**NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
SUMMER PERIOD 2011
COST OF GAS ADJUSTMENT FILING
PREFILED TESTIMONY OF
JAMES D. SIMPSON**

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is James D. Simpson. I am a Senior Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Marlborough, Massachusetts 01752.

Q. Please describe your relevant work experience.

A. I have over 30 years experience in the energy industry in a variety of roles and responsibilities with an overall focus on economics, pricing, forecasting and regulatory matters. I was employed by Bay State Gas Company ("Bay State") from 1982 until 2000; for much of that time, I was responsible for rates and regulatory affairs for Bay State and Northern Utilities, Inc. ("Northern" or "Northern Utilities"). I have been with Concentric Energy Advisors ("Concentric") since 2005. My professional qualifications and experience are provided in Attachment-1 to this testimony.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I testified on behalf of Northern Utilities in the 2009 Summer Cost of Gas proceeding, Docket No. DG 09-052, the 2009 / 2010 Winter Cost of Gas ("COG") proceeding, Docket No. DG 09-167,the 2010 Summer Cost of Gas proceeding, Docket No. DG 10-050, and the 2010 / 2011 Winter Cost of Gas proceeding, Docket No. DG 10-250. In addition, while I

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was employed by Bay State, I testified before the Commission on behalf of Northern Utilities in many proceedings on a variety of issues related to rates, growth-related projects and other economic and regulatory matters.

Q. Please explain the purpose of your prefiled direct testimony in this proceeding.

A. I will describe and explain the calculation of the COG that Northern Utilities proposes to bill for service rendered from May 1, 2011 to October 31, 2011. In addition to my testimony, the testimonies of Francis X. Wells, Senior Energy Trader for Unitil and Joseph F. Conneely, Senior Regulatory Analyst for Unitil will describe and explain the 2011 Summer New Hampshire Division COG rate adjustments that the Company is proposing to make effective May 1, 2011. Mr. Wells will describe and explain the forecast of gas demand and the resulting forecasted gas sendout and gas costs that he developed for the New Hampshire and Maine divisions. Mr. Wells will also describe the impact of the Company's Hedging Program for the 2011 Summer period. Mr. Conneely will discuss the New Hampshire 2010 Summer Cost-of-Gas Reconciliation Filing and analyses of the proposed Summer COG rates on typical bills.

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Q. Have you prepared any schedules in support of the Summer COG rate calculations?

A. Yes. The schedules that I prepared in support of the Summer COG rate calculations are listed below.

Attachment-1	James D. Simpson Professional Qualifications
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
Schedule 9	Variance Analysis / Comparison to 2010 Off-Peak
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

A. Cost of Gas Factor

Q. Please explain the calculation of the proposed New Hampshire Division Cost of Gas factors for the 2011 Summer period.

A. The Summary Schedule, which tracks COG tariff pages 38 and 39, has been prepared to explain the calculation of the proposed 2011 Summer COG factors. The text descriptions in Column A of the Summary Schedule explain the calculations on this page, and the text descriptions in Column D provide references to other schedules for the sources of the data

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that appear on COG tariff Pages 38 and 39. Summary Schedule Page 2 of 4 shows the calculation of the 2011 Summer period COGs for each of Northern's three COG Rate Groups (1) Residential classes R-1 and R-2, (2) C&I Low Winter period use classes G-50, G-51 and G-52; and (3) C&I High Winter period use classes G-40, G-41 and G-42.

As shown on Summary Schedule for the 2011 Summer period, the projected Average Cost of Gas is $0.6354 per therm (Line 76), which is the sum of the Average Direct Cost of Gas, $0.6067 per therm (Line 69), and the Average Indirect Cost of Gas, $0.0287 per therm (Line 73).

Q. What are the major components of the 2011 Summer Anticipated Direct Cost of Gas?

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

	Direct Cost Component	Anticipated Direct Gas Costs	Summary Schedule, Line:
	Purchased Gas Demand Costs	497,292	3
	Purchased Gas Supply Costs	$3,441,521	4
	Storage and Peaking Capacity Costs	$701,178	7
	Storage and Peaking Commodity Costs	$25,185	8
	Hedging (Gain) / Loss	$72,585	10
	Interruptible Costs	$0	12
	Capacity Release	$0	14
	Total Anticipated Direct Cost of gas	$4,737,762	18

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Q. What are the major components of the 2011 Summer Anticipated Indirect Cost of Gas?

