NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2014 / 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 have testified before the Commission in the 2013 / 2014 Winter Period Cost of Gas ("COG") proceeding, Docket No. DG 13-257; and the 2014 Summer Period COG proceeding, Docket No. DG 14-077. I have testified in several other Cost of Gas proceedings as well.

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

A. Francis Wells, Manager of Gas Supply for Unitil Service, Joseph Conneely, Senior Regulatory Analyst for Unitil Service and I are sharing the responsibility of supporting the proposed New Hampshire Division 2014 / 2015 Winter Period 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 2014/ 2015 Winter Period costs.

Mr. Conneely's testimony concerns the calculation of the 2014 / 2015 Local Distribution Adjustment Clause ("LDAC"), and the typical customer bill impacts resulting from the proposed 2014 / 2015 Winter Period COG rates.

My testimony presents and explains the New Hampshire Division's 2013 / 2014 Winter Period Reconciliation, the calculation of the 2014 / 2015 Winter Period COG and the rates Northern proposes to charge customers from November 1, 2014 to April 30, 2015.

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 Bad Debt, Working Capital
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 (Actual/Forecast)
Schedule 9	Variance Analysis / Comparison to 2013-2014 Winter
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 15	2013-2014 Winter Period COG Reconciliation
Schedule 18	Supplier Balancing Charge
Schedule 19	Capacity Assignment Calculations
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

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[1], 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[2] in that month. Initially, this MPR methodology was approved orally 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 granting written approval of the MPR methodology.

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 2014 / 2015 Winter Season (November 2014 through April 2015), and for the 2015 Summer Season (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.

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 2014 through October 2015 ("the COG Period") to the Maine and New Hampshire Divisions. Schedule 21 is arranged in three major sections:

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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 of 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 effective degree day ("EDD") conditions from November through April and normal EDD conditions from May through October.

(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 and 4 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.[3] Mr. Wells also provided estimates of Capacity Release revenues and

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

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.

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 2013 through April 2014.

As shown on Line 90 of Schedule 21, 47.67% of Northern's total demand costs from November 2014 through October 2015 will be allocated to the New Hampshire Division and the remaining 52.33%, 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 2014 / 2015 Winter Season and the 2015 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 2014 through October 2015 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 on Line 22 of Schedule 1A.[4]

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.

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4 These direct demand costs are adjusted by Capacity Release and Asset Management revenues (Line 76); Interruptible margins (Line 77); and Re-Entry Fee Credits (Line 78).

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.

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 and (b) Storage and Peaking costs related to Firm Sales customers for twelve months, November 2014 through October 2015. Lines 52 through 57 show the calculation of the PR factor that is used to allocate (c) Capacity Release and Asset Management revenues and (d) Interruptible margins and Delivery-to-Sales revenues to the Winter Season months, November 2014 through April 2015. These 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 85 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 2014 / 2015 Winter Season COG rates, $12,605,326, is shown in Schedule 1A, on Line 80, Winter column.

C. <u>Allocation of New Hampshire Winter Season Demand Costs to Customer Classes</u>

Q. Please explain how the New Hampshire Division sales service demand-related costs that were allocated to the Winter Season 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 prorata 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 prorata 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 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 Winter Season demand costs to New Hampshire Division firm sales classes.

I have prepared Schedule 10A to show the allocation of Winter 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 month as shown in Schedule 1A, Lines 67 through 80, 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[7] 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 2014 / 2015 Winter Season 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, 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-

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

system Sales revenues on Line 22. The pipeline commodity costs shown on Lines 12 and 19 are based on projected NYMEX prices as of September 2, 2014. Lines 27 through 35 show the estimated gains and losses based on the Company's time-triggered hedging program, and the projected NYMEX prices. The variable gas costs and hedging gains and losses for firm sales service that are summarized on Lines 35 and 38 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. Gains and losses based on the price-triggered hedging program are shown on Lines 31 through 37. The price-triggered hedging gains and losses are directly assigned to the New Hampshire Division. 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) hedging gains and losses (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[8]. 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 2015, the Company does not incur inventory finance costs on the Washington 10 inventories, and the Company anticipates contracting for similar terms beginning April 1, 2015. 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

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8 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 2014/2015 inventory finance costs allocated to New Hampshire (Line 104) are recovered in the Winter Season, as shown on Line 79 of Schedule 22.

Hampshire Division Base Commodity and Base Hedging costs[9] 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[10] 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. There are no refunds included in this filing.

F. <u>2013 – 2014 Winter Season Reconciliation</u>

Q. Please explain the 2013 / 2014 Winter Season over and under-collections.

A. The 2013 / 2014 Winter Season COG Adjustment Reconciliation ("Reconciliation") was filed with the Commission on July 31, 2014. The Reconciliation provides a detailed explanation of the Winter Season's over-collection of ($3,607,559) as of April 30, 2014, and is included in this filing as Schedule 15.

G. <u>Miscellaneous Charges and Credits</u>

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

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

Q. Are you projecting that Northern will receive any Re-Entry Fee Credits from transportation customers returning to sales service during the 2014 / 2015 Winter Season?

