NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
WINTER PERIOD 2011 / 2012
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 almost twenty years. Before joining Unitil this past January, I was employed as an Analyst with Columbia Gas of Massachusetts[1]

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[1] Columbia Gas of Massachusetts, a subsidiary of NiSource, operated under the name Bay State Gas Company until it was renamed in 2010.

("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. I have not. However, I have testified before the Federal Energy Regulatory Commission on behalf of Granite in the Wells LNG facility certificate proceedings (CP96-610, et al.) when Granite (and Northern) was a subsidiary of Columbia.

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

A. I, Francis X. Wells, Senior Energy Trader for Unitil Service, and Joseph F. Conneely, Senior Regulatory Analyst for Unitil Service, are sharing the responsibility in this proceeding for supporting Northern's proposed New Hampshire 2011/ 2012 Winter Season Cost of Gas ("COG") and other proposed rate adjustments.

Mr. Wells will sponsor, describe and explain the customer demand forecast and the resulting forecasted gas sendout and gas costs he developed for the Maine and New Hampshire Divisions. He will also describe the impact of the Company's Hedging Program for the 2011 / 2012 Winter Season.

Mr. Conneely will sponsor, discuss and explain the calculation of the 2011 / 2012 Local Distribution Adjustment Clause ("LDAC"), the New Hampshire Division 2010 / 2011 Winter COG Reconciliation filing and typical bill impact analyses of the proposed Winter Season New Hampshire Division COG rates.

I will sponsor, describe and explain the calculation of the New Hampshire Division COG rates Northern proposes to bill from November 1, 2011 to April 30, 2012.

Q. How does your testimony differ from that submitted and sponsored by Mr. James Simpson on behalf of Northern in Docket No. DG 10-250, the 2010 / 2011 Winter Season COG?

A. Overall, my testimony is quite similar to his with some minor edits. However, I do propose three substantive changes.

First, I used the results of the 2011 lead-lag study filed in Northern's rate case proceeding, Docket No. DG 11-069, by Mr. Paul Normand on behalf of the Company. I used these results to develop the purchased gas Working Capital Allowance to be recovered in the 2011 / 2012 Winter Season COG[2]. Second, I used a forecast of Bad Debt expense based on actual experience and not on a fixed percentage of Winter Season gas costs which is a proxy or estimate for Bad Debt. This change reflects the testimony sponsored by the Company's witness Mr. George Gantz, Senior Vice President, filed in

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[2] The Working Capital Allowance developed from the lead lag study used in prior COG filings was determined in Docket No. DG 01-182.

Docket No. DG 11-069[3]. Third, I used updated costs associated with the Company's local production facilities, LNG and LP, as proposed by Mr. Normand in Docket No. DG 11-069 to be recovered in the 2011 / 2012 Winter Season COG.

I will describe and explain these changes in more detail later in my testimony.

Consistent with the Company's filing in Docket No. DG 11-069, I have included these changes in this Winter Season COG filing due to the implementation of new base rates, initially in the form of temporary rates in that proceeding, on August 1. It is the intention of the Company to synchronize the implementation of new base rates with these changes in the COG by applying the change to the COG reconciliation model for the month in which the base rate change takes place.

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) / Undercollection Balances and Interest Calculations

[3] The fixed percentage used in prior COG filings was determined in Docket No. DG 01-182.

Schedule 9	Variance Analysis / Comparison to 2010-2011 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 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. 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 to the rate classes.

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

A. <u>Allocation of Demand-Related Costs to the Maine and New Hampshire Divisions</u>

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. 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 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 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 costs to the Maine and New Hampshire Divisions for the 2011 / 2012 Winter Season, i.e. November 2011 through April 2012, and for the 2012 Summer Season, i.e. May through October 2012.

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4 Pipeline, storage, and peaking

5 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 2010 through April 2011, adjusted to reflect design winter conditions from November through April and normal conditions from May through October.