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

	Indirect Cost Component	Anticipated Indirect Gas Costs	Summary Schedule, Line:
	Prior Period (Over) / Undercollection	$124,276	22
	NHPUC Consultant Costs	$28,990	23
	Interest	$2,150	24
	Refunds	$0	25
	Interruptible Margins	$0	26
	Working Capital Allowance	$(4,824)	35
	Bad Debt Allowance	$25,016	47
	Local Production and Storage	$0	49
	Miscellaneous Overhead	$25,964	51
	Total Anticipated Indirect Cost of Gas	$201,572	53

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Q. Please explain the Indirect Cost Component that is identified as "NHPUC Consultant Cost".

A. The NHPUC engaged a consultant, Jay Kumar, to participate in the Granite State Gas Transmission rate case at FERC, RP 10-896; Mr. Kumar's charges for consulting services, $33,744.31, was paid by the Company. The NHPUC Consultant Costs of $28,990 on line 23 of the Summary Schedule represents the New Hampshire sales service customers' share of the total costs of Mr. Kumar's consulting services. I have prepared Schedule 3, page 3 to show the details of the Company's payments for Mr. Kumar's invoices and the allocation of the total costs of Mr. Kumar's consulting services to New Hampshire sales and assigned transportation customers. The sales service customers' share of Mr. Kumar's charges by month that is developed in Schedule 3, page 3 is also shown in Schedule 3, page 2, line 98.

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

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The total Working Capital allowance, $(4,824) shown on Line 35 of the Summary Schedule is the sum of the current period working capital allowance, $2,670 (Line 32) plus the prior period Working Capital reconciliation balance, $(7,494) (Line 33).

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

A. The Bad Debt allowance of $25,016 (Line 47) is the sum of the current period bad debt allowance, $21,857 (Line 44) plus the prior period Bad Debt reconciliation balance, $3,159 (Line 46).

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B. Summary Analyses

Q. How does the proposed 2011 Summer period COG rate compare with the 2010 Summer period COG rate?

A. I have prepared Schedule 9 to compare the proposed 2011 Summer COG with the 2010 Summer COG. Schedule 9 indicates that the proposed 2011 Summer period COG rates are lower than the 2010 Summer period COG rates. The overall change in the proposed 2011 Summer rate compared to the 2010 Summer period is primarily due to changes in (1) gas costs and hedging gains / losses; (2) forecasted sales and sendout volumes, and (3) prior period over / undercollection balances. As shown in Schedule 9 Line 32, Total 2011 Summer gas costs are lower than 2010 Summer gas costs by approximately $123,000.

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

Q. Please explain how the projected fixed capacity-related costs, i.e. (a) pipeline reservation and gas supply demand charges, (b) underground storage capacity costs

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and (c) peaking resource capacity costs are allocated between Northern's New Hampshire and Maine divisions.

A. Total Northern capacity-related costs are allocated between the New Hampshire and Maine divisions by application of the Modified Proportional Responsibility ("MPR") methodology. The MPR methodology allocates fixed capacity-related gas costs to the New Hampshire and Maine divisions in a two-step process: (1) total Northern capacity-related costs, by resource type[1], are allocated to months by application of MPR allocation factors, and (2) the capacity-related costs allocated to each month are allocated to the New Hampshire and Maine divisions based on the relative shares of Design Year demand[2] in that month. This MPR methodology was orally 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 DG 05-080 granting written approval of the MPR methodology.

Q. Please provide a summary of the process that you followed to allocate total Northern demand costs for the period November 2010 through October 2011 to the New Hampshire and Maine divisions.

A. The allocation of total Northern capacity-related costs between the New Hampshire and Maine divisions is determined in each Winter period filing, according to the MPR methodology. Schedule 21 demonstrates how I calculated the MPR factors and then how I used these factors to allocate total Northern annual demand costs for the period November

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

2 For the MPR allocation process, Design Year demand is calculated as the actual demand to New Hampshire and Maine firm sales and assigned capacity/non-grandfathered transportation customers for the period May, 2009 through April 2010, adjusted to reflect design year conditions.

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2010 through October 2011 ("2010 / 2011 COG Period") to the New Hampshire and Maine divisions. Schedule 21 is identical to the Schedule 21 that was filed by letter dated October 15, 2011 in the Company's 2010 / 2011 Winter COG proceeding, Docket No. DG 10-250.