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

Q. Are proposing to recover any PNGTS litigation expenses in the filing?

A. Northern has incurred no additional PNGTS litigation expenses since the 2013/ 2014 Winter Period COG proceeding. Mr. Wells provides additional information on the status of the PNGTS rate cases in his testimony.

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

The Working Capital Costs were based on the Working Capital Allowance of 0.0824% which was approved in Northern's most recent base rate proceeding, Docket No. DG 11-069. This percentage, when multiplied by the forecasted Peak Period Direct Cost of Gas yields a Working Capital Cost of $31,270. This amount is included in the Summary Schedule at line 34.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2014 / 2015 Winter Season COG?

A. First, a total Bad Debt forecast over 12 months was developed for both supply and distribution. This forecast is based on actual experience.

As shown on Line 3 of Schedule 4 for the 12-months ended July 31, 2014, actual write-offs for Northern's New Hampshire Division were $573,318. For 2014 / 2015, Northern projects annual Bad Debt expense to be $700,000 (Line 17).

The annual Bad Debt forecast was then allocated to supply (55%) and distribution (45%) based on the actual Bad Debt experience of these components over the 12-months ended July 2014. This is shown on Lines 7 and 5, respectively, of Schedule 4. The annual Bad Debt forecast for supply ($385,495), as shown on Line 18, was then allocated further to the 2014 / 2015 Winter Season (92%) and 2014 Summer Season (8%) based on the actual Bad Debt experience of the respective seasons, as shown on Lines 11 and 13. This breakout establishes the Winter Season Bad Debt of $356,153 (Line 19). I have included this expense at line 41 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 last 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, $416,811 is recovered from sales customers in the Winter Season. These amounts are included in the Summary Schedule on lines 45 and 47.

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2014 / 2015 Winter Season.

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 2014 / 2015 Winter COG factors. The text descriptions in Column D, pages 2 & 4 explain the calculations on this tariff page and 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 2014 / 2015 Winter Season 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 2014 / 2015 Winter Season, the projected Average Cost of Gas is $1.1069 per therm (Line 73), which is the sum of the average Total Direct Cost of Gas, $1.1847 per therm (Line 66) and the average Indirect Cost of Gas, ($0.0778) per therm (Line 70).

Q. What are the major components of the 2014 / 2015 Winter Season 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	$3,149,210	3
2	Purchased Gas Supply Costs	$20,393,655	4
3	Storage and Peaking Capacity Costs	$14,197,961	7
4	Storage and Peaking Commodity Costs	$4,932,932	8
5	Hedging (Gain) / Loss	$27,935	10
6	Inventory Financing	$6,234	14
7	Capacity Release and AMA revenue	($4,741,845)	16
8	Total Anticipated Direct Cost of gas	$37,966,081	20

Q. What are the major components of the 2014 / 2015 Winter Season 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	$(3,607,559)	24
2	Interest	$10,648	26
3	Refunds	$0	27
4	Interruptible Margins	$0	28
5	Working Capital Allowance	$29,474	38
6	Bad Debt Allowance	$237,646	43
7	Local Production and Storage	$420,658	45
8	Miscellaneous Overhead	$416,811	47
9	Total Anticipated Indirect Cost of Gas	$(2,492,322)	49

Q. Please explain the calculation of the Working Capital allowance.

The total Working Capital allowance, $29,474 is shown on Line 38 of the Summary Schedule is the sum of the current period working capital allowance, $31,270 (Line 34), plus the prior Winter Season Working Capital reconciliation balance, ($1,796) (Line 36).

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

A. The Bad Debt allowance, $237,646 (Line 43), is the sum of the current period bad debt allowance, $356,163 (Line 41), plus the prior Winter Season Bad Debt reconciliation balance, $(118,517) (Line 42).

I. Summary Analyses

Q. How does the proposed 2014 / 2015 Winter Season COG rate compare to the actual 2013 / 2014 Winter Season COG?

A. I have prepared Schedule 9 to compare the proposed 2014 / 2015 Winter Season average COG to the actual 2013 / 2014 Winter Season COG. Schedule 9 indicates the projected 2014 / 2015 Winter Season average COG rate, $1.1069 per therm, is $0.3011 per therm higher than the actual 2013 / 2014 Winter Season Total Adjusted COG, $0.8058 per therm. This $0.3011 per therm increase is primarily due to the higher demand and commodity costs and a smaller prior period negative/credit reconciliation balance that occurred in the 2013 / 2014 Winter Season.

III. ADDITIONAL SCHEDULES AND SUPPLIER BALANCING CHARGE

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

A. Yes, Schedules 3, 19, 23 and 24. Schedule 3 determines Northern's projected over/under-collections, balances, and interest calculations. Schedule 19 calculates the capacity assignment percentages for capacity eligible transportation customers. Schedule 23 provides additional detail to the proposed tariff sheets. Lastly, Schedule 24 determines Northern's short term debt limit calculation for the period November 2014 through October 2015.

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2014 through October 31, 2015?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2014, $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.

IV. FINAL MATTERS

Q. Will the Company propose to revise the 2014 / 2015 Winter Season 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 2014 / 2015 Winter Season 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 November 1, 2014.

Q. Does this conclude your testimony?

A. Yes it does.