Q. Please give an overview of the process that you followed to allocate total Northern demand costs for the period November 2011 through October 2012 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 2011 through October 2012 ("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 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 the total Northern annual projected demand costs for Pipeline, Storage, and Peaking resources; these 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 in Lines 8 and 9 of Schedule 21. Further, as shown on Schedule 21 Line 7, Northern's share of litigation costs that have been incurred by the Portland Natural Gas Transmission System ("PNGTS") Shippers Group ("PSG") in the PNGTS rate case, RP10-729, from mid-August 2010 through July 2011 is $878,224.82[7]. For the purpose of incorporating this PNGTS Litigation Expense into the COG rates, which is discussed in Mr. Well's testimony, I have reflected these costs as an offset to expected Asset Management revenues throughout the attachments to my testimony.

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; these Injection Fees are added to

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6 The forecast of demand costs that Mr. Wells prepared is provided in Schedule 5.
7 A small portion of these costs are related to PNGTS' prior rate case – RP08-306.

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) $1/5^{th}$ of total Capacity Release revenues are allocated to each month from November through March, as shown on Line 54; and (b) $1/6^{th}$ of total Asset Management revenues, net of Northern's share of the PSG litigation costs, 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 net of Northern's share of PNGTS litigation costs, 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 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 conditions from May 2010 through April 2011.

As shown on Line 90 of Schedule 21, 47.35% of Northern's total demand costs from November 2011 through October 2012 will be allocated to the New Hampshire Division and the remaining 52.65%, 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 2011 / 2012 Winter Season and the 2012 Summer Season.

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 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 2011 through October 2012 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.[8]

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.[9] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2012[10] 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; and (b) Storage and Peaking costs related to Firm Sales customers for twelve months, i.e., November 2011 through October 2012. 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 2011 through April 2012. These PR factors are

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8 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).

9 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.

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

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 demand costs to be recovered in the 2011 / 2012 Winter Season COG rates, $14,508,348, 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 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 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. These 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 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

D. <u>Allocation of Variable Costs</u>

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[11] 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 2011 / 2012 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 11, and Lines 18 through 20 of Schedule 22. The pipeline commodity costs shown on Lines 11 and 18 are based on projected NYMEX prices as of September 6, 2011. Lines 23 through 30 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 30 and 40 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 54, 55, 59 and 60. Gains and losses based on the price-triggered hedging program are shown on Lines 31

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

through 37; these 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 65, 67, 68, and 69; New Hampshire Division: Lines 74, 76, 77, and 78); and (b) hedging gains and losses (Lines 66 and 75) to the Maine and New Hampshire Divisions. Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 99 to 101); the allocation of these costs to the Maine and New Hampshire Divisions (Lines 104 to 106), 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 115 to 117).

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 71, 80, and 89.

A. The inventory finance charges that are shown on Lines 71, 80, and 89 of Schedule 22 are derived from the inventory finance costs that are shown on Lines 99 and 100 of Schedule 22[12]. These inventory finance costs were calculated based on forecasted inventory activity calculations which are shown in Schedule 14.

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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 99 through

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 2012, the Company does not incur inventory finance costs on the Washington 10 inventories, and the Company anticipates contracting for similar terms beginning April 1, 2012. 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 51 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[14] to each rate class. A summary of all

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101. Total 2011/2012 inventory finance costs allocated to New Hampshire (Line 105) are recovered in the Winter Season, as shown on Line 80 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.

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

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. The Company is projecting no refunds in this filing.

F. 2010 – 2011 Winter Period Reconciliation

Q. Please explain the 2010 / 2011 Winter period over and under-collections.

A. The 2010 / 2011 Winter Season COG Adjustment Reconciliation (Form III) sponsored by Mr. Conneely and filed with the Commission on July 29, 2011 provides a detailed explanation of the Winter Season undercollection of $973,628 as of April 30, 2011.

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 2011 / 2012 Winter Season?

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

Q. Has the Company proposed a Working Capital Allowance different from that used in prior Winter Seasons?

A. Yes. As previously stated, the Company has included a change in the Working Capital Allowance ("WCA") in this filing with the implementation of new base rates in Docket No. DG 11-069, initially in the form of temporary rates on August 1. It is based on the

Company's 2011 lead-lag study sponsored in the testimony of Mr. Paul Normand on behalf of the Company in Docket No. DG 11-069. In that study, the lag is 9.25 days which is 2.53% of a year. This percentage when multiplied by the Working Capital Carrying Charge Rate, a.k.a., the monthly prime lending rate, 3.25%, yields a WCA% of 0.0824%.