Schedule 21 is arranged in three major sections: In Section (1), total fixed capacity costs, by type of resource (pipeline, storage, and peaking) are summarized in Lines 1 through 10. In Section (2), these fixed capacity costs for each resource type are allocated to each month in the 2010 / 2011 COG Period according to MPR allocators that were developed specifically for each resource type as shown on Lines 13 through 56 (shown on pages 2 and 3); the MPR allocators are based on design year sendout volumes for each resource type. In Section (3), the fixed capacity costs that are allocated to each month in Step 2 are then allocated to the New Hampshire and Maine divisions according to design year total firm sendout as shown in Lines 58 through 90. As shown in Schedule 21 page 3, line 90, the allocation of Northern's capacity-related costs to New Hampshire for the twelve months beginning November 2010 is 48.64%.

Q. In the last response you stated that the current version of Schedule 21 is identical to the version of Schedule 21 that was filed by letter dated October 15, 2010 in the Company's 2010 / 2011 Winter COG proceeding, Docket No. DG 09-167. Please explain this.

A. As I explained in my previous response, total Northern capacity-related costs are allocated between the New Hampshire and Maine divisions by application of the Modified Proportional Responsibility ("MPR") methodology. According to the MPR methodology,

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capacity-related allocators are determined every Winter period filing based on actual demand for gas, adjusted to design year effective degree days for the most recent twelve months ended April. Thus, the allocation of Northern capacity-related costs to New Hampshire and Maine divisions in each Summer filing will be identical to the allocators that were determined in the prior Winter COG filing.

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

Q. Please explain how the capacity-related costs to be recovered in the 2011 Summer period are determined.

A. Schedule 1A provides detailed support for the allocation of New Hampshire Sales Customer demand costs to the Summer period.

Lines 2 through 4 of Schedule 1A summarize (1) Pipeline and (2) 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 New Hampshire less the capacity assignment revenues from New Hampshire transportation customers. For the 2010 / 2011 Winter period filing, Mr. Wells calculated the capacity assignment revenue credit. Mr. Wells' calculations were provided in the 2010 / 2011 Winter period filing dated October 14, 2010, in Revised Schedule 5B, Page 1 of 6. As shown on Schedule 1A, Page 4, line 76, the Summer period gas costs do not include capacity assignment revenues; all capacity assignment revenues are credited to the Winter Cost of Gas.

The Summer rates that will be charged to New Hampshire firm sales customers from May through October 2011 will recover the portion of the following demand-related costs that

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are allocated to the 2011 Summer period: (1) the Net Pipeline Demand costs shown on Line 20 and (2) the Net Storage and Peaking demand costs shown on Line 21 and 22 of Schedule 1A. 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.[3] The Base Use that is shown on Line 32 of Schedule 1A is the average projected daily use in July and August 2011[4], for all firm sales classes; the Base 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 Net Pipeline Demand costs for sales customers, which is the difference between total net pipeline demand costs and base use pipeline demand costs.

Schedule IA, Pages 3 and 4, Lines 45 through 50 show the calculation of the PR factor that is used to allocate (a) Remaining Net Pipeline Demand costs, (b) Storage and Peaking costs, and (c) Other A&G expense related to Firm Sales customers to the twelve months, November 2010 through October 2011. Lines 52 through 57 of those pages show the calculation of the PR factor that is used to allocate (d) Capacity Release and Asset Management revenues, (e) Interruptible margins and Delivery-to-Sales revenues and (f) Local Production and Storage costs to the six Winter months, November 2010 through April 2011. These PR factors are summarized by type of capacity cost in lines 61 through 65 of Schedule 1A, Pages 3 and 4. Line 69 of of those pages shows that one twelfth of the Net annual base use pipeline demand costs are allocated to each month and Lines 70 through 85

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3 This separation is necessary because the SMBA allocation methodology assigns base use demand costs and remaining demand costs to seasons using different allocators.

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

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show the detailed allocation to months of all components that are included in the Total Net Demand Costs, based on the "All Months" and "Peaking Months Only" allocation factors.

The total anticipated direct demand costs to be recovered in the 2011 Summer COG rates, $1,198,470, is shown on Schedule 1A, Page 4, Line 80. Each Summer month, May through October 2011, one-sixth of that total, $199,745, will be recorded as Summer capacity-related costs.[5]

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

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

A. The New Hampshire Division sales service base demand-related costs for each month are allocated to each sales service rate class based on that class's pro rata share of total forecasted firm sendout to sales customer 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.

