital Allowance	$2,738	147
6	Bad Debt Allowance	$39,825	152
7	Local Production and Storage	$0	154
8	Miscellaneous Overhead	$103,760	156
9	Total Anticipated Indirect Cost of Gas	$346,308	158

Q. Please explain the calculation of the 2017 Summer Season Working Capital allowances.

As mentioned earlier in my testimony, the total Working Capital allowance, $2,738 is shown on Line 147 of the Summary Schedule is the sum of the current period working capital allowance, $2,572 (Line 143), plus the prior seasonal allocations of Working Capital reconciliation balance, $165 (Line 145).

Q. Please explain the calculation of the 2017 Summer Season Bad Debt factors.

A. As mentioned earlier in my testimony, the Bad Debt allowance, $39,825 (Line 152), is the sum of the current period bad debt allowances, $18,846 (Line 150), plus the seasonal allocations of the Bad Debt reconciliation balance, $20,979 (Line 151).

I. <u>Summary Analyses</u>

Q. How does the proposed average 2016 / 2017 Winter Season COG rate compare to the actual 2015 / 2016 Winter Season COG?

A. Schedule 9 compares the proposed 2016 / 2017 Winter Season average COG to the actual 2015 / 2016 Winter Season COG. Schedule 9 indicates the projected 2016 / 2017 Winter Season average COG rate, $0.7558 per therm, is $0.1221 per therm higher than the actual 2015 / 2016 Winter Season Total Adjusted COG, $0.6337 per therm. This $0.1221 per therm increase is partially due to higher demand costs resulting from a smaller PNGTS refund and a smaller amount of revenues from capacity release and asset management. Other factors contributing to the higher 2016 / 2017 Winter Season COG rates are off-system sales revenues in 2014 / 2015, the incurrence of New Hampshire PUC consulting costs in the 2016 / 2017 COG and a projected under-recovery for the Winter Period of the 2015 / 2016 annual reconciliation compared to an over-recovery in the 2014 / 2015 Winter Season reconciliation.

Q. How does the proposed 2017 Summer Season COG rate compare to the filed 2016 Summer Season COG?

A. Schedule 9 Compares the proposed 2017 Summer Season average COG to the filed 2016 Summer Season COG[16]. As this Schedule indicates, the projected 2017 Summer Season average COG rate, $0.4055 per therm, is $0.0859 per therm higher than the filed 2016 Summer Season COG, $0.3196 per therm. This $0.0859 per therm increase is primarily due to a reduction in Northern's Summer Period forecast and a higher projected under-

[16] The final average 2016 Summer Season COG rate may vary from the filed COG rate due to monthly rate adjustments that may occur.

recovery for the Summer Period of the 2015 / 2016 annual reconciliation compared to the 2015 Summer Season reconciliation.

III. SUPPLIER BALANCING CHARGE AND ADDITIONAL SCHEDULES

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2016 through October 31, 2017?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2016, $0.77 per MMBtu, is the same as the currently effective Supplier Balancing Charge. I have prepared Schedule 18 to support the Supplier Balancing Charge.

Q. Are there any additional schedules included in this filing that have not been discussed?

A. Yes, Schedules 3, 23 and 24 in my testimony. Schedule 3 determines Northern's projected monthly over/under-collections, balances, and interest calculations. Schedule 23 provides additional supporting detail to the calculation of the COG rates. Lastly, Schedule 24 determines Northern's short-term debt limit calculation for the period November 2016 through October 2017.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2016 / 2017 Winter Season COG if it receives any new or updated information on gas supplier or transportation rates?

A. Yes. In early October, the Company will review its calculation of its 2016 / 2017 Winter and Summer Season COGs using updated gas and pipeline transportation cost projections as well as any other changes in cost information. If Northern anticipates that a significant change in COG rates is warranted, then it will submit revised COG rates a few weeks prior to the effective date of November 1, 2016.

In addition, the Company will file proposed changes to the approved 2016 / 2017 Winter Season COG when the projected end of season variance exceeds 2% of the target projected cost of gas[17]. As mentioned above, Schedule 3 projects Northern's monthly over/under collections, balances and interest. Northern will update this schedule each month with actual costs and updated NYMEX prices in order to determine the variance between the latest projected end of season balance and the target end of season balance established in the COG filing. As indicated on Line 109 on that schedule, Northern projects an over collection target balance of ($2,086,122) on April 30, 2017. If, during the upcoming Winter Season, the Company's updated projected April 30, 2017 ending balance varies from the target balance by 2% or more of total target projected gas costs, then the Company will file to adjust the 2016 / 2017 Winter Season COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2016 / 2017 Winter Season COG.

Lastly, the Company will also file proposed changes to the approved 2017 Summer Season COG when the projected Summer Period end of season variance exceeds the target variance by 4% or more of projected gas costs. During the Summer Period,

[17] The calculation of the end of season variance is explained in greater detail in pages 7 through 12 of my testimony in Docket No. DG 16-564, submitted June 15, 2016.

Northern projects an under-collection that will offset the Winter Period under-collection. If, during the upcoming Summer Season, the Company's updated projected October 31, 2017 Summer Period ending balance varies from the target balance by 4% or more of total targeted projected gas costs, it will then file to change the 2017 Summer COG for the subsequent month. These rates will take effect without further action by the Commission for any decrease and for increases up to 25% of the initially-approved 2017 Summer Period COG.

Q. Does this conclude your testimony?

A. Yes it does.