Q. Does Northern propose to submit any new tariff pages in order to reflect the change in the WCA%?

A. Yes. Northern has submitted revised tariff Page 21. However, due to Northern's ongoing rate proceeding, DG 11-069, the Company is submitting this page for informational purposes only.

Q. Is the Company proposing to change the calculation of Bad Debt expense ?

A. Yes. As mentioned before, Northern has included a change in the derivation of Bad Debt in this filing with the implementation of new temporary base rates in Docket No. DG 11-069.

In the past, Bad Debt has been calculated by applying a fixed Bad Debt percentage, 0.45 percent, as established in Docket No. DG 97-393, to the total Winter Season forecasted gas costs, including the reconciliations. However, consistent with the testimony of George Gantz in Docket No. DG 11-069, the Company is proposing to base its Bad Debt expense on actual Bad Debt experience which is recorded each month by the accounting department.

Q. Why is Northern proposing to change the way it calculates Bad Debt at this time?

A. There are two reasons for the proposed change. First, when Unitil acquired the accounts receivable files from NiSource in the fall of 2009, the data provided did not breakout Bad Debt related to supply and distribution nor between COG seasons.[15] However, under Unitil, the Customer Information System has the ability to track and determine actual Bad Debt cost at the supply and distribution levels as well as between Winter and Summer Seasons. Actual Bad Debt recoveries are assigned to function and period based upon Company write offs for the current month. I note that Unitil's other subsidiaries apply a similar methodology when recording Bad Debt.

Second, the Company believes recording actual Bad Debt is a fairer method for cost recovery than taking a fixed percentage of purchased gas costs as Bad Debt. Basically, the prior method is a proxy for Bad Debt and the Company believes that including an actual expense is better than using a proxy expense.

Q. How did Northern develop its current projected Bad Debt expense for inclusion in the 2011 / 2012 Winter Season?

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

[15] If an acquired account receivable is written off, the Company assigns the Bad Debt expense to distribution and supply based upon revenue data during the period January through June 2009. The converted supply write off is then assigned to the Winter and Summer Seasons based on actual Company write-offs to these seasons during the current month, i.e., the month in which the converted supply was written off.

As shown in Schedule 3B, for the 12-months ended July 31, 2011, actual write-offs for Northern's New Hampshire Division were $597,000. For 2011 / 2012, Northern projects annual Bad Debt expense to be $650,000.

The annual Bad Debt forecast was then allocated to supply (64%) and distribution (36%) based on the actual Bad Debt experience of these components over the 12-months ended June 2011. The annual Bad Debt forecast for supply ($416,526) was then allocated further to the 2011 / 2012 Winter Season (91%) and 2012 Summer Season (9%) based on the actual Bad Debt experience of the respective seasons. This breakout establishes the Winter Season Bad Debt of $377,457. I have included this expense at line 43 in the summary schedule.

Also, I've included the 2010 / 2011 Winter Season Bad Debt reconciliation, an under-collection of $1,935 in the 2011/ 2012 Winter Season COG. This amount is included in the Summary Schedule at line 44.

I note that the 2010 / 2011 Bad Debt reconciliation, as sponsored by Mr. Conneely, used the fixed-factor method, 0.45%, to determine a Bad Debt expense and reconciled this expense to actual Bad Debt collections.

Q. Does Northern propose to submit any new tariff pages in order to reflect the change in methodology for recording Bad Debt?

A. Yes. Northern has submitted revised tariff pages 21, 24, 28, 29 and 33. As previously mentioned, due to Northern's ongoing rate proceeding, DG 11-069, these tariff pages are being submitted for informational purposes only.

Q. Have you updated the Company's local LNG and LP production and storage capacity costs that are includable in the Winter Season COG?

A. Yes. As mentioned above, Northern has included updated costs in this filing with the implementation of new temporary base rates in Docket No. DG 11-069.