Schedule 10B shows the calculation of the factors that are used to allocate New Hampshire Division sales service Summer period 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 (a) daily base use,

5 Each Summer month, the difference between total invoiced capacity-related costs and the Summer portion of $177,203 will be recorded as Winter period capacity-related costs.

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shown on Schedule 10B, Page 3, Lines 35 to 48; (b) base sendout, shown on Lines 49 to 64; and (c) remaining sendout, shown on Lines 66 to 80. These base and remaining sendout values for each class are used to allocate the Summer period demand costs to New Hampshire Division firm sales classes.

Schedule 10A shows the allocation of Summer period New Hampshire Net Demand costs to each firm sales rate class, based on (a) the New Hampshire Net Demand costs that are allocated to each Summer period month as shown in Schedule 1A, Lines 67 through 85 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 Demand	Lines 24 through 37
Remaining Pipeline Demand	Lines 50 through 66
Peaking and Storage Demand	Lines 68 through 84
Capacity Release and Asset Management	Lines 86 through 102
Interruptible 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 170

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The Summer total capacity-related costs shown on Line 166, $1,198,470, is the same as the Summer period capacity-related costs to be recovered during the Summer period, as determined in the 2010 / 2011 Winter COG Filing, Schedule 1A, line 80.

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F. Allocation of Variable Costs

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

A. Variable costs include commodity costs and variable pipeline and storage costs[6] 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 New Hampshire and Maine divisions based on each division's percentage of monthly firm normal sendout. Schedule 22 shows the allocation of the 2011 Summer period variable gas costs between the New Hampshire and Maine divisions.

Q. Please explain Schedule 22 in more detail.

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 18 through 20 of Schedule 22. The pipeline commodity costs shown on line 18 are based on projected NYMEX prices as of April 12, 2011. Lines 23 through 37 show the estimated gains and losses based on the Company's hedging program then in effect, and the projected NYMEX prices. As Mr. Wells has explained, the Company's hedging program applies to the Summer months of May and October only[7]. The variable gas costs that are summarized on

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6 Specifically, variable costs include Pipeline usage / commodity charges, Pipeline fuel retention, Storage commodity injection and withdrawal charges, and Storage Fuel retention.

7 In addition, the Company's hedging program applies to all six Winter period months, November through April.

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Lines 45, 46, and 47and the time triggered hedging gains and losses[8] for firm sales service that are summarized on Line 30 are allocated to New Hampshire and Maine based on projected monthly firm sales sendout in each division; the allocators are shown on Lines 59 and 60.[2] Schedule 22 also shows the allocation of (a) Commodity costs (Maine: Lines 65, 67, and 68; New Hampshire: Lines 74, 76, and 77); and (b) hedging gains and losses to Maine (Line 66) and New Hampshire (Line 75). Finally, Schedule 22 shows the inventory finance costs for underground storage and LNG resources (Lines 99 to 101); the allocation of these costs to New Hampshire and Maine (Lines 104 to 106) and the allocation of New Hampshire's allocated share of annual inventory finance costs to the Winter period, using the firm sales remaining sendout allocators (Lines 115 to 117).

Schedule 1B summarizes 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 the New Hampshire Division variable gas costs for sales customers are allocated to each firm sales class.

A. Schedule 10C shows 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 to each rate class. Lines 51 to 70 show the calculation

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8 In addition, the price-triggered
9 There are no price-triggered hedging contracts for the summer months

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 to each rate class. A summary of all commodity costs allocated to New Hampshire firm sales classes is shown on Lines 99 to 140.

G. (Over) / Undercollection Balances

Q. Have you prepared a schedule to show (Over) / Undercollection balances throughout the period October 2010 through October 2011?

A. Yes, I have prepared Schedule 3 to show monthly (Over) / Undercollection balances and associated interest calculations for Direct Gas costs, Working Capital allowance and Bad Debt allowance.

H. Refunds

Q. Are there any refunds included in this filing?

A. No, there are no refunds included in this filing.

I. 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 Summer period?

A. No. Northern is not projecting any Re-Entry Fee Credits in this period.

III. FINAL MATTERS

Q. Will the Company revise the COG if it receives any new or updated information on supplier or transportation rates?

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A. Yes. The Company plans to file a revised calculation of its 2011 Summer Period COG to reflect updated gas cost projections and/or other information a few weeks prior to the effective date of May 1, 2011.

Q. Does this conclude your testimony?

A. Yes it does.