I updated these costs based on Mr. Normand's testimony in Docket No. DG 11-069[16]. Total local production capacity and storage costs are $349,700 all of which is assigned to the Winter Season. In addition, These Other Administration and General ("A&G") expenses related to local production and storage costs are $440,825. Of this amount, 79.31% is assigned to the winter. Cost for local production and capacity storage costs, and A&G expenses are shown in the Summary Schedule on line 47 and 49. I note these costs are lower than those included in prior Winter Season COGs.[17]

Q. Does Northern propose to submit any new tariff pages in order to reflect the change in local production capacity and storage costs?

A. Yes. Northern has submitted revised tariff Page 21 for informational purposes only.

H. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division COG factors for the 2011 / 2012 Winter Season.

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[16] The costs based on Mr. Normand's testimony were subsequently updated in Northern's response to a data request from the Maine Public Advocate (OPA 5-8) in Docket No. 2011-92.
[17] Prior costs were determined in Docket No. DG 01-83.

A. The Summary Schedule, which is similar to the Company's COG tariff Pages 38 and 39, has been prepared to explain the calculation of the proposed 2011 / 2012 Winter COG factors. The text descriptions in the added column: (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 38 and 39. This Summary Schedule shows the calculation of the 2011 / 2012 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 2011 / 2012 Winter Season, the projected Average Cost of Gas is $1.1431 per therm (Line 81), which is the sum of the average Total Direct Cost of Gas, $1.071 per therm (Line 74) and the average Indirect Cost of Gas, $0.0744 per therm (Line 78).

Q. What are the major components of the 2011 / 2012 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	$2,738,878	3
2	Purchased Gas Supply Costs	$8,752,088	4
3	Storage and Peaking Capacity Costs	$14,137,610	7
4	Storage and Peaking Commodity	$6,076,270	8

	Costs		
5	Hedging (Gain) / Loss	$506,830	10
6	Inventory Financing	$7,294	12
7	Capacity Release and AMA revenue net of PNGTS Litigation Costs	($1,612,415)	16
8	Total Anticipated Direct Cost of gas	$30,606,554	20

Q. What are the major components of the 2011 / 2012 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) / Undercollection	$973,628	24
2	Interest	$74,037	26
3	Refunds	$0	27
4	Interruptible Margins	$0	28
5	Working Capital Allowance	($10,008)	38
6	Bad Debt Allowance	$279,232	51
7	Local Production and Storage	$349,700	53
8	Miscellaneous Overhead	$349,601	55
9	Total Anticipated Indirect Cost of Gas	$2,016,190	57

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

The total Working Capital allowance, ($10,008) is shown on Line 38 of the Summary Schedule is the sum of the current period working capital allowance, $25,220 (Line 34), plus the prior Winter Season Working Capital reconciliation balance, ($35,228) (Line 36).

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

A. The Bad Debt allowance, $279,232 (Line 51), is the sum of the current period bad debt allowance, $277,297 (Line 49), plus the prior Winter Season Bad Debt reconciliation balance, $1,935 (Line 50).

I. Summary Analyses

Q. How does the proposed 2011 / 2012 Winter Season COG rate compare to the actual 2010 / 2011 Winter Season COG?

A. I have prepared Schedule 9 to compare the proposed 2011 / 2012 Winter Season average COG to the actual 2010 / 2011 Winter Season COG. Schedule 9 indicates the projected 2011 / 2012 Winter Season average COG rate ($1.1400 per therm) is $0.0498 per therm lower than the actual 2010 / 2011 Winter Season Total Adjusted COG ($1.1720 per therm). The overall change in the proposed 2011 / 2012 Winter Season average rate compared to the 2010 / 2011 Winter Season actual average rate is primarily due to increases in pipeline demand and commodity costs offset by decreases in peaking demand costs, hedging losses, prior period balance, local production and miscellaneous overhead.

III. ANCILLARY RATES

Q. Have you updated the Supplier Balancing Charge for the period November 1, 2011 through October 31, 2012?

A. Yes, I have. The proposed Supplier Balancing Charge to be effective November 1, 2011, $0.78 per MMBtu, is three cents higher than 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 2011 / 2012 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 2011 / 2012 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, 2011.

Q. Does this conclude your testimony?

A. Yes it does.